bp

Energy with purpose

BP Annual Report and Form 20-F 2019

Our purpose is reimagining energy for people and our planet.

We want to help the world reach net zero and improve people’s lives.

We will aim to dramatically reduce carbon in our operations and production and grow new low carbon businesses, products and services.

We will advocate for fundamental and rapid progress towards Paris and strive to be a leader in transparency.

We know we don’t have all the answers and will listen to and work with others.

We want to be an energy company with purpose; one that is trusted by society, valued by shareholders and motivating for everyone who works at BP.

We believe we have the experience and expertise, the relationships and the reach, the skill and the will, to do this.

Strategic report

Corporate governance

Financial statements

Navigating our reports

Our fast read
provides a concise summary of the annual report, highlighting strategy, performance and sustainability information.

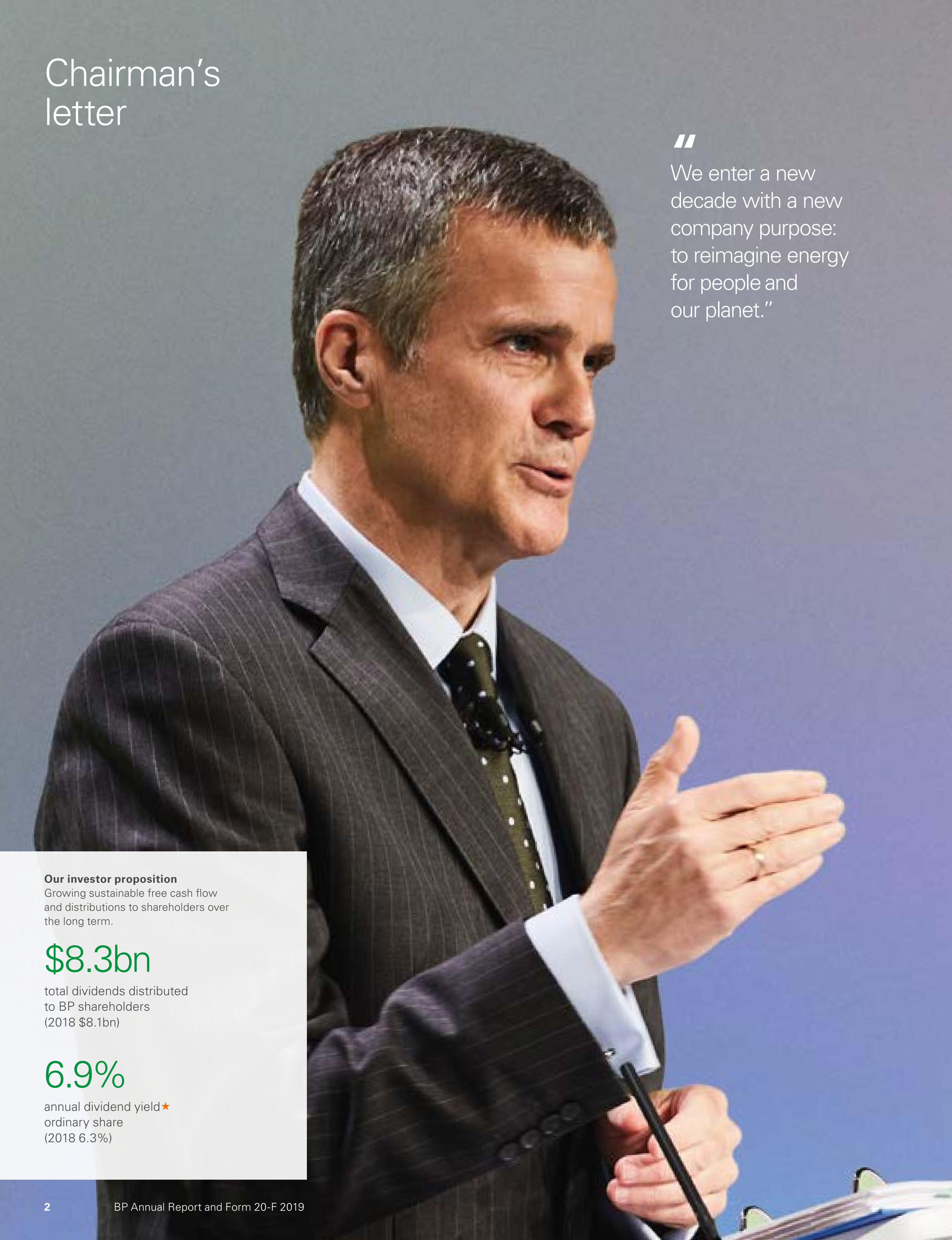
i *bp.com/annualreport.*

Our reporting centre
brings together all our key reports, including our sustainability report, as well as other reports on how we see the energy market evolving in the future.

i *bp.com/reportingcentre.*

Glossary
Like any industry, ours has its own unique language. For that reason, words and terms marked with ★ are defined in the glossary on page 337.

Chairman's letter



"We enter a new decade with a new company purpose: to reimagine energy for people and our planet."

Our investor proposition
Growing sustainable free cash flow and distributions to shareholders over the long term.

$8.3bn
total dividends distributed to BP shareholders (2018 $8.1bn)

6.9%
annual dividend yield★ ordinary share (2018 6.3%)

Dear fellow shareholders,
As I write, the world is facing an unprecedented set of challenges. The coronavirus pandemic (COVID-19) is spreading rapidly, with tragic consequences for many people across many geographies. Global efforts to stop the virus are also having significant economic consequences. And in an oil market where demand has fallen, supply has sharply increased.

Though unprecedented, a global energy company like BP should be prepared for such challenges.

BP is indeed prepared. Our global operating structure and long time-horizons are intended to mitigate the effect of near-term shocks. That is how BP has approached shocks and volatility in its 110-year history, and that is how we will approach this storm too. In particular, the past decade has given BP unique experience in successfully handling crises – and we enter this one even better prepared.

But in this world of change, BP itself is also changing. We enter a new decade with a new company purpose: to reimagine energy for people and our planet. We have also set a new ambition: to become a net zero company by 2050 or sooner, and to help the world get to net zero. And to lead and deliver on both we have a new chief executive officer, Bernard Looney, who took on the role on 5 February 2020.

Evolving for an uncertain world

This is a new direction for BP, and it is only possible because of the foundation laid by Bob Dudley. Bob served as BP's group chief executive with distinction for almost a decade, and he and his team deserve our considerable thanks for guiding BP to a position of operational and financial strength and deepened resilience.

At these times, BP's 110-year history of navigating uncertainty is also reassuring. Your company has anticipated and responded to change many times over. Indeed, throughout 2019 your board has focused on evolving BP's strategy and portfolio to address the challenges of tomorrow. This focus has included ensuring the smooth transition in leadership from Bob to Bernard, followed by regular engagement by the board with Bernard and his new leadership team to develop BP's purpose and net zero ambition. This is a process which has been supported by our dialogue with investors, governments, employees and other key stakeholders.

Our enduring commitments

BP is now set for a future that is different to its past, but some things won't change. BP's values-based culture will be maintained and further developed. BP's purpose and ambition reflect its culture, and together they position BP well to develop as an increasingly sustainable company.

Our commitment to safe and reliable operations will remain paramount. BP's safety performance has seen near continuous improvement since 2010, and we must continue to learn and improve. We believe that the new organizational structure BP set out last month will help to reinforce this commitment.

As well as our enduring commitment to safety, BP's commitment to its relationships and partnerships will not change, including with governments around the world. BP intends to use its energy market experience, skills and technology to help countries, cities and corporations decarbonize, while at the same time building a thriving, lower carbon energy business.

BP's new ambition also gives us extra reason to maintain the capital discipline and focus that has served the company so well. We can only reimagine energy if we generate the cash needed to manage the balance sheet, invest in new low carbon businesses, and continue to pay the dividend on which you, our owners, depend. That is how we will meet our ambition. It is something that I, together with the BP board, look forward to working on with Bernard and his executive team.

Our focus throughout 2020

One of the focal points for the board in 2020 will be BP's capital markets day in September, when Bernard and his leadership team will lay out more detail about the strategy, near-term targets and ways to measure progress. It will be the moment the vision and ambition set out in February becomes much more concrete. We will do this while ensuring that we maintain a strong focus on high quality and efficient operations and on delivering the promises we have made to our investors

My thanks to you all

In addition to thanking Bob, two other departing senior leaders deserve a special mention – chief financial officer Brian Gilvary, who has decided to step down from the board in June after eight years in the job, and Downstream chief executive Tufan Erginbilgic, who leaves BP at the end of March. On behalf of the board, I extend my thanks and my deep appreciation for the profound contributions they each made during an important period for the company.

Of course, each of our employees has a very important role to play in BP's progress, and they should be recognized. On behalf of the board I extend my sincere thanks to all our people for a job well done in 2019.

Today, BP's engagement with its customers, suppliers, shareholders, employees and others is wider and deeper than ever, but it has to further develop as we progress on our journey. I therefore want to use this opportunity to thank you, BP shareholders, for your continued support and engagement during 2019, including through your votes at our AGM in May. Your challenge and input have been important in our effort to set a new strategic direction. I look forward to continuing our dialogue.

Helge Lund
Chairman
18 March 2020

Chief executive officer's letter

Dear fellow shareholders,
As we publish this report, the world is working through extraordinarily difficult times. Countries around the globe are battling the coronavirus pandemic (COVID-19). People's lives are being hugely disrupted, with tragic consequences for many. The financial markets are reflecting the disruption and our sector is particularly hard hit, not just by a virus-related shock to demand but by a supply-side shock as well.

At BP, we are taking calm and deliberate actions for the well-being of our people and the health of your company. We do so with a robust balance sheet, strong liquidity and the flexibility in our portfolio and financial framework that provide us with options.

A resilient company
This resilience is a tribute to Bob Dudley's leadership over the past decade. Following the Deepwater Horizon accident, Bob's steady hand has guided BP through recovery and back to growth as a safer, stronger and more disciplined company – one that has delivered consistently for 12 consecutive quarters on the plan we put forward in 2017.

- We made an underlying profit of $10 billion in 2019.
- Operating cash flow was strong at $26 billion for the year.
- That gave us the confidence to increase our dividend, which currently stands at 10.5c per ordinary share.

During 2019, two colleagues sadly lost their lives while working at BP. My heart goes out to their families and friends. We *must* learn from these tragedies and continue to make BP safer. I believe that we can build on progress that last year saw our lowest-ever figure for BP people getting hurt at work (our recordable injury frequency measure).

Reimagining and reinventing energy
In February, we announced a new purpose for BP, and a major reorganization to deliver our new ambition to be a net zero company by 2050 or sooner and help the world get to net zero.

The current market shocks only reaffirm the need for this reimagining of energy and reinvention of BP. Our current upstream-downstream structure has served us well for over a century, but I believe we now need a different model for the rapidly changing demands of the future. We need an agile, highly integrated structure that is more focused than ever on our core capabilities in operations, customers, low carbon and innovation. The leadership team is working with the board to develop this structure, along with a new strategy and near-term targets, which we intend to share with you in September 2020.

I see huge opportunity for BP given our distinctive combination of reach, resources and relationships. The world will need to invest trillions of dollars in new energies over the next several decades. We have the skill and the will to help the world deliver a rapid energy transition.

Performing while transforming
This may be our most wide-ranging reorganization for more than a century, but I want to assure you of our commitment to perform as we transform. Among many significant changes, however, there will be no change to the fundamental principles that have served us well over the last decade and which apply equally in low price environments as well as high.

Above all, our commitment to safe and reliable operations remains unchanged. Safety will always be a BP core value and we believe that the new structure we are introducing will further strengthen our safety performance.

Our investor proposition will remain unchanged as we lay out new near-term plans later this year. This includes our commitment to growing sustainable free cash flow and returns to shareholders over the long term.

We will continue to maintain a strong financial frame, including a focus on deleveraging our balance sheet and staying within a disciplined frame for our capital expenditure.

And now, more than ever, we will focus on managing costs, pursuing efficiencies and driving waste out of the system.

A force for good and competitive returns
This new decade is a pivotal time for BP. We will continue to be an energy business, but a very different kind of energy business in years to come. We may not get everything right along the way and will need to listen and learn from others, not least you, our owners.

But with your continued support we expect to become leaner, faster-moving, lower carbon – and more valuable.

Our destination is a thriving, sustainable energy business in a net zero world. One that is a motivating and inspiring place to work for our employees. That is wanted as well as needed by society. And one that is valued by you, our shareholders, as a force for good as well as a provider of competitive returns.

Bernard Looney
Chief executive officer
18 March 2020

Profit attributable to BP shareholders

$4.0bn

Nearest GAAP equivalent to underlying profit.

"Our destination is a thriving, sustainable energy business in a net zero world. One that is a motivating and inspiring place to work for our employees."

Reimagining energy

Our purpose is reimagining energy for people and our planet. This will frame our thinking, our activities and our interactions.

Reinventing bp

Introducing a new structure, new leadership team and new ways of working.

Performing while transforming

Our commitment to safe and reliable operations remains unchanged. And our investor proposition remains unchanged.

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

Our ambition for the energy transition

Pursuing a strategy that is consistent with the Paris goals

The world needs a rapid transition to net zero and to reimagine the global energy system. This presents an opportunity for BP to provide the cleaner energy the world wants and needs.

We see opportunities in helping the world decarbonize through new business models and creating cleaner cities. We plan to provide more information on our future strategy and near-term plans at our capital markets day in September 2020.

For more information about how we believe our current strategy is consistent with the Paris goals, see page 17.

Responding to increased shareholder interest

In 2019 the board recommended that shareholders support a special resolution requisitioned by Climate Action 100+ (CA100+) on climate change disclosures.

The CA100+ resolution, which requires BP to respond to a number of different elements, passed with more than 99% of the vote. These responses are contained throughout this annual report.

The CA100+ resolution, which includes safeguards such as for commercially confidential and competitively sensitive information, is on page 337. Key terms related to this resolution response are indicated with ★ and defined in the glossary on page 337. 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	16
How BP evaluates each new material capex investment★ for consistency with the Paris goals and other outcomes relevant to BP's strategy.	Our investment process	19
Disclosure of BP's principal metrics and relevant targets or goals over the short, medium and long term, consistent with the Paris goals.	Measuring our progress	17
Anticipated levels of investment in: (i) Oil and gas resources and reserves (ii) Other energy sources and technologies.	Financial framework	18
BP's targets to promote operational GHG reductions.	Sustainability	40
Estimated carbon intensity of BP's energy products and progress over time.	Sustainability	40
Any linkage between above targets and executive pay remuneration.	Directors' remuneration report 2019 annual bonus outcome 2020 remuneration: Policy on a page	100 105 110

This is supported by 10 aims, which when taken collectively, set out a path that we believe is consistent with the Paris goals.

Five aims to get BP to net zero

Net Zero operations

Aim 1 is to be net zero★ across our entire operations on an absolute basis by 2050 or sooner. This aim relates to Scope 1 and 2 GHG emissions.

For more on our operational emissions, see Sustainability, page 40.

Net Zero oil and gas

Aim 2 is to be net zero on an absolute basis across the carbon in our upstream oil and gas production by 2050 or sooner. This aim relates to Scope 3 emissions, and is on a BP equity share basis excluding Rosneft.

See Sustainability, page 40.

Halving intensity

Aim 3 is to cut the carbon intensity★ of the products we sell by 50% by 2050 or sooner. This is a lifecycle carbon intensity approach, per unit of energy. It covers marketing sales of energy products and potentially, in future, certain other products e.g. associated with land carbon projects.

See Sustainability, page 40.

Reducing Methane

Aim 4 is to install methane measurement at all our existing major oil and gas processing sites by 2023, publish the data, and then drive a 50% reduction in methane intensity of our operations. And we will work to influence our joint ventures to set their own methane intensity targets of 0.2%.

See Modernizing the whole group, page 31.

More $ for new energies

Aim 5 is to increase the proportion of investment we make into our non-oil and gas businesses. Over time, as investment goes up in low and no carbon, we see it going down in oil and gas.

Five aims to help the world get to net zero

Advocating

Aim 6 is to more actively advocate for policies that support net zero, including carbon pricing. We will stop corporate reputation advertising campaigns and re-direct resources to promote well-designed climate policies. In future, any corporate advertising will be to push for progressive climate policy; communicate our net zero ambition; invite ideas; or build collaboration. We will continue to run recruitment campaigns and advertise our products, services and partnerships – although we aim for these to increasingly be low carbon.

See *bp.com/sustainability*.

Incentivizing employees

Aim 7 is to incentivize our global workforce to deliver on our aims and mobilize them to become advocates for net zero. This will include increasing the percentage of remuneration linked to emissions reductions for leadership and around 37,000 employees.

See Directors' remuneration report, page 100.

Aligning associations

Aim 8 is to set new expectations for our relationships with trade associations around the globe. We will make the case for our views on climate change within the associations we belong to and we will be transparent where we differ. And where we can't reach alignment, we will be prepared to leave.

See Sustainability, page 49 and *bp.com/tradeassociations*.

Transparency leader

Aim 9 is to be recognized as an industry leader for the transparency of our reporting. On 12 February 2020, we declared our support for the recommendations of the Task Force on Climate-related Financial Disclosures (TCFD). We intend to work constructively with the TCFD and others – such as the Sustainability Accounting Standards Board – to develop good practices and standards for transparency.

See Sustainability, page 44.

Clean Cities

Aim 10 is to launch a new team to create integrated clean energy and mobility solutions. The team will help countries, cities and corporations around the world decarbonize.

2019 at a glance

Our scale, our reach and range of activities, from exploration to refining and biofuels to solar, make us a truly global energy provider.

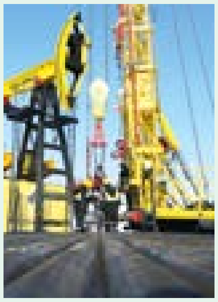
This section gives an overview of BP's structure, scale and performance in 2019. For details of our future structure, see pages 15 and 80.

Upstream

Responsible for oil and natural gas exploration, field development and production, gas and power marketing and trading activities.

Replacement cost (RC) profit before interest and tax
$4.9bn
(2018 $14.3bn)

Underlying RC profit before interest and tax★
$11.2bn
(2018 $14.6bn)



Rosneft

We have a 19.75% shareholding in Rosneft, one of Russia's largest oil and gas companies, which has both upstream and downstream operations.

RC profit before interest and tax
$2.3bn
(2018 $2.2bn)

Underlying RC profit before interest and tax
$2.4bn
(2018 $2.3bn)

Other businesses and corporate

Comprises our Alternative Energy business as well as a number of corporate activities.

RC loss before interest and tax
$(2.8)bn
(2018 $(3.5)bn)

Underlying RC loss before interest and tax
$(1.3)bn
(2018 $(1.6)bn)

Downstream

Comprises the manufacturing and marketing of fuels, lubricants, and petrochemicals, as well as our oil integrated supply and trading function.

RC profit before interest and tax
$6.5bn
(2018 $6.9bn)

Underlying RC profit before interest and tax
$6.4bn
(2018 $7.6bn)

Scale

We are an integrated energy business. We have operations in Europe, North and South America, Australasia, Asia and Africa.

70,100
employees
(2018 73,000)

79
countries
(2018 78)

19,341
million barrels of oil equivalent – group proved hydrocarbon reserves[a]
(2018 19,945mmboe)

18,900
retail sites
(2018 18,700)

Performance

Our 2019 performance has helped us deliver for our shareholders and other stakeholders, including energy consumers worldwide.

98
tier 1 and 2 process safety events★
(2018 72) KPI

$4.0bn
profit attributable to BP shareholders
(2018 $9.4bn)

$10.0bn
underlying RC profit★
(2018 $12.7bn) KPI

94.9%
downstream refining availability★
(2018 95.0%) KPI

3.8
million barrels of oil equivalent per day – group hydrocarbon production[a]
(2018 3.7mmboe/d)

Advancing low carbon

We are committed to advancing a low carbon future. We will aim to dramatically reduce carbon in our operations and in our production, and grow new lower carbon businesses, products and services.

>20
years in renewable businesses

>$500m
invested in low carbon activities in 2019

>7,500
BP Chargemaster charging points in the UK

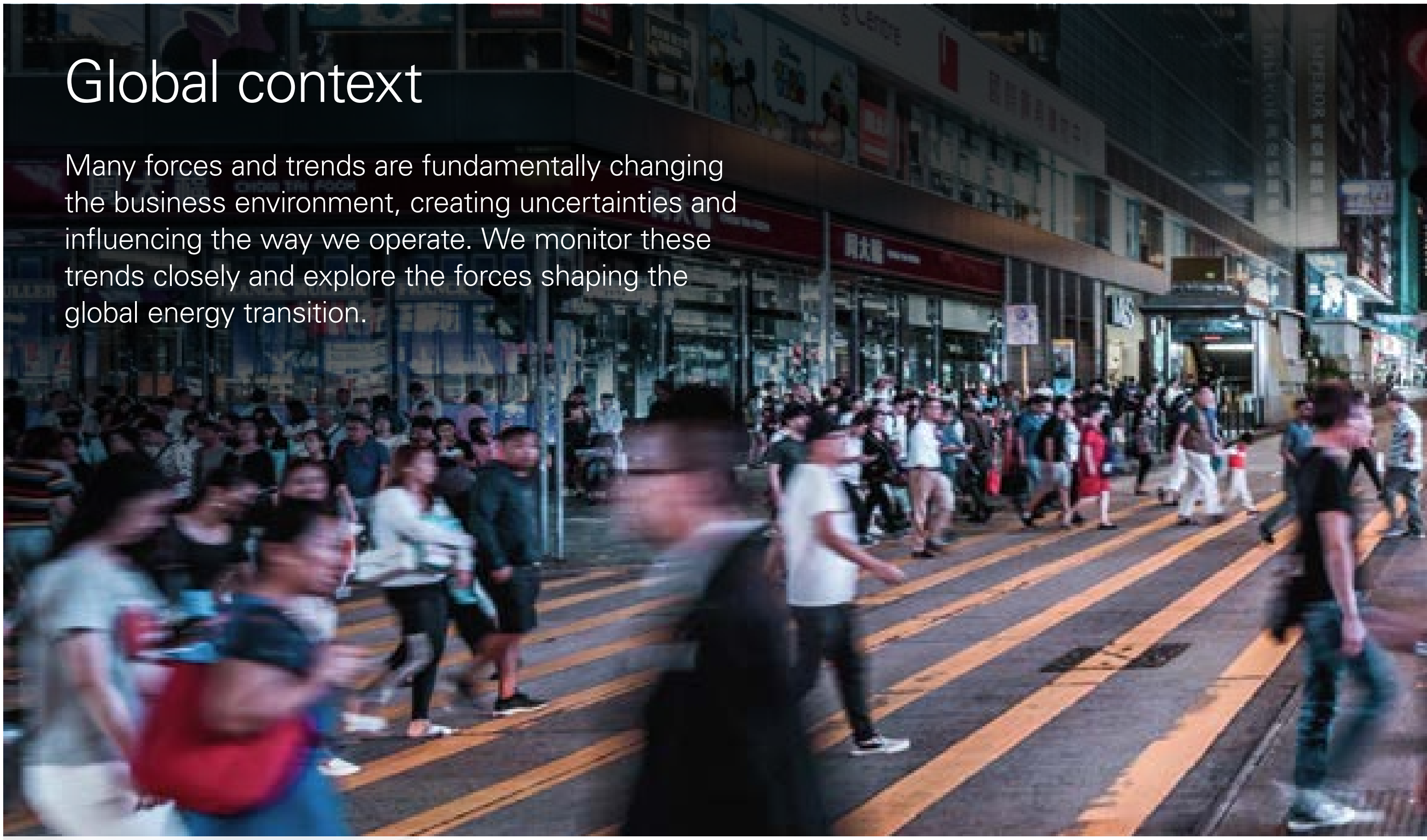
13
countries where Lightsource BP is active

a On a combined basis of subsidiaries★ and equity-accounted entities.

KPI See key performance indicators on page 32.

Global context

Many forces and trends are fundamentally changing the business environment, creating uncertainties and influencing the way we operate. We monitor these trends closely and explore the forces shaping the global energy transition.



Megatrends

The exact pace and nature of the energy transition is unclear, but it is clear that the market for our products is changing. Megatrends affecting our industry include:

- Growing global concern over climate change
- Rapidly advancing digital technology, affecting all aspects of economic activity
- Increasing prosperity in the emerging world driving economic growth
- Changing societal expectations of corporations
- Shifting geopolitical trends as trade, economies and relationships change over time

Growing global concern over climate change is a key driving force among these trends. The way the world responds to this, and the resulting impact on the energy sector, is the most significant uncertainty we face.

BP Energy Outlook 2019

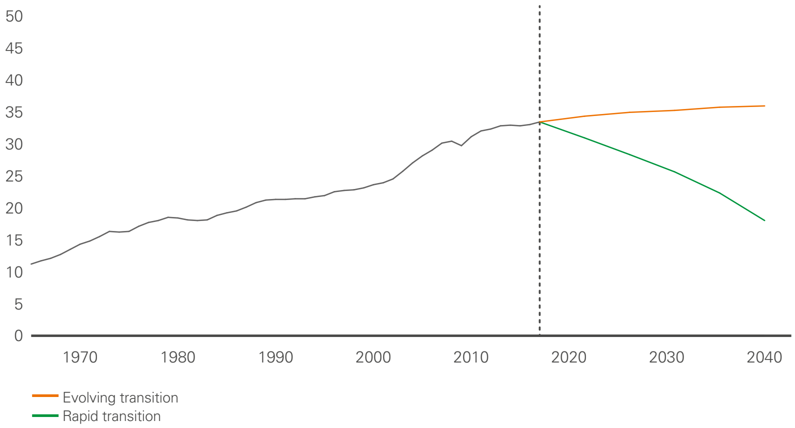
Our Outlook explores the forces shaping the global energy transition out to 2040 and the key uncertainties surrounding it. The 2019 Outlook considers a range of scenarios. They have some common features, such as ongoing economic growth and a shift towards a lower carbon fuel mix, but differ in terms of policy, technology and behavioural assumptions.

Scenarios

- **Evolving transition:** assumes that government policies, technology and social preferences continue to evolve in a manner and speed seen over the recent past.
- **Rapid transition:** envisages a more rapid transition to a lower carbon energy system, through a reduction in emissions stemming from greater energy efficiency, fuel switching and use of carbon capture, use and storage (CCUS).

For more information see *bp.com/energyoutlook*. The *BP Energy Outlook 2020* will be published later in the year.

Global carbon emissions
($GtCO_2$)



Source: *BP Energy Outlook* 2019

The transition envisaged in the 2019 Outlook

The world economy continues to grow, driven by increasing prosperity
- The global population grows by 1.7 billion, reaching close to 9.2 billion people in 2040.
- The global economy more than doubles over the next 25 years, with twice as much economic activity in 2040 than we see today.
- The emergence of a large and growing middle class, particularly in emerging Asia, is an increasingly important force shaping growth and energy trends.

Demand for energy is set to grow significantly
- Global energy demand increases by about 20-35% by 2040 in the different scenarios.
- The vast majority of demand growth comes from developing economies to support their industry and infrastructure and allow living standards to keep improving.

But carbon emissions need to fall sharply
- There is a growing commitment around the world to move to a pathway consistent with meeting the climate goals of the Paris Agreement[a].
- To help achieve this, the world needs to transition to a lower carbon energy system.

The key dimensions of the energy transition

To meet the Paris goals, we believe the world must take strong action on a range of fronts.

- Improving energy efficiency, to decouple energy demand growth from growing prosperity.
- Rapid growth in renewable energy and other low or zero carbon energy sources.
- Increasing the share of electricity in final energy use and decarbonizing power generation.
- Switching to lower or zero carbon liquid and gaseous fuels, particularly in areas such as heavy transport.
- Deploying carbon-removal technologies, such as CCUS, at scale.
- Promoting natural climate solutions, including the management and restoration of habitats, and the role of carbon credits.

The pace at which the transition can be achieved and the precise mix of elements is uncertain.

There are many possible pathways to meeting the Paris goals and we use different scenarios to explore this uncertainty. When we evaluate the consistency of our new material capex investments with the Paris goals, we consider a range of different possible pathways and scenarios, see page 21.

a Paris Agreement: (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.

The changing energy mix

Increased demand for energy is likely to be met over the coming decades through a diverse range of supplies including renewable energy, oil and natural gas.

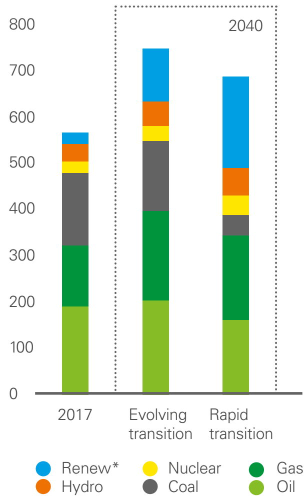
The energy mix is shifting as the transition to a lower carbon energy system continues, with renewable energy and natural gas gaining in importance relative to oil and coal.

Scenarios

- **Evolving transition:** renewables and natural gas account for almost 85% of the growth in primary energy by 2040, with their importance increasing relative to all other sources of energy.
- **Rapid transition:** renewable energy grows rapidly, accounting for more than the entire increase in primary energy by 2040 – and a sharp contraction in the use of coal. The level of oil consumption falls, but gas continues to grow aided by increasing use of carbon capture, use and storage (CCUS).

Primary energy consumption by fuel

Exajoules (EJ)



* Renewables includes wind, solar, geothermal, biomass and biofuels

Source: *BP Energy Outlook* 2019

85%

of primary energy growth is from renewables and natural gas in our 'evolving transition' scenario

What this means for oil and gas

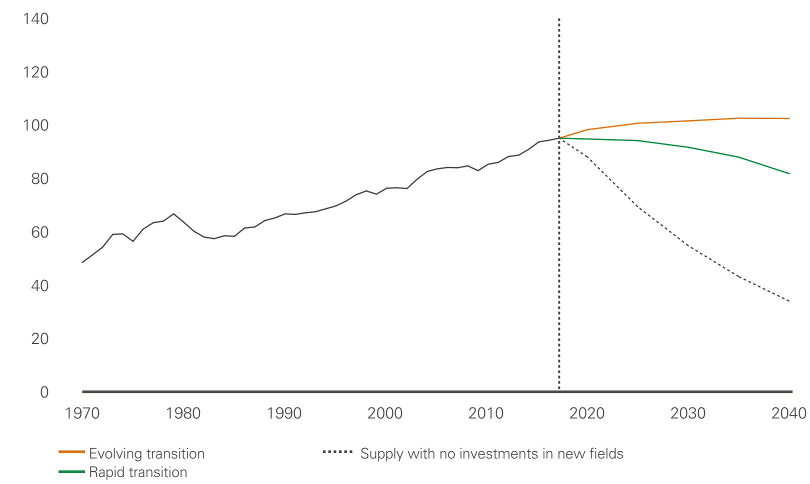
The *BP Energy Outlook 2019* considers a range of scenarios for oil demand, with the timing of the peak in demand varying from the next few years to beyond 2040.

Despite these differences, the scenarios share two common features. First, they each suggest that oil will continue to play a significant role in the global energy system in 2040, with the level of oil demand in 2040 ranging from around 80Mb/d to 100Mb/d. Second, significant levels of investment are required for there to be sufficient supplies of oil to meet demand in 2040.

Similarly there is a wide range of uncertainty in relation to the role of gas in the energy mix even in scenarios that achieve the Paris goals, with different organizations using significantly different assumptions. Those with a higher proportion of CCUS see a higher demand for gas, and in the outlook's 'rapid transition' scenario, close to a third of natural gas in 2040 is being used in conjunction with CCUS.

Demand and supply of oil

(Mb/d)



Source: *BP Energy Outlook* 2019

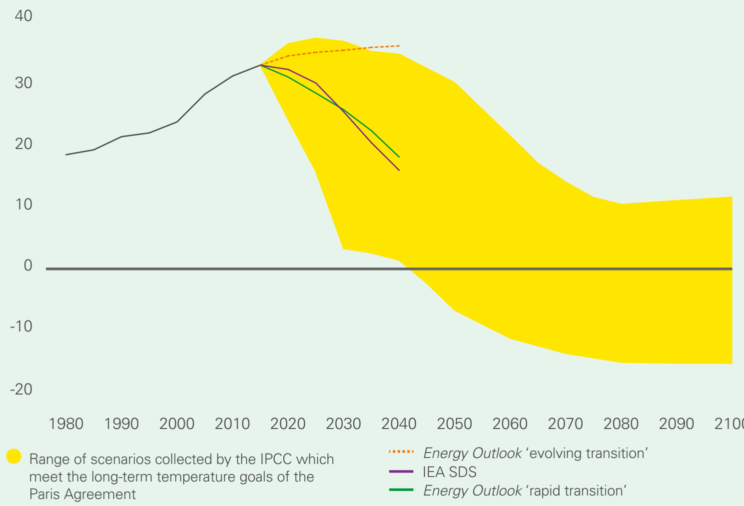
Achieving the Paris goals – a multitude of pathways

There are many different pathways to achieve the Paris goals, with substantial variation in the implied energy mix.

The Intergovernmental Panel on Climate Change (IPCC) is the United Nations' body for assessing the science related to climate change. It is the leading source of data that summarises the potential pathways to achieve the Paris goals. The IPCC compiles a database of the published results on mitigation pathways from modelling teams around the world.

The chart shows a range of modelled pathways for carbon emissions from energy and industrial use, collected by the IPCC, that meet the long-term temperature goals in the Paris Agreement, together with the paths associated with two of BP's own scenarios. The 'rapid transition' scenario clearly sits well within the range. Also highlighted is the 'Sustainable Development Scenario' from the International Energy Agency (IEA SDS), which is often cited as a reference case for a scenario that is consistent with meeting the Paris goals.

Global carbon emissions from energy use
($GtCO_2$)



Source: Integrated Assessment Modeling Consortium (IAMC) 1.5°C Scenario Explorer and Data hosted by International Institute for Applied Systems Analysis (IIASA), release 2.0. Scenario data has been rebased to common starting point that matches the *BP Energy Outlook* history for 2015.

Global energy markets in 2019

The world economy grew at 2.4% in 2019, reflecting slower growth in both advanced and emerging economies, amid weakening trade and investment. This was below the average of around 3% seen over the past 10 years. Growth in advanced economies was 1.6% in 2019 while in emerging markets was 3.5%[a].

2020 volatility
There has been considerable market volatility in the first quarter, compounded by the coronavirus (COVID-19). We expect the outlook for the year to remain challenging, see pages 52 and 57.

Oil

- **Dated Brent★ crude oil prices** averaged $64 per barrel in 2019 – a 9% decrease from 2018 levels but almost 30% above the 2015-17 average.
- **Global consumption**[b] increased by 0.9 million barrels per day (mmb/d) to 100.1mmb/d for the year (0.9%) – a slowdown from growth rates seen in the prior two years as trade tensions slowed global macroeconomic growth.
- **Global oil production** remained flat at 100.5mmb/d, with growth from non-OPEC countries offsetting supply restraint and disruptions in OPEC countries.

Natural gas

- **Gas spot prices** dropped in all three key regional markets in 2019.
- **Global consumption**[c] growth slowed down in 2019 compared with the exceptional growth in 2018, driven by slower growth in both the US and China.
- **Total gas production** growth slowed down in 2019, with the exception of the US. Meanwhile, LNG trade increased significantly during 2019.

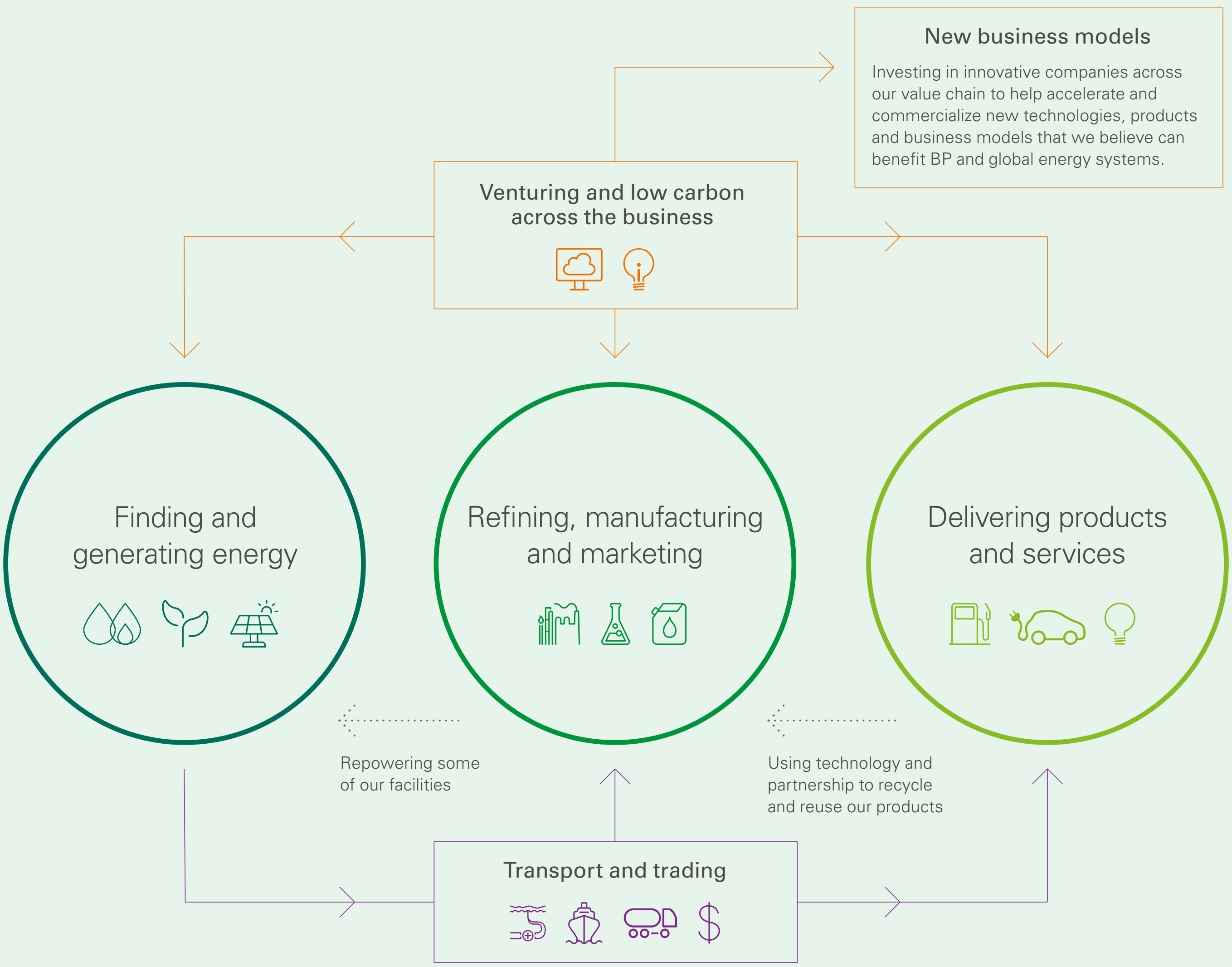
For more information on prices and margins see pages 52 and 58.

a World Bank Global Economic Prospects, January 2020.
b IEA Oil Market Report, February 2020©.
c JODI-Gas World Database, and IHS Markit: China Natural Gas Data Tables: February 2020 for China.

Our business model

We deliver a diverse range of energy products and services to people around the world.

What we do



- Finding additional resources and replenishing our development options with exploration and technology.
- Developing and extracting oil and gas, and seeking to extend the life of existing fields.
- Generating renewable energy using biofuels, biopower, wind and solar.

- Producing refined petroleum products and scaling up co-processing of lower carbon fuels at our refineries.
- Manufacturing and marketing lubricants and petrochemicals products.
- Developing technologies to help advance the circular economy, such as *BP Infinia*, which can recycle previously unrecyclable plastics.

- Delivering fuels, fast electric-vehicle charging and convenience retail services, as well as premium and lower carbon lubricants.
- Supplying petrochemical products that are used to make a range of products including clothes and building materials.
- Providing renewable power to industries and local electricity grids.

More information

Upstream on page 50.
Downstream on page 56.
Other businesses and corporate on page 63.

Reinventing BP

On 12 February 2020 we introduced our ambition and aims with a new structure, a new leadership team, and new ways of working.

To deliver our ambition we are reinventing BP, retiring our existing model and replacing it with one that is more focused, more integrated and faces the energy transition head on. One that can deliver for the changing demands of consumers, investors and governments.

Our new leadership structure is due to come into place on 1 July 2020 and is expected to be fully operational by 1 January 2021. The new leadership will focus on four core capabilities: operations, customers, low carbon and innovation. These four highly focused business groups will work with three integrators (sustainability and strategy; regions, cities and solutions; and trading and shipping) to facilitate collaboration and unlock value. And four teams will serve as enablers of business delivery.

For more information see *bp.com/reimagine*.

Business model foundations

These are the things that every energy business needs and are critical foundations for what we do and how we do it.

Partnerships and collaboration
We aim to build enduring relationships with our key stakeholders, and partner with others to find innovations that can improve efficiency and deliver low carbon solutions.

- 20 years of collaboration with the world's top universities.

Governance and oversight
Our board has a diversity of knowledge, expertise, and ways of thinking that help us transition our business, manage risks and continue to deliver value over the long term.

- ~42% of the company's board are women.

See page 74.

Safe and reliable
We value the safety of our workforce and focus on maintaining a safe operating culture every day. This culture of safety also improves the integrity and reliability of our assets.

- 94.4% BP-operated upstream plant reliability★.

See page 45.

Talented people
We work to attract, motivate and retain the best talent the world offers and equip our people with the right skills for the future. Our performance and ability to thrive globally depend on it.

- 8th most desirable employer in the UK on LinkedIn.

See page 47.

Technology and innovation
New technologies help us produce energy safely and more efficiently. We selectively invest in areas with the potential to add greatest value to our business, now and in the future, including building lower carbon businesses.

- >3,900 patents granted or pending across the BP group in 2019.

What makes us different

These are the things we believe set us apart from our peers and demonstrate our distinctive ways of working.

Global energy trading

We combine expertise in physical supply and trading and advanced analytics to deliver long-term value, from wellhead to end customer. We trade a variety of products such as crude oil, refined products, natural gas, LNG, carbon products and power.

4bn

barrels of crude a year traded, equivalent to 20% global traded oil.

Distinctive customer offers

Our convenience partnerships provide customers with a differentiated offer that includes fresh, high-quality food and drink, such as M&S Simply Food® in the UK and REWE to Go® in Germany.

~1,600

differentiated convenience partnership sites across our network of around 18,900 retail sites.

'Reduce, improve, create' framework

Our framework helps focus everyone in BP on our low carbon ambitions. It encompasses activities across the group to reduce emissions from our operations, improve the products we offer to help customers reduce their emissions, and create low or zero carbon businesses to deliver more energy with fewer emissions.

0.14%

methane intensity in 2019.

See page 40.

Rosneft partnership

Our share in Rosneft, one of Russia's largest oil and gas producers, gives us a stake in one of the largest and lowest-cost hydrocarbon resource bases in the world, with access to huge markets, both east and west.

19.75%

BP's stake in Rosneft.

See page 61.

Our strategy

We have established a track record of operational and financial delivery.

This has helped create a strong foundation for us to advance our low carbon agenda as we work to achieve our ambition to become a net zero company by 2050 or sooner and to help the world get to net zero★.

Our strategy, which we set out in 2017, allows us to be competitive, flexible and resilient while also responding to a rapidly changing energy landscape, with growing expectations for us to adapt to changing demands from stakeholders.

We remain committed to managing our portfolio for value, and investing with discipline in flexible and resilient options, which together support our pursuit of a strategy which we believe is consistent with the goals of the Paris Agreement.

Following BP's new ambition and aims, set out in February 2020, we plan to announce more information on how we intend to reimagine energy and reinvent BP, while performing as we transform, at our capital markets day in September 2020.

Strategic priorities

Growing advantaged oil and gas in the Upstream

Invest in oil and gas, producing both with increasing efficiency (lower cost, higher margin and close to markets), with a focus on carbon.

See page 25.

Market-led growth in the Downstream

Innovate with advanced products and strategic partnerships, building competitively advantaged businesses that deliver profitable marketing growth

See page 27.

Venturing and low carbon across multiple fronts

Pursue new opportunities to meet evolving technology, consumer and policy trends.

See page 28.

Modernizing the whole group

Simplify our processes and enhance our productivity through digital solutions.

See page 31.

Supported by our low carbon ambitions

Embedded within our strategy is our commitment to advance a low carbon future. We plan to deliver this across our entire business through what we call our 'reduce, improve, create' (RIC) framework.

Reducing

emissions in our operations

- Achieve zero net growth in operational emissions out to 2025.
- Make 3.5Mte of sustainable GHG reductions by 2025.
- Target industry leading methane intensity of 0.2%.

Improving

our products

- Provide lower emissions gas.
- Develop more efficient and lower carbon fuels, lubricants and petrochemicals.
- Grow lower carbon offers for customers.

Creating

low carbon businesses

- Expand low carbon and renewable businesses.
- Invest $500 million in low carbon activities each year.
- Collaborate and invest in the OGCI's $1bn+ fund for research and technology.

For more information on our RIC framework, see page 41.

Pursuing a strategy that is consistent with the Paris goals

In February 2020 we set out our ambition to be a net zero company by 2050 or sooner and to help the world get to net zero. This is supported by 10 aims which, when taken collectively, set out a path that we believe is consistent with the Paris goals, see page 7. One specific aim relates to increasing the proportion of investment in our non-oil and gas business. Over time, as investment in low or no carbon activity increases, we see investment in oil and gas going down.

Since 2017, when BP reset its five-year strategy, we have pursued a way forward that is flexible and adaptable to a range of energy and market scenarios. These different scenarios are based on a range of assumptions about policy, technology and consumer behaviour, and supply and demand changes. We do not know what path the energy transition will take, so BP's strategy is intended to be effective under a range of scenarios, and not a single, deterministic view of the future – in short, responsive to uncertainty.

We believe that our current strategy is consistent with the Paris goals. This consistency has, at its core, two key parts. And these remain relevant as we work towards our net zero ambition and aims.

1. We are striving to play our part in meeting the world's energy needs in reliable, affordable and lower carbon; and we intend to achieve this through collaboration, technology, innovation and advocating for progressive climate policies to advance a low carbon future in support of the Paris goals.

In 2019 examples included:

- Launching a review of our climate-related trade association memberships – read more on page 49. Our aim going forward is to set new expectations for trade associations around the globe.
- Establishing a collaboration with DiDi to begin building an electric-vehicle charging network in China.
- Beginning the roll out of ultra-fast chargers across BP forecourts in the UK and piloting ultra-fast charging at *Aral* forecourts in Germany, bringing charging time closer to the time taken to fill a tank.
- Increasing our stake in Lightsource BP to create a 50:50 joint venture.
- Expanding our biofuels business in Brazil by more than 50% through a joint venture with Bunge to create BP Bunge Bioenergia.
- Installing continuous methane measurement at our Khazzan central processing facility in Oman to help quickly identify new leaks and reduce time taken to respond.
- Supporting well-designed carbon pricing, such as the Washington State cap-and-invest bill. We aim to advocate more actively for policies that support net zero, including carbon pricing.

i For more information on our strategy in action, see pages 24-31.

2. We believe that our strategy positions BP to remain an attractive investment for current and prospective shareholders throughout the energy transition, including in a world that is meeting the Paris goals. Our strong and disciplined financial framework supports the delivery of our strategy. This provides us with a strong platform to deliver our purpose to reimagine energy, and work towards our new net zero ambition and aims.

i For more information on our investor proposition and financial framework, see page 18.

The role of the board

The board is responsible for setting the strategy and has oversight of the overall conduct of the group's business. During 2019, the board considered BP's strategy at every board meeting. This took into account the wider operating environment and discussed strategic themes relating to BP's purpose, including in relation to the segments and key functions. The impact of the lower carbon energy transition on the group's business model was also reviewed and discussed throughout 2019. As a result, the board considers that the strategy allows us to be flexible to adapt to market changes and scenarios to remain consistent with the Paris goals.

i For more information on the role of the board in relation to climate governance, see page 42. For the board's activity in relation to strategy, see Corporate governance on page 84.

Measuring our progress

The CA100+ resolution requires us to disclose the company's principal metrics and relevant targets or goals consistent with the Paris goals. We consider this to cover the principal metrics used at group level to help monitor progress on delivery of our strategic consistency with the Paris goals – including our near-term RIC framework.

A number of these metrics and targets are relevant to the recommendations of the Task Force on Climate-related Financial Disclosures (TCFD).

Going forward, we are considering metrics to support our ambition to be a net zero company by 2050 or sooner, and to help the world get to net zero. We plan to provide more information on our future strategy and near-term plans at our capital markets day in September 2020.

i For more information on the TCFD, see page 42.

Our group-wide principal metrics and relevant targets/goals

RIC framework i Sustainability, page 40.	Reduce • Zero net growth in operational emissions out to 2025. • 3.5Mte sustainable emissions reductions★ by 2025. • 0.2% methane intensity.
	Create • $500 million invested in low carbon activities annually. (>$500 million in 2019). • Collaborate and invest in OGCI's $1bn+ fund for research and technology.
Investment process (RCM) i Our investment process, page 22.	• Profitability index★. • Average operational carbon intensity★.
Greenhouse gas emissions i Sustainability, page 40.	• Scope 1 and 2 emissions. • Emissions from the carbon in our upstream oil and gas production. • For further GHG metrics see *bp.com/ESGdata*.
Carbon intensity i Sustainability, page 40.	• Average emissions intensity of marketed energy products★. • Ratio of Scope 1 and 2 emissions: gross production.
Remuneration i Directors' remuneration report, page 100.	• 2020 annual bonus scorecard target related to sustainable emissions reductions.

Our investor proposition

Our investor proposition is to grow sustainable free cash flow and distributions to shareholders over the long term. We believe our strategy enables this through a focus on safe, reliable and efficient execution, leveraging our distinctive portfolio, and disciplined investment to support growing returns.

Safer	Fit for the future	Focused on returns
safe, reliable and efficient execution	a distinctive portfolio fit for a changing world	value based, disciplined investment and cost focus

Growing sustainable free cash flow and distributions to shareholders over the long term

Our financial framework

We maintain a disciplined financial framework, which underpins our strategy and investment choices, and supports growth in sustainable free cash flow, returns and distributions to shareholders.

This discipline helps us maintain a focused portfolio, which we believe is resilient in the long run to many potential outcomes and seeks to grow long-term returns to shareholders.

Our capital frame is reviewed on an ongoing basis. We believe that the continuing flexibility it provides gives us the flexibility to pursue our net zero ambition and aims, allocating an increasing proportion of investment toward lower carbon businesses over time. This will help drive both the long-term resilience of the portfolio and the creation of new value. This is balanced against the pace of development of these new lower carbon business developments and levels of cash flow generation.

In addition, our capital expenditure programme has flexibility, which enables us to respond to a low-price environment by reducing or rephasing investment.

We continue to expect to deliver the 2021 targets laid out three years ago.

We plan to increasingly focus our investment on the highest-quality barrels and drive returns and cash flow, not volumes. As a result, the anticipated proportion of our investment that goes to oil and gas is expected to change.

The CA100+ resolution requires us to disclose (a) our anticipated investment in oil and gas resources and reserves – this is anticipated to be less in 2020 than it was in 2019, and (b) our anticipated investment in other energy sources and technologies – which is anticipated to be significantly greater than 2019 levels.

We also plan to provide more information on this as part of our capital markets day in September 2020.

	2019 actual	2020 guidance
Upstream production excluding Rosneft	2.6mmboe/d	**Lower than** 2019
Organic capital expenditure★	$15.2bn[i]	**Lower end of** $15-17bn **range**
Depreciation, depletion and amortization	$17.8bn	**Slightly below** 2019
Gulf of Mexico oil spill payments	$2.4bn	<$1bn
Other businesses and corporate average underlying quarterly charge	$320m	~$350m
Underlying effective tax rate★	36%[ii]	**Below** 40%

Nearest equivalent GAAP measures: i Capital expenditure★: $19.4bn.
ii Effective tax rate: 49%.

Our investment process

BP's investments fall within a governance framework.

This seeks to ensure investments align with our strategy, fall within our prevailing financial framework, and add shareholder value. The governance framework also provides for investments to be assessed consistently and against a range of other outcomes relevant to our strategy, including a range of environmental and sustainability factors.

Investments follow an integrated stage gate process designed to enable us to choose and develop the most attractive investment cases. A balanced set of investment criteria are used, see page 20. This allows for the comparison and prioritization of investments across an increasingly diverse range of business models.

The governance framework also specifies that investments are tested against a range of carbon prices for projected operational emissions and subject to assurance by functions independent of the business before a final investment decision (FID) is taken.

For more information on BP's governance framework, see page 83.

Price assumptions

Investments are evaluated against a range of alternative prices (central, upper and lower) for oil, natural gas, refining margins and carbon prices. These price ranges 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 price ranges refer to the long-run level of prices over the next 20 years. The nature of the uncertainty means that these price ranges inevitably reflect considerable judgement. The ranges are reviewed and updated on an annual basis as our understanding and judgement about the energy transition evolves.

Range of prices

	Brent★[a] ($/bbl)	Henry Hub★[a] ($/mmBtu)	RMM★[b] ($/bbl)
Upper case	90	5.0	17
Central case	70	4.0	14
Lower case	50	2.0	11

Carbon prices

	($/tonne[a])
Upper case	80
Central case	40
Lower case	0

a 2015 $ real.
b Nominal.

Resource commitment meeting

For capital investments above defined financial thresholds for organic or inorganic spend, the investment approval is conducted by the executive-level resource commitment meeting (RCM), which is chaired by the chief executive officer. The RCM reviews the merits of each such investment case against a balanced set of criteria 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 consistency of such investments with the Paris goals was undertaken by the RCM in 2019.

The role of the board

The board assesses the impact of portfolio changes, such as strategic acquisitions and the allocation of capital. They also consider specific investment cases deemed sufficiently material to warrant their attention, which have been approved by the RCM.

For more information on climate governance, see page 42.

Balanced investment criteria

For the purposes of evaluating consistency with a range of other outcomes relevant to BP's strategy, all group-wide investment cases are required to set out the investment merits in a standard format against a set of balanced criteria.

Investments are considered against a range of prices (upper, central and lower). All three 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 is not, or may not be, sufficiently rapid. They also place some weight on a range of other factors, which can drive prices, and are not related to the goals of the Paris Agreement.

In addition, investment cases are asked to present scenarios covering a range of variables, related to the economics of the investment, such as cost, resource, policy changes and schedule, to highlight the robustness of investment cases to a range of other factors.

This standardized approach creates a level playing field for decision making and allows portfolio wide comparisons of investment cases. Further, the decision to endorse an investment based on the information provided represents BP's evaluation that the investment is considered consistent with a range of other outcomes, relevant to BP's strategy.

Environment and sustainability
All investment cases are considered against appropriate environmental impacts and sustainability measures, including but not limited to carbon. Investment cases above defined thresholds for anticipated annual greenhouse gas (GHG) emissions from operations must estimate those anticipated GHG emissions and include an associated carbon price of $40/te 2015 $ real (and sensitivities of $0 and $80) in the investment economics.

Investment economics
We consider investment economics against a range of measures including profitability index★, internal rate of return, net present value, discounted payback, investment efficiency, using a set of scenarios for commodity prices, margins and carbon prices. Investments are generally considered against internal rate of return hurdles typically set in the mid to high teens. Close attention is paid to discounted payback as a measure of commercial risk in the context of the energy transition and profitability index as a measure of capital efficiency.

Capability and scale
For all investment cases, we consider whether they involve 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.

Cash flow certainty
Economic metrics are also considered in the context of the cash flow certainty of the investment assumptions. For example, a high return deepwater tieback will have less certain and more volatile (oil price linked) cash flows than a lower return but more certain renewable power project with a long-term power purchase agreement (and a fixed power price).

Safety and risks
Investment cases are required to describe risks unique to the project which have a significantly higher probability than usual or have a significantly greater impact (relative to the size of the project) were they to occur.

Optionality
All investment cases are requested to quantify the strategic optionality that might be accessed through follow-on activity. For example, a greenfield offshore platform may provide additional optionality to develop nearby satellite fields in the future.

Evaluating new material capex investments for consistency with the Paris goals

When evaluating the consistency of our 2019 new material capex investments★ with the Paris goals, a focus of the evaluation criteria was on their competitiveness and financial robustness as the prices of different forms of energy and products adjust in response to the changing market environment.

The 2019 evaluation was done in the context of a 'sustained low-price environment', which assumes the lower price case for oil ($50/bbl[a]), natural gas ($2/mmBtu[a]) and refining margins ($11/bbl (nominal)) together with the higher carbon price ($80/te$CO_2$[a]).

These price assumptions do not correspond to a single specific 'Paris-consistent' scenario, but instead place weight on a range of possibilities for how the demand for different forms of energy may change in Paris-consistent pathways and how this may affect future energy prices[b].

Sustained low-price environment

Oil price (Brent★):

$50/bbl[a]

In many 'Paris-consistent' scenarios, global oil demand peaks within the next five years or so and falls between 15-35% by 2040. Such a fall in demand, combined with the abundance of oil resources, would be expected to lead to an increasingly competitive market for oil. But the extent to which these competitive forces feed through into a sustained reduction in global oil prices is expected to be tempered by the dependence of many oil-producing economies on oil revenues to support their wider economies. For example, the IMF estimate that the fiscal break-even prices of the major Middle East and North African oil exporters is close to $80[c]. We consider that the pace at which the major oil producing economies are able to diversify their economies and so reduce the fiscally sustainable price at which they can produce oil is likely to limit the extent to which oil prices can fall on a sustained basis over the next 20 years[d].

US natural gas price (Henry Hub★):

$2/mmBtu[a]

The price of US gas (Henry Hub) is used as the main price for evaluating gas-based investments, either directly for US-based projects or indirectly (via netback pricing relationships) for gas-based projects in other parts of the world.

The outlook for natural gas in 'Paris-consistent' scenarios is more varied across different scenarios: some point to global gas consumption increasing or remaining broadly flat over the next 20 years; others point to gas demand peaking within the next five years and declining by 20-30% by 2040. These differences stem in part from the extent to which natural gas is assumed to be used in conjunction with carbon capture, use and storage (CCUS) projects, either in the power and industrial sectors directly, or to produce decarbonized gas (in the form of 'blue' hydrogen). US natural gas prices will also depend on a number of supply-side factors, such as: the extent to which productivity gains within shale gas continue to improve, and how quickly US tight oil★ production – and hence the associated gas produced as part of that production – peaks.

Refining marker margin★ (RMM):

$11/bbl
(nominal)

The outlook for refining margins is most relevant when considering investments in refineries or closely related activities.

Many 'Paris-consistent' scenarios provide less detailed information on the outlook for refined products and refining activity. However, the significant falls in global oil demand envisaged in many of these scenarios are likely to also be reflected in the demand for refined products. Indeed, some scenarios highlight the expected growth in natural gas liquids (NGLs) and biofuels which suggest that refining activity might decline by even more than the overall demand for liquid fuels. To the extent that falling demand for refined products leads to over-capacity in the refining sector, this would be expected to lead to the least-efficient refineries closing over time, raising the average efficiency of the remaining refineries and so reducing the sustainable level of refining margins. However, the need for some refineries to continue to operate can be expected to limit the extent to which refining margins can fall on a sustained basis.

Carbon prices:

$80/te$CO_2$[a]

The outlook for carbon prices has both a direct and indirect effect on the evaluation of new material investments. The direct effect relates to the operational emissions associated with different investment projects: the greater the operational emissions, the greater the exposure to increases in carbon prices. The indirect impact relates to the impact of carbon prices on the differential between retail and wholesale prices for oil and natural gas. An increase in carbon prices can be expected to increase the differential between retail and wholesale prices: potentially both dampening demand growth (due to higher retail prices) and reducing the prices received by oil and gas producers (due to lower wholesale prices). The direct effects associated with carbon prices are explicitly assessed within BP's investment evaluation criteria, whereas the indirect effects are captured within the overall prospects for oil and gas demand and the associated prices.

In many 'Paris-consistent' scenarios, carbon prices are used as a key policy instrument for accelerating the transition to a low carbon energy system, with carbon prices (on a global basis) increasing to between $100-200/te$CO_2$ by 2040. But in these scenarios, carbon prices are typically increased only gradually, in part since this mitigates the costs to the economy of prematurely scrapping and replacing productive assets. Hence, the average level of carbon prices in these scenarios over the next 20 years tends to be significantly lower than the level they are projected to reach in 2040 or so. For example, in BP's rapid transition scenario, carbon prices in developed economies are assumed to reach $200/te$CO_2$ by 2040, but the average level of carbon prices between 2017 and 2040 in that scenario is around $75/te$CO_2$.

a 2015 $ real.
b To aid this analysis, we consider a range of scenarios which claim to be consistent with meeting the Paris goals including: IEA's 'Sustainable Development Scenario', BEIS' 'Low Prices' case, Aurora Energy Research's 'Two degrees' scenario and MIT's 'Paris to 2°C' scenario.
c Regional Economic Outlook – Middle East and Central Asia, International Monetary Fund, October 2019.
d The Oil and Gas Industry in Energy Transitions | IEA 2020.

Evaluating new material capex investments for consistency with the Paris goals – continued

Evaluation process

Our new material capital investments★ are intended to support the delivery of BP's strategy. In 2019, we evaluated their consistency with the Paris goals by considering them against a balanced set of investment criteria (see page 20). For each of the investment criteria, a qualitative explanation of each business case was considered and presented to the resource commitment meeting (RCM). They then discussed and addressed key issues raised, as per the description on page 19.

Two quantitative evaluations were considered for Paris consistency. As our approach matures with experience, we may adjust or supplement these.

Quantitative evaluations

Investment economics

The calculation of profitability index★ (PI) using the 'low-price' case for commodity prices and margins and the 'high' carbon price of $80 per tonne (2015 $ real). As a guide, we would normally target a minimum threshold of greater than 1.0x on this basis.

Environment and sustainability

Where appropriate, the operational carbon intensity★ of the investment relative to that of the portfolio average for the segment or the related business activity (upstream, refining, petrochemicals). As a guide, we would normally target a ratio of less than 100%, meaning that the investment is expected to reduce the average operational carbon intensity of that portfolio.

The potential impact of new material capex investments on BP's greenhouse gas emission targets is a further consideration.

There may be instances when new material capex investments are evaluated as consistent with the Paris goals despite either or both of these guide levels not being met, due to other considerations being taken into account.

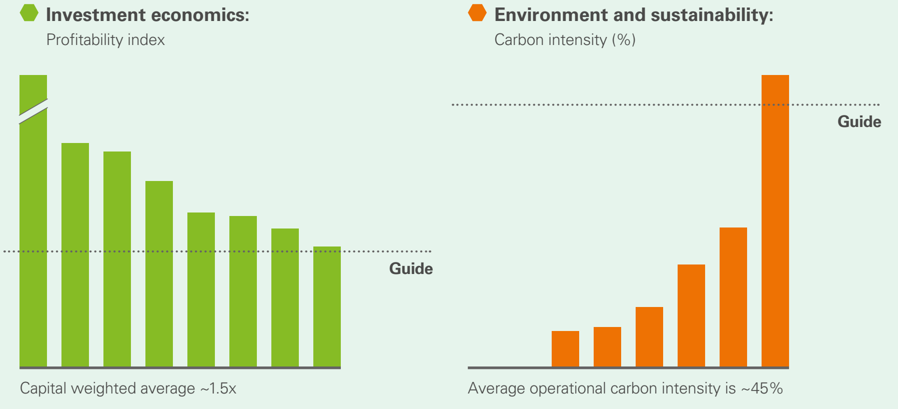
Evaluation outcome

As shown in the figure, each of the new material capex investments approved in 2019 met the evaluation guides, with the exception of one investment not meeting the guide level for carbon intensity. This investment was evaluated to be consistent with the Paris goals, based on the strength of the investment economics with a short payback period, delivering short-cycle cash returns and reducing the timeframe during which the investment would be exposed to uncertainties associated with Paris consistent pathways.

In 2019, the overall averages for the new material capex investments met the guide levels for each of the two quantitative evaluation tests:

- Profitability index on an average capital weighted basis was approximately 1.5x, versus a guide level of greater than 1.0x.
- An average operational carbon intensity of approximately 45% relative to the current portfolio(s), versus a guide level of less than 100%.

The figure shows the respective rankings of investment performance against each of the tests



1. The respective 2019 new material capex investments have been ranked against the two tests. As a result they are ordered differently in each graph above.
2. For two of the 2019 new material capex investments the operational carbon intensity was not calculated due to the nature of these investments:
   - We do not calculate operational carbon intensity for replacement of end of life assets.
   - The projected operational carbon intensity of fuels marketing businesses is not considered necessary to quantify for these purposes as the relevant operational emissions would not be expected to be significant.

Decisions taken in 2019

Eight new material capex investment decisions were taken in 2019, six in the Upstream and two in the Downstream.

Upstream

Azeri Central East (ACE)
A new offshore platform and facilities in the Azeri-Chirag-Deepwater Gunashli field in Azerbaijan.

Angola Block 18 – Platina
Four subsea well tiebacks to an existing FPSO vessel, which also support continued production from the main field under the licence extension granted by the Angolan government.

India KGD6 – MJ
The third phase of Block KG D6 gas development, seven subsea wells will tie-back to a new FPSO vessel to process and separate liquids.

Angola Block 15
Further investment, which will extend the production-sharing agreement★ for the block through 2032.

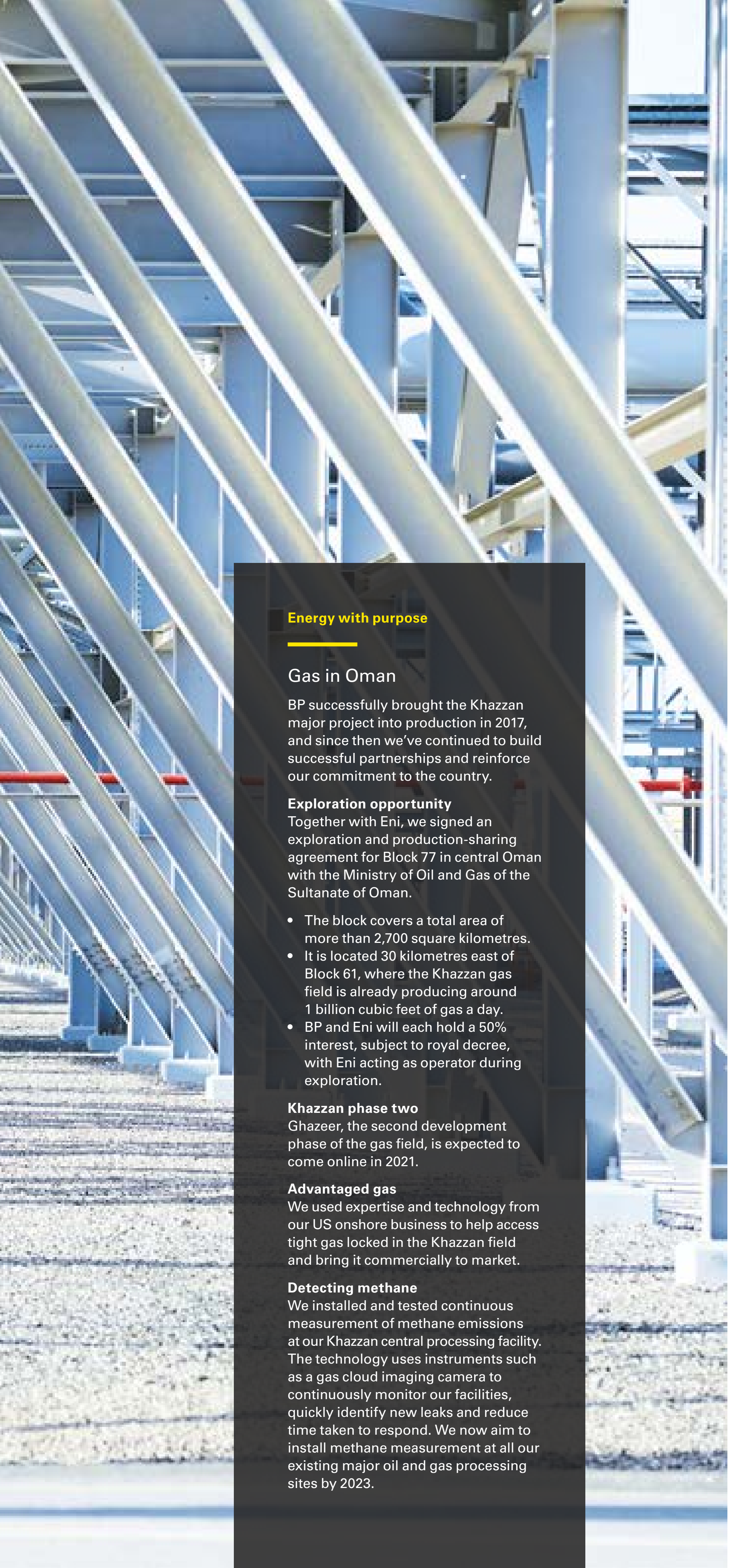
Thunder Horse South Expansion Phase 2
Two new subsea production units with eight wells tied back to existing infrastructure in the US Gulf of Mexico.

Block 61 2020 development wells
Further development and drilling of 18 wells at Ghazeer and seven wells at Khazzan, both in Oman.

Downstream

Gelsenkirchen steam and water project
Construction of four boilers and a steam turbine to further the safe and reliable management of fuel gas excess.

Reliance partnership
Strategic agreement with Reliance Industries Limited to form a retail and aviation joint venture★ in India.



Energy with purpose

Gas in Oman

BP successfully brought the Khazzan major project into production in 2017, and since then we've continued to build successful partnerships and reinforce our commitment to the country.

Exploration opportunity
Together with Eni, we signed an exploration and production-sharing agreement for Block 77 in central Oman with the Ministry of Oil and Gas of the Sultanate of Oman.

- The block covers a total area of more than 2,700 square kilometres.
- It is located 30 kilometres east of Block 61, where the Khazzan gas field is already producing around 1 billion cubic feet of gas a day.
- BP and Eni will each hold a 50% interest, subject to royal decree, with Eni acting as operator during exploration.

Khazzan phase two
Ghazeer, the second development phase of the gas field, is expected to come online in 2021.

Advantaged gas
We used expertise and technology from our US onshore business to help access tight gas locked in the Khazzan field and bring it commercially to market.

Detecting methane
We installed and tested continuous measurement of methane emissions at our Khazzan central processing facility. The technology uses instruments such as a gas cloud imaging camera to continuously monitor our facilities, quickly identify new leaks and reduce time taken to respond. We now aim to install methane measurement at all our existing major oil and gas processing sites by 2023.

Growing advantaged oil and gas in the Upstream

What this strategic priority means

We aim to invest in oil and gas, producing both with increasing efficiency. This means lower cost, higher margin and close to markets, with a focus on carbon.

Almost half of BP's upstream portfolio is natural gas, and several more gas projects are planned to come onstream in the next few years.

As the world moves towards net zero ★ emissions, we think natural gas can play an important role in getting us there. When burned for power, natural gas has, on average on a lifecycle basis, about half the GHG emissions of coal, with fewer air pollutants, so expanding its use globally to displace coal will help to reduce carbon emissions. In fact, switching from coal to gas has avoided more than 500 million tonnes of CO_2 from the power sector globally since 2010.

Progress in 2019

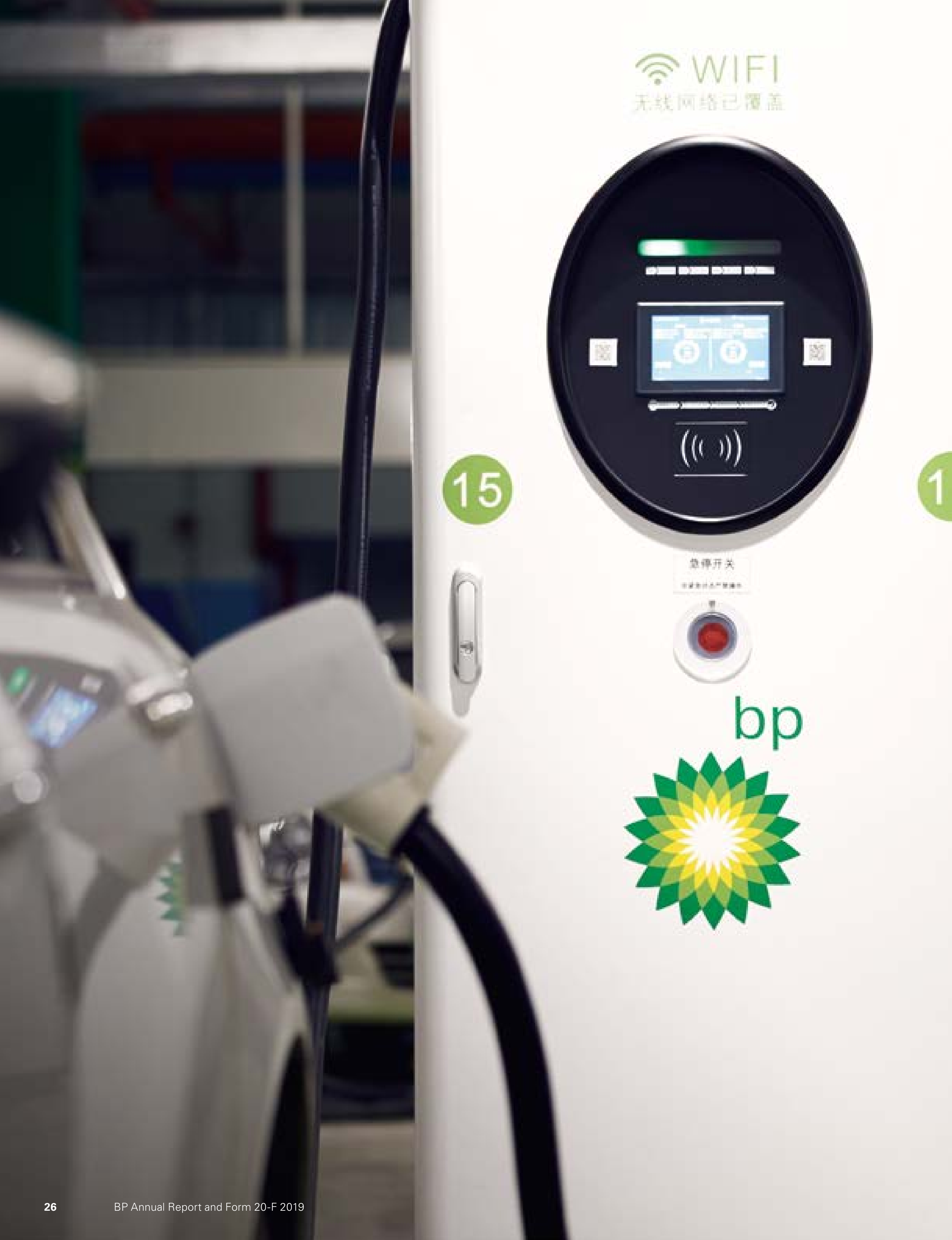
We've started up 24 of the 35 planned major projects since 2016 and are on track to deliver 900,000 barrels of oil equivalent per day of new major project production by the end of 2021.

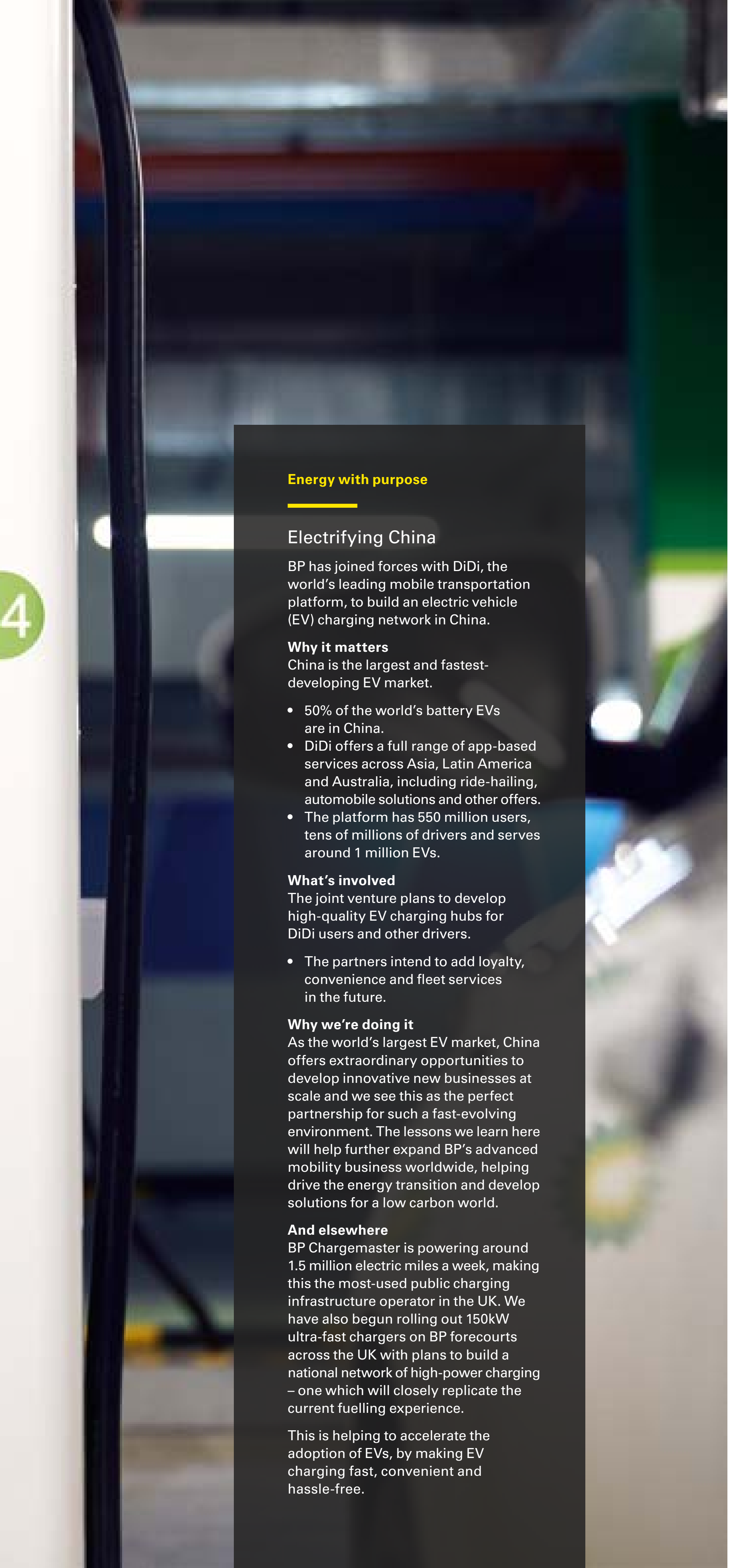
- Sanctioned $6 billion Azeri Central East development with partners.
- Agreed to sell our Alaska assets to Hilcorp.
- Sanctioned the third project in block KG D6, offshore India with our partner Reliance.

5
major project start ups.

$100m
fund for projects that will help reduce greenhouse gas emissions.

For more information see Upstream on page 50.


WIFI
无线网络已覆盖
15
急停开关
bp



Energy with purpose

Electrifying China

BP has joined forces with DiDi, the world's leading mobile transportation platform, to build an electric vehicle (EV) charging network in China.

Why it matters
China is the largest and fastest-developing EV market.

- 50% of the world's battery EVs are in China.
- DiDi offers a full range of app-based services across Asia, Latin America and Australia, including ride-hailing, automobile solutions and other offers.
- The platform has 550 million users, tens of millions of drivers and serves around 1 million EVs.

What's involved
The joint venture plans to develop high-quality EV charging hubs for DiDi users and other drivers.

- The partners intend to add loyalty, convenience and fleet services in the future.

Why we're doing it
As the world's largest EV market, China offers extraordinary opportunities to develop innovative new businesses at scale and we see this as the perfect partnership for such a fast-evolving environment. The lessons we learn here will help further expand BP's advanced mobility business worldwide, helping drive the energy transition and develop solutions for a low carbon world.

And elsewhere
BP Chargemaster is powering around 1.5 million electric miles a week, making this the most-used public charging infrastructure operator in the UK. We have also begun rolling out 150kW ultra-fast chargers on BP forecourts across the UK with plans to build a national network of high-power charging – one which will closely replicate the current fuelling experience.

This is helping to accelerate the adoption of EVs, by making EV charging fast, convenient and hassle-free.

Market-led growth in the Downstream

What this strategic priority means

We aim to innovate with advanced products and strategic partnerships, building competitively advantaged businesses that deliver profitable marketing growth.

We aim to invest in higher-returning fuels marketing and lubricants businesses with growth potential and reliable cash flows. And we are continuing to expand into fast-growing emerging markets.

We are also delivering and developing new products, offers and business models that support the transition to a lower carbon and digitally enabled future over the longer term.

Progress in 2019

We have continued to make strategic progress in fuels marketing, with our convenience partnership model now in around 1,600 sites across the network.

- Agreed to expand our partnership with Reliance Industries Ltd to include a retail service station network and aviation fuels business across India.
- Continued to expand in other material markets – most notably in Mexico where we now have more than 520 BP-branded retail sites. We also continued to grow our network in Indonesia and expanded our China network into Shandong and Hebei provinces through our joint venture with Dongming.
- Announced the development of *BP Infinia*, an enhanced recycling technology, capable of processing currently unrecyclable PET plastic waste.

>1,200
retail sites in new markets of China, Mexico and Indonesia.

~1,600
convenience partnership sites.

For more information see Downstream on page 56.

Venturing and low carbon across multiple fronts

What this strategic priority means

We aim to pursue new opportunities to meet evolving technology, consumer and policy trends.

We are building up our renewable energy portfolio – with activities spanning renewable fuels and products, wind and solar energy and biopower. We work across multiple fronts through our investments in low carbon activities with joint ventures, collaborations and new business models. Through BP Ventures we have invested more than $650 million in around 40 companies since it was set up in 2007. Our investments support technologies and innovations that we believe could benefit BP and global energy systems.

Progress in 2019

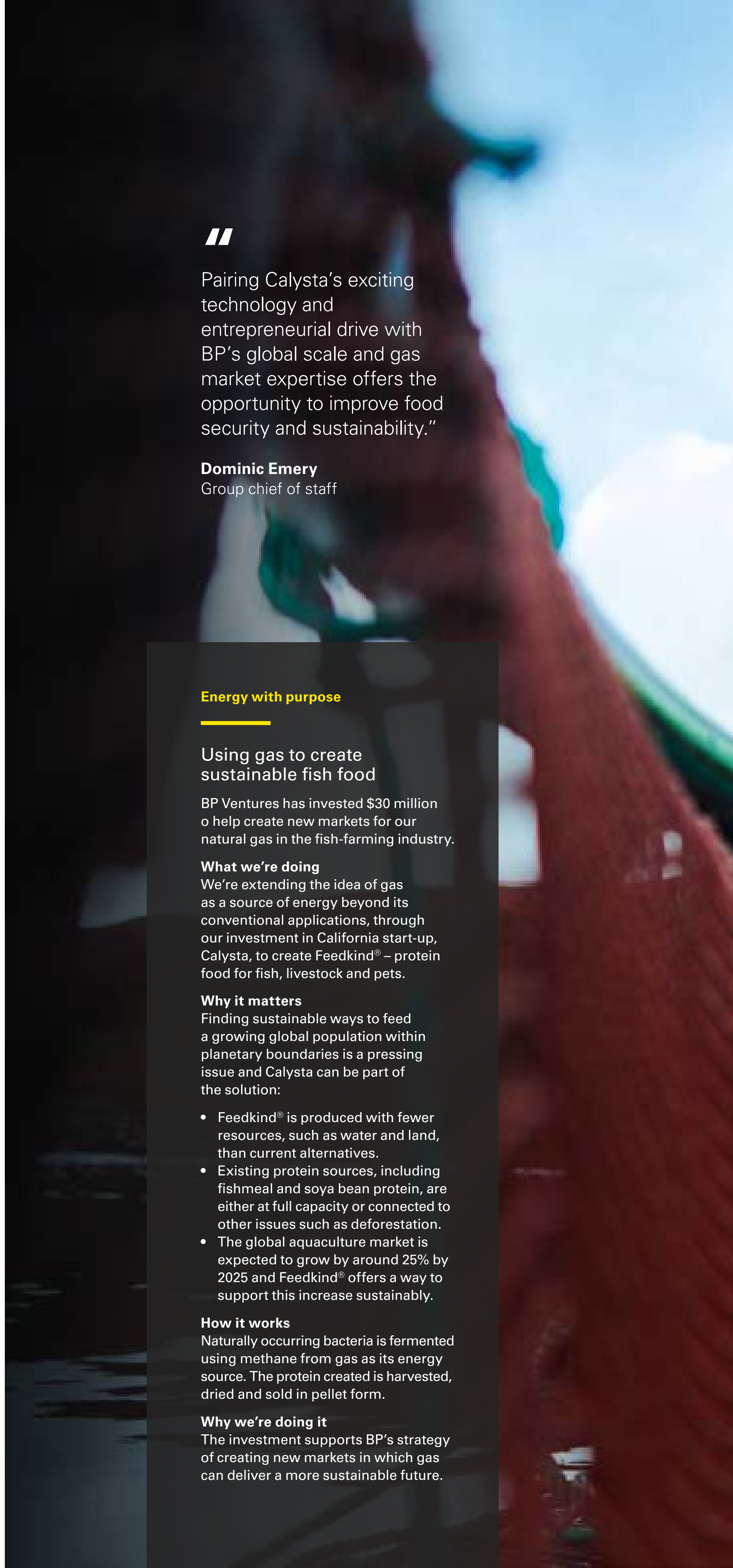
We increased our stake in Lightsource BP to create a 50:50 joint venture and expanded our biofuels business in Brazil by more than 50%, through a joint venture with Bunge to create BP Bunge Bioenergia. We also made a number of other investments spanning a range of strategic focus areas.

- Started BP Launchpad, our scale-up factory, designed to help quickly grow disruptive technologies and business models which could become future BP business units.
- Expanded our digital energy portfolio by investing in Grid Edge, which has developed an artificial intelligence-based energy management platform that helps customers predict, control and optimize their buildings' energy profile.
- Invested $5 million in Belmont Technology to further strengthen BP's artificial intelligence and digital capabilities.

>50%
increase in biofuels business in Brazil, through BP Bunge Bioenergia.

7
new investments through BP Ventures in 2019.

For more information see page 63.



"Pairing Calysta's exciting technology and entrepreneurial drive with BP's global scale and gas market expertise offers the opportunity to improve food security and sustainability."

Dominic Emery
Group chief of staff

Energy with purpose

Using gas to create sustainable fish food

BP Ventures has invested $30 million o help create new markets for our natural gas in the fish-farming industry.

What we're doing
We're extending the idea of gas as a source of energy beyond its conventional applications, through our investment in California start-up, Calysta, to create Feedkind® – protein food for fish, livestock and pets.

Why it matters
Finding sustainable ways to feed a growing global population within planetary boundaries is a pressing issue and Calysta can be part of the solution:

- Feedkind® is produced with fewer resources, such as water and land, than current alternatives.
- Existing protein sources, including fishmeal and soya bean protein, are either at full capacity or connected to other issues such as deforestation.
- The global aquaculture market is expected to grow by around 25% by 2025 and Feedkind® offers a way to support this increase sustainably.

How it works
Naturally occurring bacteria is fermented using methane from gas as its energy source. The protein created is harvested, dried and sold in pellet form.

Why we're doing it
The investment supports BP's strategy of creating new markets in which gas can deliver a more sustainable future.

> This programme reflects our commitment to be a leader in advancing the energy transition by maximizing the benefits of natural gas."

Gordon Birrell
Chief operating officer – production, transformation and carbon

Modernizing the whole group

What this strategic priority means

We aim to simplify our processes and enhance our productivity through digital solutions.

We achieve this through three pillars:

- Agility – improving and simplifying the way we operate.
- Mindset change – accepting the reality and adopting the right attitude for a business that is increasingly competitive and margin-dependent.
- Digital transformation – digitizing and automating our work.

Progress in 2019

We've introduced a range of technologies and improved ways of working across BP to support our modernization priority. Our mentors and coaches deliver a programme of training for employees to share agile practices and support changing mindsets, which are key to generating ideas to improve how we work across the whole business.

- Launched 'Connected BP' in partnership with data technology pioneer Palantir. The programme connects different systems and business areas into one platform where users can connect, transform and share data.
- Developed a holistic process for leak detection and intervention using infrared cameras, lasers and drone technology at our US onshore BPX Energy operations.
- Performed a concept trial of Spot, a robot from Boston Dynamics, at our US Whiting refinery. Spot can gather data, detect abnormalities and perform tasks, such as detecting gas emissions and helping remove people from hazardous spaces.

>1,000
transformation projects running in the Upstream.

~$1.5bn
invested every year in maintaining BP's infrastructure.

Energy with purpose

Managing methane

BP is introducing a programme of new and complementary technologies to continuously detect, measure and help reduce methane emissions at our BP-operated upstream assets.

Why it matters
Methane is the primary component of natural gas. If it escapes into the atmosphere unburnt, it can be a potent greenhouse gas.

What we're doing
We aim to install methane measurement, such as gas cloud imaging, at all BP's major oil and gas processing sites by 2023 and then reduce methane intensity of our operations by 50%.

What else?
We're also planning to deploy a new generation of drones, hand-held devices and multi-spectral flare combustion cameras – drawing upon scientific breakthroughs made in diverse fields, spanning healthcare, space exploration and defence.

Collaboration with stakeholders
We have agreed to work in collaboration with the Environmental Defense Fund, a New York-based non-profit environmental advocacy group. The three-year commitment aims to advance technologies and practices to reduce methane emissions from the global oil and gas supply chain.

Measuring our progress

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

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 executive management assess performance against our strategic priorities and business plans. BP management uses these measures to evaluate operating performance and make financial, strategic and operating decisions.

Changes to KPIs

- Added sustainable GHG emission reductions and methane intensity, in line with our 'reduce, improve, create' framework.
- Removed production as a volume measure as it doesn't reflect our value over volume approach, and is not used to assess executive remuneration. The metric is reported on At a glance, page 9.
- Combined tier 1 and tier 2 process safety events, giving investors a wider view of process safety events.
- As reported in 2018, we have now revised our refining availability metric to BP-operated refining availability, to more closely match our upstream plant reliability measure.

Remuneration

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

Key

New/amended
New or amended in 2019

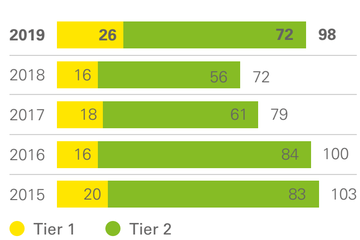
REM
Used for the remuneration policy

For more information see Directors' remuneration report on page 100.

Safety

Tier 1 and 2 process safety events[a]

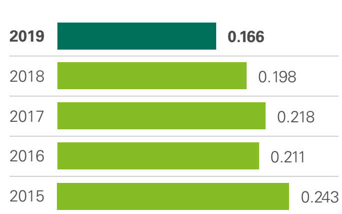
We track tier 1 and tier 2 events and report the aggregated outcome. Tier 1 events are losses of primary containment from a process of greatest consequence – causing harm to a member of the workforce, damage to equipment from a fire or explosion, a community impact or exceeding defined quantities. Tier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



2019 performance
The total number of tier 1 and tier 2 process safety events increased in 2019, mainly reflecting performance in assets acquired over the past 18 months. Underlying performance across the group improved slightly from 2018. We are implementing BP procedures and processes to help bring newly acquired assets in line with BP assets.

Reported recordable injury frequency[a]

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.



2019 performance
We have seen a decrease in RIF compared with 2018; and maintain our focus to drive toward zero incidents.

a 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.

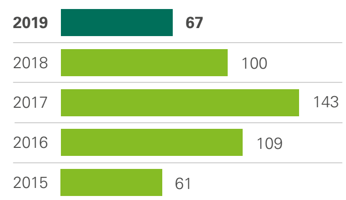
Sustainable operations

Proved reserves replacement ratio (%)

Proved reserves replacement ratio is 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. The ratio reflects both subsidiaries★ and equity-accounted entities.

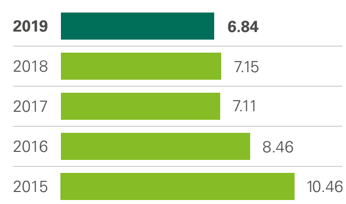
This measure helps to demonstrate our success in accessing, exploring and extracting resources.



2019 performance
The lower ratio reflects a net decrease of reserves due to lower gas and oil prices mainly within the US Lower 48, partly offset by new developments and existing field optimization in Angola, Argentina, Azerbaijan, India, Oman, Russia and the US.

Upstream unit production costs ● ($/boe)

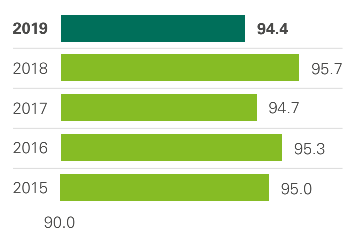
The upstream unit production cost indicator shows how supply chain, headcount and scope optimization impact cost efficiency.



2019 performance
Lower production costs compared with 2018 were mainly due to the impacts of IFRS 16.

Upstream plant reliability ● (%)

BP-operated upstream plant reliability★ is calculated as 100% less the ratio of total unplanned plant deferrals divided by installed production capacity.

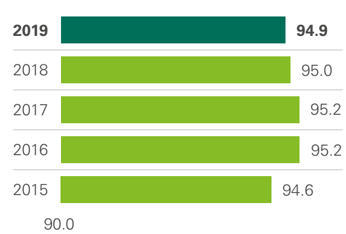


2019 performance
Plant reliability was 1.3% lower than 2018 mainly due to design and integrity issues addressed through maintenance activities.

Downstream refining availability ● ● (%)

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 deducting the time spent on turnaround activity and all mechanical, process and regulatory downtime.

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



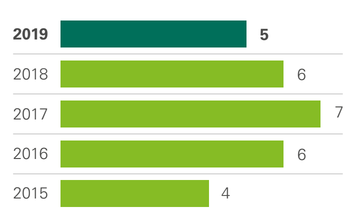
2019 performance
Refining availability was similar to 2018, reflecting continued strong operational performance in our portfolio. This performance is underpinned by our global reliability programmes.

Major project delivery

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.



2019 performance
We started up five major projects in Egypt, Trinidad, the UK and US.

Sustainable operations

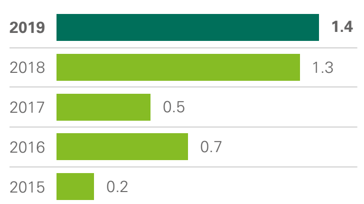
Greenhouse gas emissions ($MtCO_2e$)

We provide data on greenhouse gas (GHG) emissions material to our business on a carbon dioxide-equivalent basis. This particular KPI comprises Scope 1 (direct) emissions of CO_2 and methane, for 100% emissions from subsidiaries and the percentage of emissions equivalent to our share of joint arrangements★ and associates★, other than BP's share of Rosneft.

2019 performance
Our Scope 1 (direct) equity share emissions decreased by $0.5MtCO_2e$ to $46.0MtCO_2e$ in 2019 ($46.5MtCO_2e$ in 2018). Emissions resulting from the BHP acquisitions were balanced out by sustainable emissions reductions and the impact of divestments.

Sustainable GHG emissions reduction ●● ($MtCO_2e$)

This measure includes actions taken by our businesses to improve energy efficiency and reduce methane emissions and flaring – all leading to ongoing, quantifiable GHG reductions. These refer to the GHG emissions that would have occurred had we not made the change i.e. they could be absolute in nature or underlying. Since 2019, progress against this target is used as a factor in determining bonuses for around 37,000 employees, including executives.



2019 performance
We delivered 1.4Mte of sustainable emissions reductions (SERs), and this meant we exceeded our target of 3.5Mte of SERs for the period 2016 to 2025, six years ahead of schedule.

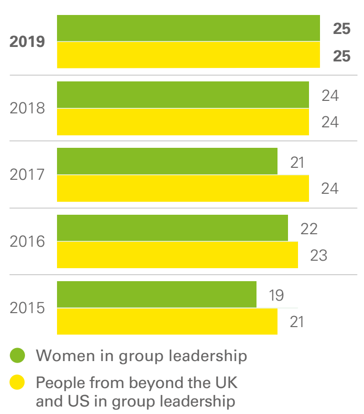
Methane intensity ● (%)

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. We have an existing methane target of 0.2% and a new ambition that seeks to reduce that – once validated – by 50%.

2019 performance
Our methane intensity was 0.14%, a reduction from 0.16% in 2018 and below our stated target of 0.2%.

Diversity and inclusion[b] (%)

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

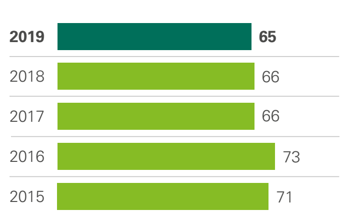


2019 performance
Both measures increased slightly. As a global business we are committed to increasing the diversity of our workforce and leadership.

b Relates to BP employees.

Employee engagement (%)

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



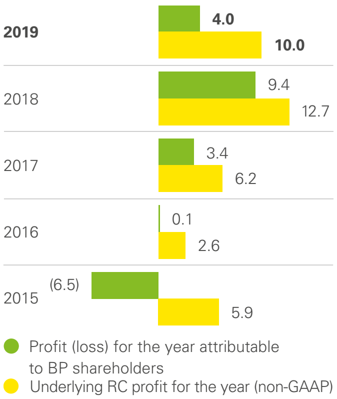
2019 performance
The overall employee engagement score saw a marginal decline since last year. We are working to identify areas for improvement. Scores prior to 2017 are based on questions on priorities set out in 2012, so the numbers are not directly comparable.

Financial performance

Underlying replacement cost profit ● ($ billion)

Underlying RC profit★ 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.

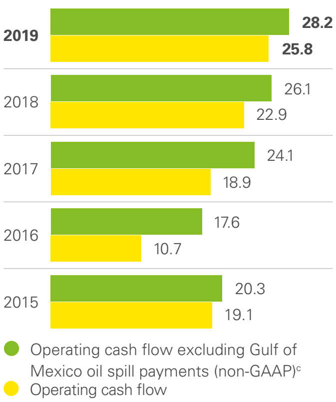
It reflects the replacement cost of inventories sold in the period and is arrived at by excluding inventory holding gains and losses★ from profit or loss. Adjustments are also made for non-operating items★ and fair value accounting effects★.



2019 performance
2019 underlying RC profit was lower, largely reflecting the impact of the weaker price environment. Profit for the year was significantly lower, due to the above factor, divestment-related impairment charges and reclassification of past foreign exchange losses on the formation of the BP Bunge Bioenergia joint venture.

Operating cash flow ● ($ billion)

Operating cash flow is net cash flow provided by operating activities, as reported in the group cash flow statement. Operating activities are the principal revenue-generating activities of the group and other activities that are not investing or financing activities. We believe it is helpful to disclose net cash provided by operating activities excluding amounts related to the Gulf of Mexico oil spill because this measure allows for more meaningful comparisons between reporting periods.

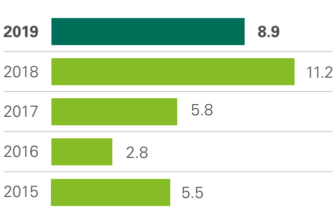


2019 performance
Operating cash flow was higher than 2018, reflecting lower Gulf of Mexico oil spill payments and the favourable impact of lease payments that are now classified as financing cash flows under IFRS 16.

c The green bars on the chart do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Return on average capital employed ● (%)

Return on average capital employed★ (non-GAAP) gives an indication of a company's capital efficiency, dividing the underlying RC profit after adding back net interest by average capital employed, excluding cash and goodwill. See page 345 for more information including the nearest equivalent GAAP data.

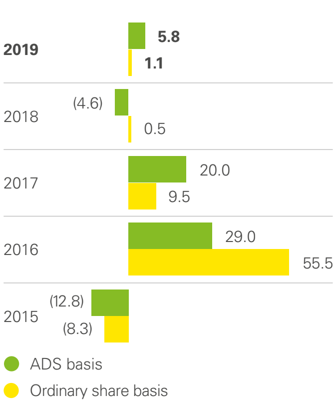


2019 performance
The decrease reflects lower profit due to the impact of lower oil and gas prices and weaker refining environment.

Total shareholder return ● (%)

Total shareholder return (TSR) represents the change in value of a BP shareholding over a calendar year. It assumes that dividends are reinvested to purchase additional shares at the closing price on the ex-dividend date.

We are committed to maintaining a progressive and sustainable dividend policy.



2019 performance
Improvement in TSR reflects increased dividends in 2019.

Group performance

"

Despite the challenging environment in 2019, we continued to deliver operating cash flow growth, which together with continued capital discipline has underpinned growth in free cash flow. Furthermore, we have made significant progress towards our $10 billion divestment target. Together this supported our decision to increase the dividend with the fourth-quarter results."

Dr Brian Gilvary
Group chief financial officer

$10.0bn

Underlying replacement cost (RC) profit★
(2018 $12.7bn)

$28.2bn

Operating cash flow excluding Gulf of Mexico oil spill payments★[a]
(2018 $26.1bn)

$4.0bn

Profit attributable to BP shareholders
(2018 $9.4bn)

$25.8bn

Operating cash flow★
(2018 $22.9bn)

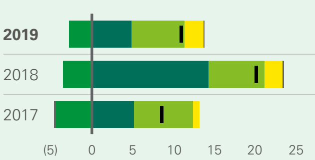
Financial and operating performance

$ million except per share amounts

	2019	2018	2017
Profit before interest and taxation	**11,706**	19,378	9,474
Finance costs and net finance expense relating to pensions and other post-retirement benefits	**(3,552)**	(2,655)	(2,294)
Taxation	**(3,964)**	(7,145)	(3,712)
Non-controlling interests	**(164)**	(195)	(79)
Profit for the year[b]	**4,026**	9,383	3,389
Inventory holding (gains) losses★, before tax	**(667)**	801	(853)
Taxation charge (credit) on inventory holding gains and losses	**156**	(198)	225
RC profit★	**3,515**	9,986	2,761
Net (favourable) adverse impact of non-operating items★ and fair value accounting effects★ before tax	**8,263**	3,380	3,730
Taxation charge (credit) on non-operating items and fair value accounting effects	**(1,788)**	(643)	(325)
Underlying RC profit	**9,990**	12,723	6,166
Dividends paid per share – cents	**41.0**	40.5	40.0
– pence	**31.977**	30.568	30.979

a This does not form part of BP's Annual Report on Form 20-F as filed with the SEC.
b Profit (loss) attributable to BP shareholders.

Segment RC profit (loss) before interest and tax
($ billion)



● Upstream ● Downstream ● Rosneft
● Other businesses and corporate (includes costs related to the Gulf of Mexico oil spill)
● Consolidation adjustment – UPII★
❙ Group RC profit before interest and tax

More information

Upstream, see page 50.
Downstream, see page 56.
Rosneft, see page 61.
Other businesses and corporate, see page 63.
Oil and gas disclosures for the group, see page 308.

For a discussion of BP's financial and operating performance for the year ending 31 December 2017, see *BP Annual Report and Form 20-F 2018*, pages 19-39 and *BP Annual Report and Form 20-F 2017*, pages 21-43.

Results

Profit for the year ended 31 December 2019 attributable to BP shareholders was $4.0 billion, compared with $9.4 billion in 2018. Excluding inventory holding gains, replacement cost (RC) profit was $3.5 billion, compared with $10.0 billion in 2018.

After adjusting RC profit for a net charge for non-operating items of $7.2 billion and net favourable fair value accounting effects of $0.7 billion (both on a post-tax basis), underlying RC profit for the year ended 31 December 2019 was $10.0 billion, a decrease of $2.7 billion compared with 2018. The decrease was predominantly due to lower oil and gas prices in the Upstream segment and a significantly weaker environment in the Downstream segment.

Profit for the year ended 31 December 2018 attributable to BP shareholders was $9.4 billion, including inventory holding losses, RC profit was $10.0 billion. After adjusting RC profit for a net charge for non-operating items of $2.8 billion and net favourable fair value accounting effects of $68 million (both on a post-tax basis), underlying RC profit for the year ended 31 December 2018 was $12.7 billion. This reflected higher oil prices, record plant reliability and the benefit of new major projects start-ups in Upstream; stronger refining margins and strong fuels marketing growth in Downstream; and higher oil prices in Rosneft segment.

Non-operating items

The net charge for non-operating items was $7.2 billion after tax in 2019, mainly related to impairment charges, principally resulting from the announcements to dispose of certain assets in the US and reclassification of accumulated foreign exchange losses from reserves to the income statement on the formation of the BP Bunge Bioenergia joint venture★.

The net charge for non-operating items was $2.8 billion post-tax in 2018, mainly related to additional charges for the Gulf of Mexico oil spill, environmental and other provisions, and further restructuring costs.

More information on non-operating items and fair value accounting effects can be found on pages 300 and 344.

Taxation

The charge for corporate income taxes was $3,964 million in 2019 compared with $7,145 million in 2018. The decrease mainly reflects the lower level of profit in 2019. The effective tax rate (ETR) on the profit or loss for the year was 49% in 2019 and 43% in 2018. The ETR for both years was impacted by various one-off items.

Adjusting for inventory holding impacts, non-operating items and fair value accounting effects, the underlying ETR★ was 36% in 2019 (2018 38%). The lower underlying ETR in 2019 compared with 2018 reflects the reassessment of the recognition of deferred tax assets. In the current environment, the underlying ETR in 2020 is expected to be lower than 40%.

Cash flow and net debt information

			$ million
	2019	2018	2017
Operating cash flow excluding Gulf of Mexico oil spill payments[a]	**28,199**	26,091	24,098
Operating cash flow	**25,770**	22,873	18,931
Net cash used in investing activities	**(16,974)**	(21,571)	(14,077)
Net cash used in financing activities	**(8,817)**	(4,079)	(3,296)
Cash and cash equivalents at end of year	**22,472**	22,468	25,586
Capital expenditure★			
Organic capital expenditure★	**(15,238)**	(15,140)	(16,501)
Inorganic capital expenditure★	**(4,183)**	(9,948)	(1,339)
	(19,421)	(25,088)	(17,840)
Finance debt	**67,724**	65,132	62,574
Net debt★	**45,442**	43,477	37,819
Finance debt ratio★ (%)	**40.2%**	39.3%	38.6%
Gearing★ (%)	**31.1%**	30.0%	27.0%

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

Operating cash flow

Operating cash flow for the year ended 31 December 2019 was $25.8 billion, $2.9 billion higher than 2018. Operating cash flow in 2019 reflects $2.7 billion of pre-tax cash outflows related to the Gulf of Mexico oil spill. Compared with 2018, operating cash flows in 2019 also reflected the favourable effect of an estimated $2.0 billion of lease payments being classified as financing cash flows from 1 January 2019 following the implementation of IFRS 16.

Movements in working capital★ adversely impacted cash flow in the year by $2.9 billion, including an adverse impact on working capital from the Gulf of Mexico oil spill of $2.6 billion. BP actively manages its working capital balances to optimize and reduce volatility in cash flow.

Operating cash flow for the year ended 31 December 2018 was $22.9 billion, reflecting $3.5 billion of pre-tax cash outflows related to the Gulf of Mexico oil spill.

Movements in working capital adversely impacted cash flow in the year by $4.8 billion. There was an adverse impact on working capital from the Gulf of Mexico oil spill of $3.1 billion. Other working capital effects, principally an increase in other current and non-current assets partially offset by a decrease in inventory, had an adverse effect of $1.7 billion.

Net cash used in investing activities

Net cash used in investing activities for the year ended 31 December 2019 decreased by $4.6 billion compared with 2018.

The decrease mainly reflected the phasing of the payments to BHP for the Petrohawk acquisition.

Total capital expenditure for 2019 was $19.4 billion (2018 $25.1 billion), of which organic capital expenditure was $15.2 billion (2018 $15.1 billion). Sources of funding are fungible, but the majority of the group's funding requirements for new investment comes from cash generated by existing operations. We expect 2020 organic capital expenditure to remain towards the lower end of our $15-17 billion range.

Total divestment and other proceeds for 2019 amounted to $2.8 billion including $0.6 billion received in relation to the sale of a 49% interest in BP's retail property portfolio in Australia, shown within financing activities in the group cash flow statement. Total divestment and other proceeds for 2018 amounted to $3.5 billion including a $0.6 billion loan repayment, relating to the refinancing of Trans Adriatic Pipeline AG.

BP expects to meet its target of $10 billion proceeds by end-2020 and expects to announce a further $5 billion of agreed disposals by mid-2021.

Net cash used in financing activities

Net cash used in financing activities for the year ended 31 December 2019 was $8.8 billion, compared with $4.1 billion in 2018. This was mainly as a result of $2.3 billion in lease liability repayments which were presented as operating cash flows and capital expenditure prior to the implementation of IFRS 16, an increase of $1.5 billion in debt financing, an increase of $1.2 billion in net repurchase of shares and an increase in dividend payments of $0.3 billion offset by $0.6 billion in cash received in relation to the sale of the 49% interest in BP's retail property portfolio in Australia as described above.

Total dividends distributed to shareholders in 2019 were 41.0 cents per share, 0.5 cents higher than 2018. This amounted to a total distribution to shareholders of $8.3 billion (2018 $8.1 billion), of which shareholders elected to receive $1.4 billion (2018 $1.4 billion) in shares under the scrip dividend programme. The total distributed in cash during the year amounted to $6.9 billion (2018 $6.7 billion).

Debt

Finance debt at the end of 2019 increased by $2.6 billion from the end of 2018. The finance debt ratio at the end of 2019 increased by 0.9%. Net debt at the end of 2019 increased by $2.0 billion from the 2018 year-end position. Gearing at the end of 2019 increased by 1.1%. Net debt and gearing are non-GAAP measures. See Financial statements – Note 26 for finance debt, which is the nearest equivalent measure on an IFRS basis, and Note 27 for further information on net debt, including the amendment of comparative information for finance debt, net debt and gearing following the implementation of IFRS 16.

For information on financing the group's activities, see Financial statements – Note 29 and Liquidity and capital resources on page 301.

Group reserves and production (including Rosneft segment)[a]

			$ million
	2019	2018	2017
Estimated net proved reserves (net of royalties)			
Liquids★ (mmb)	**11,478**	11,456	10,672
Natural gas (bcf)	**45,601**	49,239	45,060
Total hydrocarbons★ (mmboe)	**19,341**	19,945	18,441
Of which:			
Equity-accounted entities[b]	**9,965**	9,757	8,949
Production (net of royalties)			
Liquids (mb/d)	**2,211**	2,191	2,260
Natural gas (mmcf/d)	**9,102**	8,659	7,744
Total hydrocarbons (mboe/d)	**3,781**	3,683	3,595
Of which:			
Subsidiaries★	**2,420**	2,328	2,164
Equity-accounted entities[c]	**1,360**	1,355	1,431

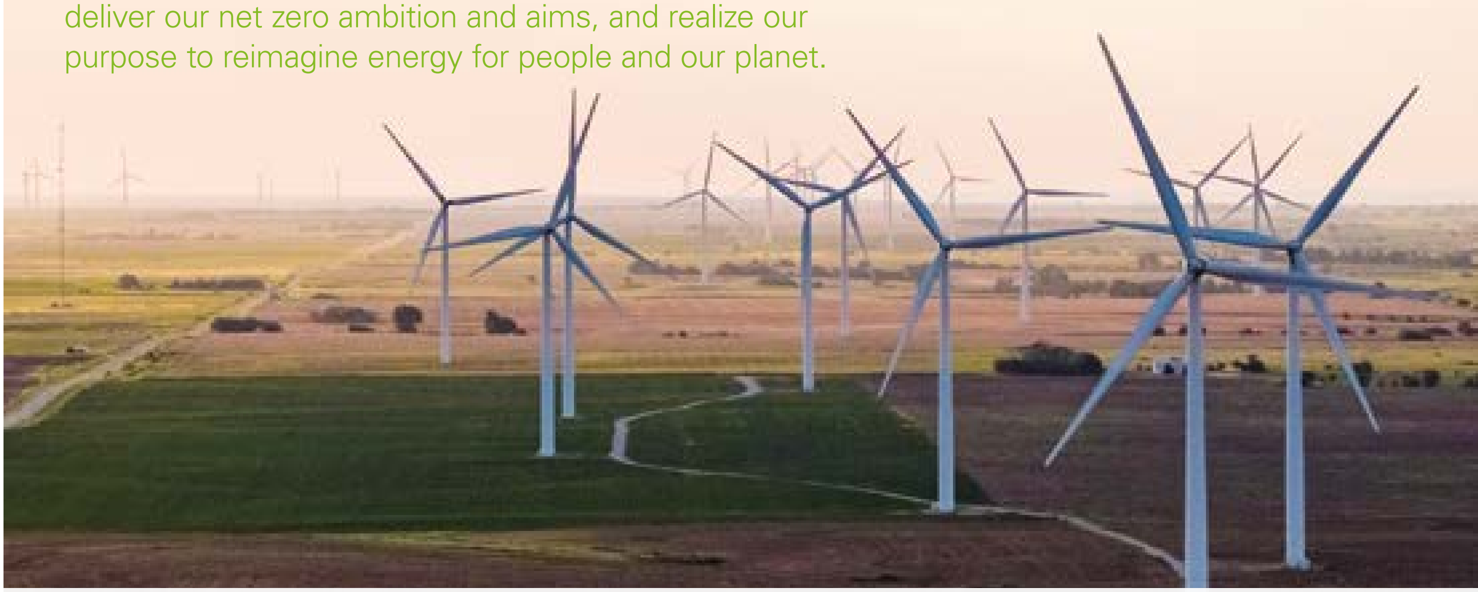
a Because of rounding, some totals may not agree exactly with the sum of their component parts.
b Includes BP's share of Rosneft. See Rosneft on page 61 and Supplementary information on oil and natural gas on page 232 for further information.
c Includes BP's share of Rosneft. See Rosneft on page 61 and Oil and gas disclosures for the group on page 308 for further information.

Total hydrocarbon proved reserves at 31 December 2019, on an oil equivalent basis including equity-accounted entities, decreased by 3% (decrease of 8% for subsidiaries and increase of 2% for equity-accounted entities) compared with 31 December 2018. Natural gas represented about 41% (48% for subsidiaries and 34% for equity-accounted entities) of these reserves. The change includes a net decrease from acquisitions and disposals of 133mmboe (decrease of 134mmboe within our subsidiaries and increase of 1mmboe within our equity-accounted entities). Acquisition activity in our subsidiaries occurred in India, and divestment activity in our subsidiaries in the US and Egypt. There were no material acquisitions or divestments in our equity-accounted entities.

Total hydrocarbon production for the group was 3% higher compared with 2018. The increase comprised a 4% increase (1% increase for liquids and 7% increase for gas) for subsidiaries and was broadly flat with 2018 for equity-accounted entities.

Sustainability

Operating sustainably, safely and responsibly is core to our ability to create long-term value for our stakeholders, deliver our net zero ambition and aims, and realize our purpose to reimagine energy for people and our planet.



Our sustainability focus areas

We refreshed and expanded our sustainability materiality assessment process in 2019. We asked a range of external and internal stakeholders, including shareholders and employees, to share their feedback on the issues that matter most to them. We also asked them to consider the relative impact of these issues on our business and how they think BP can influence them positively. We validated and prioritized the findings with experts in BP to help prioritize our sustainability reporting. We've covered the main issues they consider in this section, along with additional key non-financial information.

Our reporting

- For more information on our sustainability performance, see the *BP Sustainability Report 2019*.
- For key environmental, social and governance data, see our ESG datasheet at *bp.com/ESGdata*.
- For our mapping to some key sustainability frameworks and standards, including GRI and IPIECA, see *bp.com/reportingcentre*.

Environment	• Climate change and the energy transition. • Net zero★ aims. • Carbon intensity of our products. • GHG emissions from our operations. • Our 'reduce, improve, create' framework.	• Accrediting our low carbon activities. • Calling for more progressive climate policies • Climate-related financial disclosures. • Working with others. • Managing our impacts.
Safety and security	• Keeping people safe. • Managing safety. • Our operating management system★. • Preventing incidents. • Emergency preparedness.	• Cyber threats. • Security. • Working with contractors • Our partners in joint arrangements★.
Our people	• Attraction and retention. • Diversity. • Inclusion.	• Employee engagement. • Share ownership.
Communities	• Value to society.	• Human rights.
Governance and business ethics	• Our values. • The BP code of conduct. • Anti-bribery and corruption.	• Lobbying and political donations. • Trade associations. • Tax and transparency.

Non-financial reporting information statement

This sustainability section, and other pages referenced below, provide information as required by section 414CB of the Companies Act 2006 in relation to:

	Page
Environmental matters	40-45
Our employees	47, 88-89, 221
Social matters	48
Human rights	48
Anti-bribery and corruption	49

Other related information	Page
Business model	14-15
Strategy	16-18
Non-financial KPIs	32-34
Principal risks	69-71
Policies	39-49, 68-69

Environment

Climate change and the energy transition

The world needs more energy to fuel prosperity and improve standards of living for a growing global population. This energy must be delivered in affordable and reliable ways, but it must also be lower carbon. BP's purpose is to reimagine energy for people and our planet. To deliver this, we have set out a new ambition to become a net zero★ company by 2050 or sooner, and to help the world reach net zero.

Net zero aims

Aim 1: Net zero operations
We aim to be net zero across our entire operations on an absolute basis by 2050 or sooner. This aim relates to Scope 1 (direct) and Scope 2 (indirect) greenhouse gas (GHG) emissions.

Aim 2: Net zero oil and gas
We aim to be net zero on an absolute basis across the carbon in our upstream oil and gas production by 2050 or sooner. This is our Scope 3 aim, and is on a BP equity share basis excluding Rosneft. This carbon was equivalent to 360MteCO_2e[a] of emissions in 2019.

Scope 3

There are 15 categories of Scope 3 emissions. For our industry the most important of these categories is the 'use of sold products' (category 11). For this category of Scope 3, we are reporting for the first time the estimated CO_2 emissions from the carbon in our upstream oil and gas production[a]. This metric replaces the 'customer emissions' metric, which we previously reported in our Sustainability Report. For more information see *bp.com/sustainabilityreport*.

a This figure assumes that 100% of the oil and gas produced is combusted with no carbon capture, use and storage, although a proportion of global oil and gas goes into non-combusted uses, such as petrochemicals and lubricants.

Aim 3: Halving intensity
Our aim is to cut the carbon intensity of the products we sell by 50%, by 2050 or sooner. This is a lifecycle GHG emissions intensity approach, per unit of energy. It covers marketing sales of energy products and, potentially, in the future, certain other products, such as those associated with land carbon projects.

This metric also responds to the CA100+ resolution, which requires us to report the estimated carbon intensity of our energy products.

Estimated emissions intensity (gCO_2e/MJ)

	2019
Average emissions intensity of marketed energy products★	79.7
Refined energy products	93.7
Gas products	71.6
Bio-products	28.8
Power products	43.8

Greenhouse gas emissions from our operations

We report Scope 1 (direct) and Scope 2 (indirect) GHG emissions on a carbon dioxide equivalent (CO_2e) basis. Direct emissions include CO_2 and methane from the combustion of fuel and the operation of facilities, and indirect emissions include those resulting from the purchase of electricity and steam we import into our operations.

Our overall emissions, on an operational control basis, increased in 2019, mainly due to major acquisitions. But the SERs we achieved came close to countering this increase. We achieved zero net growth in our operational emissions with no offsets required against our adjusted 2015 baseline★.

Greenhouse gas emissions (MteCO_2e)[a]

Operational control[b]

	2019	2018	2017
Scope 1 (direct) emissions	**49.2**	48.8	50.5
Scope 2 (indirect) emissions	**5.2**	5.4	6.1
Total	**54.4**	54.2	56.6

BP equity share[c]

	2019	2018	2017
Scope 1 (direct) emissions	**46.0**	46.5	49.4
Scope 2 (Indirect) emissions	**5.7**	5.7	6.8
Total	**51.7**	52.2	56.2

a Our approach to reporting GHG emissions broadly follows the IPIECA/API/IOGP Petroleum Industry Guidelines for Reporting GHG Emissions. We calculate CO_2 emissions based on the fuel consumption and fuel properties for major sources. 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 and it is not practical to collect this data.
b Operational control data comprises 100% of emissions from activities that are operated by BP, going beyond the IPIECA guidelines by including emissions from certain other activities such as contracted drilling activities.
c BP equity share data comprises 100% of emissions from subsidiaries★ and the percentage of emissions equivalent to our share of joint arrangements★ and associates★, other than BP's share of Rosneft.

Ratio of Scope 1 (direct) and Scope 2 (indirect) GHG emissions to gross production (teCO_2e/te)[d]

2019	2018	2017	2016
0.22	0.22	0.24	0.24

d Gross production comprises upstream production, refining throughput and petrochemicals produced.

Our 'reduce, improve, create' framework

In 2018 we set out our low carbon ambition and targets in our 'reduce, improve, create' (RIC) framework:

- Reducing GHG emissions in our own operations.
- Improving products to help our customers and consumers lower their emissions.
- Creating low carbon businesses.

In 2019 we announced plans to link our annual cash bonus to our sustainable emissions reduction (SER) target. This means around 37,000 employees, including executives, are now incentivized and rewarded for their contribution to reducing carbon emissions in BP.

We've met our SER target six years ahead of schedule and this has motivated us to start work to set new targets. We plan to provide more detail in September 2020.

Reducing
emissions in our operations

2019 progress

- Achieved zero net growth in operational emissions. Our total GHG emissions (operated) increased slightly in 2019, largely due to the major acquisitions at the end of 2018. This was countered by other emissions reductions. Total emissions were still below the adjusted 2015 baseline so no offsets were required.
- 1.4Mte of SERs delivered in 2019 and 3.9Mte since 2016. And we linked this target to the annual cash bonus of around 37,000 eligible employees in 2019.
- Methane intensity of 0.14%, below our target of 0.2%.

Improving
our products

2019 progress

- Continued to scale up our co-processing business, growing the volume of lower carbon bio-feedstock processed at our refineries.
- Established more than 30 carbon neutral BP retail sites, offering a range of carbon neutral products and services.
- Increased the supply of BP biojet, our sustainable aviation fuel, to 11 locations worldwide – including in Sweden, France and the US.

Creating
low carbon businesses

2019 progress

- Began rolling out BP Chargemaster ultra-fast charging across BP forecourts in the UK and piloted ultra-fast charging at *Aral* forecourts in Germany.
- Increased our stake in Lightsource BP, to create a 50:50 joint venture, see page 73.
- Took a leading role in the OGCI's Net Zero Teesside project in the UK. Using integrated carbon capture, use and storage, the project aims to store the carbon dioxide emissions of the carbon-intensive industries situated within the Teesside industrial cluster.

More information
Our strategy on page 16.
Directors' remuneration report on page 100.
bp.com/sustainability.

Accrediting our lower carbon activities

Our advancing low carbon (ALC) accreditation programme aims to inspire every part of BP to identify lower carbon opportunities. Since its launch, the programme has motivated people across BP to do more to advance low carbon, with 76 activities being accredited in 2019. Each activity supports one of our low carbon ambitions. Deloitte conducts independent assurance on ALC activities. We estimate that 64MteCO_2e have been saved or offset through activities delivered by BP, and 5.4Mte through activities delivered by BP partners since the programme began in 2017[a].

See *bp.com/advancinglowcarbon* for details on the programme and Deloitte's assurance statement.

a The total emissions saved or offset from the accredited activities are estimated using a variety of methodologies and baselines. The figures aim only to illustrate the impact of the activities within the programme, and delivered by BP or a BP partner only refers to the organization leading on delivering the activity. Savings or offsets may be claimed by or attributed to other parties. The scope of accredited activities is wider than, and does not seek to align with, our GHG reporting boundaries. Therefore, the figures are not directly comparable to BP's reported emissions.

Calling for more progressive climate policies

We plan to allocate more resources to advocate for well-designed policies, including carbon pricing. We believe carbon pricing is the most efficient way to reduce GHG emissions and incentivize everyone, including energy producers and consumers, to play their part. In our view, pricing can be as effective as a tax or a cap-and-trade system.

While we support well-designed carbon pricing, we're prepared to oppose poorly designed proposals. For example, we opposed the ballot initiative to introduce a carbon fee in Washington State, US in November 2018. We believed that the policy was badly designed and would have harmed Washington's economy without significantly reducing carbon emissions. The ballot was not passed.

We continued to work with legislative leaders in the state and in 2019 supported a cap-and-invest bill, which we believe will be more effective. We intend to continue working with the Washington legislature during its 2020 session to see if a new carbon bill can be advanced.

Climate-related financial disclosures

We support the recommendations of the Task Force on Climate-related Financial Disclosures (TCFD), which was established by the Financial Stability Board with the aim of improving the reporting of climate-related risks and opportunities. We intend to work constructively with the TCFD, and others, to develop good practices and standards for transparency. This will be a multi-year journey, but we have already started, and our latest reporting provides information supporting the TCFD's recommended disclosures.

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

The board

The board is responsible for the overall conduct of the group's business, which extends to setting our strategy and approach to the energy transition. The board and its associated committees, where appropriate, have oversight of climate-related matters (which include issues and opportunities) and are updated on these matters as frequently as necessary. In 2019 climate matters were included on the agenda for each of the six board meetings. This informed the board's consideration of strategy.

The process by which the board is updated on climate-related matters is managed by our company secretary's office and depends on the topic being discussed. In 2019 these processes included formal analysis of our RIC targets, briefings with subject matter experts from the business and the preparation and consideration of corporate reporting documents and AGM materials. The board has reviewed the consistency of our current strategy with the Paris goals, see page 17.

The executive

The assessment and management of climate-related matters is embedded across BP at various levels and delegated authority flows down from the board, see page 83.

Climate-related matters were discussed at each of the 11 executive team meetings in 2019 including the development of BP's net zero ambition and aims ahead of discussion with the board.

The executive team is supported by BP's senior-level leadership and their respective teams, with dedicated business and functional expertise focused on climate-related matters. This includes our carbon management, safety and operational risk, group policy and our economics teams.

Alignment between group, business and functional leaders is fostered through cross-functional bodies, including the group, upstream and downstream carbon steering committees.

Climate governance: investments in 2019

BP board

Considers investment cases deemed sufficiently material to warrant the board's attention.

New business models

Renewal committee

Reviews strategic, commercial and investment decisions outside of core activity and related to new lines of business (up to $250 million organic and $25 million inorganic capital investment). Chaired by our chief transition officer.

New energy frontiers steering committee

Oversees strategy and development of growth opportunities in low carbon business models that can be scaled up to create new businesses for BP. Chaired by our chief transition officer.

Ventures investment committee

Oversees strategic, commercial and investment decisions in venturing business. Chaired by our group head of technology.

BP Launchpad

Launchpad is BP's business-builder and scale-up factory. Its mission is to build five $1 billion business unicorns. Chaired by our group head of technology.

Existing and new business models

Resource commitment meeting

Reviews strategic, commercial and investment decisions related to existing and new lines of business (above $250 million organic and $25 million inorganic capital investment). Chaired by our chief executive.

- Executive-level committee.
- Cross-functional committee.

Strategy

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.

We recognize the significance of the energy transition and the risks and opportunities it presents. As part of their consideration of BP's strategy, the board and executive team consider risks and opportunities associated with climate change and the energy transition informed by a range of external inputs, including the International Panel on Climate Change (IPCC), academic research and emerging regulatory requirements, and BP materials such as the different scenarios described in the *BP Energy Outlook 2019*.

We believe that the transition to a lower carbon economy presents significant business opportunities for BP. One of our strategic priorities is to pursue new opportunities to meet evolving technology, consumer and policy trends through venturing and low carbon, see page 28. Some of the opportunities we see are set out in our RIC framework – to improve our products, to help customers lower their emissions and to create new, lower carbon businesses, see page 41.

We have set out 10 aims to support our ambition to be a net zero company by 2050 or sooner and to help the world reach net zero. We believe that collectively, these 10 aims set out a path that is consistent with the Paris goals. One of our specific aims relates to halving the carbon intensity of our marketed products by 2050 or sooner.

i See page 6 for more information on our net zero ambition and aims.

For the first time we have published the estimated lifecycle carbon intensity of our marketed energy products, see page 40.

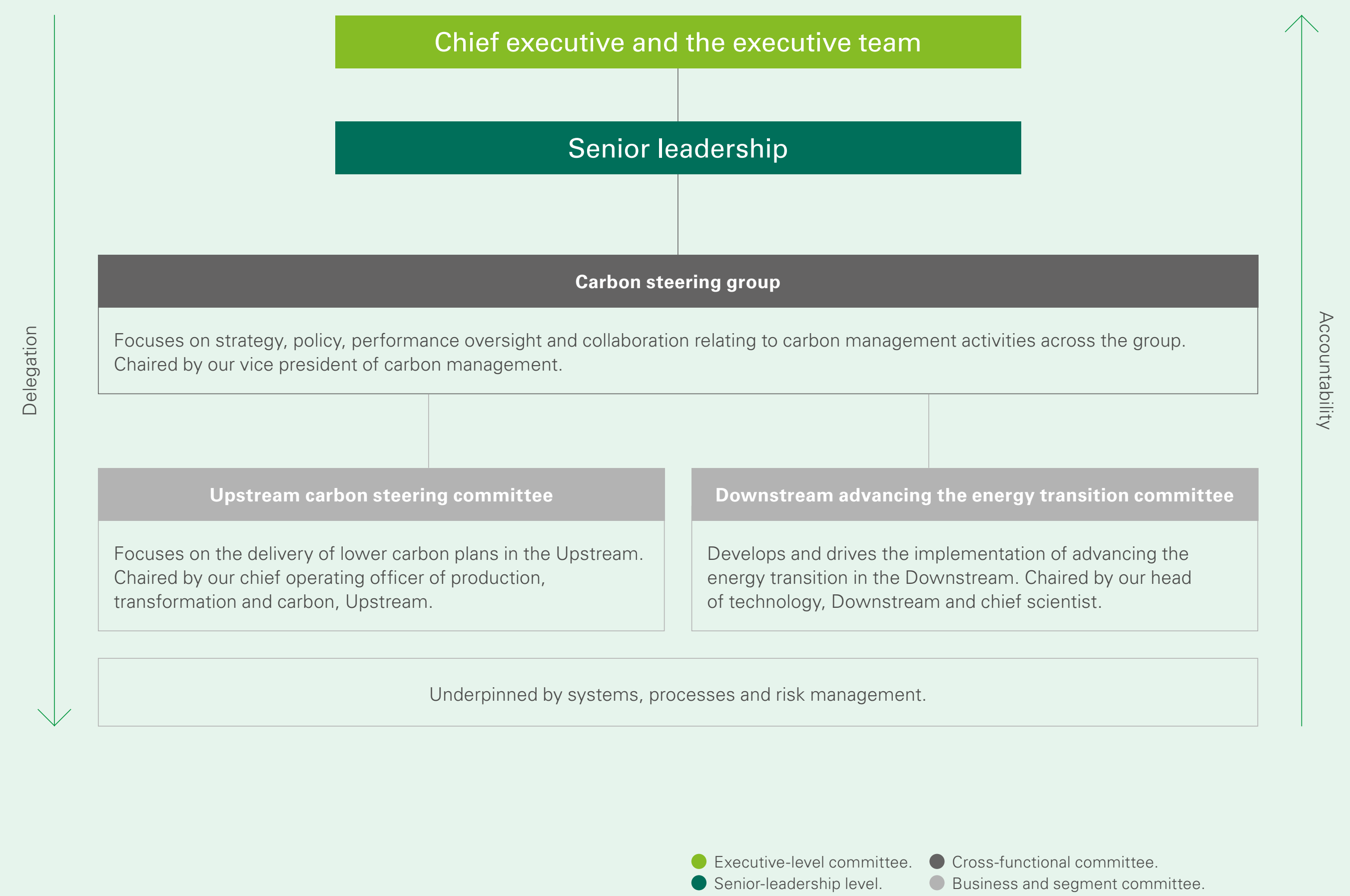
We recognize that climate-related risks include both:

- **Physical risks** – risks related to the physical impacts of climate change including event driven risks such as changes in the severity and/or frequency of extreme weather events.
- **Transition risks** – risks related to the transition to a lower carbon economy including policy and legal, technology, markets and reputational risks.

The potential impacts of such climate-related risks are described in Risk factors, see pages 70-71. We place importance on pursuing a flexible strategy which gives us optionality where there is uncertainty about the pathways to achieve the Paris goals. This positions us to deliver our strategic priorities, and net zero ambition and aims.

When developing our strategy, we draw on expertise from across the organization. This includes our group economics team and their work on the scenarios described in the *BP Energy Outlook 2019*. The Energy Outlook, together with other scenarios, informs our price assumptions which are part of our investment governance processes. The evaluation of new material capex investment in 2019 for consistency with the Paris goals is discussed on page 21.

Climate governance: management of climate-related matters in 2019



Our group strategic planning team is responsible for using data from the *BP Energy Outlook* and implementing the insights in our strategic frameworks, including our net zero ambition and mid-term RIC targets. We recognize that climate-related risks are an important consideration in developing our strategy. Climate-related risks are incorporated into BP's governance process, see How we manage risk on page 69.

Risk management

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

Our processes for identifying and managing climate-related risks are integrated into BP's risk management policy and the associated risk management procedures. BP's risk management system is designed to address all types of risks and as part of this system our operating businesses are responsible for identifying and managing their risks. 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 planning process we review the group's principal risks and uncertainties. Climate change and the transition to a lower carbon economy has been identified as a principal risk, see page 69. This covers various aspects of how risks associated with the energy transition could manifest. Similarly, physical climate-related risks such as extreme weather are covered in our principal risks related to safety and operations.

Metrics and targets

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 on page 17. This includes the targets we set out in 2018 in our RIC framework.

In addition, in 2019 BP announced that sustainable GHG emissions reductions would be included as a factor in the reward of around 37,000 eligible employees across the group and around the world, including executive directors. This target was 10% of the group's annual cash bonus scorecard and we exceeded the target set of 1.0Mte (1.4Mte). In 2020 we plan to increase the percentage of remuneration which is linked to emissions reductions for our leadership and eligible employees. Our aim is to mobilize our workforce to become advocates for our net zero ambition.

i For information on our 2020 remuneration policy, see page 110.

TCFD index table

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 42.
	b. Describe the management's role in assessing and managing climate related risks and opportunities.	Page 42.
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.	Achieving the Paris goals, page 13 – for a discussion of the different pathways and time horizons considered RIC framework, page 41 – for an outline of opportunities. Risk factors, pages 70-71 – description of principal risks.
	b. Describe the impact of climate-related risks and opportunities on the organization's businesses, strategy, and financial planning.	Risk factors, pages 70-71 – description of principal risks.
	c. Describe the resilience of the organization's strategy, taking into consideration different climate-related scenarios, including a 2°C or lower scenario.	Achieving the Paris goals, page 13. Our strategy, page 16.
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 44. Upstream, page 50. Downstream, page 56. Other businesses and corporate, page 63.
	b. Describe the organization's processes for managing climate-related risks.	Risk management, page 44.
	c. Describe how processes for identifying, assessing, and managing climate-related risks are integrated into the organization's overall risk management.	Risk management, page 44. How we manage risk, pages 68-69. Risk factors, pages 70-71.
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.	Relevant group-wide metrics and targets, page 17.
	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.	RIC framework, page 41. (Also note: Net zero ambition and aims, page 6).

Working with others

We work with peers, non-governmental organizations and academic institutions to support the energy transition.

The Oil and Gas Climate Initiative (OGCI) brings together 13 oil and gas companies to increase the ambition, speed and scale of the initiatives undertaken by its individual companies to help reduce manmade GHG emissions. OGCI announced a collective methane intensity target for member companies in 2018.

i For more information on BP's methane intensity, see page 34.

BP is working with OGCI Climate Investments and certain other OGCI member companies to help progress the UK's first commercial full-chain carbon capture, use and storage project. Net Zero Teesside plans to capture CO_2 from new, efficient gas-fired power generation and transport it by pipeline to be stored in a formation under the southern North Sea. The infrastructure would also allow other industries in Teesside to store CO_2 captured from their processes. The project, which is currently undergoing a feasibility study, could be in operation by the mid-2020s.

Managing our impacts

We work hard to avoid, mitigate and manage our environmental and social impacts over the life of our operations.

The way our businesses around the world are expected to understand and manage their environmental and social impacts is set out in our operating management system★ (OMS). This includes requirements on engaging with stakeholders who may be affected by our activities.

In planning our projects, we identify potential impacts from our activities in areas such as land rights, water use and protected areas. We use the results of this analysis to identify actions and mitigation measures and look to implement these in project design, construction and operations. For example, in Mauritania and Senegal we are working with national and international scientists on the biodiversity action plan for the Greater Tortue Ahmeyim development.

Our OMS requires each of BP's operating businesses and functions to create and maintain its own OMS handbook, describing how it will carry out its local operating activities. Through self-verification, local business processes are reviewed and areas for improvement are prioritized, allowing focus on delivering safe, reliable and compliant operations.

i For information on our oil spill performance see page 46.

Water
We review water risks every year, taking into account availability, quantity, quality and regulatory requirements. We also use a range of tools, including the Global Environmental Management Initiative Local Water Tool and the World Resources Institute Aqueduct Global Water Risk Atlas.

In 2019 we saw a 4% rise in freshwater withdrawals and a 3% rise in freshwater consumption. This was largely due to increased production, with freshwater withdrawal and consumption intensities remaining flat, compared with 2018.

Air emissions
We put measures in place to manage our air emissions, in line with regulations and industry guidelines designed to protect the health of local communities and the environment. In 2019 we took delivery of the last three vessels in our new fleet of six liquefied natural gas (LNG) carriers. These use around 25% less fuel and emit less nitrogen oxides than the older LNG carriers in the BP operated fleet.

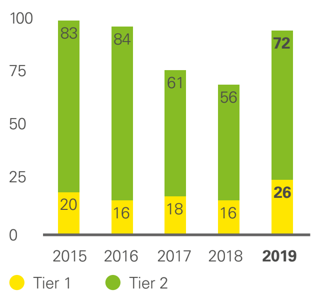
i See *bp.com/environment* for more information.

Safety and security

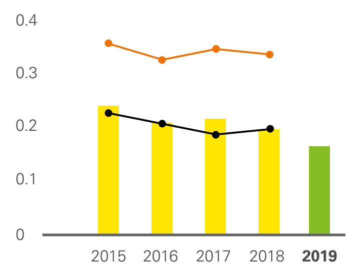
Safety remains our number one priority and one of our core values. Our aim is to have no accidents, no harm to people and no damage to the environment.

We are working to continue to improve personal and process safety and operational risk management across BP and to strengthen our safety management. Our approach builds on our experience, including learning from incidents, operations audits, annual risk reviews and sharing lessons learned with our industry peers.

Process safety events
(number of incidents)



Recordable injury frequency
(workforce incidents per 200,000 hours worked)



	2015	2016	2017	2018	2019
Workforce	0.243	0.211	0.218	0.198	**0.166**
Employee	0.203	0.194	0.202	0.152	**0.128**
Contractor	0.279	0.222	0.229	0.233	**0.193**

American Petroleum Institute US benchmark*
International Association of Oil & Gas Producers benchmark*

* API and IOGP 2019 data reports are not available until May 2020.

Keeping people safe

All our employees and contractors have the responsibility and the authority to stop unsafe work. Our safety rules guide our workers on staying safe while performing tasks with the potential to cause most harm. The rules are aligned with our OMS and focus on areas such as working at heights, lifting operations and driving safety.

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

Tragically we suffered two fatalities in 2019. In July a fire-fighting assistant in our biofuels business in Brazil was fatally injured following a fire truck accident while attending to an agricultural fire. In October a contractor at our Whiting refinery in the US was fatally injured when he fell from a scaffold ladder.

	2019	2018	2017
Recordable injury frequency[a]	**0.166**	0.198	0.218
Day away from work case frequency[b]	**0.047**	0.048	0.055
Severe vehicle accident rate	**0.05**	0.04	0.03

a Incidents that result in a fatality or injury per 200,000 hours worked.
b Incidents that result in an injury where a person is unable to work for a day (shift) or more per 200,000 hours worked.

Our recordable injury frequency, which includes BHP assets acquired in 2018, reduced by 16% in 2019. There is always more we can do and we remain focused on achieving better results today and in the future.

Managing safety

BP-operated businesses are responsible for identifying and managing operating risks and bringing together people with the right skills and competencies to address them. Our safety and operational risk team works alongside BP-operated businesses to provide oversight and technical guidance, while our group audit team visits sites on a risk-prioritized basis to check how they are managing risks.

Our operating management system

Our OMS is a group-wide framework designed to help us manage risks in our operating activities and drive performance improvements. 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.

Our OMS also helps us improve the quality of our activities by setting a common framework that our operations must work to. 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. Recently acquired operations need to transition to our OMS.

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 safety performance using industry metrics such as the American Petroleum Institute recommended practice 754 and the International Association of Oil & Gas Producers recommended practice 456.

	2019	2018	2017
Tier 1 and tier 2 process safety events★[a]	**98**	72	79
Oil spills – number[b]	**152**	124	139
Oil spills contained	**90**	63	81
Oil spills reaching land and water	**58**	57	58
Oil spilled – volume (thousand litres)	**710**	538	886
Oil unrecovered (thousand litres)	**300**	131	265

a Tier 1 process safety events are losses of primary containment of greatest consequence – such as causing harm to a member of the workforce, costly damage to equipment or exceeding defined quantities. Tier 2 events are those of lesser consequence.
b Number of spills greater than or equal to one barrel (159 litres, 42 US gallons).

The total number of tier 1 and tier 2 process safety events increased in 2019, mainly reflecting performance in assets recently acquired. Underlying performance across the group improved slightly from 2018. We are implementing BP procedures and processes to help bring newly acquired assets in line with BP assets.

We investigate incidents including near misses. And we use leading indicators, such as inspections and equipment tests, to monitor the strength of controls to prevent incidents. We also use techniques that help teams to analyse and redesign tasks to reduce the chance of mistakes occurring.

Emergency preparedness

The scale and spread of BP's operations means we must be prepared to respond to a range of possible disruptions and 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.

Cyber threats

The severity, sophistication and scale of cyber attacks continues to evolve. The increasing digitalization and reliance on IT systems makes managing cyber risk an even greater priority for many industries, including our own.

The risk comes from a variety of cyber-threat actors, including nation states, criminals, terrorists, hacktivists and insiders. As with previous years, we've experienced threats to the security of our digital infrastructure, but none of these had a significant impact on our business in 2019. We have a range of measures to manage this risk, including the use of cyber-security policies and procedures, security protection tools, continuous threat monitoring and event detection capabilities, and incident response plans. We also conduct exercises to test our response to and recovery from cyber attacks. To encourage vigilance among our staff, our cyber-security training and awareness programme covers topics such as phishing and the correct classification and handling of our information. We collaborate closely with governments, law enforcement and industry peers to understand and respond to new and emerging threats.

Security

We monitor for hostile actions that could harm our people or disrupt our operations. These actions might be connected to political or social unrest, terrorism, armed conflict or criminal activity. We take these potential threats seriously and assess them continuously.

Our 24-hour response information centre in the UK uses state-of-the-art technology to monitor evolving high-risk situations in real-time. It helps us to assess the safety of our people and provide them with practical advice if there is an emergency.

This year, we faced a number of protests. We worked with local police, including marine authorities, to minimize any disruption from these to our operations.

Working with contractors

Through documents that help bridge between our policies and those of our contractors, we define the way our safety management system co-exists with those of our contractors to manage risk on a site. For our contractors facing the most serious risks, we conduct quality, technical, health, safety and security audits before awarding contracts. Once they 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

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. We monitor performance and how risk is managed in our joint arrangements, whether we are the operator or not.

Where we are not the operator, our OMS is available as a reference point for BP businesses when engaging with operators and co-venturers. We have a group framework to assess and manage BP's exposure related to safety, operational and bribery and corruption risk 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.

Our people

BP's success depends on having a talented and diverse workforce that represents the communities we serve.

Number of employees at 31 December[a]	2019	2018	2017
Upstream	**16,600**	16,900	17,700
Downstream	**44,300**	42,700	42,100
Other businesses and corporate	**9,200**	13,400	14,200
Total	**70,100**	73,000	74,000

a Reported to the nearest 100. For more information see Financial statements – Note 35.

Our people are the most important element of our success. We need a motivated, engaged, and diverse workforce to deliver our purpose and strategy. We aim to build a culture that generates the diversity of thought, approach and ideas needed to play a leading role in the energy transition, a culture in which people's wellbeing is valued and differences are respected.

The group people committee helps facilitate the group chief executive's oversight of policies relating to employees. In 2019 the committee discussed people policies, including our remuneration policy, progress in our diversity and inclusion programme, modernizing and strengthening our attractiveness as an employer, our talent and learning programmes and long-term people priorities.

Attraction and retention

We aim to recruit talented people from diverse backgrounds, and invest in training, development and competitive rewards for all our people. We invest in employee development – with a focus on driving safe, reliable and compliant operations, and on building technical, functional and leadership capability. This includes a range of development opportunities for our people through a mix of on-the-job learning, developmental relationships with mentors, managers and peers, and training delivered face-to-face, virtually and through simulation or e-learning.

Diversity

We set out our current diversity and inclusion ambition in 2012. It is based on our core values of safety, respect, excellence, courage and one team.

We aim to attract, develop and retain the best talent and to create a diverse and inclusive working environment, where everyone is accepted, valued and treated equally without discrimination.

A total of 25% of our group leaders came from countries other than the UK and the US in 2019 (2018 24%).

Workforce by gender

As at 31 December 2019	Male	Female	Female %
Board directors	7	5	42
Executive team	11	2	15
Group leaders	285	93	25
Subsidiary directors	1,202	247	17
All employees	43,762	26,280	38

The gender balance across BP as a whole is improving, with women representing 38% of BP's total population (2018 35%). We are working to improve these numbers further by, for example, developing mentoring, sponsorship and coaching programmes to help more women advance. But we still have work to do at the executive and senior levels.

At the end of 2019 we had five female directors (2018 5) on our board. Our nomination committee remains mindful of diversity when considering potential candidates. For more information on the composition of our board, see page 74.

In the UK we report the gender pay gap for five BP entities. Our 2019 report shows small improvements since 2018, including improvements in our highest pay gap entities – BP p.l.c. and BP Exploration Operating Company Limited. Six of the 10 gaps have narrowed. Our challenge is to maintain and, if possible, accelerate this trend. We are working to address the differences but recognize that this is a long-term challenge.

i See *bp.com/ukgenderpaygap* for data and more information on our gender pay gap in the UK.

Inclusion

To promote an inclusive culture we provide leadership training and support employee-run advocacy groups in areas such as gender, ethnicity, sexual orientation and disability. As well as bringing employees together, these groups support our recruitment programmes and provide feedback on the potential impact of policy changes. Each group is sponsored by a senior executive.

In 2019 we built closer ties between our central diversity and inclusion team and local business resource groups (BRGs). We also held a number of events for employees from our BRGs, including an 'economics of diversity' webcast, a roadshow and a diversity and inclusion week.

We aim to ensure 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. Where existing employees become disabled, our policy is to engage and use occupational assistance where needed, and to use reasonable accommodations or adjustments to enable continued employment.

We have been recognized by a number of external awards in 2019, including The Times newspaper's Top 50 Employers for Women, Stonewall Global Leader and the FT's Inclusive Companies recognition.

Employee engagement

Our managers hold regular 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.

To understand what our employees think and feel about BP, we run an annual 'Pulse' survey and in 2019 we introduced 'Pulse Live', which enables us to monitor changes in employee sentiment on a weekly basis. The overall employee engagement score in our 2019 survey was 65% (2018 66%). Pride in working for BP was 75% (2018 76%). In the 2019 survey, participating employees told us we should focus more attention in several areas, including: sharing our strategy, reinforcing the need for an open speak-up culture, explaining how BP is taking action to help create a low carbon future and providing updates on safety improvements and other priorities.

Share ownership

We encourage employee share ownership and have a number of employee share plans in place. For example, we operate a ShareMatch plan in more than 50 countries, matching BP shares purchased by our employees. We also operate a group-wide discretionary share plan, which allows employee participation at different levels globally and is linked to the company's performance.

BP Target Neutral
By buying carbon offsets, Target Neutral is supporting finance in projects that not only reduce carbon but make a critical difference to the health of low-income families.

The ONIL cookstove project has equipped 25,000 rural homes in Mexico with cookstoves that burn more efficiently, using up to 58% less firewood than a traditional open fire, and are equipped with chimneys to take harmful cooking fumes outside the household.

Communities

Value to society

We aim to have a positive and enduring impact on the communities in which we operate. In supplying energy, we contribute to economies around the world by employing local staff, helping to develop national and local suppliers, and through the funds we pay to governments from taxes and other agreements.

Additionally, our social investments support community efforts to increase incomes and improve standards of living. We committed $84 million in social investment in 2019 (2018 $114.2 million).

We aim to recruit our workforce from the community or country in which we operate. We also run programmes to build the skills of businesses and develop the local supply chain in a number of locations. For example, in the West Nile Delta, we provided training on vocational skills and health and safety standards for local people. We reached more than 2,000 people by the end of 2019.

Nationals employed

	2019	2018
Angola	**88%**	87%
Azerbaijan	**92%**	91%
Egypt	**81%**	78%
Indonesia	**97%**	96%
Oman	**80%**	77%
Trinidad & Tobago	**96%**	96%

See *bp.com/society* for more information on how we generate value to society.

Human rights

We are committed to respecting the rights and dignity of all people when conducting our business.

We respect internationally recognized human rights as set out in the International Bill of Human Rights and the International Labour Organization's Declaration on Fundamental Principles and Rights at Work. These include the rights of our workforce and those living in communities potentially affected by our activities.

We set out our commitments in our business and human rights policy and our code of conduct. Our OMS contains guidance on respecting the rights of workers and community members.

We are incorporating the UN Guiding Principles on Business and Human Rights, which set out how companies should prevent, address and remedy human rights impacts, into our business processes. Our focus areas include ethical recruitment and working conditions, responsible security and community health and livelihoods.

See *bp.com/humanrights* for more information about our approach to human rights.

Governance and business ethics

Our values

Our values of safety, respect, excellence, courage and one team represent the qualities and actions we wish to see in BP. They inform the way we do business and the decisions we make. We use these values as part of our recruitment, promotion and individual performance management processes.

See *bp.com/values* for more information.

The BP code of conduct

Our code of conduct is based on our values and sets clear expectations for how we work at BP. It applies to all BP employees, including members of the board.

Employees, contractors or other third parties who have a question about our code of conduct or see something that they feel is unethical or unsafe can discuss this with their managers, supporting teams, works councils (where relevant) or through OpenTalk, a confidential and anonymous helpline operated by an independent company.

We received more than 1,800 concerns or enquiries through these channels in 2019 (2018 1,712). The most commonly raised concerns were related to the 'Our people' section of our code. The section addresses issues such as harassment, equal opportunity, and diversity and inclusion.

We take steps to identify and correct areas of non-conformance and take disciplinary action where appropriate. In 2019 our businesses dismissed 74 employees for non-conformance with our code of conduct or unethical behaviour (2018 50). This excludes dismissals of staff employed at our retail service stations.

See *bp.com/codeofconduct* for more information.

Anti-bribery and corruption

We operate in parts of the world where bribery and corruption present a high risk. We have a responsibility to our employees, our shareholders and to the countries and communities in which we do business to be ethical and lawful in all our work. Our code of conduct explicitly prohibits engaging in bribery or corruption in any form.

Our group-wide anti-bribery and corruption policy and procedures include measures and guidance to assess risks, understand relevant laws and report concerns. They apply to all BP-operated businesses. We provide training to employees appropriate to the nature or location of their role. Around 11,000 employees completed anti-bribery and corruption training in 2019 (2018 10,957).

We assess any exposure to bribery and corruption risk when working with suppliers and business partners. Where appropriate, we put in place a risk mitigation plan or we reject them if we conclude that risks are too high. We also conduct anti-bribery compliance audits on selected suppliers when contracts are in place. For example, our upstream business conducts audits for a number of suppliers in higher-risk regions to assess their conformance with our anti-bribery and corruption contractual requirements. We take corrective action with suppliers and business partners that fail to meet our expectations, which may include terminating contracts. In 2019 we issued 25 audit reports (2018 27).

Lobbying and political donations

Our aim is to more actively advocate for policies that support net zero, including carbon pricing, see page 41.

We work with governments on a range of issues that are relevant to our business, from regulatory compliance, to understanding our tax liabilities, to collaborating on community initiatives. The way in which we interact with those governments depends on the legal and regulatory framework in each country.

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 in which we operate. For example, in the US we provide administrative support for the BP employee political action committee (PAC), which is a non-partisan committee that encourages voluntary employee participation in the political process. All BP employee PAC contributions are reviewed for compliance with federal and state law and are publicly reported in accordance with US election laws.

Trade associations

We aim to set new expectations for our relationships with trade associations around the world. BP is a member of many industry associations that offer opportunities to share good practices and collaborate on issues of importance to our sector. In 2019 we began an in-depth review assessing the alignment of the climate-related policies and activities of 30 key trade associations to which we belong with BP's position. As a result of this process we will be leaving three associations due to misalignment on climate policy. For more information on the review process and outcomes see *bp.com/tradeassociations.*

Tax and transparency

We are committed to complying with tax laws in a responsible manner and having open and constructive relationships with tax authorities. We paid $6.9 billion in income and production taxes to governments in 2019 (2018 $7.5 billion).

We disclose information on payments to governments for our upstream activities on a country-by-country and project basis under national reporting regulations such as those in effect in the UK. We also make payments to governments in connection with other parts of our business – such as the transporting, trading, manufacturing and marketing of oil and gas.

We are a founding member of the Extractive Industries Transparency Initiative (EITI), which requires disclosure of payments made to and received by governments in relation to oil, gas and mining activity.

Through EITI we work with governments, NGOs and international agencies to improve transparency. For example, in 2019 we enacted our global commitment through membership of the international board, including supporting decision making on the new global EITI standard, which represents a further evolution in transparency. The focus is on making disclosure and open data a routine part of government and corporate reporting, providing information to stakeholders in a way that supports its widespread use in analysis and decision making. It now requires contract transparency for new contracts from 2021, as well as new requirements on environmental reporting and gender.

See *bp.com/tax* for our approach to tax and our payments to governments report.

Upstream

The Upstream segment is responsible for our activities in oil and natural gas exploration, field development and production.

Business model

Exploration

The **exploration** function is responsible for renewing our resource base through access, exploration and appraisal, while the **reservoir development** function is responsible for the stewardship of our resource portfolio over the life of each field.

Wells and projects

The **global wells** organization and the **global projects** organization are responsible for the safe, reliable and compliant execution of wells (drilling and completions) and major projects.

Global operations organization

The **global operations** organization is responsible for safe, reliable and compliant operations, including upstream production assets and midstream transportation and processing activities.

Performance in 2019

58,000km^2
new exploration access
(2018 63,000km^2)

94.4%
BP-operated upstream plant reliability★
(2018 95.7%)

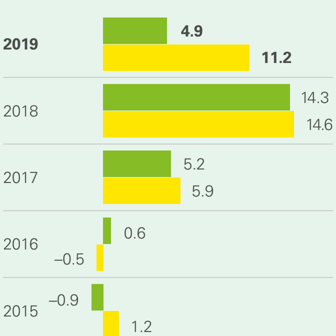
9
successful completion of turnarounds
(2018 7)

5
final investment decisions
(2018 9)

5
major project★ start ups
(2018 6)

2.6
million barrels of oil equivalent per day – hydrocarbon production
(2018 2.5mmboe/d)

Upstream profitability
($ billion)



● RC profit (loss) before interest and tax
● Underlying RC profit (loss) before interest and tax★

Strategy

Our strategy has three parts and is enabled by:

Quality execution
We want to be the best at what we do – everywhere we work. This starts with executing our activity safely. In every basin, we will benchmark against the competition and aim to be the best – whether it be operating facilities reliably and cost effectively, with a focus on emissions, drilling wells, managing our reservoirs, exploring, building projects, or deploying technology. Through the quality of our execution, scale and infrastructure, we aim to be competitive in every basin, and as a business, get more from a unit of capital than our peers.

Growing advantaged oil and gas
We manage our portfolio through disciplined investment in the world's great oil and gas basins.

We intend to make longer-term investments in natural gas as a lower carbon fuel which can complement renewables and provide stable cash flows while contributing to the energy transition to a lower carbon future. We see our gas portfolio being complemented by oil assets that we consider to be advantaged in the energy transition; this is oil we can produce at a lower cost and higher margin, with faster payback times and ready access to markets, and maintaining a rigorous focus on carbon.

We aim to maintain a strong financial frame, allocating capital to build resilience to withstand uncertainty and change in the external environment. Ensuring sustainability of our business model and products will be key to maintaining competitiveness.

Returns-led growth
We want to grow returns and value, and believe this will come from many sources – expanding and managing our margins, operational efficiency, unit cost reduction, and capital efficiency with disciplined levels of capital reinvestment.

Our major projects are selected and evaluated on a balanced set of investment criteria, which allow for comparison and prioritization, and to evaluate for consistency with Paris goals within an appropriate portfolio context. In the Upstream this evaluation includes confirming whether we expect them to generate positive returns within a price and demand environment we consider to be consistent with those goals, with a bias towards shorter payback times and a comparison with the operational emissions profile of our wider Upstream portfolio.

Underpinning our business model and strategy is our transformation agenda. In 2019 we had more than 1,000 projects across the Upstream aimed at sustainably improving both performance and ways of working in the Upstream. Since the inception of our transformation programme in 2016, projects are estimated to have delivered an additional $1.5 billion of cash flow to the business.

In addition to our core upstream exploration, development and production activities, the segment is responsible for the midstream transportation, storage and processing that support its operations. We also market and trade natural gas, including liquefied natural gas (LNG), power and natural gas liquids. In 2019 our activities took place in 34 countries.

BPX Energy, our onshore oil and gas business in the US Lower 48 states, continues to operate as a separate, asset-focused, onshore business. Integration of the BHP assets acquired in 2018 has gone well, with realized savings from synergies more than double our original target for 2019.

We optimize and integrate the delivery of our activities across 12 regions, with support provided by global functions in specialist areas of expertise: technology, finance, procurement and supply chain, human resources, information technology and legal.

In 2016 we identified a future growth target of 900,000 barrels of oil equivalent per day of production from new major projects by 2021 and we remain on track to deliver that, having started up 24 of the 35 major projects needed to reach this target by the end of 2019.

We see our scale and long history in many of the great basins in the world as a differentiator for BP and believe in the strength of our incumbent positions. We believe we are balanced and flexible – in terms of geography, hydrocarbon type and geology – and rather than being restricted by a traditional way of working, we have and will continue to use creative business models to generate value.

This describes our strategy and organizational model in 2019. Following BP's new ambition and aims set out in February 2020, we are transforming our business. We plan to provide more information on our future strategy and near-term plans at our capital markets day in September 2020.

Financial performance

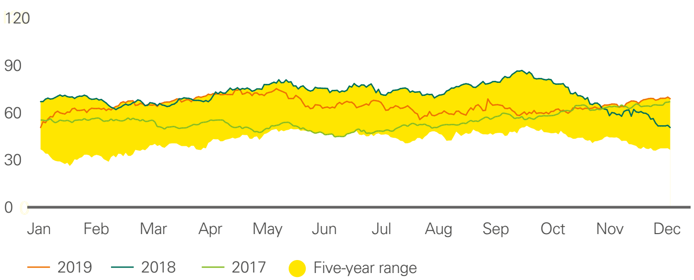
			$ million
	2019	2018	2017
Sales and other operating revenues[a]	**54,501**	56,399	45,440
RC profit before interest and tax	**4,917**	14,328	5,221
Net (favourable) adverse impact of non-operating items★ and fair value accounting effects★	**6,241**	222	644
Underlying RC profit (loss) before interest and tax	**11,158**	14,550	5,865
Organic capital expenditure★[b]	**11,904**	12,027	13,763
BP average realizations[c]			$ per barrel
Crude oil[d]	**61.56**	67.81	51.71
Natural gas liquids	**18.23**	29.42	26.00
Liquids★	**57.73**	64.98	49.92
			$ per thousand cubic feet
Natural gas	**3.39**	3.92	3.19
US natural gas	**1.93**	2.43	2.36
			$ per barrel of oil equivalent
Total hydrocarbons★	**38.00**	43.47	35.38
			$ per barrel of oil equivalent
Average oil marker prices[e]			$ per barrel
Brent★	**64.21**	71.31	54.19
West Texas Intermediate	**57.03**	65.20	50.79
Average natural gas marker prices			$ per million British thermal units
Average Henry Hub★ gas price[f]	**2.63**	3.09	3.11
			pence per therm
Average UK National Balancing Point gas price★[e]	**34.70**	60.38	44.95

a Includes sales to other segments.
b A reconciliation to GAAP information at the group level is provided on page 299.
c Realizations are based on sales by consolidated subsidiaries only, which excludes equity-accounted entities.
d Includes condensate.
e All traded days average.
f Henry Hub First of Month Index.

Market prices

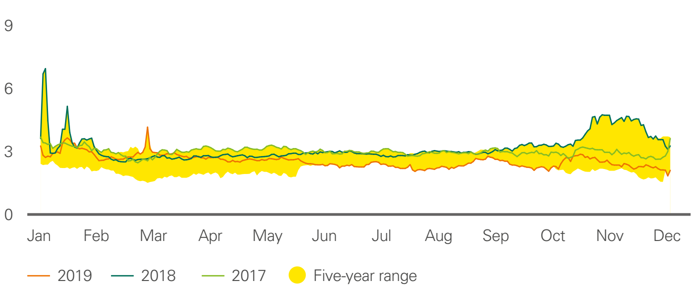
Brent remains an integral marker to the production portfolio, from which a significant proportion of production is priced directly or indirectly.

Brent ($/bbl)



Dated Brent prices averaged $64.21 per barrel in 2019 – a 9% decrease from 2018 levels but almost 30% above the 2015-17 average. Prices fluctuated during the year reaching a peak of $71 in April on OPEC+ supply restraints and the decline in Venezuelan and Iranian output. In the second half of the year, prices fluctuated between $59 in August to $67 in December as OPEC+ restrained supply amid trade tensions. Global consumption increased by 0.9 million barrels per day (mmb/d) to 100.1mmb/d for the year (0.9%) – a slowdown from growth rates seen in the prior two years as trade tensions slowed global macroeconomic growth. Global oil production remained flat at 100.5mmb/d, with growth from non-OPEC countries offsetting supply restraint and disruptions in OPEC countries. The fall in output in Venezuela and Iran due to sanctions significantly contributed to the 1.9mmb/d decline in OPEC output in 2019.

Henry Hub ($/mmBtu)



Henry Hub prices decreased to $2.63/mmBtu in 2019 from $3.09/mmBtu in 2018 as US associated gas production continued to grow strongly while US gas consumption growth slowed down.

The UK National Balancing Point hub price was almost halved from 60.38 pence per therm in 2018, down to 34.70 in 2019, due to a significant increase in European LNG imports and record high storage levels. Asian spot prices declined from $9.76/mmBtu in 2018, down to $5.49/mmBtu on the back of global LNG oversupply, declining LNG demand in Japan and Korea and a slow-down of Chinese LNG imports.

Financial results

Sales and other operating revenues for 2019 decreased compared with 2018, primarily reflecting lower liquids and gas realizations partially offset by higher production and strong gas marketing and trading revenues.

Replacement cost profit before interest and tax for the segment included a net non-operating charge of $6,947 million. This primarily relates to impairments arising from disposal transactions. See Financial statements – Note 5 for further information. Fair value accounting effects had a favourable impact of $706 million relative to management's view of performance.

The 2018 result included a net non-operating charge of $183 million, primarily related to impairment charges associated with a number of assets, following changes in reserves estimates, the decision to dispose of certain assets and the decision to relinquish a number of leases expiring in the near future, partially offset by reversals of prior year impairment charges. Fair value accounting effects had an adverse impact of $39 million relative to management's view of performance.

After adjusting for non-operating items and fair value accounting effects, the underlying replacement cost result before interest and tax was lower in 2019 compared with 2018. This primarily reflected lower liquids and gas realizations and higher depreciation, depletion and amortization partly offset by strong gas marketing and trading results and higher production.

Organic capital expenditure was $11.9 billion (2018 $12.0 billion).

In total, disposal transactions generated $2 billion in proceeds in 2019, with a corresponding reduction in net proved reserves of 134mmboe within our subsidiaries. The major disposal transaction during 2019 was the disposal of our interests in Gulf of Suez oil concessions in Egypt.

At year end, a number of balances associated with assets awaiting the completion of announced disposals were held within the Assets held for sale category in the balance sheet. These related to assets in Alaska and US Lower 48. Impairment charges totalling $6.0 billion were recognized in connection with these planned disposals. See Financial statements – Notes 2 and 4 for further information.

More information on disposals is provided in Upstream analysis by region on page 303.

Outlook for 2020

At the current time the global spread of the coronavirus (COVID-19) is causing considerable uncertainty in the market, lowering demand forecasts. This, and the changing dynamic among OPEC+ members, has put downward pressure on prices. Aside from these factors, we had expected price volatility in the near term. Taking these factors into account, we expect the outlook for the year as a whole to remain challenging.

Exploration

The group explores for oil and natural gas under a wide range of licensing, joint arrangement and other contractual agreements. We may do this alone or, more frequently, with partners.

Our exploration and new access teams work to find advantaged barrels to build our hopper of options for potential future development. That hopper of options gives us the flexibility to grow the cash and value in the Upstream business while increasing the average quality of the portfolio.

In line with our strategy, we are spending less on exploration and we plan to spend a significant part of our exploration budget on lower-risk, shorter-cycle-time opportunities around our incumbent positions.

New access in 2019

We gained access to new acreage covering around 58,000km^2 in nine countries – Argentina, Australia, Brazil, the Gambia, India, Oman, Peru, the UK North Sea and the US Gulf of Mexico.

Exploration success

We participated in 10 potentially commercial discoveries in 2019 – King Embayment in the US Gulf of Mexico, Bele-1, Tuk-1, Hi-Hat-1, Boom-1 and Ginger in Trinidad, Nour North Sinai in Egypt, GTA-1 and Yakaar-2 in Senegal and Orca-1 in Mauritania.

Exploration and appraisal costs

Total exploration and appraisal costs were $1,587 million (2018 $1,478 million), of which $302 million (2018 $180 million) related to lease acquisition.

These costs included exploration and appraisal activities, which were capitalized within intangible fixed assets, and geological and geophysical exploration costs, which were charged to income as incurred.

Approximately 6% of exploration and appraisal costs were directed towards appraisal activity. We participated in 47 gross (21.15 net) exploration and appraisal wells in 11 countries. Of these, 11 were lower risk wells around incumbent positions.

Exploration expense

Total exploration expense of $964 million (2018 $1,445 million, 2017 $2,080 million) comprised the write-off of expenses related to unsuccessful drilling activities, lease expiration or uncertainties around development, as well as geological and geophysical exploration costs (see Financial statements – Note 8).

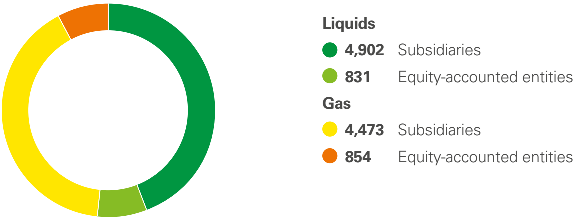
Reserves booking

Reserves bookings from new discoveries will depend on the results of ongoing technical and commercial evaluations, including appraisal drilling. The segment's total hydrocarbon reserves on an oil-equivalent basis, including the segment's equity-accounted entities at 31 December 2019, decreased by 6% (a decrease of 8% for subsidiaries and an increase of 6% for equity-accounted entities) compared with proved reserves at 31 December 2018.

Proved reserves replacement ratio

The proved reserves replacement ratio★ for the segment in 2019 was 41% for subsidiaries and equity-accounted entities (2018 69%), 25% for subsidiaries alone (2018 66%) and 210% for equity-accounted entities alone (2018 106%). For more information on proved reserves replacement for the group see page 308.

Upstream proved reserves
(mmboe)



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

	2019	2018	2017
Liquids			million barrels
Crude oil[b]			
Subsidiaries★	**4,367**	4,378	4,129
Equity-accounted entities[c]	**810**	794	674
	5,177	5,172	4,803
Natural gas liquids			
Subsidiaries	**535**	576	318
Equity-accounted entities[c]	**21**	15	18
	556	590	336
Total liquids			
Subsidiaries[d]	**4,902**	4,954	4,447
Equity-accounted entities[c]	**831**	808	692
	5,733	5,762	5,139
Natural gas			billion cubic feet
Subsidiaries[e]	**25,946**	30,355	29,263
Equity-accounted entities[c]	**4,951**	4,559	2,274
	30,897	34,914	31,537
Total hydrocarbons			million barrels of oil equivalent
Subsidiaries[e]	**9,375**	10,188	9,492
Equity-accounted entities[c]	**1,685**	1,594	1,085
	11,060	11,782	10,577

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 Upstream segment. During 2019 upstream operations in Argentina, Bolivia, Mexico, Russia and Norway as well as some of our operations in Angola were conducted through equity-accounted entities.
d Includes 11 million barrels (12 million barrels at 31 December 2018 and 14 million barrels at 31 December 2017) in respect of the 30% non-controlling interest in BP Trinidad & Tobago LLC.
e Includes 1,330 billion cubic feet of natural gas (1,573 billion cubic feet at 31 December 2018 and 1,860 billion cubic feet at 31 December 2017) in respect of the 30% non-controlling interest in BP Trinidad & Tobago LLC.

Developments

We achieved five major project start-ups in 2019 – in the US Gulf of Mexico, Egypt, Trinidad and the UK North Sea. The Raven project in Egypt is now expected to come onstream at the end of 2020. In addition to these, we continued to progress all 11 of the remaining projects that we expect will deliver our future production growth target announced in 2016. Highlights from a selection of these are:

- **India** – Work on the KG D6 series of projects continued and the first of the three projects is expected to begin production in 2020.
- **Mauritania and Senegal** – In Phase 1 of the Greater Tortue Ahmeyim project, the first deepwater cross-border LNG project is underway following sanction in early 2019 with a ramp up in engineering, procurement and fabrication activity.
- **UK North Sea** – At Vorlich, two wells were drilled during the year and production is expected to start in 2020.

Subsidiaries' development expenditure incurred, excluding midstream activities, was $10.8 billion (2018 $9.9 billion, 2017 $10.7 billion).

Angelin, Trinidad & Tobago
Includes a new platform and four wells, with gas flowing to the Serrette platform hub via a new 13-mile pipeline.

Operator: BP
Partners: BP (70%) and Repsol (30%)
Project type: LNG

Major project start-ups in 2019

Giza and Fayoum, Egypt
Includes a deepwater, long-distance tieback to an existing onshore plant and eight wells.

Operator: BP
Partners: BP (82.75%), DEA Deutsche Erdoel AG (17.25%)
Project type: Conventional gas

Culzean, UK North Sea
Includes a standalone three-bridge-linked platform development with six production wells.

Operator: Total
Partners: Total (50%), BP (32%), JX Nippon (18%)
Project type: High-pressure gas

Constellation, US Gulf of Mexico
Discovered in 2016, the field has been developed as a subsea tieback to Anadarko's Constitution spar.

Operator: Anadarko
Partners: Anadarko (33.33%), BP (66.67%)
Project type: Deepwater oil

Alligin, UK North Sea
Includes two wells, tied-back into the existing Schiehallion and Loyal subsea infrastructure.

Operator: BP
Partners: BP (50%) and Shell (50%)
Project type: Conventional Oil

Production

Our offshore and onshore oil and natural gas production assets include wells, gathering centres, in-field flow lines, processing facilities, storage facilities, offshore platforms, export systems (e.g. transit lines), pipelines and LNG plant facilities. These include production from conventional and unconventional assets.

Our principal areas of production are Angola, Argentina, Australia, Azerbaijan, Egypt, Oman, Trinidad, the UAE, the UK and the US. With BP-operated plant reliability increasing from around 86% in 2011 to 94% in 2019, efficient delivery of turnarounds and strong infill drilling performance, we have maintained base decline to 3-5% on average over the last five years. Our long-term expectation for managed base decline remains at 3-5% per guidance we have previously given.

Production[a] (net of royalties)

	2019	2018	2017
Liquids			thousand barrels per day
Crude oil[b]			
Subsidiaries	**1,046**	1,051	1,064
Equity-accounted entities[c]	**127**	121	199
	1,173	1,172	1,263
Natural gas liquids			
Subsidiaries	**104**	88	85
Equity-accounted entities[c]	**10**	8	8
	114	96	93
Total liquids			
Subsidiaries	**1,150**	1,139	1,149
Equity-accounted entities[c]	**138**	129	207
	1,288	1,268	1,356
Natural gas			million cubic feet per day
Subsidiaries	**7,366**	6,900	5,889
Equity-accounted entities[c]	**457**	474	547
	7,823	7,374	6,436
Total hydrocarbons			thousand barrels of oil equivalent per day
Subsidiaries	**2,420**	2,328	2,164
Equity-accounted entities[c]	**216**	211	302
	2,637	2,539	2,466

a Because of rounding, some totals may not agree exactly with the sum of their component parts.
b Includes condensate and bitumen.
c Includes BP's share of the production of equity-accounted entities in the Upstream segment.

Our total hydrocarbon production for the segment in 2019 was 3.8% higher compared with 2018. The increase comprised a 3.9% increase (1.0% for liquids and 6.8% for gas) for subsidiaries and a 2.5% increase (6.4% increase for liquids and 3.6% decrease for gas) for equity-accounted entities compared with 2018. For more information on production, see Oil and gas disclosures for the group on page 308. Underlying production was broadly flat compared to 2018.

The group and its equity-accounted entities have numerous long-term sales commitments in their various business activities, all of which are expected to be sourced from supplies available to the group that are not subject to priorities, curtailments or other restrictions. No single contract or group of related contracts is material to the group.

Gas and power marketing and trading activities

Our integrated supply and trading function markets and trades our own and third-party natural gas (including LNG), biogas, power and NGLs. This provides us with routes into liquid markets for the gas we produce and generates margins and fees from selling physical products and derivatives to third parties as well as asset optimization and trading. This means we have a single interface with gas trading markets and a single set of trading compliance and risk management processes, systems and controls. We are continuing to expand our LNG portfolio, which includes global partnerships with utility companies, gas distributors and national oil and gas companies.

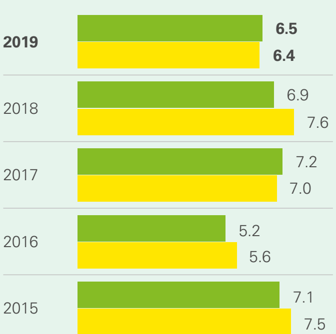
This activity primarily takes place in North America, Europe and Asia, and supports group LNG activities, managing market price risk and creating incremental trading opportunities through the use of commodity derivative contracts. It also enhances margins and generates fee income from sources such as the management of price risk on behalf of third-party customers.

Our trading financial risk governance framework is described in Financial statements – Note 29 and the range of contracts used is described in Glossary – commodity trading contracts on page 337.

Downstream

The Downstream segment has global marketing and manufacturing operations. It is the product and service-led arm of BP and is made up of three businesses.

Downstream profitability
($ billion)



RC profit before interest and tax
Underlying RC profit before interest and tax★

This describes our strategy and organizational model in 2019. Following BP's new ambition and aims set out in February 2020, we are transforming our business. We plan to provide more information on our future strategy and near-term plans at our capital markets day in September 2020.

Business model

Fuels

Includes refineries, logistic networks and fuels marketing businesses, which together with global oil supply and trading activities make up our integrated fuels value chains (FVCs). We sell refined petroleum products including gasoline, diesel and aviation fuel, and have a significant presence in the convenience retail sector. We also have a growing presence in electric vehicle charging with a focused strategy to build the fastest, most convenient networks for our customers.

Lubricants

Manufactures and markets lubricants and related products and services to the automotive, industrial, marine and energy markets globally. We add value through brand, technology and relationships, such as collaboration with original equipment manufacturing partners.

Petrochemicals

Manufactures and markets products that are produced using industry-leading proprietary BP technology, and are then used by others to make consumer products such as food packaging, textiles and building materials. Through our new *BP Infinia* technology, we are working to reduce plastic waste, helping to enable a stronger circular economy.

Performance in 2019

$2.7bn
fuels marketing earnings +2.5% vs 2018 (2018 $2.6bn)

~1,600
convenience partnership sites (2018 ~1,400)

49%
of lubricant sales were premium grade (2018 46%)

94.9%
refining availability★ (2018 95.0%)

1.7
million barrels of oil refined per day (2018 1.7mmb/d)

12.1
million tonnes of petrochemicals produced (2018 11.9mmte)

Strategy

We aim to run safe and reliable operations across all our businesses, supported by leading brands and technologies, to deliver high-quality products and services that meet our customers' needs. Our strategy is to deliver underlying earnings growth and build resilient, competitively advantaged businesses, and we are working at pace to create low carbon businesses that can advance the energy transition.

The execution of our strategy in 2019 has continued to deliver, with underlying replacement cost profit of $6.4 billion in the year.

Safe and reliable operations
This remains our core value and first priority and we continue to drive improvements in personal and process safety performance.

Profitable marketing growth
We invest in higher-returning fuels marketing and lubricants businesses with growth potential and reliable cash flows.

Advantaged manufacturing
We aim to have a competitively advantaged refining and petrochemicals portfolio underpinned by operational excellence and to grow earnings potential, making the businesses more resilient to margin volatility.

Simplification and efficiency
This remains central to what we do to support performance improvement and make our businesses even more competitive.

Transition to a lower carbon and digitally enabled future
We are delivering and developing new products, offers and business models that support the transition to a lower carbon and digitally enabled future.

Financial performance

	2019	2018	$ million 2017
Sale of crude oil through spot and term contracts★	**59,738**	62,484	47,702
Marketing, spot and term sales of refined products	**180,236**	195,020	159,475
Other sales and operating revenues	**10,923**	13,185	12,676
Sales and operating revenues[a]	**250,897**	270,689	219,853
RC profit before interest and tax[b]			
Fuels	**4,791**	5,261	4,679
Lubricants	**1,315**	1,065	1,457
Petrochemicals	**396**	614	1,085
	6,502	6,940	7,221
Net (favourable) adverse impact of non-operating items★ and fair value accounting effects★			
Fuels	**(32)**	381	193
Lubricants	**(57)**	227	22
Petrochemicals	**6**	13	(469)
	(83)	621	(254)
Underlying RC profit before interest and tax[b]			
Fuels	**4,759**	5,642	4,872
Lubricants	**1,258**	1,292	1,479
Petrochemicals	**402**	627	616
	6,419	7,561	6,967
Organic capital expenditure★[c]	**2,997**	2,781	2,399

a Includes sales to other segments.
b Income from petrochemicals produced at our Gelsenkirchen and Mülheim sites in Germany is reported in the fuels business. Segment-level overhead expenses are included in the fuels business result.
c A reconciliation to GAAP information at the group level is provided on page 299.

Financial results

Sales and other operating revenues in 2019 were lower than in 2018, mainly due to lower crude and product prices.

Replacement cost (RC) profit before interest and tax for 2019 included a net non-operating charge of $77 million, which includes environmental provisions. The 2018 result included a net non-operating charge of $716 million, primarily reflecting restructuring costs. In addition, fair value accounting effects had a favourable impact of $160 million, compared with a favourable impact of $95 million in 2018.

After adjusting for non-operating items and fair value accounting effects, underlying RC profit before interest and tax in 2019 was $6,419 million.

Outlook for 2020

The coronavirus (COVID-19) has already had significant impact on margins and activity at the start of the year. We expect this uncertainty to continue and anticipate lower industry refining margins during 2020. We also anticipate wider North American heavy crude oil discounts and a lower level of turnaround activity than in 2019.

Energy with purpose

Making more plastics recyclable

Thinking beyond business as usual, we're using our know-how to explore a breakthrough technology for recycling opaque and difficult-to-recycle PET plastic waste – familiar to consumers as coloured bottles and food trays. Our enhanced recycling technology, *BP Infinia*, enables PET to be diverted from landfill or incineration and transformed into virgin-quality feedstocks.

We plan to build a $25 million pilot plant in the US to prove the technology, which is expected to be operational in late 2020. And we've now joined forces with leading businesses across the PET packaging value chain to help accelerate commercialization of the technology.

We believe *BP Infinia* has the potential to be a game-changer and important stepping stone in enabling a stronger circular economy and helping to reduce unmanaged plastic waste.

Companies joining the consortium:

- Packaging and recycling specialist ALPLA.
- Food, drink and consumer goods producers Britvic, Danone and Unilever.
- Waste management and recycling specialist REMONDIS.

Our fuels business

Our fuels strategy focuses primarily on fuels value chains (FVCs). This includes an advantaged refining portfolio through operating reliability and efficiency, location advantage and feedstock flexibility, as well as commercial optimization opportunities. We believe that having a quality refining portfolio connected to strong marketing positions is core to our integrated FVC businesses as this provides optimization opportunities in highly competitive markets.

Our fuels marketing business comprises retail, business-to-business and aviation fuels. It is a material part of Downstream with a strong track record of growth. We have an advantaged portfolio of assets with good growth potential, attractive returns and reliable cash flows. We continue to grow our fuels marketing business through our differentiated marketing offers and strategic convenience partnerships. We also partner with leading retailers, creating distinctive retail offers that aim to deliver good returns and reliable profit growth and cash generation.

We have also grown our presence in electric vehicle charging in recent years, with a focus on the key markets of China, UK and Germany, where we aim to build the fastest, most convenient networks for electric vehicle customers.

Underlying RC profit before interest and tax for our fuels business was lower compared with 2018, with strong refining operational performance, which led to a second consecutive year of record refining throughput and higher commercial optimization, despite high levels of turnaround activity. This was more than offset, however, by lower refining margins, including significantly narrower heavy crude oil discounts, which together represented one of the weakest refining environments across our portfolio in the last 10 years. In fuels marketing we saw volumes and margins grow year on year, offset by adverse foreign exchange effects. The full year result also reflects a higher contribution from supply and trading.

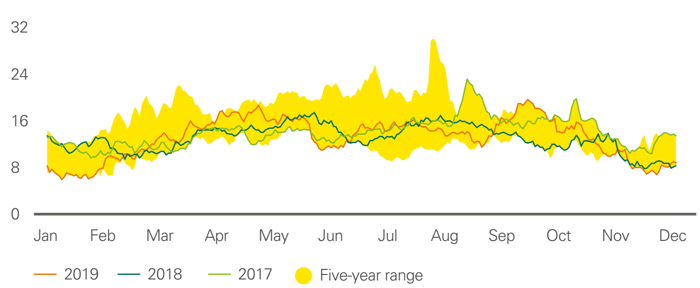
Refining marker margin★

We track the refining margin environment using a global refining marker margin (RMM). Refining margins are a measure of the difference between the price a refinery pays for its inputs (crude oil) and the market price of its products. Although refineries produce a variety of petroleum products, we track the margin environment using a simplified indicator that reflects the margins achieved on gasoline and diesel only. 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.

				$ per barrel
Region	Crude marker	**2019**	2018	2017
US North West	Alaska North Slope	**17.6**	16.2	18.8
US Mid West	West Texas Intermediate★	**16.0**	16.0	16.9
Northwest Europe	Brent★	**11.1**	11.1	11.7
Mediterranean	Azeri Light	**9.1**	9.8	10.4
Australia	Brent	**11.1**	11.5	12.9
BP RMM		**13.2**	13.1	14.1

The global RMM averaged $13.2/bbl in 2019, similar to the level in 2018 ($13.1/bbl), with weaker demand balanced by reduced supply due to an increased level of refinery maintenance over the year. In addition refining margins across our portfolio were significantly impacted by other crude and product differentials outside of the global RMM, primarily due to narrower heavy crude oil discounts.

BP refining marker margin ($/bbl)



Refining

At 31 December 2019 we owned or had a share in 10 refineries[ab] producing refined petroleum products that we supply to retail and commercial customers. For a summary of our interests in refineries and average daily crude distillation capacities see page 307.

Underlying growth in our refining business is underpinned by our multi-year business improvement plans, which comprise globally consistent programmes focused on operating reliability and efficiency, advantaged feedstocks and commercial optimization. Operating reliability is a core foundation of our refining business and in 2019 operations remained strong, with refining availability at BP-operated refineries of 94.9% (2018 95%) and refinery utilization★ rates across our refining portfolio at 91% (2018 91%). As a result, we achieved record levels of refining throughput for a second consecutive year, despite high levels of turnaround activity.

Our refinery portfolio – along with our supply capability – enables us to process advantaged crudes. For example, in the US, our three refineries all have location-advantaged access to Canadian crudes which are typically cheaper than other crudes. Our commercial optimization programme aims to maximize value from our refineries by capturing opportunities in every step of the value chain, from crude selection through to yield optimization and utilization improvements.

During 2019 we also continued to scale up co-processing at our refineries, growing the volume of lower carbon bio-feedstock processed.

The refining result was lower in 2019 compared with 2018, with strong operational performance and higher commercial optimization, which was more than offset by a significantly weaker refining environment, primarily driven by narrower heavy crude oil discounts.

			thousand barrels per day
	2019	2018	2017
Refinery throughputs[ac]			
US	**737**	703	713
Europe	**787**	781	773
Rest of the world	**225**	241	216
Total	**1,749**	1,725	1,702
			%
Refining availability	**94.9**	95.0	95.2

a This does not include BP's interest in Pan American Energy Group.
b On 31 December we completed the sale of our interest in the German Bayernoil refinery.
c Refinery throughputs reflect crude oil and other feedstock volumes.

Fuels marketing and logistics

Across our fuels marketing businesses, we operate an advantaged infrastructure and logistics network that includes pipelines, storage terminals and tankers for road and rail. We seek to drive excellence in operational and transactional processes and deliver compelling customer offers in the various markets where we operate. Through our retail business, we supply fuel and convenience retail services to consumers through company-owned and franchised retail sites, as well as other channels, including dealers and jobbers. We also supply commercial customers in the transport and industrial sectors.

Retail is the most material part of our fuels marketing business and a significant source of earnings growth through our strong market positions, brands and distinctive customer offers. This is underpinned by the strength of our retail convenience partnerships, technology such as our advanced fuels and use of digital technology, as well as our customer relationships. This differentiation enables our growth in existing markets and supports our growth plans in new material markets such as Mexico, India, Indonesia and China.

During 2019 we continued to expand our convenience partnership model, which is now in around 1,600 sites across our network, including our differentiated REWE to Go® offer, now in around 550 sites across Germany.

We also made significant progress towards our growth ambition in new markets, most notably in Mexico where we now have more than 520 BP-branded retail sites, with volumes more than doubling in 2019, and in December we signed an agreement with Reliance Industries Limited to form a fuels retail and aviation joint venture across India, providing access to one of the world's largest and fastest growing fuels markets.

We have a clear strategy and focused activity set for the transition to a lower carbon and digitally enabled future. We are actively implementing and developing new offers and business models centred around digital and advanced mobility trends.

In 2019 we signed an agreement with DiDi, the world's leading mobile transportation platform, to build an electric vehicle charging network in China, the world's largest market for electric vehicles. In addition, in the UK, BP Chargemaster began installing 150kW ultra-fast electric vehicle chargers at our BP retail sites, with plans to build a national network of high-power charging – one which will closely replicate the current fuelling experience. These advances support BP's strategy to create the fastest and most convenient electrification networks in these markets.

BPme is our global customer engagement platform, which is also fast becoming the portal to a suite of offers and services that will transform our retail offer and deliver an enhanced and personalized customer experience. The platform provides an easy, fast and convenient way for customers to pay for fuel from their car, and for customers in the UK, Australia and the US, it also incorporates our new loyalty programme *BPme Rewards*.

Fuels marketing earnings in 2019 were similar to 2018, with volume and margin growth offset by adverse foreign exchange effects.

Aviation

Our Air BP business is one of the world's largest suppliers of aviation fuels and services, selling fuel to commercial airlines, the military and general aviation customers. Air BP supplies around 6.6 billion gallons of aviation fuel a year at over 800 locations in more than 55 countries. Air BP's services include the design, build and operation of fuelling facilities, technical consultancy and training, supporting customers to meet their lower carbon goals and digital fuelling solutions to increase efficiency and reduce risk. Our Air BP business is differentiated through its strong market positions, brand strength, partnerships, technology and customer relationships. Our strategy is to maintain a strong presence in our core geographies of Australia, New Zealand, Europe, the Middle East and the US, while expanding into major growth markets that offer long-term competitive advantages, such as Asia, Africa and Latin America.

In 2019 we continued to develop new offers and solutions to advance the energy transition and to meet the changing needs of our customers. Through our collaboration with Neste, a leading producer of renewable products, we began supplying aviation fuel made from sustainable materials to a number of airports in Sweden. We also expanded our partnership with China National Aviation Fuel Group, signing a joint venture agreement to operate a general aviation fuel and services business in southwest China. The joint venture intends to support the growth and development of China's general aviation sector.

Oil supply and trading

Our integrated supply and trading function is responsible for delivering value across our crude and oil products supply chain. This enables our downstream businesses to maintain a single interface with oil trading markets and operate with a single set of trading compliance and risk management processes, systems and controls. It principally achieves this objective in two ways:

First, it seeks to identify the best markets and prices for our crude oil, source optimal raw materials for our refineries and provide competitive supply for our marketing businesses. We will often sell our own crude and purchase alternative crudes from third parties for our refineries where this will generate incremental margin.

Second, it aims to create and capture trading opportunities by entering into a full range of exchange-traded commodity derivatives★ and over-the-counter spot and term contracts. In combination with its rights to access storage and transportation capacity, it also seeks to access advantageous price differences between locations, time periods, and markets.

The function has trading offices in Europe, North America and Asia. Our presence in the more actively traded regions of the global oil markets supports the overall understanding of the supply and demand forces across these markets.

Our trading financial risk governance framework is described in Financial statements – Note 29 and the range of contracts used is described in Glossary – commodity trading contracts on page 337.

		thousand barrels per day	
Sales volume	**2019**	2018	2017
Marketing sales[a]	**2,727**	2,736	2,799
Trading/supply sales[b]	**3,268**	3,194	3,149
Total refined product sales	**5,995**	5,930	5,948
Crude oil[c]	**2,713**	2,624	2,616
Total	**8,708**	8,554	8,564

a Marketing sales include branded and unbranded sales of refined fuel products and lubricants to business-to-business and business-to-consumer customers, including service station dealers, jobbers, airlines, small and large resellers such as hypermarkets, and the military.
b Trading/supply sales are fuel sales to large unbranded resellers and other oil companies.
c Crude oil sales relate to transactions executed by our integrated supply and trading function, primarily for optimizing crude oil supplies to our refineries and in other trading. 2019 includes 118 thousand barrels per day relating to revenues reported by the Upstream segment.

		Number of BP-branded retail sites	
Retail sites[d]	**2019**	2018	2017
US	**7,200**	7,200	7,200
Europe	**8,200**	8,200	8,100
Rest of world	**3,500**	3,300	3,000
Total	**18,900**	18,700	18,300

d Reported to the nearest 100. Includes sites not operated by BP but instead operated by dealers, jobbers, franchisees or brand licensees under a BP brand. These may move to or from the BP brand as their fuel supply or brand licence agreements expire and are renegotiated in the normal course of business. Retail sites are primarily branded *BP, ARCO, Amoco* and *Aral*.

Our lubricants business

We manufacture and market lubricants and related products and services to the automotive, industrial, marine and energy markets across the world. Our key brands are *Castrol*, *BP* and *Aral*. *Castrol* is a recognized brand worldwide that we believe provides us with significant competitive advantage. We are one of the largest purchasers of base oil in the market but have chosen not to produce it or manufacture additives at scale. Our participation choices in the value chain are focused on areas where we can leverage competitive differentiation and strength.

Our strategy is to focus on our premium lubricants and growth markets while leveraging our strong brands, technology and customer relationships – all of which are sources of differentiation for our business. With 65% of profit generated from growth markets and 49% of our sales from premium grade lubricants, we have a strong base for further expansion and sustained profit growth.

In 2019 we strengthened our strategic relationship with Groupe Renault, extending the Renault Sport Racing Formula 1 sponsorship through to the end of 2024 and taking over as global service fill engine oil lubricants partner. We also announced a partnership with Bosch to run jointly branded workshops in China and the US.

We have a robust pipeline of technology development through which we seek to respond to engine developments and evolving consumer needs and preferences, including lower carbon options. We apply our expertise to create differentiated, premium lubricants and high-performance fluids for customers in on-road, off-road, sea and industrial applications.

With the onset of electrification, demand for EV-fluids is expected to grow. These include transmission fluids, battery coolants and greases. Castrol is investing in and partnering with original equipment manufacturers (OEMs) to develop advantaged EV-fluid technologies, and in 2019 we announced a new partnership with the Panasonic Jaguar Racing Formula E Team for season 2019/20. Using Castrol's EV-fluids allows Jaguar and Castrol to collaborate and further develop advanced technology and EV-fluids for both race and road cars of the future.

The lubricants business delivered an underlying RC profit before interest and tax that was similar to 2018, reflecting year-on-year unit margin improvement, offset by adverse foreign exchange rate movements.

Our petrochemicals business

Our petrochemicals business manufactures and markets three main product lines: purified terephthalic acid (PTA), paraxylene (PX) and acetic acid. These have a large range of uses including polyester fibre, food packaging and building materials. We also produce a number of other specialty petrochemicals products. In addition, we manufacture olefins and derivatives at Gelsenkirchen and solvents at Mülheim in Germany, the income from which is reported in our fuels business.

Along with the assets we own and operate, we have also invested in a number of joint arrangements in Asia, where our partners are leading companies in their domestic market.

Our strategy is to grow our underlying earnings and ensure the business is resilient to margin volatility, positioning ourselves to capture growth and investment opportunities in an attractive and growing market.

We do this through the execution of our business improvement programmes which include operational efficiency, deploying our industry-leading proprietary technology, commercial optimization and competitive feedstock sourcing. We have also grown our third-party technology licensing income to create additional value.

We aim to create material, industry leading business models in sustainable chemicals and plastics circularity and in 2019 we announced the development of *BP Infinia*, an enhanced recycling technology, capable of processing currently unrecyclable PET plastic waste. We also formed a consortium with a number of leading companies operating across the polyester packaging value chain which aims to accelerate the commercialization of *BP Infinia* technology and to develop a new circular approach to dealing with PET plastic waste. In 2020 BP plans to build a pilot plant in the US to prove the technology, before progressing to full-scale commercialization. We believe these are important steps in enabling a stronger circular economy in the PET plastics industry, underpinned by our advantaged technology and strategic partnerships.

In addition, we signed an agreement with Virent and Johnson Matthey to further advance the development of bio-paraxylene, a key raw material for the production of renewable polyester.

As part of our growth agenda we expanded capacity at our joint venture acetyls site in South Korea and signed an agreement with Zhejiang Petroleum and Chemical Corporation (ZPCC) to explore the creation of a new, world-scale joint venture to build and operate a 1 million tonne per annum acetic acid plant in Zhejiang Province, China.

In December 2018 we signed a heads of agreement with SOCAR to evaluate the creation of a joint venture to build and operate a world-scale petrochemicals complex in Turkey. This advantaged facility would be the largest integrated aromatics and PTA complex in the western hemisphere. Significant progress has been made in defining the project with a final investment decision expected towards the end of 2020.

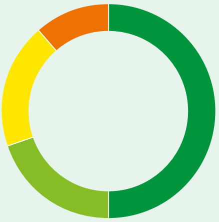
In 2019 the petrochemicals business delivered an underlying RC profit before interest and tax that was lower compared with 2018, reflecting a significantly weaker margin environment across both aromatics and acetyls.

Our petrochemicals production of 12.1 million tonnes in 2019 was higher than in 2018 (2018 11.9mmte).

Rosneft

Rosneft is the largest oil company in Russia, with a strong portfolio of current and future opportunities. Russia has one of the largest and lowest-cost hydrocarbon resource bases in the world and its resources play an important role in long-term energy supply to the global economy.

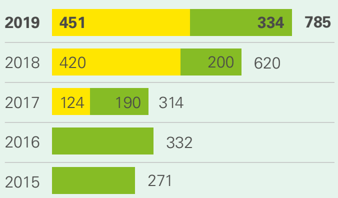
Rosneft shareholding



ROSNEFTEGAZ JSC	**50.00%[a]**
BP	**19.75%**
QH Oil Investments LLC	**18.93%**
Others	**11.32%**

a 50% plus one share.

BP share of Rosneft dividend
($ millions)[b]



Interim
Annual for previous year, less interim
b Net of withholding taxes.

About Rosneft

Rosneft is the largest oil company in Russia and one of the largest publicly traded oil companies in the world based on hydrocarbon production volume. Rosneft has a major resource base of hydrocarbons onshore and offshore, with assets in all of Russia's key hydrocarbon regions and abroad.

Rosneft is the leading Russian refining company based on throughput. It owns and operates 13 refineries in Russia, and holds stakes in three refineries in Germany, one in India and one in Belarus.

Downstream operations include jet fuel, bunkering, bitumen and lubricants. Rosneft also owns and operates Rosneft-branded retail service stations, as well as BP-branded sites operating under a licensing agreement.

Rosneft's largest shareholder with 50% plus one share is Rosneftegaz JSC (Rosneftegaz), which is wholly owned by the Russian government.

BP has a 19.75% shareholding and two directors on the 11-person board.

Bob Dudley and Guillermo Quintero are currently elected to those roles.

2019 summary

- BP received $785 million, net of withholding taxes, (2018 $620 million), representing its share of Rosneft's dividends. This dividend represents 50% of IFRS net profit, and is paid twice a year in line with the dividend policy adopted in 2017.
- BP remains committed to our strategic investment in Rosneft, while complying with all relevant sanctions.

8,281
million barrels of oil equivalent – BP share of Rosneft proved reserves (2018 8,163mmboe)

18
refineries – owned or hold a stake in (2018 18)

19.75%
BP's shareholding in Rosneft

1.1
million barrels of oil equivalent per day – BP share of Rosneft hydrocarbon production (2018 1.1mmboe/d)

2.24
million barrels of oil refined per day (2018 2.33mmb/d)

>3,000
retail service stations in Russia and abroad (2018 >2,960)

Co-operation with Rosneft

Our strategy is to work in co-operation with Rosneft to increase total shareholder return. We also partner with Rosneft in building a material business in addition to our shareholding.

Joint ventures
BP partners with Rosneft to generate incremental value from joint ventures and associates that are separate from BP's core 19.75% shareholding.

- BP holds a 49% interest in Kharampurneftegaz LLC (Kharampur), together with Rosneft (51%), which develops resources within the Kharampurskoe and Festivalnoye licence areas in Yamalo-Nenets in northern Russia. BP's interest is reported through the Upstream segment.
- BP holds a 20% interest in Taas-Yuryakh Neftegazodobycha (Taas), together with Rosneft (50.1%) and a consortium comprising Oil India Limited, Indian Oil Corporation Limited and Bharat PetroResources Limited (29.9%). In 2019 BP received dividends from Taas of $157 million, net of withholding taxes (2018 $48 million). BP's interest in Taas is reported through the Upstream segment.
- Rosneft (51%) and BP (49%) jointly own Yermak Neftegaz LLC (Yermak). The joint venture conducts onshore exploration in the West Siberian and Yenisei-Khatanga basins. In April the right to explore two additional oil and gas licence areas located in Sakha (Yakutia) was transferred to a wholly owned subsidiary of Yermak. BP's interest in Yermak is reported through the Upstream segment.
- Rosneft and BP are in the process of creating a joint venture investment fund (VIF). This supports BP and Rosneft's agenda to accelerate new innovations in the oil and gas industry.

Collaboration
BP collaborates on the provision of technical, HSE and non-technical services on a contractual basis to improve functional asset performance.

BP and Rosneft have developed an innovative cable-less onshore seismic acquisition system and are in discussions about further collaboration.

Social projects
BP together with Rosneft sponsor the Petroleum Engineering Masters degree programme led by the Kazan Federal University (Russia) and Imperial College London (UK), providing financial support, mentoring and lecturing for the students.

Also, with Rosneft, BP sponsors the Britten-Shostakovich Festival Orchestra which brings together the finest young talents from British and Russian music schools, with an average age of 22. Performances in 2019 took place in both the UK and Russia.

Rosneft segment performance

BP's investment in Rosneft is managed and reported as a separate segment under IFRS. The segment result includes equity-accounted earnings, representing BP's 19.75% share of the profit or loss of Rosneft, as adjusted for the accounting required under IFRS relating to BP's purchase of its interest in Rosneft and the amortization of the deferred gain relating to the disposal of BP's interest in TNK-BP. See Financial statements – Note 17 for further information.

			$ million
	2019	2018	2017
Profit before interest and tax[a b]	**2,306**	2,288	923
Inventory holding (gains) losses★	**10**	(67)	(87)
RC profit before interest and tax	**2,316**	2,221	836
Net charge (credit) for non-operating items★	**103**	95	–
Underlying RC profit before interest and tax★	**2,419**	2,316	836

Average oil marker prices			$ per barrel
Urals (Northwest Europe – CIF)	**62.96**	69.89	52.84

a BP's share of Rosneft's earnings after finance costs, taxation and non-controlling interests is included in the BP group income statement within profit before interest and taxation.
b Includes $(11) million (2018 $(5) million, 2017 $(2) million) of foreign exchange (gain)/losses arising on the dividend received.

Market price
The price of Urals delivered in North West Europe (Rotterdam) averaged $62.96/bbl in 2019. The discount to dated Brent was $1.25/bbl in line with 2018 ($1.42/bbl).

Financial results
Replacement cost (RC) profit before interest and tax for the segment included a non-operating charge of $103 million for 2019 and $95 million for 2018.

After adjusting for non-operating items, the increase in the underlying RC profit before interest and tax compared with 2018 primarily reflected favourable foreign exchange and certain one-off items offset by lower oil prices. See also Financial statements – Notes 17 and 32 for other foreign exchange effects.

Balance sheet

			$ million
As at 31 December	**2019**	2018	2017
Investments in associates★[c]	**12,927**	10,074	10,059

Production and reserves

	2019	2018	2017
Production (net of royalties) (BP share)			
Liquids★ (mb/d)			
Crude oil[d]	**920**	919	900
Natural gas liquids	**3**	4	4
Total liquids	**923**	923	904
Natural gas (mmcf/d)	**1,279**	1,285	1,308
Total hydrocarbons★ (mboe/d)	**1,144**	1,144	1,129
Estimated net proved reserves (net of royalties) (BP share)			
Liquids (million barrels)			
Crude oil[d]	**5,604**	5,539	5,402
Natural gas liquids	**141**	154	131
Total liquids[e]	**5,745**	5,693	5,533
Natural gas (billion cubic feet)[f]	**14,705**	14,325	13,522
Total hydrocarbons (mmboe)	**8,281**	8,163	7,864

c See Financial statements – Note 17 for further information.
d Includes condensate.
e Includes 357mmb (356mmb at 31 December 2018; 338mmb at 31 December 2017) for the 6.21% non-controlling interest (6.32% at 31 December 2018; 6.31% at 31 December 2017) in Rosneft held assets in Russia including 26 million barrels (24mmb at 31 December 2018; 6mmb at 31 December 2017) held through BP's interests in Russia other than Rosneft.
f Includes 1,430bcf (1,211bcf at 31 December 2018; 306bcf at 31 December 2017) for the 9.72% non-controlling interest (8.60% at 31 December 2018; 2.30% at 31 December 2017) in Rosneft held assets in Russia including 569bcf (480bcf at 31 December 2018; 2bcf at 31 December 2017) held through BP's interests in Russia other than Rosneft.

Other businesses and corporate

Currently comprises our Alternative Energy business, shipping, treasury, BP Ventures and corporate activities, including centralized functions and any residual costs of the Gulf of Mexico oil spill.

Alternative Energy

BP Ventures

Shipping

Treasury

Insurance

Financial performance

			$ million
	2019	2018	2017
Sales and other operating revenues[a]	**1,788**	1,678	1,469
RC profit (loss) before interest and tax			
Gulf of Mexico oil spill	**(319)**	(714)	(2,687)
Other	**(2,452)**	(2,807)	(1,758)
RC profit (loss) before interest and tax	**(2,771)**	(3,521)	(4,445)
Net adverse impact of non-operating items★			
Gulf of Mexico oil spill	**319**	714	2,687
Other	**1,172**	1,249	160
Net charge (credit) for non-operating items	**1,491**	1,963	2,847
Underlying RC profit (loss) before interest and tax★	**(1,280)**	(1,558)	(1,598)
Organic capital expenditure★[b]	**337**	332	339

a Includes sales to other segments.
b A reconciliation to GAAP information at the group level is provided on page 299.

The replacement cost (RC) loss before interest and tax for the year ended 31 December 2019 was $2,771 million (2018 $3,521 million). The 2019 result included a net charge for non-operating items of $1,491 million, primarily relating to the reclassification of $877 million of accumulated foreign exchange losses from reserves to the income statement, which arose as a result of the contribution of our Brazilian biofuels business to BP Bunge Bioenergia, as well as Gulf of Mexico oil spill related costs of $319 million (non-operating items in 2018 $1,963 million).

After adjusting for these non-operating items, the underlying RC loss before interest and tax for the year ended 31 December 2019 was $1,280 million (2018 $1,558 million). This result mainly reflected improved shipping performance.

Outlook

Other businesses and corporate annual charges, excluding non-operating items, are expected to be around $1.4 billion in 2020.

Alternative Energy

Renewables are the fastest-growing energy source, potentially contributing half of the growth in global energy, with its share in primary energy increasing from 4% in 2019 to around 15% by 2040[a].

In BP, we have an established and growing alternative energy business, with a significant portfolio across renewable fuels, power and products. And we are developing new business models in areas such as low carbon power and digital energy.

a *BP Energy Outlook 2019*: 'evolving transition' scenario.

Our 'reduce, improve, create' framework
We have set targets and aims to reduce emissions in our operations, improve our products to help customers reduce their emissions and create low carbon businesses – see page 41.

Our Alternative Energy portfolio

Biofuels	We formed BP Bunge Bioenergia, a joint venture that combines BP and Bunge's Brazilian bioenergy and sugarcane ethanol businesses. The venture operates 11 biofuels sites and has a production capacity of 32 million metric tonnes of sugarcane a year (see Going big in biofuels).	**Solar energy**	We increased our stake in Lightsource BP to become a 50:50 joint venture. Lightsource BP aims to develop 10GW of solar projects by 2023, see page 73 for more information.
Biopower	BP Bunge Bioenergia produces renewable energy from its biofuels manufacturing sites. The joint venture is capable of exporting 1,200GW hours of biopower to the national grid.	**Renewable products**	Butamax® our 50:50 joint venture with DuPont produces bio-isobutanol from corn. The energy-rich bioproduct has a variety of uses, such as in paints and lubricants.
Wind energy	We operate nine sites in six US states and hold an interest in another facility in Hawaii. Together they have a net generating capacity of 926MW.	**Low carbon power and digital energy**	We are developing a number of digital platforms to connect consumers with local, low carbon electricity to power their homes and transport, and are exploring opportunities to create value at the interplay between gas and renewable energy.

Energy with purpose

Investing in energy management

To help grow our digital energy portfolio, we have invested in Grid Edge, an energy management company. Its technology helps customers predict, control and optimize a building's energy profile.

- Grid Edge can help customers lower carbon emissions by 10-15% on average.

The cloud-based software can anticipate a building's energy demand using data such as weather forecasts and expected occupancy.

- This allows building managers to adapt energy use and take advantage of periods of high renewable power generation.
- Customers can also use the building's flexibility in energy demand and generation like a giant battery.

"This investment is in support of our strategy to create an ecosystem of distinctive, digitally enabled, low carbon businesses for commercial and industrial customers."

Nick Wayth
Chief development officer, Alternative Energy

Going big in biofuels

BP has formed a 50:50 joint venture in Brazil with leading agri-commodities company Bunge Limited. The deal expands our existing biofuels business by more than 50%.

- BP Bunge Bioenergia is now the second-largest operator by effective crushing capacity in the country's bioethanol market.

Brazil is the world's second-largest market for ethanol as a transportation fuel, with around 75% of the country's vehicles able to run on it.

- Demand for ethanol is growing rapidly in the country. In 2019 demand increased 10% versus 2018 and is set to increase up to 55% by 2030.

"With a shared commitment to safety and sustainability, bringing together our assets and expertise allows us to improve performance, develop options for growth and generate real value."

Dev Sanyal
Chief executive, Alternative Energy

BP Ventures

The energy transition is driving the need for rapid change in technology and ways of working, and the imperative for innovation has never been more urgent.

Venturing plays a key role in BP, helping meet the world's need for more energy, while at the same time reducing carbon emissions. We aim to do this by leveraging our investments across a portfolio of relevant technology businesses that can help BP transition to a lower carbon economy.

BP Ventures is set up to grow new energy businesses in the Upstream, Downstream, Alternative Energy and in five areas: advanced mobility, power and storage, carbon management, bio and low carbon products, and digital transformation. We have invested over $650 million dollars since 2007 in more than 40 companies with technologies and innovations that we believe will materially impact BP and global energy systems.

We invested $30 million into Calysta in 2019. This alternative protein producer uses natural gas to produce protein for fish, livestock and pet feeds, see page 28. We also invested a further $30 million into Fulcrum Bioenergy®, a pioneer in making low carbon, low-cost, transportation fuels from one of the most abundant resources – household garbage. And we made two investments in energy management companies – Grid Edge and R&B – totalling $5.4 million.

BP Launchpad

BP's scale-up factory, BP Launchpad, became fully operational in 2019. The initiative aims to quickly create multiple businesses valued over $1 billion that can help tackle the dual energy challenge. Launchpad is focused on building world-scale businesses that specialize in digital and low carbon technologies and the circular economy, with potential for these businesses to become future BP business units.

Examples of growth businesses in the Launchpad portfolio:

- **Lytt:** a subsurface analytics business, providing fibre optic development, deployment and operational services, including acoustic and temperature sensing.
- **STRYDE:** a land seismic receiver technology business. STRYDE's technology breaks the cost/time trade-off to generate high-quality seismic images of the subsurface.
- **Fotech:** a technology company focused on developing and deploying advanced fibre optic sensing hardware. Launchpad acquired Fotech in late 2019; BP Ventures has been a minority investor since 2013.

Energy with purpose

"The conservation and restoration of forests is vital to combatting climate change. We look forward to supporting the team's expansion into the voluntary carbon market."

Nacho Gimenez
Managing director, BP Ventures

BP invests in forest carbon offsets leader

BP Ventures' investment in Finite Resources is helping to grow its business, supporting sustainable forest management practices.

The funding will help Finite Carbon, a subsidiary of Finite Resources, scale up its voluntary carbon offsets programme for businesses.

The programme aims to connect landowners to businesses that want to purchase forest carbon offsets, with corporations paying a fee per tonne of carbon stored in the forest.

This investment is part of our aim to support the technologies and innovations we believe will benefit BP and global energy systems during the transition to a low carbon economy.

Shipping

BP's shipping and chartering activities help to ensure the safe and efficient transportation of our hydrocarbons using a combination of BP-operated, time-chartered and spot-chartered vessels. At 31 December 2019, BP had 35 BP-operated and 40 time-chartered vessels for our international oil and LNG shipping operations. All vessels conducting BP shipping activities are required to meet BP approved standards.

Treasury

Treasury manages the financing of the group centrally, with responsibility for managing the group's debt profile, share buyback programmes and dividend payments, while seeking to ensure that liquidity is sufficient to meet group requirements. It also manages key financial risks including interest rate, foreign exchange, pension funding and investment, and financial institution credit risk. From locations in the UK, US and Singapore, treasury provides the interface between BP and the international financial markets and supports the financing of BP's projects around the world. Treasury holds foreign exchange and interest rate products in the financial markets to hedge group exposures. In addition, treasury generates incremental value through optimizing and managing cash flows and the short-term investment of operational cash balances. For more information, see Financial statements – Note 29.

Insurance

The group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. Some risks are insured with third parties and reinsured by group insurance companies. This approach is reviewed on a regular basis or if specific circumstances require such a review.

Section 172 statement

How the board complied with its Section 172 duty.

The board welcomes the new reporting requirement as an opportunity to explain how dialogue with stakeholders has informed and helped to shape its decisions. For example the board's engagement with Climate Action 100+ in the lead up to the 2019 AGM.

Following the announcement of Bernard Looney's appointment as chief executive officer (CEO) in October 2019, the board engaged with Bernard and the leadership team to develop the company's new purpose, net zero★ ambition and aims. This was supported by extensive dialogue with investors, governments, employees and other stakeholders.

Through working collaboratively with management and listening to feedback from the company's many stakeholders, the board believes that BP is well positioned to respond to increasing uncertainty. We are embarking on a period of change to deliver on our purpose to reimagine energy for people and our planet, while reinventing BP so that we can succeed over the long term. This means continuing to deliver our investor proposition, while responding to society's expectations.

Delegation of authority

The board believes governance of BP is best achieved by delegation of its authority for the executive management of BP to the CEO, subject to defined limits and monitoring by the board. The board routinely monitors the delegation of authority, ensuring that it is regularly updated, while retaining ultimate responsibility.

The board has adopted a long-standing corporate governance framework, which includes principles outlining:

- The board's relationship with shareholders and executive management.
- The conduct of board affairs and the tasks and requirements for board committees.
- The board's focus on activities that enable it to promote shareholders' interests, including development of strategy, monitoring of executive action and ongoing board and executive management succession.

The framework is being reviewed to ensure it is best suited to support the evolving strategy and BP's new purpose, ambition and aims.

The current framework covers the following principal areas:

1. **Company purpose:** pursuing BP's purpose and accountability to shareholders for the company's actions. This means focusing primarily on strategic issues, while having regard to economic, political and social issues and other relevant external matters which may influence or affect the development of BP's business and exemplify through the board principles (including the executive limitations), its expectations for the conduct of the BP business and its employees.
2. **Strategy:** responsibility for establishing and reviewing the long-term strategy and the annual plan (the plan) for BP, based on proposals made by the CEO for achieving BP's purpose.
3. **Monitoring decisions and actions of the CEO and the performance of BP:** including implementation of, and performance against, the strategy and the plan; and the exercise of authority delegated to the CEO. The board satisfies itself that emerging and principal risks to BP are identified and understood, systems of risk management, compliance and controls are in place to mitigate such risks and expected conduct of BP's business and its employees is reflected in a set of values established by the CEO.
4. **Succession:** ensuring systems and processes are in place for succession, evaluation and compensation of the CEO, executive and non-executive directors and key members of senior management.

Those delegated to by the directors to take decisions have access to functional assurance support to identify matters which may have an impact on a proposed decision.

The Companies Act 2006 (CA2006) sets out a number of general duties which directors owe to the company. New legislation has been introduced to help shareholders better understand how directors have discharged their duty to promote the success of the company, while having regard to the matters set out in section 172(1)(a) to (f) of the CA2006 (s172 factors). In 2019 the directors continued to exercise all their duties, while having regard to these and other factors as they reviewed and considered proposals from senior management and governed the company on behalf of its shareholders through the BP board.

Further information as to how the board has had regard to the s172 factors:

Section 172 factor	Key examples	Page
Consequence of any decision in the long term	New ambition and purpose Investment process Strategy	6 19 16
Interests of employees	Engagement, below and page Sustainability 'Our people' Parental leave Alignment of ACB and option to carbon offset	88 47 89 34, 41, 44
Fostering business relationships with suppliers, customers and others	Engagement, below and page	88
Impact of operations on the community and the environment	New ambition and purpose See our support for CA100+ resolution and response Engagement, below and pages	6 6 40-45, 48
Maintaining high standard of business conduct	Governance, pages Sustainability	81-99, 101 40-49
Acting fairly between members	Stakeholder engagement, below and page Balanced long-term decision making Investor proposition	88 67 18

How we engage and foster strong relationships with some of our key stakeholders

Customers

- Original equipment manufacturer collaborations.
- Global customer brand tracking.
- Customer events.

See *bp.com/sustainabilityreport*.

Employees

- Pulse survey.
- Town halls.
- Helios awards.

See Sustainability on page 47 and Corporate governance on page 88.

Government and regulators

- Country economic impact reports.
- Multi-stakeholder groups.
- Government lobbying.

See *bp.com/tradeassociations* and *bp.com/tax*.

Investors and shareholders

- Annual engagement programme.
- Quarterly and year-end results.
- Annual general meeting.

See Corporate governance on page 88.

Partners and suppliers

- Industry events and memberships.
- Supplier workshops and training.
- University collaborations.

See *bp.com/technology*.

Society

- Social media.
- Community workshops and training.
- Social investment programmes.

See Sustainability on page 39 and *bp.com/sustainabilityreport*.

How our board considers stakeholders in decision making

Strategy

At every board meeting the directors review, with the management team, the progress against strategic priorities and the changing shape of the business portfolio. This collaborative approach by the board, together with the board's approval of the company strategy, helps it to promote the long-term success of BP. The board assesses different areas of the business so that BP is well positioned to deliver on its ambition to become a net zero company by 2050 or sooner, and to help the world get to net zero. Ultimately board decisions are taken against the backdrop of what it considers to be in the best interest of the long-term financial success of the company and BP's stakeholders, including shareholders, employees, the community and environment, our suppliers and customers.

We made strong progress with our divestment plans and built exciting new opportunities in fast-growing markets in 2019. BP's flexible strategy allows it to grow in ways that can make a significant contribution to the energy transition, helping deliver the lower carbon energy the world wants and needs, while fostering strong relationships with our stakeholders. This further strengthens the company's balance sheet, enabling us to pursue new advantaged opportunities for BP's portfolio within our disciplined financial framework.

Performance

In order to become a net zero company by 2050 or sooner, BP must perform as we transform.

The board regularly reviews and monitors BP's safety, reliability and environmental performance, with the aim of continually making BP safer for our entire workforce and minimizing our environmental impact. It also focuses on maintaining financial discipline and delivering strong earnings, cash flow and returns to shareholders.

In 2019, BP increased its stake in Lightsource BP, see page 73; formed a new joint venture with BP Bunge Bioenergia, see page 64; partnered with the world-leading mobility platform, DiDi, to create a new electric vehicle charging network in China, see page 27; and is exiting BP's Alaska business as part of a two-year $10 billion divestment programme.

In 2019 a recordable injury frequency rate of 0.166 was the lowest since reporting began, while the number of injuries recorded fell by 17%. Safety will always be one of our core values. This is important to our workforce, local communities and the environment, while securing strong operational availability and reliability is crucial to our partners, suppliers and customers.

People

BP's workforce is key to its success. Our people help us maintain our strong reputation for high standards of business conduct are fundamental in delivering our purpose to reimagine energy.

The past year was significant for BP, with the announcement of Bernard Looney as new CEO. As part of the succession planning for this role, the board considered a number of factors, including the values and leadership behaviours that this role requires. Bernard has been with BP since 1991 and has a strong sense of BP's culture and values. As chief executive of Upstream, he oversaw improvements in personal safety and initiated developments in the workplace in areas such as mental health, diversity and inclusion.

Together the board and new CEO reviewed the new organizational structure, including the appointment of the leadership team and restructuring plans.

The board is reviewing the manner in which it engages with the workforce to enable it to better understand the interests and concerns of BP's people, see page 88.

Governance

The board, led by the chairman, believes that strong governance is essential to the success of the company. At the end of 2018, it participated in an external evaluation of its performance. The board discussed the findings of this review and the chairman introduced changes to the board's ways of working. It agreed to implement changes to board meetings, so that agendas will be structured around four distinct pillars in 2020 – strategy, performance, people and governance.

In light of BP's new corporate purpose, ambition and aims and the changing corporate governance landscape, the board is reviewing its governance framework in order to modernize its principles and processes. The new framework will continue to drive the highest levels of business standards and best practice, aligning these with BP's business purpose, values, strategy and culture.

The board will continue to assess and monitor culture and will look to obtain useful insight through effective dialogue with our key stakeholders and taking feedback into account in the board's decision-making process.

Relevant section 172 factors

The board

(including delegation of authority)

Customers

Our broad customer base spans industries, businesses and end consumers of our products and services. We work closely with our customers to understand their evolving needs so we can improve and adapt to meet them.

>10m

retail customers served every day

Employees

We work to attract, develop and retain the world's best talent, equipped with the right skills for the future. Our people have a crucial role in delivering against our strategy and creating value.

70,100

employees worldwide

Government and regulators

We aim to help countries around the world grow their domestic energy supplies and boost energy security. This in turn helps create jobs and generates revenues for governments. We aim to maintain dialogue with governments and engage in policy debates that are of concern to us and the communities in which we operate.

$6.9bn

paid in income and production taxes to governments in 2019

Investors and shareholders

Our investment proposition is to grow sustainable free cash flow★ and distributions to shareholders over the long term. We rely on the support of our investors, analysts and proxy voting agencies and engage with global investment centres, sharing updates on our strategic progress and our financial and non-financial plans.

$8.3bn

total dividends distributed to BP shareholders in 2019

Partners and suppliers

We depend on the capability and performance of our suppliers, contractors and other partners, such as small businesses, industry peers and academia, to help deliver the products and services we need for our operations and our customers.

$364m

invested in research and development

Society

We consult with local people and NGOs to gain valuable perspectives on the ways in which our activities could impact the local community or environment. We typically engage well before any physical work begins on a project and continue the conversation throughout a project's lifespan.

$84m

committed to social investment in 2019

How we manage risk

BP manages, monitors and reports on the principal risks and uncertainties that can impact our ability to deliver our strategy. These risks are described in the Risk factors on page 70.

Our management systems, organizational structures, processes, standards, code of conduct and behaviours together form a system of internal control that governs how we conduct the business of BP and manage associated risks.

BP's risk management system

BP's risk management system and policy is designed to be a consistent and clear framework for managing and reporting risks from the group's operations to management and to the board. The system seeks to avoid incidents and maximize 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 of 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 significant risks are being managed, monitored, assured and the improvements that are being made.

Our risk management activities

Day-to-day risk management – management and staff at our facilities, assets 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. We 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 the year functional leadership, the executive team, the board and relevant committees provide oversight of how significant risks to BP are identified, assessed and managed. They help to ensure that risks are governed by relevant policies and are managed appropriately. Such oversight may include 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 risk management system. Our group audit team provides independent assurance to the group 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 oversight and governance

Key risk oversight and governance committees include the following:

Executive committees

- Executive team meeting – 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 reporting risks.
- Group people committee – for employee risks.
- Group ethics and compliance committee – for legal and regulatory compliance and ethics risks.
- Resource commitment meeting – for investment decision risks.
- Renewal committee – for strategic, commercial and investment decision risks related to new lines of business.

Board and its committees

- BP board.
- Audit committee.
- Safety, environment and security assurance committee.
- Geopolitical committee.

See BP governance framework on page 83, Board activity in 2019 on page 84, committee reports on pages 90-99 and 101 and Risk management and internal control on page 128.

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.

Businesses and functions review significant risks and associated risk management activities in alignment with key business processes to help enable key decisions to be risk informed.

As part of BP's annual planning process, the executive team and board review the group's principal risks and uncertainties and determine risks for particular oversight by the board and its committees. These may be updated during the year in response to changes in internal and external circumstances.

Our risk profile

The nature of our business operations is long term, resulting in many of our risks being enduring in nature. Nonetheless, 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 BP's risk management system, BP's Energy Outlook, BP's Technology Outlook and group strategic reviews.

We identify longer-term strategic risks and high priority risks for particular oversight by the board and its various committees in the coming year. Those identified for particular oversight in 2020 are listed in this section. These may be updated throughout the year in response to changes in internal and external circumstances. The oversight and management of other risks is undertaken in the normal course of business.

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 we face are set out in Risk factors on page 70.

Risks for particular oversight by the board and its committees in 2020

The risks for particular oversight by the board and its committees in 2020 have been reviewed. In addition to the risks reviewed in 2019, climate-related risks have been added as a longer-term strategic risk.

Climate-related risks

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 considered through key business processes including the strategy, annual plan, capital allocation and investment decisions. The outputs of these key business processes are reviewed in line with the cadence of these activities.

Further details are described in Environment on page 40 and Climate change and the transition to a lower carbon economy on page 70.

Strategic and commercial risks

Financial liquidity
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, consumer preferences for low carbon energy, global economic conditions and the influence of OPEC.

We seek to manage this risk through BP's diversified portfolio, our financial framework, liquidity stress testing, maintaining a significant cash buffer, regular reviews of market conditions and our planning and investment processes.

See Prices and markets and Liquidity, financial capacity and financial, including credit, exposure on page 70.

The impact of coronavirus (COVID-19)
The spread of coronavirus coupled with actions from OPEC+ has caused a significant drop in the oil price. Our financial frame is designed to be robust to periods of low price, with flexibility to reduce cost and capital expenditure if required. We continue to assess the potential impact of coronavirus on our staff and operations and have instigated appropriate mitigation plans.

Cyber security
The targeted and indiscriminate threats to the security 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 cyber security standards, security protection tools, ongoing detection and monitoring of threats and testing of cyber response and recovery procedures. We collaborate closely with governments, law enforcement agencies and industry peers to understand and respond to new and emerging cyber threats. We build awareness with our staff, share information on incidents with leadership for continuous learning and conduct regular exercises including with the executive team to test response and recovery procedures.

Geopolitical
The diverse locations of our 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 through development and maintenance of relationships with governments and stakeholders and by becoming trusted partners in each country and region. In addition, we closely monitor events and implement risk mitigation plans where appropriate.

The impact of the UK's exit from the EU
We have been assessing the potential impact on BP of Brexit and the UK's future global relationships and have considered different outcomes but do not believe any of these outcomes pose a significant risk to our business. The board's geopolitical committee continues to monitor these developments.

Safety and operational risks

Process safety, personal safety and environmental risks
The nature of the group's operating activities exposes us to a wide range of significant health, safety and environmental risks such as incidents associated with releases of hydrocarbons when drilling wells, operating facilities and transporting hydrocarbons.

Our operating management system★ helps us manage these risks and drive performance improvements. It sets out the rules and principles 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 global wells organization in order to promote a consistent approach for designing, constructing and managing wells.

Security
Hostile acts such as terrorism 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 central security team provides guidance and support to our businesses through a network of regional security advisors who advise and conduct assurance activities with respect to the management of security risks affecting our people and operations. We continue to monitor threats globally and maintain disaster recovery, crisis and business continuity management plans.

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, adversely affect operational results and shareholder value, and potentially affect our licence to operate.

Our code of conduct and our values and behaviours, applicable to all employees, are 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 and international trade regulations. We seek to keep abreast of new regulations and legislation and plan our response to them. We offer an independent confidential helpline, OpenTalk, for employees, contractors and other third parties.

Trading non-compliance
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.

Risk factors

The risks discussed below, separately or in combination, could have a material adverse effect on the implementation of our strategy, our business, financial performance, results of operations, cash flows, 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, 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, increased supply from new oil and gas or alternative low carbon energy sources, technological change, global economic conditions, public health situations and the influence of OPEC can impact supply and demand and prices for our products. Decreases in oil, gas or product prices could have an adverse effect on revenue, margins, profitability and cash flows. If significant or for a prolonged period, we may have to write down assets and re-assess the viability of certain projects, which may impact future cash flows, profit, capital expenditure★ and ability to maintain our long-term investment programme. Conversely, an increase in oil, gas and product prices 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 and petrochemicals activities can be volatile, with periodic over-supply 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.

Access, renewal and reserves progression – inability to access, renew and progress upstream resources in a timely manner could adversely affect our long-term replacement of reserves.

Renewing our reserve base depends on our ability to continually replenish future opportunities to access and produce oil and natural gas. Competition for access to investment opportunities, heightened political and economic risks in certain countries where significant hydrocarbon basins are located, unsuccessful exploration activity and increasing technical challenges and capital commitments may adversely affect our reserve replacement. This, and our ability to progress upstream resources and sustain long-term reserves replacement, could impact our future production and financial performance.

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, 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 and regions where political, economic and social transition may take place. Political instability, changes to the regulatory environment or taxation, international sanctions, expropriation or nationalization of property, civil strife, strikes, insurrections, acts of terrorism, acts of war and public health situations (including an outbreak of an epidemic or pandemic) may disrupt or curtail our operations or development activities. These may in turn cause production to decline, limit our ability to pursue new opportunities, affect the recoverability of our assets or cause us to incur additional costs, particularly due to the long-term nature of many of our projects and significant capital expenditure required. Events in or relating to Russia, including trade restrictions and other sanctions, could adversely impact our income and investment in or relating to Russia. Our ability to pursue business objectives and to recognize production and reserves relating to these investments could also be adversely impacted.

Liquidity, financial capacity and financial, including credit, exposure – failure to work within our financial framework could impact our ability to operate and result in financial loss.

Failure to accurately forecast or work within our financial framework 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 framework 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 ratings 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.

Credit rating downgrades could also trigger a requirement for the company to review its funding arrangements with the BP pension trustees and may cause other impacts on financial performance. 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. See Liquidity and capital resources on page 301 and Financial statements – Note 29.

Joint arrangements and contractors – varying levels of control over the standards, operations and compliance of our partners, contractors and sub-contractors could result in legal liability and reputational damage.

We conduct many of our activities through joint arrangements★, associates★ or with contractors and sub-contractors where we may have limited influence and control over the performance of such operations. Our partners and contractors are responsible for the adequacy of the resources and capabilities they bring to a project. If these are found to be lacking, there may be financial, operational or safety risks for BP. Should an incident occur in an operation 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 venture, we may still be pursued by regulators or claimants in the event of an incident.

Digital infrastructure and cyber security – 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 oil and gas industry is subject to fast-evolving risks from cyber threat actors, including nation states, criminals, terrorists, hacktivists and insiders. 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, injury to people, disruption to our business, harm to the environment or our assets, legal or regulatory breaches and legal liability. 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. These could result in significant costs including fines, cost of remediation or reputational consequences.

Climate change and the transition to a lower carbon economy – policy, legal, regulatory, technology and market developments related to the issue of climate change could increase costs, reduce demand for our products, reduce revenue and limit certain growth opportunities.

Laws, regulations, policies, obligations, social attitudes and customer preferences relating to climate change and the transition to a lower carbon economy could have an adverse impact on our business (including increased costs from compliance, litigation, and regulatory or litigation outcomes), and could lead to constraints on production and supply and access to new reserves and a decline in demand for certain products.

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 oil and gas. Depending on the nature and speed of any such changes and our response, this could adversely affect the demand for our products, 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 including goodwill, the judgement as to 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. See Financial statements – Note 1 and Environment on page 40.

Competition – inability to remain efficient, maintain a high-quality portfolio of assets, innovate and retain an appropriately skilled workforce 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, or to sustain, develop and operate a high-quality portfolio of assets efficiently. We could be adversely affected if competitors offer superior terms for access rights or licences, or if our innovation in areas such as exploration, production, refining, manufacturing, renewable energy, new technologies or customer offer that lags the industry. Our performance could also be negatively impacted if we fail to protect our intellectual property. Our industry faces increasing challenge to recruit and retain diverse, skilled and experienced people in the fields of science, technology, engineering and mathematics. Successful recruitment, development and retention of specialist staff is essential to our plans.

Crisis management and business continuity – failure to address an incident effectively could potentially disrupt our business.

Our business activities could be disrupted if we do not respond, or are perceived not to respond, in an appropriate manner to any major crisis or if we are not able to restore or replace critical operational capacity.

Insurance – our insurance strategy could expose the group to material uninsured losses.

BP generally purchases insurance only 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.

Security – hostile acts against our staff and activities could cause harm to people and disrupt our operations.

Acts of terrorism, piracy, sabotage 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.

Safety and operational risks

Process safety, personal safety, and environmental risks – exposure to a wide range of health, safety, security 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 hydrocarbons or other hazardous materials. This could also lead to constrained availability of resources used in our operating activities, as well as fires, explosions or other personal and process safety incidents, including when drilling wells, operating facilities and those associated with transportation by road, sea or pipeline. There can be no certainty that our operating management system★ 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. See Safety and security on page 45.

Such events or conditions, including a marine incident, 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 is 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.

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 and anti-fraud laws, trade restrictions or other sanctions, could damage our reputation, and result in litigation, regulatory action and penalties.

Regulation – changes in the regulatory and legislative environment could increase the cost of compliance, affect our provisions and limit our access to new growth opportunities.

Governments that award exploration and production interests may impose specific drilling obligations, environmental, health and safety controls, controls over the development and decommissioning of a field and possibly, nationalization, expropriation, cancellation or non-renewal of contract rights. Royalties and taxes tend to be high compared with those imposed on similar commercial activities, and in certain jurisdictions there is 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, resulting in increased amounts payable to them or their agencies.

Such factors could increase the cost of compliance, reduce our profitability in certain jurisdictions, limit our opportunities for new access, 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. Potential changes to pension or financial market regulation could also impact funding requirements of the group. Following the Gulf of Mexico 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.

Treasury and trading activities – ineffective oversight of treasury and trading activities could lead to business disruption, financial loss, regulatory intervention or damage to our reputation.

We are subject to operational risk around our treasury and 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. See 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 systems and people. Failure to report data accurately and in compliance with applicable standards could result in regulatory action, legal liability and damage to our reputation.

The Strategic report was approved by the board and signed on its behalf by Ben J. S. Mathews, company secretary on 18 March 2020.

Energy with purpose means helping the world reach net zero.

Corporate governance

Energy with purpose

Expanding solar

Lightsource BP is helping shape the future of global energy delivery by developing solar capacity around the world.

- We increased our stake in Lightsource BP to create a 50:50 joint venture in 2019.

Lightsource BP highlights in 2019

- Entered the Spanish solar market with the purchase of a 300MW portfolio of solar development projects across six sites.
- Signed a long-term agreement to build a 240MW facility, supplying EVRAZ, a US steel company.
- Established a presence in Brazil with the purchase of 1.9GW of solar projects in various stages of development.

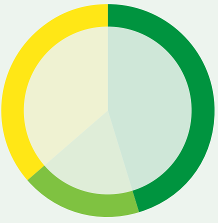
Board of directors

as at 18 March 2020

Committee membership key

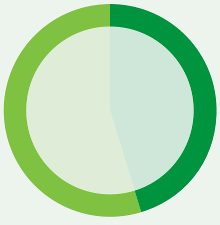
- Chairman
- A Audit
- S Safety, environment and security assurance
- R Remuneration
- G Geopolitical
- C Chairman's
- N Nomination and governance

Non-executive directors' tenure



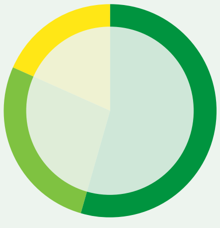
1 – 3 years	5
4 – 6 years	2
7+ years	4

Board gender diversity



Female	5
Male	6

Board nationality



UK	6
US	3
Non UK/US	2

View the directors' biographies in full at *bp.com/board.*

C N

Helge Lund

Chairman
Appointed to the board 26 July 2018 (appointed chairman 1 January 2019)

Outside interests:
Chairman 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 of Industrialists

Age: 57

Nationality: Norwegian

Career summary:
Helge served as chief executive of BG Group from 2015 to 2016, when the company merged with Shell. He joined BG Group from Equinor (formerly Statoil) where he served as its president and chief executive officer for 10 years from 2004. Prior to Equinor, Helge was president and chief executive officer of the industrial conglomerate, Aker Kvaerner, and has also held executive positions in the Norwegian industrial holding company, Aker RGI and the former Norwegian power and industry company, Hafslund Nycomed. He worked as a consultant with McKinsey & Company and served as a political adviser for the parliamentary group of the Conservative party in Norway. Prior to joining BP, he was a non-executive director of the oil service group Schlumberger from 2016 to 2018, and Nokia from 2011 to 2014. He served as a member on the United Nations Secretary-General's Advisory Group on Sustainable Energy from 2011 to 2014.

Relevant skills and experience:
Helge has an impressive track record of leadership in the oil and gas industry. His open-minded and forward-looking approach is vital as the industry focuses on the transition to a lower carbon world. He has deep industry knowledge and global business experience – not only in the oil and gas industry but also in pharmaceuticals, healthcare and construction.

Bernard Looney

Chief executive officer
Appointed 5 February 2020

Outside interests:
Fellow of the Royal Academy of Engineering, Fellow of the Energy Institute, Mentor for FTSE 100 Cross-Company Mentoring Executive Programme

Age: 49

Nationality: Irish

Career summary:
Bernard Looney joined BP in 1991 as a drilling engineer working in roles in the North Sea, Vietnam and the Gulf of Mexico. Prior to becoming the chief executive of BP Upstream in April 2016, Bernard held a range of senior roles, including chief operating officer of production, managing director BP North Sea and vice president in Norway and North Sea infrastructure and BP Alaska. He has led access into new countries, including Mauritania and Senegal, high-graded the portfolio with the acquisition of onshore US assets from BHP Billiton and the sale of the Alaska business, and created innovative new business models, such as Aker BP in Norway.

As chief executive of BP Upstream, Bernard oversaw improvements in both process and personal safety performances and production grew by 20%. There were also significant improvements in both gender and global diversity. Bernard initiated a group-wide dialogue on mental health in hope of 'ending the stigma' associated with the issue.

Relevant skills and experience:
Bernard has spent his career at BP and has demonstrated dynamic leadership and vision as he has progressed through various roles within the Company. As part of the appointment process to becoming the new chief executive officer, Bernard exceeded at range of aptitude and psychometric testing. During his 10 years as a leader of Upstream, Bernard saw the segment through one of the most difficult periods in the BP's history, helping transform the company into a safer, stronger and more resilient business. He was instrumental in a number of workforce based initiatives to promote a diverse and inclusive environment.

Brian Gilvary

Chief financial officer
Appointed 1 January 2012

Brian will retire on 30 June 2020.

Outside interests:
Non-executive director of Air Liquide SA, Non-executive director of Barclays PLC, Non-executive director of Royal Navy Board, Senior independent director of The Francis Crick Institute, Chairman of The Hundred Group of Financial Directors (The 100 Group), Fellow of the Energy Institute; Great Britain Age Group Triathlete

Age: 58

Nationality: British

Career summary:
Brian joined BP in 1986 after obtaining a PhD in mathematics from the University of Manchester. Following a broad range of roles across the group in upstream, downstream and trading in Europe and the US, he became downstream's commercial director in 2002. From 2005 until 2009 he was chief executive of BP's commodity trading arm and, in 2010, he was appointed deputy group chief financial officer. Brian was a director of TNK-BP over two separate periods, from 2003 to 2005 and from 2010 until the sale of the business and BP's acquisition of Rosneft equity in 2013. He served on the HM Treasury Financial Management Review Board from 2014 to 2017.

Relevant skills and experience:
Brian's broad experience of working across the group has provided him with deep insight into BP's assets and businesses. He has been key during BP's strategy implementation to transform into a 'value over volume' business where trading is a key creator of value. His deep understanding of finance and trading has been vital in adjusting capital structures and operational costs while ensuring the group continues to be capable of meeting new opportunities. Brian played a major role in overseeing financial aspects of the Gulf of Mexico oil spill, and leading settlement negotiations to resolve outstanding federal and state claims. He also played a lead role in the negotiations around the exit of TNK-BP and investment into Rosneft and led the 2018 acquisition of the BHP onshore Lower 48 assets.

A C

Dame Alison Carnwath

Independent non-executive director
Appointed 21 May 2018

Outside interests:
Member of Supervisory Board of BASF SE, Director of Zurich Insurance Group, Independent director of PACCAR Inc, Member of UK Panel on Takeovers and Mergers, Trustee of The Economist Group

Age: 67

Nationality: British

Career summary:
Dame Alison is a qualified chartered accountant with a wealth of financial industry experience obtained during an expansive career in London and New York. In addition to her current appointments, she was previously Chairman of Land Securities Group plc from September 2004 until July 2018 and served as a non-executive director of Barclays PLC from 2010 to 2012 and Man Group plc from November 2012 to May 2013. In 2014, Dame Alison was appointed to the order of Dame Commander of the Most Excellent Order of the British Empire for her services to business and diversity.

Relevant skills and experience:
Dame Alison has extensive financial experience both as an executive and non-executive director. Dame Alison has chaired significant boards and has deep experience of the workings of investors and the finance industry in the City of London. She has worked with global organizations and brings this broad range of skills to the BP board and to the audit committee.

A R C

Pamela Daley

Independent non-executive director
Appointed 26 July 2018

Outside interests:
Director of BlackRock, Inc, Director of SecureWorks, Inc

Age: 67

Nationality: American

Career summary:
Pam joined General Electric Company in 1989 as tax counsel and held a number of senior executive roles in the company, overseeing a wide range of corporate transactions and serving as senior vice president and senior advisor to the chairman in 2013, before retiring from GE. Pam has served as a director of BlackRock since 2014 and of SecureWorks since 2016. She was a director of BG Group plc from 2014 to 2016 until its acquisition by Shell, a director of Patheon N.V. from 2016 to 2017 until its acquisition by Thermo Fisher, and was previously a partner at Morgan, Lewis & Bockius, a major US law firm, where she specialized in domestic and cross-border tax-oriented financings and commercial transactions.

Relevant skills and experience:
Pam is a qualified lawyer with significant management insight obtained from previous senior positions held at companies that operate in highly regulated industries. Pam has a wealth of experience in global business and strategy gained from over 20 years in an executive role at GE. She also has experience in the UK oil and gas industry from her time served on the BG Group plc board. Pam contributes important insight to the audit committee from her previous executive experience. In 2019, she joined the remuneration committee, where her understanding of employee and investor perspectives brings value.

R G N C

Sir Ian Davis

Senior independent director
Appointed 2 April 2010

Outside interests:
Chairman of Rolls-Royce Holdings plc, Non-executive director of Majid Al Futtaim Holding LLC, Non-executive director of Johnson & Johnson, Inc.

Age: 68

Nationality: British

Career summary:
Sir Ian began his career at The Bowater Corporation Limited, a paper manufacturing company, before joining McKinsey & Company in 1979. He was a partner at McKinsey & Company for 31 years until his retirement in 2010 and also served as chairman and managing director between 2003 and 2009. Sir Ian has remained as a senior partner emeritus of McKinsey & Company since his retirement. He also served as a lead non-executive board member for the Cabinet Office from 2015 to 2016. Sir Ian was given the honour of knighthood in the 2019 Birthday Honours for services to business.

Relevant skills and experience:
Sir Ian brings global financial and strategic experience to the board. He has worked with and advised global organizations and companies in a wide variety of sectors including oil and gas and the public sector. He is able to draw on knowledge of diverse issues and outcomes to assist the board and its committees.

Sir Ian's previous experience as a non-executive director for the Cabinet Office gives him an important perspective on government affairs which is an asset to both the board and the geopolitical committee.

S C

Professor Dame Ann Dowling

Independent non-executive director
Appointed 3 February 2012

Outside interests:
Deputy vice-chancellor and emeritus professor of Mechanical Engineering at the University of Cambridge, Non-executive director of Smiths Group plc

Age: 67

Nationality: British

Career summary:
Professor Dame Ann is a deputy vice-chancellor and emeritus professor of Mechanical Engineering at the University of Cambridge where her research includes fluid mechanics, acoustics and combustion. She has held visiting posts at MIT and at Caltech. Dame Ann is a fellow of the Royal Society and the Royal Academy of Engineering and a foreign associate of the US National Academy of Engineering, the Chinese Academy of Engineering and the French Academy of Sciences. She was an advisor at Rolls-Royce until 2015. Dame Ann was President of the Royal Academy of Engineering from September 2014 to 2019. In December 2015 she was appointed to the Order of Merit.

Relevant skills and experience:
Dame Ann is an internationally respected leader in engineering research and the practical application of new technology in industry. Her contribution, research and academic leadership in these fields are admired internationally. Her academic background provides balance to the board and brings a different perspective to the safety, environment and security assurance committee, particularly as developments in technology accelerate. Her work in this area is supplemented by her chairing the company's technology advisory council.

S G C R

Melody Meyer

Independent non-executive director
Appointed 17 May 2017

Outside interests:
President of Melody Meyer Energy LLC, Director of the National Bureau of Asian Research, Trustee of Trinity University, Non-executive director of AbbVie Inc., Non-executive director of National Oilwell Varco, Inc.

Age: 62

Nationality: American

Career summary:
Melody started her career in 1979 with Gulf Oil which later merged with Chevron Corporation, where she remained until her retirement in 2016. During her career with Chevron, Melody held several key leadership roles in global exploration and production, working on a number of international projects and operational assignments. Melody was the executive sponsor of the Chevron Women's Network and continues as a mentor and advocate for the advancement of women in the industry. Melody has received several awards and accolades throughout her career including being recognized as a 2009 Trinity Distinguished Alumni, with the BioHouston Women in Science Award and she was most recently recognized by Hart Energy as an Influential Woman in Energy in 2018.

Relevant skills and experience:
Melody has spent her entire career in the oil and gas industry. The breadth, variety and geographic scope of her experience is distinctive. Her career has been marked by a focus on excellence, safety and performance improvement. She has expertise in the execution of major capital projects, creation of businesses in new countries, strategic and business planning, merger integration and safe and reliable operations.

Melody brings a world-class operational perspective to the board, with a deep understanding of the factors influencing safe, efficient and commercially high-performing projects in a global organization.

A C N R

Brendan Nelson

Independent non-executive director
Appointed 8 November 2010

Outside interests:
Non-executive director of NatWest Markets plc, Member of the Financial Reporting Review Panel

Age: 70

Nationality: British

Career summary:
Brendan is a qualified chartered accountant and former partner at KPMG having held a number of senior positions at KPMG International. He served on the KPMG UK board from 2000 until his retirement in 2010. Brendan previously served as a member of the Financial Services Practitioner Panel for six years and was president of the Institute of Chartered Accountants of Scotland in 2013/14. He has extensive financial and banking experience having been a non-executive director of The Royal Bank of Scotland Group p.l.c. and National Westminster Bank p.l.c. from 2010 until April 2019 and December 2018 respectively.

Relevant skills and experience:
Brendan has completed a wide variety of audit, regulatory and due-diligence engagements over the course of his career. He played a significant role in the development of the profession's approach to the audit of banks in the UK, with particular emphasis on establishing auditing standards. He continues to contribute in his role as a member of the Financial Reporting Review Panel.

This wide experience makes him ideally suited to chair the audit committee and to act as its financial expert. He brings related input from his role as the chair of the audit committee of a major bank. His specialism in the financial services industry allows him to contribute insight into the challenges faced by global businesses by regulatory frameworks.

R A C N

Paula Rosput Reynolds

Independent non-executive director
Appointed 14 May 2015

Outside interests:
Non-executive director of BAE Systems plc, Non-executive director of General Electric Company

Age: 63

Nationality: American

Career summary:
Paula commenced her energy career at Pacific Gas & Electric Corp in 1979 and spent over 25 years in the energy industry. She has held a number of executive positions during her career, including CEO of Duke Energy Power Services, Chairman, President and CEO of AGL Resources as well as Chairman and CEO of Safeco Corporation and Vice Chairman and Chief Restructuring Officer of AIG. Paula was a non-executive director of TransCanada Corporation and CBRE Group, Inc until May 2019, having been appointed in 2011 and 2016 respectively. Paula was awarded the National Association of Corporate Directors (US) Lifetime Achievement Award in 2014.

Relevant skills and experience:
Paula has had a long career leading global companies in the energy and financial sectors. Her financial background and deep experience of trading makes her ideally suited to serve on the audit committee.

Her experience with international and US companies, including several restructuring processes and mergers, gives her insight into strategic and regulatory issues, which is an asset to the board.

Paula currently serves as the chair of the remuneration committee of BAE Systems plc. Her experience there and her wider business experience and understanding of the views of investors are well suited to her being the chair of the BP remuneration committee.

G S N C

Sir John Sawers

Independent non-executive director
Appointed 14 May 2015

Outside interests:
Visiting professor at King's College London, Governor of the Ditchley Foundation, Trustee of the Bilderberg Association, UK, Executive Chairman of Newbridge Advisory Limited

Age: 64

Nationality: British

Career summary:
Sir John spent 36 years in public service in the UK, working on foreign policy, international security and intelligence. He was chief of the Secret Intelligence Service, MI6, from 2009 to 2014 and prior to that spent the bulk of his career in the Diplomatic Service, representing the British government around the world and leading negotiations at the UN, in the European Union and in the G8. After he left public service, Sir John was chairman and general partner of Macro Advisory Partners, a firm that advises clients on the intersection of policy, politics and markets, from February 2015 to May 2019. He then set up his own firm, Newbridge Advisory, to carry out similar work. Sir John was appointed Knight Grand Cross of the Order of St Michael and St George in the 2015 New Year Honours for services to national security.

Relevant skills and experience:
Sir John's deep experience of international political and commercial matters is an asset to the board in navigating the geopolitical issues faced by a modern global company. Sir John brings a unique perspective and broad experience which makes him ideal to lead the geopolitical committee. His knowledge and skills gained in government, diplomacy and policy analysis and advice are invaluable to both the board and the safety, environment and security assurance committee.

Ben J S Mathews

Company secretary
Appointed 7 May 2019

Ben joined BP as a company secretary in May 2019. He is chairman of the The Association of General Counsel and Company Secretaries of the FTSE 100 (GC100) and the co-chair of the Corporate Governance Council of the Conference Board. Ben is also a Fellow of the Institute of Chartered Secretaries and Administrators. Former appointments include Group Company Secretary of HSBC Holdings plc and Rio Tinto plc.

Executive team

as at 18 March 2020

Gordon Birrell

Interim head of upstream
Appointed 12 February 2020

Gordon will continue as part of the new leadership team.

Outside interests:
No external appointments

Age: 57 **Nationality:** British

Career summary:
Before being appointed to his new role, Gordon was chief operating officer for production, transformation and carbon. In a long BP career, Gordon has spent time in various technical, safety and operational risk (S&OR) and leadership roles including four years as BP president Azerbaijan, Georgia and Turkey.

Susan Dio

Chairman and president of BP America
Appointed 1 September 2018

Susan will step down from her role on 30 June 2020 and retire from the company in the second half of 2020.

Outside interests:
Member of the American Petroleum Institute Board and Executive Committee, Member of the Greater Houston Partnership Executive Committee, Member of the Ford's Theatre Board of Trustees Executive Committee.

Age: 59 **Nationality:** American

Career summary:
Susan is chairman and president of BP America, providing leadership and oversight to BP's US businesses.

Since joining the company in 1984, she has held key operational and executive positions in the US, UK and Australia. Before assuming her current role, Susan served as chief executive officer of BP Shipping.

Tufan Erginbilgic

Chief executive, Downstream
Appointed 1 October 2014

Tufan will retire from the company on 31 March 2020.

Outside interests:
Member of the Turkish-British Chamber of Commerce & Industry Board of Directors, Member of the Strategic Advisory Board of the University of Surrey.

Age: 60 **Nationality:** British and Turkish

Career summary:
Tufan was appointed chief executive, Downstream on 1 October 2014.

Prior to this, Tufan was the chief operating officer of the fuels business, accountable for BP's fuels value chains worldwide, the global fuels businesses and the refining, sales and commercial optimization functions for fuels. Tufan joined Mobil in 1990 and BP in 1997 and has held a wide variety of roles in refining and marketing in Turkey, various European countries and the UK.

David Eyton

Group head of technology
Appointed 1 September 2018

David will continue as part of the new leadership team.

Outside interests:
Fellow of the UK Royal Academy of Engineering, Fellow of the Institute of Materials, Minerals & Mining, Fellow of the Institute of Directors, Trustee of the John Lyons Foundation, Member of Oil & Gas Climate Initiative Climate Investments Board.

Age: 58 **Nationality:** British

Career summary:
As group head of technology, David is accountable for technology strategy and its implementation across BP. This includes corporate venture capital investments and conducting research and development in areas of corporate renewal. In this role, David sits on the Oil & Gas Climate Initiative Climate Investments Board. David was recognized for his services to engineering and energy in 2018 and awarded a CBE.

Bob Fryar

Executive vice president, safety and operational risk
Appointed 1 October 2010

Bob will retire from the company in the second half of 2020.

Outside interests:
No external appointments

Age: 56 **Nationality:** American

Career summary:
Bob is responsible for safety, operational risk management and the systematic management of operations across the BP group. He is accountable for a variety of group-level disciplines. In this capacity, he looks after the group-wide operating management system implementation and capability programmes.

Bob has over 30 years' experience in the oil and gas industry, having joined Amoco Production Company in 1985.

Andy Hopwood

Executive vice president, chief operating officer, upstream strategy
Appointed 1 November 2010

Andy will retire from the company in the second half of 2020.

Outside interests:
No external appointments

Age: 62 **Nationality:** British

Career summary:
Andy was appointed chief operating officer, upstream strategy in April 2018. Andy joined BP in 1980, spending his first 10 years in operations in the North Sea, Wytch Farm and Indonesia. In 1989 Andy joined the corporate planning team formulating BP's upstream strategy and subsequent portfolio rationalization.

Following the BP-Amoco merger, Andy spent time leading BP's businesses across the world. He was appointed executive vice president, exploration and production in 2010.

Lamar McKay

Chief transition officer
Appointed 16 June 2008

Lamar's current portfolio will be redistributed on 1 July and he will continue in his capacity as chief transition officer.

Outside interests:
No external appointments

Age: 61 **Nationality:** American

Career summary:
Lamar took on a new role as chief transition officer in 2019. He is responsible for supporting the chairman and new group chief executive in achieving a full and orderly transfer of leadership. In addition, he continues to hold responsibility for leading BP's strategy work for the energy transition.

Lamar started his career in 1980 with Amoco and has since held a number of senior roles including most recently group deputy CEO.

Eric Nitcher

Group general counsel
Appointed 1 January 2017

Eric will continue as part of the new leadership team.

Outside interests:
No external appointments

Age: 57 **Nationality:** American

Career summary:
Eric is responsible for legal matters across the BP group. He joined Amoco in 1990 and over the years has held a wide variety of roles.

Eric moved to London in 2000, to join the mergers and acquisitions legal team. He returned to Houston in 2007 to serve as special counsel and chief of staff to BP America's chairman and president.

Most recently he played a leading role in the settlement of the Deepwater Horizon US government claims and resolution of many of the remaining private claims.

Dev Sanyal

Chief executive, alternative energy and executive vice president, regions
Appointed 1 January 2012

Dev will continue as part of the new leadership team.

Outside interests:
Independent non-executive director of Man Group plc; Member of the International Advisory Board on Energy, Government of India; Advisory Board of the Centre for European Reform; Board of Advisors of The Fletcher School of Law and Diplomacy, Tufts University; Fellow of the Energy Institute.

Age: 54 **Nationality:** British and Indian

Career summary:
Dev is responsible for BP's global alternative energy business and for the group's interests in the Europe and Asia regions. He was appointed to the BP Group executive committee in 2011.

Dev joined BP in 1989 and has held a variety of international roles in London, Athens, Istanbul, Vienna and Dubai. Dev was previously appointed group treasurer in 2007 and was also chairman of BP Investment Management. Until April 2016, Dev was executive vice president, strategy and regions.

Dame Angela Strank

BP chief scientist and head of technology, downstream
Appointed 1 September 2018

Angela will retire from the company at the end of 2020.

Outside interests:
Non-executive director of Severn Trent plc, Fellow of the Royal Society, Fellow of the Royal Academy of Engineering.

Age: 67 **Nationality:** British

Career summary:
Dame Angela is responsible for technology across a number of BP's businesses. As BP's chief scientist she is accountable for developing strategic insights from advances in science and managing technology capability in BP.

She joined BP in 1982 as a geologist in exploration and has held various leadership roles across the business. She was recognized for her services to the oil industry and women in science, technology, engineering and mathematics in 2017 and awarded a DBE.

Helmut Schuster

Executive vice president, group human resources director
Appointed 1 March 2011

Helmut will step down from his current role on 1 July and continue working with BP as an advisor.

Outside interests:
Non-executive director of Ivoclar Vivadent AG, Germany

Age: 59 **Nationality:** Austrian and British

Career summary:
Helmut became group human resources (HR) director in March 2011. Since joining BP in 1989, Helmut has held a number of leadership roles. He has worked for BP in the US, UK and continental Europe and within most parts of refining, marketing, trading and gas and power.

Before taking on his current role, his portfolio of responsibilities as vice president, HR, included leading the people agenda for roughly 60,000 people across the globe.

The leadership team

from 1 July 2020

Murray Auchincloss

Executive vice president, finance

From 2015 until being announced to his new position, Murray was chief financial officer for BP Upstream. He has held other senior roles in the segment and spent three years as head of the group chief executive's office. He spent his early career in North America and qualified as a Chartered Financial Analyst.

Giulia Chierchia

Executive vice president, strategy and sustainability

Giulia joins BP from 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. She begins this role with more than 10 years' experience in the energy sector, including helping companies shape their strategies for the energy transition.

Emma Delaney

Executive vice president, customers and products

Emma has spent 25 years working in BP, both in the Upstream and the Downstream, most recently as regional president, West Africa. Prior to this role she held a variety of senior roles: CFO (chief financial officer) for Asia Pacific, head of business development for Upstream gas value chains and commercial director for Iraq. She was the vice president for integrated social and economic programmes in Indonesia. In Downstream she held a number of roles in marketing and planning.

Kerry Dryburgh

Executive vice president, people and culture

Kerry was previously head of HR for the Upstream and has held a series of senior HR positions. She was a key driver behind the Upstream people transformation during 2015-2017. Kerry previously ran HR in BP's shipping, integrated supply and trading (IST) and corporate functions teams. She brings experience from other sectors in Europe and Asia, having worked at both BT and Honeywell before joining BP. She currently sits as a non-executive director for the United Kingdom Strategic Command.

Carol Howle

Executive vice president, trading and shipping

Before taking on her current role, Carol ran BP shipping and was the chief operating officer for IST oil. She has more than 20 years' experience in the energy industry, many in IST. 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.

William Lin

Executive vice president, regions, cities and solutions

William served as chief operating officer, upstream regions before joining the leadership team. Previous senior roles include vice president – gas development and operations for Egypt, regional president for Asia Pacific and head of the group chief executive's office. William managed the successful start-up of the Tangguh LNG facility during his time in Indonesia. He is a non-executive director for Pan American Energy Group that operates in Argentina.

Geoff Morell

Executive vice president, communications and advocacy

Geoff has run group communications and external affairs (C&EA) since 2017, after six years leading BP America's communications and government relations teams. He was instrumental in rebuilding BP's reputation in the years following Deepwater Horizon. Prior to BP, Geoff spent four years at the Pentagon, serving as the chief spokesperson for the military under presidents Bush and Obama. He previously worked in television, including as White House correspondent for ABC News.

Biographies for the other members of the leadership team

Bernard Looney, chief executive officer, page 74.

Gordon Birrell, executive vice-president, production and operations, page 78.

David Eyton, executive vice president, innovation and engineering, page 78.

Eric Nitcher, executive vice president, legal, page 79.

Dev Sanyal, executive vice president, gas and low carbon energy, page 79.

Introduction from the chairman

"Our new purpose is the result of a period of careful development and wide debate with the management team and also reflects the valuable feedback we have received from a number of our stakeholders, both inside and outside of BP."

Helge Lund
Chairman

It has been a privilege to lead BP's board for the past year, especially given the important decisions we have taken together. BP now begins the new decade with a new direction. Our new purpose, to reimagine energy for people and our planet, is supported by a new ambition - for BP to get to net zero by 2050 or sooner, and to help the world get to net zero too. And we have appointed a new chief executive officer, Bernard Looney, who under the board's oversight, will lead BP in achieving both its purpose and its ambition.

BP's board has been deeply involved in each of these changes. It is the board's responsibility to define and set the company's purpose, its values and its strategy, and to be assured that these are aligned with BP's culture. Our strategy and evolving portfolio have been discussed with the management team at every board meeting in 2019. Our new purpose is the result of a period of careful development and wide debate with the management team and also reflects the valuable feedback we have received from a number of our stakeholders, both inside and outside of BP.

BP's new leadership
During the year, the board, through its nomination and governance committee, took equal care in its executive succession planning, including in our appointment of a successor to Bob Dudley. When we began that planning in earnest in autumn 2018, we knew that Bob's many achievements in the role set a high bar for his eventual successor. That was reflected in the time we took to define the qualities we were looking for in the new leadership of BP at a time of considerable change. A year on, we were delighted to welcome Bernard Looney to the role. He is both capable, performance oriented and deeply aware of the importance that we attach to working in close dialogue with BPs stakeholders.

New ways of working
The board itself is an important component of BP's leadership. The most effective boards – and the most effective board meetings – are inclusive, collaborative, open and transparent. During 2019, I was pleased with the support I received from my colleagues on the board as we fostered an atmosphere with the management team in which those standards are clearly exhibited.

These improvements have gone in-hand with improvements to the board's efficiency and productivity. We have strengthened how we manage the board's meeting agenda, the materials developed for the board and the division of labour between the committees and the board. I believe that these changes have enabled us to effectively manage both the leadership succession and develop our new purpose and ambition.

Evolving board composition
The make-up of the board has also evolved, and I expect that to continue in future as we seek to ensure we have the right balance of skills, experience and diversity. In November last year, Nils Andersen was appointed Chairman of Unilever, and therefore stepped down from BP's board on 18 March after a period of transition. On behalf of the board, I thank Nils for his service to BP. In Nils' place, Melody Meyer agreed to chair the safety, environment and security assurance committee (SESAC), recognizing her strong operational and safety experience. Separately, the board has assumed direct oversight of ethics and compliance matters, previously the responsibility of SESAC.

One of the chairman's responsibilities is to ensure cohesion of the board over time, especially during times of transition. To provide continuity, Sir Ian Davis and Brendan Nelson have kindly agreed to stand for re-election at the 2020 AGM for up to a further year. Because they have now each exceeded nine years in the role, in putting them forward for re-election this year the board carefully considered whether, they still demonstrate the necessary qualities of independence. I am pleased to confirm that the board is satisfied that they do, and I am grateful for the support and wisdom that Sir Ian and Brendan bring to the board. Our nomination and governance committee has, as you would expect, begun a process to identify successors to these important roles.

While continuity is important, BP's new direction gives reason to examine whether the board's composition is optimally aligned to BP's new direction. We'll always need a core cadre of members with global executive experience from similar industries, but different specialist skills may also be valuable. These include skills relevant to BP's ambition, individuals with strong digital and transformational skills and those with broader energy and sustainability experience.

In light of the changes ahead of us, but also as a consequence of natural succession, I anticipate that we will add new competences and experiences to the board during 2020.

Evolving remuneration structure

The year 2019 also marked a transition for executive remuneration. In order to develop a new remuneration policy, which will be proposed at the 2020 AGM, the remuneration committee sought candid feedback from some of our largest shareholders. Consequently, while we will retain our current structure, which is simple and well understood, we will strengthen the elements relating to our energy transition ambition. More details of our new policy are set out in the Directors' remuneration report on page 100.

Our stakeholders

This year also marks the first year in which the board is required to report on how it has fulfilled its duties under section 172 of the Companies Act, which requires directors to promote the success of the company for the benefit of its members, and in doing so to have regard to our stakeholders, including employees, suppliers and customers, the impact of our operations on communities and the environment, and the likely consequences of any decision in the long term.

Regard for a wider group of stakeholders is not new. Indeed, it has been incorporated into the board's working for some time. But new reporting requirements are an opportunity to explain the processes we have followed, and how dialogue with stakeholders has shaped decisions. Details can be found on page 66, and information about how the board has engaged with BP's workforce is on page 88.

Closing thanks

Finally, I want to express my gratitude to Bob Dudley, Bernard Looney, the executive team, our employees and my board colleagues for their hard work, their commitment, and their contribution to BP's new direction.

I look forward to working with our teams to compete effectively in a changing energy market.

Helge Lund
Chairman

Governance framework

Shareholders

BP board

Delegation ↓ / Accountability ↑

Audit committee

HPGR* monitored
- Financial liquidity.
- Cyber security.
- Compliance with business regulations.
- Trading compliance and control.

Responsibilities
- Reviewing financial disclosures.
- Monitoring compliance.
- Reviewing audit effectiveness, including internal controls and risk management.
- Advice on external auditor.

See page 91.

Safety, environment and security assurance committee

HPGR monitored
- Monitor marine, well and pipeline incidents.
- Oversee effective controls around releases at facilities and/or explosion.
- Review and advise on major security incident.
- Cyber security.

Responsibilities
- Review safety and operational risk.
- Monitor security developments.
- Review environmental matters.

See page 96.

Geopolitical committee

HPGR monitored
- Geopolitical.

Responsibilities
- Monitor social, economic and political events around the world.
- Identify major and correlated geopolitical risks.
- Consider broader political policy developments.

See page 98.

Remuneration committee

Responsibilities
- Recommend remuneration principles and policy.
- Maintain dialogue with shareholders and workforce on remuneration issues.
- Monitor alignment of remuneration and incentives for all employees.
- Report on implementation of remuneration policy.

See page 101.

Nomination and governance committee

Responsibilities
- Review composition of board.
- Review outside commitments of the NEDs.
- Maintain strong pipeline.
- Review developments in corporate governance, law and ESG.

See page 90.

Chairman's committee

Responsibilities
- Evaluate performance and effectiveness of chief executive officer.
- Review the structure and effectiveness of the business organization.
- Review system of executive development and succession.

See page 99.

Chief executive officer

Executive committee

- Group operations risk committee
- Group financial risk committee
- Group disclosure committee
- Group people committee
- Group ethics and compliance committee
- Resource commitment meeting
- Technical advisory council

Framework changes in 2020
As part of the governance framework review, the board committees and their responsibilities will be reviewed.

* HPGR – highest priority group risks.

Board activities in 2019

Role of the board

The board is responsible for the overall conduct of the group's business. Directors have duties under the both UK company law and BP's Articles of Association. The primary tasks of the board in 2019 included:

- Active consideration and establishment of long-term strategy and approval of the annual plan.
- Monitoring of BP's performance against the strategy and plan including ethics and compliance.
- Ensuring that the principal and emerging risks and uncertainties to BP are identified and that systems of risk management and control are in place.
- Board and executive management succession.

"The board is responsible for establishing the company's purpose, its values and strategy, and satisfying itself that these and its culture are aligned."

Helge Lund
Chairman

Strategy

During 2019 the board considered the BP strategy at every board meeting and held a two-day strategy discussion in September. The board also received a number of technical briefings to expand the directors' knowledge in particular areas, such as Scope 3 emissions, the *BP Energy Outlook* and environmental, social and corporate governance (ESG) matters, to best equip the board to consider and debate strategic themes relating to BP's segments, key functions and the impact of the lower carbon transition on the group's business model. This included looking at long-term energy trends and projections for world energy markets.

The board monitored the company's performance against the annual plan for 2019 and approved the annual plan for 2020 after taking into account management's revised assumptions and outlook for the year. They received regular reports on the progress and implementation of the strategy from the group chief executive (GCE) and chief financial officer (CFO) by means of a strategic performance scorecard, which is discussed at each board meeting.

The board undertook portfolio reviews of various parts of the BP group, including upstream, downstream and renewables. It assessed the potential impact changes to the portfolio might have on the financial framework and discussed allocation of capital. The board looked at circular and sustainable solutions and business development opportunities in a low carbon future, through the lens of what was in the best interest of long-term success of the company.

In a year that saw BP face significant transition, both internally with the announcement of Bob Dudley's retirement and more widely as the company looks to play an important role in the world's energy transition, the board discussed BP's purpose and ambitions and their alignment with strategy and the BP culture.

Performance and monitoring

The board reviews financial, operational and safety performance throughout the year, as well as the latest view on expected full-year delivery against external scorecard measures. During the year there were a number of business and regional reviews, including North Sea, Russia, the lubricants business and BPX Energy.

Updates are also given on various components of value delivery for BP's business. Regular reports presented to the board include:

- Chief executive's report.
- Group performance report.
- Group financial outlook.
- Effectiveness of investment review.
- Quarterly and full-year results.
- Shareholder distributions.

In 2019 the board re-assumed primary responsibility for ethics and compliance (E&C), having previously managed oversight jointly through the SESAC and the audit committee. The group head of E&C attended the board meeting four times in 2019, providing an update on E&C matters, and how the importance of such was embedded within the BP culture throughout the business. The board was also provided ethics and compliance training. The NEDs held private sessions with the head of E&C.

The board reviews the quarterly and full-year results, including shareholder and capital distributions. The 2019 annual report was assessed in terms of the directors' obligations and reflects the briefings on updated corporate governance requirements and best practice.

The board monitors employee opinion via an annual 'Pulse' survey which includes measurement of how the BP values are incorporated into culture around our global operations.

Feedback from other stakeholders is also considered by the board as part of its monitoring of performance, as outlined in the BP Section 172 statement and on pages 88-89.

Risk

The board, either directly or through its committees, regularly reviews the processes whereby principal and emerging risks are identified, evaluated and managed.

Each of the highest priority group risks were reviewed in 2019. The board has a focus on emerging risks and how these are being managed and mitigated. The board undertook its annual review of cyber security risk in particular in December 2019.

Each year the board assesses the effectiveness of the group's system of internal control and risk management as part of the review and sign off of the *BP Annual Report and Form 20-F*, to satisfy itself that the report, taken as a whole, is fair, balanced and understandable, and provides the information necessary for shareholders to assess the company's position, performance, business model and strategy.

Further information on BP's system of risk management is outlined in How we manage risk on page 68. Information about BP's system of internal control is on page 128.

Succession

The board, in conjunction with the nomination and governance and chairman's committees, reviews succession plans for executive and non-executive directors and senior executives on a regular basis. The board ensures that potential candidates are identified and evaluated against objective criteria and on merit, with due regards to the benefits of diversity of thought, gender, social and ethnic backgrounds and cognitive and personal strengths, through a formal and rigorous procedure. BP operated board and senior executive succession planning across three horizons.

1. Contingency planning is constantly at the forefront as mitigation against key person risk in cases of sudden and unforeseen departures.
2. Medium-term planning relates to the orderly replacement of board and committee members and senior executives as they retire or change roles.
3. Finally, long-term planning seeks to equip BP with the skills required now and in the future as we implement the long-term strategy.

The board employs executive search firms when it concludes that this is an effective way of finding suitable candidates. Bernard Looney's appointment as chief executive officer (CEO) resulted from a review of both internal and external candidates. The nomination and governance committee engaged with external headhunters to source external candidates for this purpose of the CEO succession and in support of the overall process.

- Pamela Daley was appointed to the remuneration committee on 30 January 2019.
- Nils Andersen was appointed to the nomination and governance and remuneration committees upon becoming the chair of the safety, environment and security assurance committee on 8 April 2019. Subsequently Nils stepped down as chair of the safety, environment and security assurance committee on 13 November 2019 following the announcement of his appointment as chairman of Unilever. He was succeeded by Melody Meyer as chair of the SESAC on the same day. He resigned from the board and all other committees on 18 March 2020.
- Alan Boeckmann and Admiral Frank Bowman stood down as directors and from all committees following the AGM on 21 May 2019.
- Bob Dudley retired as group chief executive and a director on 4 February 2020. Bernard Looney succeeded him as chief executive officer on 5 February 2020.
- Brian Gilvary announced his retirement in January 2020. He will be succeeded by Murray Auchincloss on 1 July 2020.

Looking forward, the board is implementing changes to its ways of working and redefining its primary responsibilities. As outlined on page 66, from 2020, board agendas will be structured along the following four distinct pillars – strategy, performance, people and governance. Within those areas the key areas of focus will be:

Strategy: the board will consider and help establish the strategy of BP alongside the new CEO and leadership team to achieve the purpose, ambition and aims set out on 12 February 2020, see page 6. In doing so, the board will ensure that every member of the board has a deep understanding of the board's role in determining BP's capital allocation process and enabling effective decision making.

Performance: the board will continue to perform an important monitoring role, making sure the CEO and the leadership team are held to account against the 2020 Annual Plan to satisfy itself that BP is performing while transforming.

People: the board will focus on reviewing the composition, skills, experience and diversity of the board and executive management, as well as the process for executive succession planning talent management and development. It will ensure that workforce policies and practices are consistent with the company's values and the manner in which BP invests and rewards its workforce is designed and implemented in a way that supports the company's long-term sustainable success.

Governance: as outlined on page 83,the board is developing a new corporate governance framework. This framework will reinforce the effectiveness of the internal control framework and be more closely aligned with BP's new purpose and ambition.

Board and committee attendance

Non-executive director	Board	Audit committee	SESAC	Remuneration committee	Geopolitical committee	Nomination and governance committee	Chairman's committee
Helge Lund	9 (9) ●					6 (6) ●	7 (7) ●
Nils Andersen*	8 (9)		6 (6)	4 (6)	3 (4)		6 (7)
Alan Boeckmann	3 (3)		2 (2)	3 (3)		2 (2)	2 (2)
Admiral Frank Bowman	3 (3)		2 (2)		2 (2)		2 (2)
Dame Alison Carnwath	9 (9)	8 (8)					7 (7)
Pamela Daley	9 (9)	7 (8)		8 (8)			6 (7)
Sir Ian Davis	9 (9)			8 (9)	4 (4)	6 (6)	7 (7)
Professor Dame Ann Dowling	9 (9)		6 (6)				6 (7)
Melody Meyer	9 (9)		6 (6) ●		4 (4)		7 (7)
Brendan Nelson	9 (9)	8 (8) ●		9 (9)		6 (6)	7 (7)
Paula Rosput Reynolds	9 (9)	8 (8)		9 (9) ●		6 (6)	7 (7)
Sir John Sawers	9 (9)		6 (6)		4 (4) ●	6 (6)	7 (7)

Executive directors	Board
Bob Dudley*	9 (9)
Brian Gilvary	9 (9)

● Chairman of board/committee

* Bob Dudley stepped down from the board 4 February; Nils Andersen stepped down from the board 18 March 2020

Background

Non-executive director	Background and experience						
	Energy markets	Operational excellence and risk management	Global business leadership and governance	People leadership and organizational transformation	Technology, digital and innovation	Society, politics and geopolitics	Finance, risk, trading, etc
Dame Alison Carnwath		●	●				●
Pamela Daley			●				●
Sir Ian Davis			●	●		●	●
Professor Dame Ann Dowling					●		
Helge Lund	●	●	●	●		●	●
Melody Meyer	●	●					
Brendan Nelson			●				●
Paula Rosput Reynolds	●		●	●			●
Sir John Sawers				●		●	●

Diversity

BP believes diversity and inclusion is vital to our values, the group strategy and the success of the company. We understand that better decisions and outcomes are achieved when we have different people, with differences of opinions from different backgrounds.

We recognize the importance of diversity, whether that be gender, social or ethnic backgrounds, personal identities, age, religion, physical abilities and more. These all promote diversity of thought and reduce the risk of groupthink. This approach is followed by the board, senior executives and their direct reports and throughout the BP group.

We are committed to attracting the best talent to BP and feel an inclusive and respectful work environment, where people are valued as individuals, is key. When reviewing the composition of the board, the nomination and governance committee reviews not only the skills and experience of existing board members, but also their background and diversity. Equally, when seeking to identify candidates to join the board, the committee gives consideration to merits of diversity, including gender, in helping to bring greater balance to the board's discussion and debates on strategy and associated matters.

Diversity is considered as an integral part of succession planning. Executive gender and ethnicity were taken into consideration as part of the board's wider executive succession review in 2019, while diversity of thought, deriving from a robust combination of gender, social or ethnic backgrounds, was a prominent factor in the selection process, ensuring that BP has a diverse executive pipeline.

At the end of 2019 the board comprised five female directors (2018 5, 2017 3) representing 42% of a 12-person board (46% of an 11 person board at the time of publication). Our senior management, as defined by the Corporate Governance Code 2018, and their direct reports comprise 38% female and 18% black, Asian and minority ethnic (BAME) individuals. For details of BP workforce diversity and inclusion, see Our people on page 47. The board looked at diversity across the group as part of its annual review of HR, capability and talent management. BP continues to take action to address the broader issue of diversity within the group.

Independence

Non-executive directors (NEDs) are expected to be independent in character and judgement and free from any business or other relationship that could materially interfere with exercising that judgement. It is the board's view that all BP NEDs are independent.

The board is satisfied that there is no compromise to the independence of, and nothing to give rise to conflicts of interest for, those directors who serve together as directors on other company's boards or who hold other external appointments. Directors are required to provide the board with sufficient information to evaluate their independence and the board keeps the other interests of the NEDs under review and regularly reviews the conflicts of interest register.

Sir Ian Davis and Brendan Nelson are proposed for re-election notwithstanding that they have both served beyond nine years as non-executive directors.

Following careful consideration, the board believes that both Sir Ian and Brendan continue to provide constructive challenge and robust scrutiny of matters that come before the board and the committees on which they serve. Neither director has served simultaneously with an executive director for over nine years and the overall average tenure of the board is similar to that of the average FTSE 100 directors' tenure. In 2018 the board undertook significant refreshment of its composition with a number of new non-executives and a new chairman. Since assuming the chairmanship of the board at the beginning of the year, Helge Lund has led the process to identify and, in October 2019, to announce the appointment of a new group CEO. This was supplemented by a process to identify and, in January 2020, announce the appointment of a new group CFO. Sir Ian and Brendan will play crucial roles in the transition period as these new appointments come into effect, so that BP's culture and values are not adversely impacted and that the integrity of its financial reporting is maintained. After careful consideration, the board is satisfied that Sir Ian and Brendan continue to demonstrate the qualities of independence in carrying out their duties.

Appointment and time commitment

The chairman and NEDs each have letters of appointment. There is no term limit on a director's service, as BP proposes all directors for annual re-election by shareholders in line with best governance practice.

The chairman's letter of appointment sets out the time commitment expected of him. The NEDs' letters of appointment do not set out a fixed time commitment. The time required of directors fluctuates depending on the demands of BP business and other events. They are expected to allocate appropriate time to BP to perform their duties effectively and make themselves available for all regular and ad hoc meetings. The board believes that, notwithstanding the NEDs' other appointments, they have sufficient time to fulfil their BP duties.

Executive directors are normally permitted to take up one board appointment at an external listed company, subject to the agreement of the chairman and after consultation with the company secretary. In February 2020, Brian Gilvary was appointed as a non-executive director of Barclays PLC. An announcement in respect of Brian's plans to retire as CFO of BP was made in January 2020. He will stay in the role until June 2020 to work with his successor, Murray Auchincloss, in order to ensure an orderly transition. Given these circumstances and after consideration by the chairman and company secretary, it was concluded that Brian's role at Barclays PLC was unlikely to be detrimental to his duties as outgoing CFO. Fees received for an external appointment may be retained by the executive director and are reported in the Directors' remuneration report (see page 100). Neither the chairman nor the senior independent director are employed as an executive of the group.

The board also considers all NED external appointments and considers the impact those requiring significant commitment might have on the director's ability to dedicate sufficient capacity in times of increased demand. In November 2019, the board acknowledged the appointment of Nils Andersen as Chairman of Unilever NV/PLC and accepted his resignation from the BP board. Nils remained as a non-executive director until March 2020 to support Melody Meyer who took over as chair of the SESAC in November 2019.

Learning, development and inductions

The board held a number of developmental briefing sessions during the year, in which field experts with a range of academic and practical knowledge were invited to provide bespoke training sessions, updating them on latest intelligence in their particular area. This develops and optimizes the skill set within the board on evolving technical topics and aids conversation around strategic planning.

The board continued to build its knowledge of the BP business through briefings and site visits as part of its learning programme, see examples on page 89.

No new directors were appointed during 2019. In October 2019, BP announced that Bob Dudley would be retiring in 2020, succeeded by Bernard Looney. Bernard's functional and operational knowledge of BP meant that an in-depth induction programme was not necessary. Nonetheless, Bernard attended a number of town halls with Helge Lund in 2019 to engage with BP people.

Board evaluation

Each year, BP completes a review of the board, its committees and of the individual directors. It is generally recommended that such reviews are externally led once every three years. Having undertaken an externally facilitated review in 2018, the 2019 evaluation was facilitated by the incoming company secretary. The process involved interviews with each member of the board based around a number of themes, including strategy formulation and portfolio development, the role of the new chairman and boardroom dynamics, the evolution of BP's purpose and wider stakeholder engagement and the processes in place for managing succession across the organization. Positive feedback was received on the new chairman's style and the benefits his inclusive leadership approach had brought to the board during the year. The outputs of this review highlighted three areas of future focus and attention:

- Reviewing the composition, skills, experience and diversity of the board and the process for executive succession planning talent management and development.
- Ensuring every member of the board has a deep understanding of the board's role in determining BP's capital allocation process and enabling effective decision making.
- Re-shaping the BP corporate governance framework and how this it should reinforce the effectiveness of the internal control framework and be more closely aligned with BP's new purpose and ambition.

A new corporate governance framework is in development, supported by the outputs from this year's board review process, with the aim of ensuring that this new framework is in place by the time that the new organizational structure and reporting arrangements take effect.

UK Corporate Governance Code compliance

BP complied throughout 2019 with the principles and provisions of the 2018 UK Corporate Governance Code except in the following aspects:

Provision 33

The remuneration of the chairman is not set by the remuneration committee. Instead, the chairman's remuneration is reviewed by the remuneration committee which makes a recommendation to the board as a whole for final approval, within the limits set by shareholders. This wider process enables all board members to discuss and approve the chairman's remuneration, rather than solely the members of the remuneration committee.

Provision 38

The pension arrangements for Bob Dudley and Brian Gilvary reflect the historical retirement benefits available to employees that joined BP at similar times. We recognize that the contribution rates under these arrangements are higher than the majority of the current workforce and as such the pension contributions for the new executive directors, Bernard Looney and Murray Auchincloss, have been aligned with those available to the majority of the workforce.

A copy of the 2018 UK Corporate Governance Code is available at *frc.org.uk*.

How the board has engaged with shareholders, the workforce and other stakeholders

Shareholders

Institutional investors
The company engages with its institutional shareholders through its active investor relations programme. The board receives feedback on shareholder views in many ways, particularly through the chairman and senior management who meet regularly with shareholders throughout the year, as well as through the results of an independent investor study and report.

In September 2019 the chair of the remuneration committee hosted an event for large investors on considerations for the new remuneration policy which is to be tabled at the 2020 AGM in May (see Remuneration committee report on page 101). The chairman also held one-to-one meetings with major institutional investors during the year, collecting their views and sharing these with the other board members and the remuneration committee.

During the course of the year, senior management met regularly with institutional investors through road shows, group and one-to-one meetings, events for socially responsible investors (SRIs), meetings with various investors to discuss environment, social and governance matters, and oil and gas sector conferences.

In May 2019, the chairman and board committee chairs held their annual investor event. This meeting enabled BP's largest shareholders to hear about the work of the board and its committees and for investors to share their views directly with non-executive directors.

See *bp.com/investors* for investor and strategy presentations, including the group's financial results and information on the work of the board and its committees.

Shareholder engagement cycle 2019

Q1	• Fourth quarter and full year 2018 results and strategy update • Investor roadshows with executive management – fourth quarter and full year 2018 results • BP Energy Outlook presentation • BP Annual Report 2018 launch • BP Sustainability Report 2018 launch
Q2	• Chairman and board committee chairs meeting with investors • UKSA (retail shareholders') meeting with the chairman • First quarter 2019 results presentation • Annual general meeting • BP Statistical Review of World Energy launch
Q3	• Second quarter 2019 results presentation • Investor roadshows with executive management following 2Q results
Q4	• Third quarter 2019 results presentation • Investor roadshows with executive management following 3Q results

Retail investors
BP held an event for retail investors in conjunction with the UK Shareholders' Association (UKSA) in 2019. The chairman and a representative from investor relations gave presentations on BP's annual results, strategy and the work of the board. Shareholders' questions were focused on BP's activities and performance.

AGM
Voting levels were relatively consistent at 67.1% (of issued share capital, including votes cast as withheld) in 2019, compared to 67.3% in 2018. The lower voting level of 50.8% in 2017 was due to the negative impact of stock lending.

In 2019 the AGM was held in Aberdeen for the first time, which enabled the board to engage with shareholders who might not have had the opportunity to attend a meeting before. There were two shareholder requisitioned resolutions put to the meeting in 2019.

All resolutions supported by the board, including the shareholder resolution from the Climate Action 100+ group, passed at the meeting, see page 6. The shareholder resolution from Follow This, which was not supported by the board, did not pass.

Each year the board receives a report after the AGM giving a breakdown of the votes and investor feedback on its voting decisions to inform it on any issues arising.

Workforce

At BP we believe a diverse and engaged workforce is critical to us successfully delivering our group strategy. BP strives to create an open culture where dialogue between the board, senior management and the workforce, which includes a wide range of employees, contractors, agency and remote workers across all of its geographical locations, is encouraged and expected. 'Respect' and 'courage' are two of our corporate values that underpin this and are embedded in our performance management system. Employees are informed of information on matters of concern to them as employees through BP's intranet and local sites, social media channels, town halls, site visits and webinars including topics such as quarterly results, strategy, the low carbon transition and diversity. We have a number of employee-led forums and business resource groups and aim to build constructive relationships with labour unions formally representing some employees. Employees are consulted on a regular basis through regular team and one-to-one meetings and through our annual 'Pulse' survey. These initiatives are applied where practicable.

Our annual employee 'Pulse' survey results for overall engagement, long-term cultural metrics and listening and involvement have shown a steady and sustained improvement over this period, see page 47.

With such a diverse and globally distributed workforce, we believe ongoing dialogue through multiple channels is the best way for the board and management to engage with our people and listen to what they have to say. The board is firmly of the opinion that face-to-face interaction with our people is the best way to get direct feedback and an understanding of the important issues of the workforce, as well as deepen the board's operational understanding. Only by visiting and meeting with employees from all aspects of the business can the board fully assess the culture and tone of BP. The board held a number of site visits in 2019 to a number of different locations, including Busan, Kuala Lumpur, Singapore, Aberdeen and Denver. A number of non-executive directors also took opportunities to engage directly with local workforce at various BP offices around the globe. As part of Helge Lund's first year as chairman, he conducted town hall meetings with the workforce in Washington DC, Baku, Rotterdam, Beijing, Houston and London.

The board and its committees are committed to meeting with a wide range of employees across the entire workforce and at times exclude senior management from meetings to get the unfettered opinions of their teams. An example of this was the SESAC's visit to a new LNG vessel off the coast of South Korea immediately prior to its maiden voyage. This was the first shipping visit of its kind, during which members of the SESAC held private informal meetings with the ship's crew, away from senior officers. The crew highlighted a couple of potential improvements, the SESAC members agreed and, as a consequence, certain improvements were undertaken by shipping leadership.

As an example of how engagement has directly contributed to shaping policy, in 2019 we launched a new global commitment to minimum parental leave for new parents. This policy was established through engagement with our employee-led business resource groups and employee forums, including the working parents' forum.

BP invests in its workforce through a number of employee share ownership schemes and plans. For example, we operate 'ShareMatch' in more than 50 countries. The plan matches BP shares purchased by our employees. We also operate a group-wide discretionary share plan, which rewards employees with participation in BP's equity at different levels globally and is linked to BP performance.

As we look to achieve our purpose, ambition and aims – engagement with our global talent pool is as critical as ever. BP wants to recruit, retain and reward people from wide-ranging and diverse backgrounds who can support us in the global transition to a low carbon energy system. We will continue to expand our existing networks of communication to foster a listening culture that enables the board and management to gain meaningful insight directly from our colleagues around the world, and respond accordingly. For instance, following feedback from BP's working parents' forum, agile working and parental leave policies have been improved, and in response to growing demand from our workforce, BP introduced a way for some employees to offset their personal carbon emissions and is working towards expanding this scheme to more employees across the group. The board will dedicate time to specifically review the outputs from the various channels of workforce engagement at board sessions.

The board believes the existing approaches and mechanisms described above enable comprehensive two-way engagement opportunities with BP's workforce, and as such, is satisfied that these are effective alternatives to the proposed workforce engagement methods set out in Provision 5 of the Code. Given the current period of transition within BP, the board will continue to review its engagement mechanisms to seek new ways to strengthen existing workforce forums to ensure a continuing robust relationship and collaboration.

Other stakeholders

For details of how the board complied with Section 172 of the Companies Act 2006 and how it further engaged with other stakeholders, see page 66.

Site visits

Denver
The board visited BP's Denver office in September 2019 where they hosted several employee events. A town hall took place, led by Helge Lund, with the rest of the board present to talk with the workforce and answer questions over a community lunch with over 150 employees in attendance. The board was also introduced to emerging talent in the region and met with senior leadership. As part of the suite of events the board also met with external stakeholders at a business reception in the city.

150

employees attended a community lunch with the board.

Kuala Lumpur and Singapore
Members of the audit committee visited the global business services in Kuala Lumpur. Touring BP's offices gave valuable insight into the workforce which has been responsible for centralizing and standardizing key business processes across the organization and transforming processes end-to-end. The directors then visited the IST team in Singapore where they met with senior leadership and the wider workforce at BP's offices.

300

employees attended the town hall presented by Helge Lund and Bob Dudley.

Aberdeen
Following the AGM in Aberdeen, the board held a number of engagement activities. Helge Lund and Bob Dudley led a town hall which was attended by over 300 employees at BP's Dyce office and streamed live to the offshore teams in the North Sea. The board hosted a business reception, inviting members of the local community, local political and government officials, employees and local businesses.

Members of the board had further engagement with the workforce at the Dyce office, observing new agile ways of working and gaining technological insight into new initiatives. Members of the board also visited the Clair Ridge platform, where they learnt more about operations offshore. They discussed the safety agenda onsite, visited the drilling floor and spoke with employees directly to better understand the culture when working offshore.

South Korea
The SESAC visited BP's shipping function and spent a day at sea in South Korea on board a new LNG vessel. They experienced the vessel in a period of 'shakedown' ahead of going into service. The committee observed safety processes in action and were able to discuss physical and cyber security planning. Members of the SESAC met with sea farers without management present to discuss life working on board the vessels.

"The committee members noted strong morale."

Nomination and governance committee

"The committee dedicated a significant amount of time to its role in 2019 and this will continue as BP implements its new purpose, ambition and aims."

Helge Lund
Committee chair

Chairman's introduction

The committee dedicated a significant amount of time to its role in 2019, a year which was vitally important for BP and the future direction of the company. This will continue as BP implements its new purpose, ambition and aims.

During the year the committee led the search for a new CEO to succeed Bob Dudley. This involved agreeing the leadership credentials and desired experiences for the executive role. External headhunters were engaged to support the process and to identify candidates with the required skills, experience and diversity credentials. After a thorough and transparent process, Bernard Looney was identified as the best suited candidate and his appointment was announced in October 2019.

The committee's focus on executive succession planning continued, and BP announced Murray Auchincloss as Brian Gilvary's successor as CFO in January 2020.

Finally, a review was undertaken by the committee of the new leadership team which was announced in February 2020.

As part of the selection and appointment process for each of these roles, candidates completed extensive leadership assessment testing and were asked to give insight to their aims for BP's future.

During the year the committee also undertook a review of the executive succession pipeline, considering the process, emerging talent and leadership role key-person-risks. As part of this review, the committee took into account the importance of diverse talent pipelines and the current and future skill sets required to help the company achieve its strategy

The committee discussed the implications of the UK Corporate Governance Code 2018 and how to maintain the highest standards of governance.

Lastly, the committee considered the findings of the 2018 board evaluation and made proposals to the board on new ways of working. Together with the results from the 2019 board review, these changes are being incorporated into a new corporate governance framework.

Helge Lund
Committee chair

Role of the committee

The committee seeks to ensure an orderly succession of candidates for directors, the company secretary and senior executives and oversees corporate governance matters for the group.

Key responsibilities

- Identify, evaluate and recommend candidates for appointment or reappointment as directors.
- Review the outside directorships/commitments of the Non-Executive Directors (NEDs).
- Review the mix of knowledge, skills, experience and diversity of the board for the orderly succession of directors.
- Identify, evaluate and recommend candidates for appointment as company secretary.
- Review developments in law, regulation and best practice relating to corporate governance and make recommendations to the board on appropriate action, including on Environmental, Social and Governance matters.

Membership

Helge Lund	Member since July 2018 and chairman since September 2018
Alan Boeckmann	Member (resigned April 2019)
Sir Ian Davis	Member
Nils Andersen	Member (resigned March 2020)
Brendan Nelson	Member
Paula Reynolds	Member
Sir John Sawers	Member

Meetings and attendance

The committee met six times in 2019. All members attended each meeting with the exception of Nils Andersen who missed two meetings owing to prior commitments.

Activities during the year

2019 saw the workload and required time commitment of committee members increase significantly as the committee continued to monitor the composition and skills of the board, with foresight across the three succession planning horizons, as part of the process of developing a reinvented BP.

During the year, it supported the board in the selection of the new CEO, which was announced in October 2019, and the new CFO, which was announced in January 2020. Regular updates were provided to the chairman's committee to ensure that all NEDs were kept informed of the pending changes to BP's executive leadership. The committee also reviewed the wider executive team's succession planning, considered the implications of the new UK Corporate Governance Code 2018 and made recommendations to the board following the results of the external board evaluation in 2018. We will continue to focus on ensuring that the board's composition is strong and diverse and to promote best practice governance in the boardroom and throughout the company.

Audit committee

"

The committee robustly challenges reports...enabling it to determine whether BP's financial reporting is fair, balanced and understandable."

Brendan Nelson
Committee chair

Chairman's introduction

During 2019, in keeping with the new UK Corporate Governance Code 2018, the committee continued its focus on monitoring the integrity of the group's financial reporting and risk management systems. Each quarter the committee robustly challenges the reports from management and the external auditor highlighting significant accounting issues and judgements, enabling it to determine whether BP's financial reporting is 'fair, balanced and understandable'. Throughout the year, the committee reviewed the group's principal and emerging risks, including scenarios which could impact the company's long-term viability which also helped to inform the committee's debates on what would constitute significant failings and weaknesses in our system of internal control.

In 2019 the committee focused on the effectiveness of a number of group functions including integrated supply and trading, treasury, tax, information technology and security. We also received presentations regarding, and reviewed performance of, both the Upstream and Downstream segments and regularly considered climate change risk affecting the whole business. These reviews helped inform the committee of the work and future plans of those functions and businesses and enabled the committee to understand the key risks and challenges (and associated mitigations and lessons learned) faced by each of them. In addition, the committee carried out reviews into the group risks of financial liquidity, cyber security and compliance with business regulations.

There were no changes to the committee membership during the year and the skills and experience of our committee members remain strong, enabling the committee to continue to perform effectively.

Brendan Nelson
Committee chair

Role of the committee
The committee monitors the effectiveness of the group's financial reporting, systems of internal control and risk management and the integrity of the group's external and internal audit processes.

Key responsibilities
- Monitoring and obtaining assurance that the process to identify, manage and mitigate principal and emerging financial risks are appropriately addressed by the chief executive officer and that the system of internal control is designed and implemented effectively in support of the limits imposed by the board ('executive limitations'), as set out in the BP board governance principles.
- Reviewing financial statements and other financial disclosures and monitoring compliance with relevant legal and listing requirements.
- Reviewing the effectiveness of the group audit function, BP's internal financial controls and systems of internal control and risk management.
- Overseeing 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.
- Reviewing the systems in place to enable those who work for BP to raise concerns about possible improprieties in financial reporting or other issues and for those matters to be investigated.

Membership

Brendan Nelson	Member since November 2010 and chair since April 2011
Dame Alison Carnwath	Member
Pamela Daley	Member
Paula Reynolds	Member

Brendan Nelson is chair of the audit committee. He was formerly vice chairman of KPMG and president of the Institute of Chartered Accountants of Scotland. Currently he is chairman of the group audit committee of NatWest Markets plc and a member of the Financial Reporting Review Panel. The board is satisfied that he is the audit committee member with recent and relevant financial experience as outlined in the UK Corporate Governance Code and competence in accounting and auditing as required by the FCA's Corporate Governance Rules in DTR7. It considers that the committee as a whole 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 oil and gas sector. The board also determined that the audit committee meets the independence criteria provisions of Rule 10A-3 of the US Securities Exchange Act of 1934 and that Brendan may be regarded as an audit committee financial expert as defined in Item 16A of Form 20-F.

Meetings and attendance
There were eight committee meetings in 2019. All members attended each meeting with the exception of Pamela Daley who was absent from the September meeting owing to prior commitments. Regular attendees at the meetings include the chief financial officer, group controller, chief accounting officer, group head of audit, group general counsel and external auditor.

Activities during the year

How the committee reviewed financial disclosure

The committee reviewed the quarterly, half-year and annual financial statements with management, focusing on the:

- Integrity of the group's financial reporting process.
- Clarity of disclosure.
- Compliance with relevant legal and financial reporting standards.
- Application of accounting policies and judgements.

As part of its review, the committee received quarterly updates from management and the external auditor in relation to accounting judgements and estimates including those relating to the Gulf of Mexico oil spill, recoverability of asset carrying values and other matters. The committee keeps under review the frequency of results reporting during the year.

The committee reviewed the assessment and reporting of longer-term viability, systems of risk management and internal control, including the reporting and categorization of risk across the group and the examination of what might constitute a significant failing or weakness in the system of internal control. It also examined the group's modelling for stress testing different financial and operational events, and considered whether the period covered by the company's viability statement was appropriate.

The committee considered the *BP Annual Report and Form 20-F 2018* and assessed whether the report was fair, balanced and understandable and provided the information necessary for shareholders to assess the group's position and performance, business model and strategy. In making this assessment, the committee examined disclosures during the year, discussed the requirement with senior management, confirmed that representations to the external auditors had been evidenced and reviewed reports relating to internal control over financial reporting. The committee made a recommendation to the board, which in turn reviewed the report as a whole, confirmed the assessment and approved the report's publication.

Other disclosures reviewed included:

- Oil and gas reserves.
- Pensions and post-retirement benefits assumptions.
- Risk factors.
- Legal liabilities.
- Tax strategy.
- Going concern.
- IFRS 16 (lease accounting).

How risks were reviewed

The principal risks allocated to the audit committee for monitoring in 2019 included those associated with:

Trading activities: including risks arising from shortcomings or failures in systems, risk management methodology, internal control processes or employees.

In reviewing this risk, the committee focused on external market developments and how BP's trading function had responded to a rapidly changing environment, including modernizing its control environment policies to strengthen its compliance and control culture. The committee further considered updates in the integrated supply and trading function's risk management programme, including compliance with regulatory developments, activities in response to cyber threats, and efficiencies derived from more collaborative ways of working across group functions and businesses and the use of digital technologies.

Compliance with business and regulations: including ethical misconduct or breaches of applicable laws or regulations that could damage BP's reputation, adversely affect operational results and/or shareholder value and potentially affect BP's licence to operate.

The committee reviewed the group's programme of controls and contingencies for managing this risk, including enhanced approaches to monitor the risk in light of business evolution (such as an increase in venturing), as well as other internal and external trends. The committee also reviewed key areas of BP's legal function that advise on compliance matters.

Cyber security risk: including inappropriate access to or misuse of information and systems and disruption of business activity.

The committee reviewed ongoing developments in the cyber security landscape, including events in the oil and gas industry and within BP itself. The review focused on a strengthened approach in order to manage the ever increasing threat of cyber risk and maintain cyber security, as the focus on a digital transformation across BP continues.

Financial liquidity: including the risk associated with external market conditions, supply and demand and prices achieved for BP's products which could impact financial performance.

The committee reviewed the key assumptions, and underlying judgements, used to manage the group's liquidity, and capital investments (including appraisal, effectiveness and efficiency).

How other reviews were undertaken

Other reviews undertaken in 2019 by the committee included the following, and in each case where the committee received segment and function reviews, each reported on strategy, performance, capability and risk management as well as on their first, second and third lines of defence policies as appropriate:

- Non-operated joint venture: including management of exposure to financial, reputational and regulatory risks.
- Upstream: including strategy, business model, financial performance and risk management.
- Downstream: including strategy, performance, capability and risk management.
- Tax: including strategy, performance, key drivers of the group's effective tax rate, the global indirect tax environment, the tax modernization programme and the evolving approach to management of key risks.
- Other businesses and corporate: including overview of the businesses and functional activities, financial performance and financial control framework.
- Treasury: including performance, capability, and risk management.
- Integrated supply and trading: including strategy, performance, capability and risk management.
- Capability and succession in BP's finance function, including the group's finance summary of change programme.
- Effectiveness of investment: annual review of performance of projects with sanctioned capital over a certain threshold.
- Assessment of financial metrics for executive remuneration: consideration of financial performance for the group's 2019 annual cash bonus scorecard and performance share plan, including adjustments to plan conditions and non-operating items.
- Internal controls: assessments of management's plans to remediate the external auditor's findings.
- Information technology and security: including an update on the transformation of the function to enable the digitization and modernization of the firm at pace.

How internal control and risk management was assessed

Group audit

The committee received quarterly reports on the findings of group audit in 2019, including their assessment of issues raised in previous years, especially those relating to IT access controls. The committee met privately with the group head of audit and key members of his leadership team. The committee monitored and reviewed the effectiveness of internal audit and considered whether it had the appropriate level of independence and its importance in assessing the company culture.

Training

The committee considered market updates and developments throughout the year including the CMA statutory audit market study, the Brydon Review and the Kingman Review. It received technical updates from the chief accounting officer on developments in financial reporting and accounting policy, in particular an update on IFRS 16 'Leases' and the stakeholder engagement disclosures required under The Companies (Miscellaneous Reporting) Regulations 2018 for the 2019 accounting year, and amendments to IFRS 9 'Financial Instruments' for interest rate benchmark reform from the start of 2020.

GBS and integrated supply and trading visit

In March the committee visited BP's global business services (GBS) centre in Kuala Lumpur. During the visit they met with the head of country and his leadership team who presented GBS strategy to 2025 enabling modernization of BP through accelerated standardization, digital solutions and process transformation – underpinned by a global functional operating model. They also met with the Procurement and HR services teams including an interactive session with local business resource colleagues.

In March the committee also visited BP's integrated supply and trading (IST) function in Singapore, meeting with senior leaders to discuss the role of this function in BP, review of the risks and controls processes and a floor walk through key functions and the trading desks. See page 89 for more information on these visits by the committee.

In October, the committee held its meeting at BP's IST function in London and conducted its annual tour, which covered global oil strategy, integrated gas and power, associated key risks and risk and compliance management and how the function was responding to a fast evolving market by using digital tools to drive efficiencies. The following trading desks were visited by the committee: treasury trading, global environmental products and integrated gas and power.

External audit

How the committee assessed audit risk

The external auditor set out its audit strategy for 2019, identifying significant audit risks to be addressed during the course of the audit. These included:

- Focus on the consistency of management's judgements and estimates within BP's strategy in the context of climate change.
- Responding to the risk of material misstatements in the group, by way of substantive testing and the use of detailed data analytics.
- The risk of impairment of upstream oil and gas property, plant and equipment, and exploration and appraisal assets.
- Accounting for structured commodity transactions in the integrated supply and trading function.
- Valuation of level 3 financial instruments held by the integrated supply and trading function.
- Management override of controls.

The committee received updates during the year on the audit process, including how the auditor had challenged the group's assumptions on these issues.

How the committee assessed audit fees

The audit committee reviews the fee structure, resourcing and terms of engagement for the external auditor annually; in addition it reviews the non-audit services that the auditor provides to the group on a quarterly basis.

Fees paid to the external auditor for the year were $49 million (2018 $42 million), of which 2% was for non-audit assurance work (see Financial statements – Note 36). The audit committee is satisfied that this level of fee is appropriate in respect of the audit services provided and that an effective audit can be conducted for this fee. Non-audit or non-audit related assurance fees were $1 million (2018 $2 million). Non-audit or non-audit related services consisted of other assurance services.

How the committee assessed audit effectiveness

Management undertook a survey which comprised questions across five main criteria to measure the auditor's performance:

- Robustness of the audit process.
- Independence and objectivity.
- Quality of delivery.
- Quality of people and service.
- Value added advice.

The results of the survey indicated that the external auditor's performance was broadly comparable with the previous year. Areas with high scores and favourable comments included quality of accounting and auditing judgement and robust stance on issues. Areas for improvement were identified but none impacted on the effectiveness of the audit, mostly in recognition of it having been Deloitte's first year in role. The results of the survey were discussed with Deloitte for consideration in their 2019 audit approach.

The committee held private meetings with the external auditor during the year and the committee chair met separately with the external auditor and group head of audit at least quarterly.

The effectiveness of the external auditor is evaluated by the audit committee. The committee assessed the auditor's approach to providing audit services. On the basis of such assessment, the committee concluded that the audit team was providing the required quality in relation to the provision of the services. The audit team had shown the necessary commitment and ability to provide the services together with a demonstrable depth of knowledge, robustness, independence and objectivity as well as an appreciation of complex issues. The team had posed constructive challenge to management where appropriate.

The committee specifically considered the findings of the FRC's Audit Quality Review team's review of Deloitte's 2018 audit. The committee noted the single observation raised and Deloitte's proposed response thereto. Overall the committee noted the review did not raise any concerns in respect of audit quality.

How the auditor reappointment and independence was assessed

The committee considers the reappointment of the external auditor each year before making a recommendation to the board. The committee assesses the independence of the external auditor on an ongoing basis and the external auditor is required to rotate the lead audit partner every five years and other senior audit staff every five to seven years. No partners or senior staff associated with the BP audit may transfer to the group.

How the committee had oversight of non-audit services

The audit committee is responsible for BP's policy on non-audit services and the approval of non-audit services. Audit objectivity and independence is safeguarded through the prohibition of non-audit tax services and the limitation of audit-related work which falls within defined categories. BP's policy on non-audit services states 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) and the UK Financial Reporting Council (FRC).

The audit committee approves the terms of all audit services as well as permitted audit-related and non-audit services in advance. The external auditor is considered for permitted non-audit services only when its expertise and experience of BP is important.

Approvals for individual engagements of pre-approved permitted services below certain thresholds are delegated to the group controller or the chief financial officer. Any proposed service not included in the permitted services categories must be approved in advance either by the audit committee chairman or the audit committee before engagement commences. The audit committee, chief financial officer and group controller monitor overall compliance with BP's policy on audit-related and non-audit services, including whether the necessary pre-approvals have been obtained. The categories of permitted and pre-approved services are outlined in Principal accountant's fees and services on page 322.

How accounting judgements and estimates were considered and addressed

Key judgements and estimates in financial reporting	Audit committee activity	Conclusions/outcomes
Exploration and appraisal intangible assets		
BP uses technical and commercial judgements when accounting for oil and gas exploration, appraisal and development expenditure and in determining the group's estimated oil and gas reserves. Judgement is required to determine whether it is appropriate to continue to carry intangible assets related to exploration costs on the balance sheet.	• Reviewed exploration write-offs as part of the group's quarterly due diligence process. • Received the output of management's annual intangible asset certification process used to ensure accounting criteria to continue to carry the exploration intangible balance are met. • Received briefings on the status of upstream intangible assets, including the status of items on the intangible assets 'watch-list'.	• Exploration write-offs totalling $0.6 billion were recognized during the year. • Exploration intangibles totalled $14.1 billion at 31 December 2019. • BP believes it is appropriate to continue to capitalize the costs relating to intangible assets, on the 'watch-list'.
Recoverability of asset carrying values		
Determination as to whether and how much an asset, 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. Reserves estimates based on management's assumptions for future commodity prices have a direct impact on the assessment of the recoverability of asset carrying values reported in the financial statements.	• Held an in-depth review of BP's policy and guidelines for compliance with oil and gas reserves disclosure regulation, including the group's reserves governance framework and controls. • Reviewed the group's oil and gas price assumptions. • Reviewed the group's discount rates for impairment testing purposes. • Upstream impairment charges, reversals and 'watch-list' items were reviewed as part of the quarterly due diligence process.	• The group's long-term price assumption for Brent oil★, was reduced by $5 from 2018 assumptions and was unchanged for Henry Hub★ gas. • The period over which the group's price assumptions transition from recent market prices to the long-term assumption was unchanged at five years for Brent oil and increased from 5 to 12 years for Henry Hub gas from 2018. • A sensitivity analysis estimating the effect of reductions in the price assumptions has been disclosed in Note 1. • The methodology for determining the group's discount rates used for impairment testing was enhanced, resulting in country-specific rates being applied. • Impairments of $6.6 billion were recorded in the year, net of impairment reversals, primarily relating to decisions to dispose of certain assets.
Investment in Rosneft		
Judgement is required in assessing the level of control or influence over another entity in which the group holds an interest. BP uses the equity method of accounting for its investment in Rosneft and BP's share of Rosneft's oil and natural gas reserves is included in the group's estimated net proved reserves of equity-accounted entities. The equity-accounting treatment of BP's 19.75% interest in Rosneft continues to be dependent on the judgement that BP has significant influence over Rosneft.	• Reviewed the judgement on whether the group continues to have significant influence over Rosneft, including following Bob Dudley stepping down from his role as BP group chief executive. • Considered IFRS guidance on evidence of participation in policy-making processes. • Received reports from management which assessed the extent of significant influence, including BP's participation in decision-making.	• BP has retained significant influence over Rosneft throughout 2019 as defined by IFRS.

Key judgements and estimates in financial reporting	Audit committee activity	Conclusions/outcomes
Derivative financial instruments		
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 longer-term LNG★ contracts.	• Received a briefing on the group's trading risks and reviewed the system of risk management and controls in place. • The committee annually reviews the control process and risks relating to the trading business.	• BP considers that longer-term contracts to buy or sell LNG do not meet the definition of a derivative under IFRS. BP has assets and liabilities of $5.5 and $4.4 billion respectively, recognized on the balance sheet for level 3 derivative financial instruments at 31 December 2019, mainly relating to the activities of the integrated supply and trading function (IST). • BP's use of internal models to value certain of these contracts has been disclosed in Note 30.
Provisions		
BP's most significant provisions relate to decommissioning, environmental remediation and litigation. The group holds provisions for the future decommissioning of oil and natural gas production facilities and pipelines at the end of their economic lives. Most of these decommissioning events are many years in the future and the exact requirements that will have to be met when a removal event occurs are uncertain. Assumptions are made by BP in relation to settlement dates, technology, legal requirements and discount rates. 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.	• Received briefings on decommissioning, environmental, asbestos and litigation provisions, including those related to the Gulf of Mexico oil spill. These included the requirements, governance and controls for the development and approval of cost estimates and provisions in the financial statements. • Reviewed the group's discount rates for calculating provisions.	• Decommissioning provisions of $15.1 billion were recognized on the balance sheet at 31 December 2019. • The discount rate used by BP to determine the balance sheet obligation at the end of 2019 was a nominal rate of 2.5% – based on long-dated US government bonds – a reduction of 0.5% from 2018. • The impact of applying the revised rate has been disclosed.
Pensions and other post-retirement benefits		
Accounting for pensions and other post-retirement 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 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.	• The method for determining the group's assumptions remained largely unchanged from 2018. The values of these assumptions and a sensitivity analysis of the impact of possible changes on the benefit expense and obligation are provided in Note 24. • At 31 December 2019, surpluses of $7.1 billion and deficits of $8.6 billion were recognized on the balance sheet in relation to pensions and other post-retirement benefits.

Safety, environment and security assurance committee (SESAC)

"The committee has continued to focus on working with executive management to drive safe and reliable operations."

Melody Meyer
Committee chair

Chairman's introduction

At the end of 2019 I took the role of chair for the committee. Alan Boeckmann retired from the board in April 2019 and Nils Andersen replaced him as the committee chair. In November last year, Nils announced his intention to step down from the board in March 2020 and I replaced Nils as SESAC chair with immediate effect.

During 2019 the committee has continued to focus on working with executive management to drive safe and reliable operations. As part of the committee's review of the executives' management of the highest priority non-financial group risks assigned to SESAC we provide constructive challenge and oversight. The risks under our remit remained the same as for 2018: marine, wells, pipelines, explosion or release at facilities, major security incidents and cyber security in the process control network. The committee receives reports on each of these risks and monitors their management and mitigation.

In 2019 the committee reviewed the *BP Sustainability Report 2018*. It also reviewed work practices in BP in relation to and following publication of the company's Modern Slavery Act (MSA) statement in 2019. The committee will continue to review progress in developing and embedding practices to mitigate the risk of modern slavery and related human rights.

In March, members of the committee visited the shipping function as one of the new LNG vessels went into service from the building yard in Busan, South Korea. This afforded the committee time with the crew on board the vessel, employees in the office and with contractors in the shipyard. See page 89 for more details. The level of access into the operations on such visits gives the directors first-hand, direct insight. This framework provides an opportunity for meaningful and open dialogue with the local site teams, allowing the committee to better fulfil its obligations.

Melody Meyer
Committee chair

Committee overview

Role of the committee
The role of the SESAC is to look at the processes adopted by BP's executive management to identify and mitigate significant non-financial risk. This includes monitoring the management of personal and process safety risk, security and environment risks and receiving assurance that processes to identify and mitigate such non-financial risks are appropriate in their design and effective in their implementation.

Key responsibilities
The committee receives specific reports from the business segments and functions, which include, but are not limited to, the safety and operational risk function, shipping, group audit and group security. The SESAC can access any other independent advice and counsel it requires on an unrestricted basis. The SESAC and audit committee worked together, through their chairs and secretaries, to ensure that agendas did not overlap or omit coverage of any key risks during the year.

Meetings and attendance
There were six committee meetings in 2019. All directors attended every meeting for which they were eligible.

In addition to the committee members, all SESAC meetings were attended by the group chief executive, the executive vice president for safety and operational risk (S&OR) and the head of group audit or his delegate. The external auditor has access to the chair and secretary to the committee as required. The group general counsel also attended some of the meetings. At the conclusion of each meeting the committee scheduled private sessions for the committee members only, without the presence of executive management, to discuss any issues arising and the quality of the meeting. The group chief executive receives invitations to join the private meetings on an ad hoc basis and at least once a year the head of group audit is invited to a private meeting with the committee.

Membership

Melody Meyer	Member since May 2017 and chair since November 2019
Nils Andersen	Member (resigned March 2020)
Alan Boeckmann	Member (retired April 2019)
Admiral Frank Bowman	Member (retired May 2019)
Professor Dame Ann Dowling	Member
Sir John Sawers	Member

Activities during the year

System of internal control and risk management

The review of operational risk and performance forms a large part of the committee's agenda. Group audit provided quarterly reports on its assurance work and its annual review of the system of internal control and risk management.

The committee also received regular reports from the group chief executive and vice president for S&OR on operational risk, including regular reports prepared on the group's health, safety, security and environmental performance and operational integrity. These included meeting-by-meeting measures of personal and process safety, environmental and regulatory compliance, security and cyber risk analysis, as well as quarterly reports from group audit. In addition, the group auditor regularly met in private with the chairman and other members of the committee over the course of the year. During the year the committee received separate reports on the company's management of risks relating to:

- Marine.
- Wells.
- Pipelines.
- Explosion or release at our facilities.
- Major security incidents.
- Cyber security (process control networks).

The committee reviewed these risks and their management and mitigation in depth with relevant executive management. The committee reviewed the 2019 forward programme for the group audit function.

Site visits

In March members of the committee made a physical visit to the shipping function for the first time. While the committee has regular access to senior leaders in the function, attempting to visit the vessels needed careful planning. With the launch of six new LNG vessels between October 2018 and April 2019, the committee took the opportunity to visit, and arrived as the fifth LNG vessel was in its period of 'shakedown' – a period post-launch and pre-service, when checks are made onboard the ship. The visit, hosted by the chief operating officer of shipping, was made to The British Mentor while it was at sea, just off the coast of South Korea. Committee members went on board and were met by the ship's crew, undertook a thorough tour, and later met with various seafarers, without the captain present, to get a sense of the culture on board. The committee also spent time at the office and held an informal town hall and lunch to hear from employees. The following day the committee was also able to visit the shipyard which had built the LNG vessels, and meet with management. The committee members were able to take a tour of a LNG vessel in the building phase and see the technology used in the construction of the vessel at various stages of completion. The committee spent time with the shipyard owners, important stakeholders in the programme of delivery. In respect of the visit, committee members and other directors received briefings on operations, the status of conformance with BP's operating management system, key business and operational risks and risk management and mitigation. Committee members reported back in detail about the visit to the committee and subsequently to the board. See page 89 for further details.

The board also undertook a site visit. This was not a SESAC site visit but, nevertheless, safety and non-financial risk matters were covered during the visit to Clair Ridge in May 2019.

Corporate reporting

The committee oversaw the *BP Sustainability Report 2018*. The committee reviewed the content and worked with the external auditor with respect to its assurance of the report.

Geopolitical committee

"The committee continued to address key geopolitical matters and their potential impact on BP."

Sir John Sawers
Committee chair

Role of the committee

The committee monitors the company's identification and management of geopolitical risk.

Key responsibilities

- Monitor the company's identification and management of major and correlated geopolitical risk and consider reputational as well as financial consequences.
- Review BP's activities in the context of political and economic developments on a regional basis and advise the board on these elements in its consideration of BP's strategy and the annual plan.
- Major geopolitical risks are those brought about by social, economic or political events that occur in countries where BP has material investments.
- Correlated geopolitical risks are those brought about by social, economic or political events that occur in countries where BP may or may not have a presence but that can lead to global political instability.

Membership

Sir John Sawers	Member since September 2015 and chair since April 2016
Nils Andersen	Member (resigned March 2020)
Admiral Frank Bowman	Member (resigned May 2019)
Sir Ian Davis	Member
Melody Meyer	Member

Meetings and attendance

The chairman and group chief executive regularly attend committee meetings. The chief executive of Alternative Energy and executive vice president, regions and the head of government and political affairs attend meetings as required. The committee met four times during the year. All directors attended each meeting that they were eligible to attend, with the exception of Nils Andersen who missed one meeting due to a prior commitment.

Chairman's introduction

The work of the geopolitical committee in 2019 continued to address key geopolitical matters and their potential impact on BP and how these evolved during the year. As chair of this committee I also attended all of the international advisory board (IAB) meetings in 2019. Now that the IAB has been disbanded, this committee will look to take some of the IAB's remit and we will report next year on how that evolves. In May 2019, Admiral Frank Bowman stood down from the committee. Nils Andersen left the committee upon his resignation from the board in March 2020. I would like to thank Frank and Nils, both of whose contributions were much valued. Other board members joined our meetings from time to time.

Sir John Sawers
Committee chair

Activities during the year

The committee discussed BP's involvement in the key countries where it has existing investments or is considering investment. These included the EU, Mexico, Brazil, Algeria, Libya, Egypt, Iraq, Oman and The Gambia.

The committee also discussed the potential impact of Brexit on BP, and the negotiations between the UK and the EU on their future relationship.

It reviewed the geopolitical background to BP's global investments, the global politics of climate change, the geopolitics of gas, Russian energy exports, OPEC, the USA-China trade war, and developments in the Persian Gulf.

Chairman's committee

"The committee spent significant time discussing the development and progression of BP's purpose, expanding upon what the purpose actually means for the company and how it impacts BP's stakeholders."

Helge Lund
Committee chair

Role of the committee
To provide a forum for matters to be discussed by the non-executive directors.

Key responsibilities
- Evaluate the performance and the effectiveness of the chief executive officer.
- Review the structure and effectiveness of the business organization.
- Review the systems for senior executive development and determine succession plans for the chief executive officer, executive directors and other senior members of executive management.
- Determine any other matter that is appropriate to be considered by non-executive directors.
- Opine on any matter referred to it by the chairman of any committees comprised solely of non-executive directors.

Membership
The committee is made up solely of non-executive directors, each of whom is appointed to the committee upon their appointment to the board.

Meetings and attendance
The committee met seven times in 2019. Nils Andersen, Pamela Daley and Professor Dame Ann Dowling each missed one meeting during the year, all other directors attended every meeting for which they were eligible.

Chairman's introduction

The chairman's committee worked closely with the nomination and governance committee on the selection process of the new group CEO and CFO, receiving regular updates and providing feedback on the succession planning. The committee also spent significant time discussing the development and progression of BP's purpose, expanding upon what the purpose actually means for the company and how it impacts BP's stakeholders. We discussed the updated UK Corporate Governance Code 2018 and the implications for the business. In May 2019, Alan Boeckmann and Frank Bowman stood down from the board and the chairman's committee. I would like to pay tribute to their exceptional service and thank them for their dedication to the committee and BP as a whole.

Helge Lund
Committee chair

Activities during the year

- Evaluated the performance of the group chief executive.
- Reviewed the composition of and the succession plans for the executive team.
- Discussed the company's purpose and what it meant for the business.
- Considered updates to the UK Corporate Governance Code 2018.

Directors' remuneration report

"Through a vibrant exchange of views, we believe the committee will be wiser."

Paula Rosput Reynolds
Committee chair

Contents

Dear shareholder,

This is my second letter to you as chair of the remuneration committee. It comes at the end of a period during which we have engaged with many of you on our new remuneration policy. I have been fortunate to get to know a number of you individually, and as a committee we have deeply appreciated the spirit of collaboration evident throughout our dialogue on remuneration matters.

It also comes at a time when, as a global community, we are navigating uncharted territory because of the global onset of coronavirus (COVID-19). None of us yet know quite how broad its impact will be, nor how deeply it will be felt. What we do know is that our industry is seeing a significant demand and supply-side shock, with consequent share price volatility. The board and I will remain close as the situation develops, and we will respond with consideration of the facts. Clearly, the remuneration targets we have set for the year will need to be adjusted to the circumstances as they unfold. I can also confirm that the remuneration committee will monitor business conditions and exercise judgement in applying discretion relating to 2020 remuneration. We will proceed with great care in determining the timing and magnitude of equity awards. At year-end, when we assess performance, we will be thoughtful in the interpretation of results, balanced with the shareholder experience. I do believe that the 2020 policy as drafted provides us with maximum flexibility in applying discretion – which the times call upon us to exercise.

Turning to our 2019 report, we cover three areas. First the remuneration outcomes over 2019 and the 2017-19 performance shares cycle are presented, along with a discussion about the relationship between company performance, earned rewards and the shareholder experience. Second, the largely regulatory driven reporting of stewardship and related matters is shown. Third, the 2020 directors' remuneration policy, which will be the subject of a binding vote at our annual general meeting in May.

With the number of statutory requirements increasing, this report continues to grow. For those of you needing a quick overview, I recommend our summary pages on 104 and 110 which reflect outcomes for 2019 and the 2020 policy respectively.

Results, progress and incentive outcomes

2019 has been another year of challenges and accomplishments in our operating and financial performance, and concludes a three-year cycle which has seen significant strategic progress. From a shareholder perspective, robust operating cash flow gave headroom for distributions of $8.3 billion through dividends, together with $1.5 billion of share buybacks. Although recent share price performance has been disappointing for BP and global share markets generally, the year nonetheless concludes a three-year cycle that has delivered a 29% total return.

From our analysis of annual performance outcomes, the committee determined that the 2019 bonus should be 67.5% of maximum, rather than the purely formulaic 71.5% derived from the performance scorecard. This was to reflect our judgment that strong cash receipts at year-end would potentially impact receipts in 2020, hence the reduction in the formulaic result.

The committee also determined that the performance share outcome should be 71.2% of maximum. We took the financial measures as reported but used our discretion in determining the quality of the strategic progress. We determined that, over the three-year performance cycle that ended in 2019, significant strategic progress was made towards a lower carbon future. But our message, too, with scoring of strategic progress, is that there is the need for greater pace and accomplishment in the years ahead.

To this point, as we look forward, the committee is faced with measuring strategic progress through a different lens. As our recently appointed BP leadership realigns strategy to reduce the carbon footprint of our business with greater urgency, the committee must strike the balance between rewarding progress in energy transition matters and rewarding delivery of our commitment to strong financial performance and safe operations. As we progress the energy transition, we will be faced with establishing new goals for which benchmark measures may not be readily and immediately available. You will read herein, even the question of the peer group to be used to measure relative total shareholder returns (rTSR) is greatly complicated by the question of whose performance should be tracked in the energy transition.

Remuneration committee

Role of the committee
The role of the committee is to determine and recommend to the board the remuneration policy for the chairman and executive directors. In determining the policy, the committee takes into account various factors, including structuring the policy to promote the long-term success of the company and linking reward to business performance. The committee recognizes the remuneration principles applicable to all employees below board level.

Key responsibilities
- Recommend to the board the remuneration principles and policy for the chairman and the executive directors while considering policies for employees below the board and the executive team.
- Determine the terms of engagement, remuneration, benefits and termination of employment for the chairman and the executive directors, executive team and the company secretary in accordance with the policy.
- Prepare the annual remuneration report to shareholders to show how the policy has been implemented.
- Approve the principles of any equity plan that requires shareholder approval.
- Ensure termination terms and payments to executive directors and the executive team are fair.
- Receive and consider regular updates on workforce views and engagement initiatives related to remuneration, insight from data sources on pay ratio, gender pay gap and other workforce remuneration outcomes as appropriate.
- Maintain appropriate dialogue with shareholders on remuneration matters.

Membership

Paula Rosput Reynolds	Member since September 2017 and chair since May 2018
Nils Andersen	Member (resigned March 2020)
Pamela Daley	Member
Sir Ian Davis	Member
Melody Meyer	Member
Brendan Nelson	Member

Meetings and attendance
The chairman and the group chief executive attend meetings of the committee except for matters relating to their own remuneration. The group chief executive is consulted on the remuneration of the chief financial officer, the executive team and more broadly on remuneration across the wider employee population. Both the group chief executive and chief financial officer are consulted on matters relating to the group's performance.

The group human resources director attends meetings 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 nine times during the year. All directors attended each meeting that they were eligible to attend, except Nils Andersen who was not able to attend two meetings. Pamela Daley and Sir Ian Davis each missed one committee meeting.

We understand that these are matters of great importance to our shareholders. Therefore we will work closely with the incoming leadership team to assure that goal-setting, in particular for progress against the carbon agenda, remains ambitious while also delivering pay outcomes that align with your own experience. We intend to confer with shareholders later in 2020 to establish goals once the details of our energy transition efforts have been provided.

Single figure results for executive directors

2019 single figures of total remuneration for Bob Dudley and Brian Gilvary are $13.23 million and £6.56 million respectively, as reported on page 108. These outcomes represent a 13% decrease for Bob, and a 20% decrease for Brian, reflecting reductions in the performance shares outcome, and in particular lower share price growth over the three-year cycle. As noted above, the committee applied the well-established formulas where relevant and, in conjunction with strategic progress, carefully reviewed the contributions of the executives. The impact of weaker share price performance on realized value is consistent with the experience of shareholders and thus we deem these outcomes reasonable.

For an overview of our executive remuneration structure, please refer to the "at a glance" table on page 103.

Succession arrangements

2019 also marked a point of succession, as our group chief executive Bob Dudley announced his intention to retire from BP, to be succeeded by Bernard Looney.

Bob has now stepped down from the BP board, and ceases employment from 31 March. As we announced in October 2019, he has waived his entitlement to notice pay for the unserved part of his notice period, and to any bonus for any part of 2020. By any measure, Bob has been an exemplar of corporate service; he leaves BP as a 'good leaver' under the terms of our executive director incentive plan, and therefore his interests under various deferred share awards are preserved and will vest in line with scheduled vesting dates and decisions, subject only to the committee retaining its discretion in the administration of the underpin on safety.

For our new chief executive officer, Bernard Looney, pay will be governed by the 2020 remuneration policy. The committee disclosed in October 2019 that it had set Bernard's salary at £1.3 million (approximately 9% below Bob Dudley's salary) as of 5 February 2020, with a reduced cash allowance retirement benefit of 15% of salary, which puts his allowance in line with the majority of our wider workforce. Bernard retains a deferred pension benefit from service prior to April 2011, and certain deferred share awards from service prior to 2020.

Earlier this year we made similar announcements regarding the retirement of Brian Gilvary and the appointment of his successor, Murray Auchincloss, with effect from 1 July 2020. Further detail is provided on page 103 for the new executives.

Our 2020 policy renewal

During 2019 we have been grateful for the time and attention our major shareholders gave us as we consulted on requirements for the new 2020 policy. In particular, 30 of our largest shareholders joined us in September for a novel session focused on expressing unconstrained views on remuneration arrangements. Together with subsequent discussions and correspondence, the key issues emerging for consideration have been:

- Clear end-to-end alignment from strategy, through measurable performance indicators and reward outcomes, to shareholder experience.
- Balance our contribution to the energy transition with delivering shareholder returns. The committee was encouraged to use appropriate discretion, given the complexity of the environment in the energy transition.
- Assure that strategic moves align to long-term sustainability, relative to a wider peer group.
- Use meaningful and transparent measures to reflect our progress in the energy transition and reductions to our carbon impact.

With all of this in mind, we have established a policy proposal which we believe reflects our strategic imperatives and allows for competitive remuneration outcomes aligned to the shareholder experience. The proposal makes modest but appropriate adjustments to our 2017 framework which, to our mind, is well understood and has delivered appropriate results for both shareholders and executive directors. We studied many far-reaching alternatives in concluding our final proposal but typically found other approaches carried too much complexity, an amplified concern given the transition our industry faces.

The key changes we are making include a reduced emphasis on relative total shareholder return, but measuring our returns against a more diverse group of companies; a sharpened focus on energy transition measures throughout the structure; tighter limits on pension benefits; and a reduction in the number of measures that will be considered for the annual bonus plan.

Other matters

Our committee activity in 2019 was extensive. It included a review of the principles of remuneration to support our updated policy (page 119) and engagement with shareholders and shareholder representatives. We also spent considerable time on remuneration matters related to the succession of the group chief executive and the various leadership changes that followed, in line with our increasing accountability for setting senior executive pay.

As UK remuneration committees now have the regulatory obligation to review remuneration of the wider workforce, our committee has sought to understand how pay practices vary across the globe and to examine issues of fundamental fairness. We examined pay outcomes by gender and other criteria. We have also considered how the committee can effectively add value to our stewardship of the wider workforce and our 2020 plans will include some additional engagement in this area.

The committee reviewed the breadth of historical pension arrangements across the spectrum of our employees in 2019. As an outcome, BP made changes that have brought pensions for executive directors and the wider workforce into alignment.

Our committee appreciated the time and thoughtful input shareholders and their representatives have given to the refreshment of the remuneration policy. Through a vibrant exchange of views, we believe the committee will be wiser as it considers executive pay against the backdrop of a challenging environment. We respectfully ask for your endorsement of the committee's 2019 remuneration decisions and your approval of the proposed 2020 policy framework.

Paula Rosput Reynolds
Chair of the remuneration committee

18 March 2020

In this Directors' remuneration report RC profit (loss), underlying RC profit, return on average capital employed and operating cash flow (excluding Gulf of Mexico oil spill payments) are non-GAAP measures. These measures and upstream plant reliability, refining availability, major projects and underlying production and reserves replacement ratio are defined in the Glossary on page 335.

Remuneration at a glance

	Key features	Purpose and link to strategy	Outcomes for 2019 (2017 policy)	Implementation in 2020 (2020 policy proposal unless stated otherwise)
Salary and benefits	• Salary is reviewed annually and, if appropriate, increased following the AGM. • Benchmarked to market at inception with increases reflective of those of our wider workforce.	• Fixed remuneration reflecting the scale and complexity of our business, enabling us to attract and keep the highest calibre global talent.	• Bob Dudley's salary unchanged at $1,854,000. • Brian Gilvary's salary increased by 2% to £790,500. • Benefits remain unchanged.	• Bob Dudley's salary to remain at $1,854,000 until he ceases employment on 31 March. • Bernard Looney's salary is set at £1,300,000. • Brian Gilvary's salary to remain at £790,500 until he ceases employment. • Murray Auchincloss's salary to be set at £695,000. • Bernard's benefits remain unchanged. Murray will be eligible for standard UK benefits from his appointment on 1 July.
Retirement benefits	• Bob is a member of both US pension (defined benefit) and retirement savings (defined contribution) plans. • Brian is a member of a UK final salary defined benefit pension plan and receives a cash allowance in lieu of further service accrual.	• To recognize competitive practice in home country.	• Bob's defined benefit pension did not increase in 2019. His actual and notional company contributions, together with investment returns within his retirement savings plans, amounted to $543,661. • Brian's accrued defined benefit pension increase was below inflation. He received a cash allowance at 35% of salary to 31 May, and at 30% of salary from 1 June 2019, which is included in the single figure table.	• Arrangements for Bob will continue unchanged until he ceases employment on 31 March. • Bernard's cash allowance reduces to 15% of salary from the date of his appointment. Accrued service for his deferred pension is already capped, and the pension calculation will be based on his pre-appointment salary. • Brian's cash allowance is subject to a previously agreed schedule of reductions and will terminate when he ceases employment on 30 June. • Murray's cash allowance will be set at 15% of salary from his appointment on 1 July. He retains a deferred pension arrangement from his US service, which will be based on his pre-appointment salary.
Annual bonus	• 112.5% of salary at target, and 225% at maximum. • 50% of the bonus is paid in cash and 50% is mandatorily deferred and held in BP shares for three years. • To continue under 2020 policy.	• To incentivize delivery of our annual and strategic goals. • The 50% deferral reinforces the long-term nature of our business and the importance of sustainability.	• Against our scorecard of safety (20%), environment (10%), reliable operations (20%) and financial performance (50%), our performance score is 135% of target (67.5% of maximum).	• Bob has waived any entitlement to an annual bonus for 2020. • Brian will qualify for a pro-rated bonus for his service in 2020. • Proposed scorecard with four measures across safety (20%), environment (20%), operational (10%) and financial (50%) performance.
Performance shares	• Annual grant of performance shares, representing the maximum outcome. 500% of salary for group chief executive and 450% of salary for chief financial officer. • Shares only vest to the extent performance conditions are met. • To continue under 2020 policy.	• To link the largest part of remuneration opportunity with the long-term performance of the business. The outcome varies with performance against measures linked directly to financial returns and strategic priorities.	• Against our balanced scorecard of financial measures (80%), and strategic progress (20%), our 2017-19 performance score is 71.2% of maximum.	• Awards granted in 2018, under our 2017 policy, at 500% (Bob Dudley) and 450% (Brian Gilvary) of salary will vest in proportion to success against the measures of our 2018-20 scorecard, on a pro-rata basis for time in service. • For our 2020-23 cycle, grant levels will remain unchanged for our incoming chief executive and chief financial officer at 500% and 450% of salary respectively, with weightings of 40% for relative total shareholder return (rTSR), 30% for return on average capital employed (ROACE) and 30% for energy transition measures.
Shareholding requirement	• Executive directors are required to maintain a shareholding equivalent to at least five times their salary. • Additionally, they have been expected to maintain shareholdings of at least two and a half times salary for two years post employment.	• To ensure sustained alignment between the interests of executive directors and our shareholders.	• Both Bob Dudley and Brian Gilvary materially exceed the share ownership requirements.	• From 2020, executive directors are required to maintain their full minimum shareholding requirement for two years post employment. • The minimum shareholding requirement remains five times salary for the group chief executive and is four and a half times salary for other executive directors.

2019 performance and pay outcomes

Business performance

A strong year of operational performance, set against challenging external conditions. Improvement across safety metrics, and significant growth in our retail business. Strong underlying profits for 2019, with a 29% return to shareholders over the three-year cycle.

Key strategic highlights
- $10 billion underlying replacement cost profit
- Dividend increased to 10.5 cents per share
- Expansion of our convenience partnership sites to around 1,600 globally
- Created BP Bunge Bioenergia, a world-class bioenergy company

2nd (29%)
Among peers for total shareholder return 2017-19

$28.2bn
Operating cash flow (excluding Gulf of Mexico oil spill payments)

$8.3bn
Dividends paid, including scrip

Performance outcomes

Strong results for the year, beating targets on five out of six measurement categories in our scorecards.

2019 Annual bonus

71.5%
Formulaic outcome (% of maximum)

-4.0%
Committee judgement, discretionary reduction

67.5%
Final outcome (% of maximum)

Performance dimensions (% weighting)

Safety (20%)	KPI	15.5/20
Environment (10%)	KPI	7/10
Reliability (20%)	KPI	8.5/20
Financial (50%)	KPI	40/50[a]

Annual bonus outcome (67.5% of maximum)
Bob Dudley $2,815,763
Brian Gilvary £1,200,572

2017-19 Performance shares

71.2%
Formulaic outcome (% of maximum)

0%
Committee judgement, no adjustment

71.2%
Final outcome (% of maximum)

Performance dimensions (% weighting)

Financial (80%)	KPI	57/80
Strategic progress (20%)	KPI	14/20

Performance shares outcome (71.2% of maximum)
Bob Dudley $7,936,660
Brian Gilvary £2,752,815

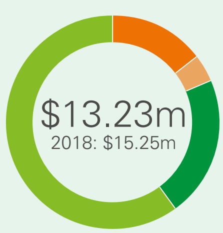
KPI This legend denotes remuneration measures that directly relate to BP’s key performance indicators. See page 32.

Total remuneration 2019

Bob Dudley
Group chief executive

18.7% fixed
81.3% variable

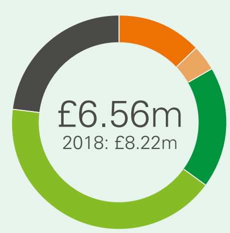
- Salary and benefits, (14.6)%
- Retirement benefits, (4.1)%
- Annual bonus, (21.3)%
- Performance shares, (60.0)%



Brian Gilvary
Chief financial officer

16.7% fixed
83.3% variable

- Salary and benefits, (12.9)%
- Retirement benefits, (3.8)%
- Annual bonus, (18.3)%
- Performance shares, (42.0)%
- Discontinued plans, (23.0)%



Share ownership

Shareholding is a key means by which the interests of executive directors are aligned with those of shareholders. As at 3 March 2020 both directors had holdings in BP which significantly exceeded our shareholding policy requirement of five times salary.

Bob Dudley, Group chief executive — 15.18 times salary, 5,290,446 shares[b].
Brian Gilvary, Chief financial officer — 16.20 times salary, 3,086,437 shares.

Policy requirements (5x) Actual

a Due to rounding, these figures do not precisely equal the overall outcome, 71.5%
b Held as American depository shares (ADSs)

2019 annual bonus outcome

For 2019 the committee established a bonus scorecard of eight measures across four areas of focus: safety and operational risk, the environment, reliable operations and financial performance. These measures align with our strategy and investor proposition and, in particular, reflect the annual plan. Seven of the eight measures align with our 2018 scorecard. The eighth measure, sustainable emissions reduction, was new and marked an acceleration of our intent to gear elements of financial reward to our progress in navigating the low carbon transition.

In order to build on the strong results of 2018, the committee again set notably stretching targets for each measure. For instance, our 2019 threshold outcome for recordable injury frequency was set at the level of our 2018 outcome, meaning we had to exceed that 2018 result to achieve even a minimum contribution to the 2019 bonus. Overall, our focus on safety delivered a year with both the fewest process safety incidents on record (excluding the impact of recent Mexico retail and BHP onshore aquisitions), and the lowest recordable injury frequency on record.

As noteworthy as this result is, we still regard any accident as one too many, and it is a matter of great regret that two of our colleagues suffered fatal injuries in 2019. To underscore our determination to eliminate these tragic incidents, we reflect any fatality in the performance assessment of the relevant business, thereby causing a material reduction in bonus for every individual in that business. In reaching our final conclusion, we rely on the judgement of the safety, environment and security assurance committee (SESAC) on the evaluation of safety outcomes.

Similarly, we sought the input of the audit committee to ensure our conclusions are robust and properly reflect underlying financial performance relative to markets. This included a review of the adjustments we make in our financial targets to reflect any pricing impacts, and thereby avoid windfall outcomes in our financial measures. For 2019, this led to a proportional reduction in our profit and cash flow targets, reflecting the weaker oil price environment. Over the eight years to 2019, we have increased targets four times, and reduced them four times, consistently stripping out the impact of the price environment.

2019 annual bonus scorecard

These measures were set under the terms of our 2017 policy

KPI See key performance indicators on page 32.

Safety		Environment		Reliable operations		Financial performance		Formulaic score
0.31	+	0.14	+	0.17	+	0.80	=	1.43[a] out of 2.0

Measures		Weighting	Threshold (0)	Target (1)	Maximum (2)	Outcome
Safety (20% weight)	Process safety tier 1 and tier 2 events[b]	KPI 10%	80 events 0	72 events 0.1	56 events 0.2	70 events 0.11
	Recordable injury frequency	KPI 10%	0.198/200k hrs 0	0.188/200k hrs 0.1	0.168/200k hrs 0.2	0.159/200k hrs 0.20
					Outcome	0.31
Environment (10% weight)	Sustainable emissions reductions	KPI 10%	0.49 mte 0	1.0 mte 0.1	2.0 mte 0.2	1.4 mte 0.14
Reliable operations (20% weight)	BP-operated refining availability[c]	KPI 10%	94.5% 0	95.0% 0.1	95.5% 0.2	94.9% 0.08
	BP-operated upstream plant reliability	KPI 10%	92.6% 0	94.6% 0.1	96.6% 0.2	94.4% 0.09
					Outcome	0.17
Financial performance (50% weight)	Operating cash flow (excluding Gulf of Mexico oil spill payments)	KPI 20%	$24.0 bn 0	$26.5 bn 0.2	$29.0 bn 0.4	$28.2 bn 0.33
	Underlying replacement cost profit	KPI 20%	$8.1 bn 0	$8.9 bn 0.2	$9.7 bn 0.4	$10.0 bn 0.40
	Upstream unit production costs	KPI 10%	$7.12/bbl 0	$6.72/bbl 0.1	$6.32/bbl 0.2	$6.84/bbl 0.07
					Outcome	0.80
Formulaic score						1.43[a] out of 2.0

Formulaic scorecard outcome	Input audit committee and SESAC	Remuneration committee judgement	Final scorecard outcome	
1.43 out of 2	No adjustment	Minus 0.08	1.35 out of 2	67.5% of maximum

a Due to rounding, the total does not equal the sum of the parts.
b Measure excludes data from Mexico retail and BHP onshore operations for two years from the date of their acquisition by BP.
c Solomon Associates' operational availability.

While we continue to believe these adjustments are appropriate, they potentially create some tension between the relative basis of our financial measurement, and shareholders' experience of cash flow and profit. With this context, we decided to reduce the formulaic bonus scorecard outcome to reflect our judgement that strong cash receipts at year end would potentially impact receipts in 2020.

Our bonus outcome for 2019 is therefore 135% of target and 67.5% of maximum. This compares with 81% of target and 40.5% of maximum in 2018. With the rigour of our process and discussions, and the support we have received from the SESAC and audit committee, we believe the 2019 annual bonuses fairly reflect and reward 2019 performance for the executive directors and senior leadership of BP.

As shown below, half of the bonus is paid in cash after year end, and half is deferred into shares that will vest in three years, according to 2017 policy terms. The full value of the 2019 bonus, including the deferred shares, is included in the 2019 single figure table. This differs from reporting in respect of the 2014 policy, under which deferred shares related to the 2016 bonus are included in the 2019 single figure, i.e. the year in which they vest.

	Adjusted outcome	Paid in cash	Deferred into BP shares
Bob Dudley	$2,815,763[a]	$1,407,881	$1,407,881
Brian Gilvary	£1,200,572	£600,286	£600,286

a Due to rounding the total does not match the sum of the parts.

The annual bonus outcome is unrelated to the BP share price, and therefore no part of the bonus is attributable to share price appreciation.

2017-19 performance share plan outcome

Vesting levels for the 2017-19 performance share awards are determined under the terms of the 2017 policy, in line with the performance measures and outcomes shown on the scorecard on page 107, and the committee's broader deliberations in line with the 'underpin' established in that policy. The scorecard for this period included relative total shareholder return (50%), return on average capital employed (30%) and four strategic progress measures (20%) that are assessed both quantitatively and qualitatively.

Assessed against the two financial scorecard measures, the group's performance for the three years from 2017 to 2019 is strong. We placed second on relative total shareholder return (with a 29% total return) which measures us against our super-major peers, Chevron, ExxonMobil, Shell and Total. Return on average capital employed (ROACE) was 8.9%, comfortably ahead of the 8.1% target.

We introduced the four strategic progress measures in our 2017 policy. Hence this is the first cycle for which we have made an assessment on strategic progress. We find that a rating of 13.8% out of 20% maximum opportunity is appropriate. Below are the four strategic pillars and a short description of some of the factors that influenced our scoring decision:

Shift to gas and advantaged oil in the upstream. Gas production has grown 35% (comparing 2019 with 2016), and 75% of all pre-2022 start-ups planned during the 2017-19 cycle are in gas. Pre-2022 start-ups in oil are lower-cost or adjacent to existing basins, creating additional value and lowering carbon intensity relative to BP's legacy portfolio.

Market-led growth in the downstream. BP has materially entered the retail markets in Mexico and Indonesia and expanded our overall retail network with 850 sites opened since 2016. Marketing of premium fuels has seen compound growth of 7% per annum in these higher value sales.

Venturing and low carbon across multiple fronts. BP has made signature investments in BP Chargemaster, our DiDi fast-charging joint venture in China and Lightsource BP, all of which underpin growth in electric vehicle charging and solar. We merged our biofuels business with another operator to create BP Bunge Bioenergia thereby creating synergies and scale for growth in biofuels. We have created a 'scale-up' factory known as BP Launchpad, to enhance our access to investment in new ventures, and have increased the portfolio over the last three years. The committee will be monitoring and measuring the progress of these ventures over time.

Gas, power and renewables trading and marketing growth. We noted robust early progress with BP's new integrated gas and power organization, mainly through a growing presence as a merchant in the global LNG trade, although financial results remain volatile. We also noted the development of infrastructure to undertake renewables trading, which has included building diverse counter-party relationships, such as with renewable energy source producers and owners of forests for the purposes of creating a market for natural climate solutions (NCS).

Along with the combination of financial and strategic measures that shareholders approved in the 2017 policy, the provision for 'underpin' decision by the committee was instituted. Namely, before deciding on the final result, the committee takes a broader view of performance to ensure that reward outcomes align with absolute shareholder returns, safety and environmental factors, and progress in low carbon and climate change matters. Our conclusion is that returns from the 2017-19 performance shares cycle are proportional and appropriate. Therefore, we have made no further adjustment to the scorecard outcome. Vesting therefore has been set at 71.2% of maximum, delivering the outcomes detailed below.

	Shares awarded	Shares vesting including dividends	Value of vested shares
Bob Dudley[a]	1,571,628	1,319,478	$7,936,660
Brian Gilvary	722,093	606,347	£2,752,815

a Bob Dudley's award is granted in respect of American depositary shares (ADSs). The numbers in this table reflect calculated equivalents in ordinary shares. One ADS equates to six ordinary shares.

The value of vested shares reflects the share price changes all shareholders experienced over the three-year period. For this 2017-19 award cycle, the original grant was calculated based on ordinary share and ADS prices of £4.73 and $35.39 respectively, while the equivalent prices on 18 February 2020, the vesting date, were £4.54 and $36.09. Consequently, share price appreciation in this cycle accounts for $130,549 (1.6%) of the value of Bob's vested shares, and none of the value of Brian's vested shares.

2017-19 performance shares scorecard

These measures were set under the terms of our 2017 policy

KPI See key performance indicators on page 32.

Financial 57.4% + Strategic progress 13.8% = Formulaic vesting 71.2%

Measures		Weighting at maximum	Threshold performance	Maximum performance	Outcome
Financial	Relative total shareholder return	KPI 50%	Third	First	Second 40.0%
	Return on average capital employed	KPI 30%	7.25%	11.0%	8.9% 17.4%
				Outcome	57.4%
Strategic progress	Shift to gas and advantaged oil in the upstream	5%	Qualitative and quantitative assessment by the committee. No numeric scale for vesting outcome – see page 106.		3.75%
	Market-led growth in the downstream	5%			3.0%
	Venturing and low carbon across multiple fronts	5%			4.25%
	Gas, power and renewables trading and marketing growth	5%			2.75%
				Outcome	13.8%
Total formulaic score					71.2%

Formulaic vesting 71.2%

Underpin: Committee review of absolute shareholder returns, long-term safety and environmental performance, low carbon and climate change considerations.

No adjustment

71.2% final vesting after committee judgement

Executive directors' pay for 2019

Single figure table – executive directors (audited)

Remuneration is reported in the currency in which the individual is paid		Bob Dudley (thousand)		Brian Gilvary (thousand)	
		2019	2018	**2019**	2018
Salary and benefits	Salary	**$1,854**	$1,854	**£785**	£769
	Benefits	**$84**	$79	**£59**	£67
Retirement benefits	Pension and retirement saving – value increase[a]	**$544**	$0	**£0**	£0
	Cash in lieu of future accrual	**–**	–	**£252**	£269
Annual bonus	Cash bonus	**$1,408**	$845	**£600**	£353
	Shares – deferred for three years	**$1,408**	$845	**£600**	£353
Performance shares	Performance shares	**$7,937**[b]	$11,630[c]	**£2,753**[b]	£4,295[c]
Discontinued plans	Deferred share awards from prior-year bonuses	**–**[d]	–[d]	**£1,510**[e]	£2,113[e]
Total remuneration[f]		**$13,234**	$15,253	**£6,558**	£8,219
Value attributed to share price appreciation[g]		**$131**	$2,033	**–**	£1,753

a For Bob Dudley this represents the aggregate value of the company match and investment gains on the accumulating unfunded BP Excess Compensation (Savings) Plan (ECSP) account under Bob's US retirement savings arrangements. Full details are set out on page 109. For Brian Gilvary this represents the annual increase in accrued pension, net of inflation, multiplied by 20. In 2019 Brian's salary increased by less than inflation, hence there is no net increase in accrued pension, and zero is reported as per regulations. Full details are set out on page 109.

b Represents the vesting of shares on 18 February 2020 following the end of the 2017-19 performance period, based on the assessment of performance achieved under the rules of the plan and includes accrued dividends on shares vested. The value of shares at vesting was $36.09 for ADSs and £4.54 for ordinary shares.

c In accordance with UK regulations, in the 2018 single figure table, the performance outcome values were based on fourth quarter average prices of $41.48 for ADSs and £5.33 for ordinary shares. In May 2019, after the external data became available, the committee reviewed the relative reserves replacement ratio position, and this resulted in no adjustment to the final vesting of 80%. On 3 May 2019, 269,974 ADSs for Bob Dudley and 776,611 ordinary shares for Brian Gilvary vested at prices of $43.08 and £5.53. The 2018 values for the total vesting have increased by $587,301 for Bob Dudley and £211,889 for Brian Gilvary because of the higher share prices and additional accrued dividends.

d In line with previous practice Bob Dudley has voluntarily agreed to defer performance assessment and vesting of the awards related to his 2016 annual bonus until at least one year after retirement, therefore the performance period will exceed the minimum term of three years. As stated in the 2017 and 2018 directors' remuneration reports, Bob voluntarily deferred performance assessment and vesting of the 2014 and 2015 deferred and matching awards until at least one year after retirement. See the Deferred shares table on page 115 for further details on these awards.

e The amounts reported for 2019 relate to the matching element of the 2014 annual bonus deferral, which Brian had voluntarily deferred for an additional two years, and the deferred element of the 2016 annual bonus. These awards vested on 18 February 2020 at the market price of £4.54 for ordinary shares and include accrued dividends on shares vested. The amounts reported for 2018 relate to the 2015 annual bonus, comprising the underlying award that vested on 19 February 2019 at a market price of £5.38 (as disclosed in our 2018 report), and the additional vesting of accrued dividends on 3 May 2019 at the market price of £5.53. See the Deferred shares table on page 115 for further details on these awards.

f Due to rounding, the totals do not agree exactly with the sum of their component parts.

g The values shown for performance shares and deferred share awards include the share price appreciation, if any, experienced over the applicable three-year vesting periods. This additional line shows the value of those awards that is directly attributable to share price appreciation, being the number of shares vesting multiplied by the increase in share price from grant date to vesting date. The 2018 values have been restated from the 2018 reported values to exclude share price growth relating to accrued dividends.

Overview of single figure outcomes (audited)

The single figures of total remuneration for Bob Dudley and Brian Gilvary are $13.234 million and £6.558 million respectively. This is a 13% decrease for Bob, and a 20% decrease for Brian.

Salary and benefits
Bob Dudley's salary remained at $1,854,000 throughout 2019. Brian Gilvary's salary was increased by 2% to £790,500 with effect from 21 May 2019. Both executive directors received car-related benefits, assistance with tax return preparation, security assistance, insurance and medical benefits.

2019 annual bonus and 2017-19 performance shares
Please refer to pages 105-107 for details of the performance measures, targets, results and the related reward outcomes for annual bonus and performance shares.

Discontinued plans: deferral of 2014 and 2016 bonus
In accordance with 2014 policy, Bob Dudley and Brian Gilvary compulsorily deferred one third of their 2016 annual bonus and each received an equivalent value matching award of BP shares. Both the deferred and matching awards were subject to a three-year performance period which ended on 31 December 2019.

Bob has requested that the committee delay the performance assessment and hence the vesting of his 2016 deferred and matching awards. This is a continuing practice from previous years and reflects his ongoing commitment to the long-term success of BP, even post employment. These awards will vest, subject to an assessment against the original safety and environmental sustainability conditions, after his retirement.

Brian had previously voluntarily requested that the committee delay the performance assessment and vesting of his 2014 matching award for two years. In 2018 he requested that the committee delay the performance assessment and vesting of his 2016 matching award until at least one year post employment.

For Brian's 2014 matching award and 2016 deferred awards, the committee considered operational and financial performance and reviewed safety and environmental sustainability performance over the 2015-19 and 2017-19 periods, seeking input from the SESAC on safety and sustainability measures. The committee concluded that safety performance continues to show improvement, with safety embedded in the culture of the organization and supporting strong operational and financial performance. The committee concluded that these two awards should vest in full.

Name	Shares granted	Vesting agreed	Total shares vesting, including dividends	Total value at vesting
Bob Dudley[a]				
2016 Deferred award	147,642	–[a]	–	–
2016 Matching award	147,642	–[a]	–	–
Brian Gilvary[b]				
2014 Matching award	176,576	100%	246,359	£1,118,470
2016 Deferred award	73,070	100%	86,176	£391,239
2016 Matching award	73,070	–[a]	–[a]	–[a]

a Vesting of these awards deferred until at least one year post employment, subject to conditions.
b Based on a vesting share price of £4.54.

Retirement benefits
Bob Dudley is provided with pension benefits and retirement savings through a combination of tax-qualified and non-qualified benefit plans. His normal retirement age is 60.

The BP Supplemental Executive Retirement Benefit Plan (SERB) is a non-qualified defined benefit pension plan which provides a proportion of earnings for each year of service. In 2019 his accrued defined benefit pension did not increase and in accordance with the requirements of UK regulations, the amount included in the single figure table on page 108 is zero.

The BP Employee Savings Plan (ESP) is a US tax-qualified defined contribution plan to which both Bob and BP contribute. The BP Excess Compensation (Savings) Plan (ECSP) is a non-qualified, unfunded, retirement savings plan to which BP notionally contributes 7% of base salary above the annual IRS limit. In 2019 Bob made contributions to the ESP totalling $28,000 and BP made matching contributions to the ESP, and notional contributions to the ECSP, totalling $129,780. In addition to these contributions, Bob realised investment gains of $413,881 in his unfunded ECSP account (aggregating the unfunded arrangements relating to his overall service with BP and TNK-BP), hence the amount included in the single figure table is $543,661.

Brian Gilvary is provided with pension benefits through a combination of tax-qualified and non-qualified plans for service to 31 March 2011, but linked to his final salary, and a cash allowance for service thereafter. In common with more than 3,800 UK employees employed prior to 2010 (or before 2014 in the North Sea) Brian is a member of the BP Pension Scheme (BPPS), a UK final salary defined benefit pension plan. Pension benefits accrued in excess of the individual lifetime tax allowance set by legislation are provided to Brian via a non-qualified, unfunded pension arrangement designed to mirror the design of the approved BPPS. His normal retirement age is 60, although due to his long service, benefits accrued before 1 December 2006 may be paid unreduced from age 55 with BP's consent.

In 2019 Brian's salary increase was below inflation. In accordance with the requirements of UK regulations, the amount included in the single figure table on page 108 is zero.

Brian receives a cash allowance of 30% of salary (this will reduce to 25% on 1 June 2020 for his last month of service). This amount has been separately identified in the single figure table.

History of group chief executive remuneration

Year	Group chief executive	Total remuneration thousand[a]	Annual bonus % of maximum	Performance shares % of maximum
2010[b]	Tony Hayward	£3,890	0	0
	Bob Dudley	$8,057	0	0
2011	Bob Dudley	$8,439	66.7	16.7
2012	Bob Dudley	$9,609	64.9	0
2013	Bob Dudley	$15,086	88.0	45.5
2014	Bob Dudley	$16,390	73.3	63.8
2015	Bob Dudley	$19,376	100.0	74.3
2016	Bob Dudley	$11,904	61.0	40.0
2017	Bob Dudley	$15,108	71.5	70.0
2018	Bob Dudley	$15,253	40.5	80.0
2019	Bob Dudley	$13,234	67.5	71.2

a Total remuneration figures include pension. The total figure is also affected by share vesting outcomes and these amounts represent the actual outcome for the periods up to 2011, the adjusted outcome for the years 2012 to 2018 where preliminary assessments of performance for EDIP had initially been made, and the actual outcome for 2019.
b 2010 figures show full year remuneration for both Tony Hayward and Bob Dudley, although Bob Dudley did not become group chief executive until October 2010.

2020 remuneration: Policy on a page

Approach: We will retain the structure that has served well since 2017, reserving increased flexibility to adapt as BP pursues its ambition to become a net zero★ company by 2050 or sooner, and help the world get to net zero.

Salary and benefits	Salary will be reviewed annually. Increases are measured against external pay relativity, and will not exceed the increase for our wider workforce.	Benefits are unchanged and include car-related provisions (or cash in lieu), security assistance, insurance and medical cover.
Retirement benefits	New appointees from within the BP group retain previously accrued benefits. For their service as a director, retirement benefits will be no more than the median provision offered to the wider workforce in the UK.	This is a material reduction from our 2017 policy.
Annual bonus	Bonus is measured against an annual scorecard. Measures will include financial (50%), operational (10%), safety (20%) and environmental (20%) goals. The committee holds discretion to choose the specific measures to be adopted within each of these categories and the relative weightings to assign to them to reflect the annual plan as agreed with the board. Numeric scales are set for each measure, to score outcomes relative to targets.	The committee will set appropriately stretching targets for each measure. Target bonus is 112.5%, and maximum bonus is 225% of salary. Half of the bonus for each year is paid in cash, and half is delivered as a deferred share award vesting in three years.
Performance shares	Performance shares are granted with a three-year performance period. Awards to be granted under this policy will vest in 2023, 2024 and 2025, and shares held until 2026, 2027 and 2028. Measures will include rTSR (40%), assessed against a broader peer group, ROACE (30%) and an assessment related to the low carbon transition (30%). For 2020, the rTSR peer group will include additional energy companies in our sector, but ones who also have low carbon businesses or material commitments, such as Equinor, ENI and Repsol. Beyond 2020, the committee will consider additional companies whose programmes provide meaningful challenge to BP regarding its own lower carbon ambitions.	At the outset of each award the committee will review the measures that are to govern the award, along with weightings and targets, to ensure they remain focused on delivering the strategy and are in the interests of shareholders. Annual grants will be at 500% of salary for the chief executive officer, and 450% of salary for any other executive director. These awards will vest in three years and in proportion to the outcomes measured through the performance scorecard, with a holding period that requires the shares to be retained for a further three years. The committee will assess safety outcomes over the perfomance cycle as an underpin in determining the final vesting percentage.
Shareholding requirement	Chief executive officer 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.
Malus and clawback	Malus provisions may apply 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	Under this policy, the committee will hold flexibility to choose the measures and weightings to be adopted for each annual bonus and performance shares scorecard, and to adjust the peer group for the rTSR measure, at the start of each performance cycle. This will allow appropriate re-alignment, over the policy term, to the anticipated evolution of the low carbon competitor market.	The committee reserves discretion in determining the outcomes for annual bonus and performance shares, allowing it to take broad views on alignment with shareholder experience, environmental, societal and other inputs.

The table above shows an at-a-glance summary of our proposed 2020 executive director remuneration policy. For the full remuneration policy, which will be proposed for shareholder approval at our 2020 AGM, please see pages 119 to 127.

Alignment with strategy

Bernard Looney recently announced a bold new purpose and ambition for BP, reaching out to 2050. This reframes a crucial part of our investor proposition with an explicit commitment to the energy transition that investors and wider society rightly expect. It also recommits us to delivering competitive financial returns, through our 'performing while transforming' programme.

While the specifics of our strategic milestones are yet to be defined, our direction is clear. For alignment of remuneration policy to corporate strategy, we will broadly retain our policy structure, while reserving specific flexibility to allow an evolution of performance measures and their weightings over the three-year policy term. Our 2017 policy structure, driven by an annual bonus and three-year performance shares, has allowed us to harness the energy and commitment of our executive directors and senior leadership through a set of clearly articulated and ambitious goals. By retaining flexibility to adjust performance measures and weightings, we have been able to maintain alignment between shareholders and executives even as BP's strategy has developed over time. We therefore believe that this combination of structure and flexibility, that has served us well through the last policy cycle, is equally well suited to the transition years ahead.

The annual bonus is determined in line with performance relative to annual targets for safety, environmental, operational and financial measures. Performance shares vest in line with performance relative to three-year targets for rTSR, ROACE and a set of low carbon/energy transition measures. This suite of measures allows for an end-to-end alignment between our strategic direction, our executive focus and our remuneration outcomes, always with the underpin of committee discretion to adjust outcomes as appropriate to match shareholders' own experience.

Safety is and will remain a core value, hence continues to drive a material part of the bonus outcome, as well as forming part of the committee's 'underpin' consideration in the finalvesting of performance shares. Likewise, BP has made clear strategic commitment to maintain focus on financial returns to shareholders, which therefore remain well-represented in the performance measures for annual bonus (50% weighting) and performance shares (40% weighting on rTSR and 30% weighting on ROACE). Reflecting the views of our shareholders, we have reduced the rTSR weighting (from 50%) and also started to widen the comparator group. For the first performance share cycle under the new 2020 policy, the comparator group is expanded from the four super majors to include ENI, Equinor and Repsol, all of whom have some lower carbon elements in their strategies. We have studied opportunities to expand the peer group further. But we conclude that other low carbon operators and indices have yet to reach sufficient maturity for inclusion at this time. Nevertheless it is possible that this will change during the policy cycle and hence we retain the discretion to introduce other companies or an index of low carbon companies in the coming equity cycles within the life of this policy.

The strategic shift that BP signalled in February, and which will be further detailed during our capital markets presentation in September, sharply increases the need for the remuneration policy to reflect low carbon ambitions and the energy transition. For this reason, the environmental measure in annual bonus will increase from 10% to 20% weighting, and the strategic measures for performance share vesting are now explicitly tied to low carbon/energy transition, and carry a 30% weighting. As BP's leadership continues to develop specific strategic goals in this space, we are reserving committee discretion to define and communicate the precise measures and weighting that will apply for the performance share awards, and to adjust from cycle to cycle.

Wider workforce in 2019

Workforce experience

Delivery of our strategy, both near and long term, depends upon BP's success in attracting and engaging a highly talented workforce, and on equipping our people with the skills for the future. While the board considers ways to deepen engagement with the workforce, and to understand the workplace in its broadest sense, the remuneration committee continues to receive and review information on pay outcomes and processes for our wider workforce.

During 2019, we have taken a measured path towards deepening our understanding of this complex field by studying these five areas:

- The overall demographics of the workforce, to understand where we employ our people, at what levels within the organization, and in what business areas.
- The distinct reward frameworks used by our major business areas, to understand different approaches to fixed pay, incentives and benefits. This review included a detailed consideration, by way of case study examples, of the progression of total reward across the job hierarchy in seven representative business areas.
- A deeper look at annual bonus, to build a greater appreciation of the business and geographic profile of our total bonus spend, and how target levels of bonus vary across the employee hierarchy in our top eight countries.
- An analysis of the use of equity-based reward, to understand the extent to which equity forms a core element of reward in different locations and business areas.
- The structure of workforce pensions in the US and UK, to deepen our understanding of the variety of entitlements that exist across different levels of the organization, given obligations to honour legacy arrangements from prior policies.

This wider workforce context is helpful to our thinking about future reward policies. Aside from our specific oversight of remuneration in the IST business, the committee does not intend to supplant the appropriate role of management in setting rewards for the wider workforce. But the committee believes our engagement and our own experiences in other companies and other industries can be additive to the thought process of management.

In addition to the board's workforce engagement initiatives, as a committee we have started a programme of engagement directly related to remuneration. This includes focus group sessions related to our remuneration practices and the connectivity we see between executive and wider workforce remuneration.

Summary of remuneration structure for employees below the board

Element	Policy features for the wider workforce	Comparison with executive director remuneration
Salary	Our 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. As we determine salaries in this review, we take account of market rates of pay at relevant comparators, the skills, knowledge and experience of each individual, relativity to peers within BP, individual performance, and the overall budget we set for each country. In setting the budget each year, we assess how employee pay is currently positioned relative to market rates, forecasts of any further market increases, and business context related to such things as growth plans, workforce turnover and affordability.	The salaries of our executive directors and executive team form the basis of their total remuneration, and we review these salaries annually. The primary purpose of the review is to stay aligned with relevant market comparators, although we ensure any increases are kept within the budgets set for our wider workforce salary review.
Pensions and benefits	We offer market-aligned benefits packages reflecting normal practice in each country in which we operate. Where appropriate, and subject to scale, we offer significant elements of personal benefit choice to our employees. Given the variety of markets in which we operate, and with the aspect of choice available to many employees, there is no identifiable pension rate for our wider workforce. For context, however, a majority of our UK employees are entitled to a 15% (of salary) benefits budget.	Other than the addition of security-related benefits, our executive director benefit packages are broadly aligned with other employees who joined BP in the same country at the same time. For new executive directors, pension benefits have been sharply reduced. Bernard Looney's cash-in-lieu of pension allowance is set at 15% of salary. His defined benefit calculation is based on his pre-appointment salary and his accrued service is capped.
Annual bonus	Approximately half of our global workforce participate in an annual cash bonus plan that multiplies a target bonus amount by a performance factor in the range 0 to 2. The performance factor is an average of performance outcomes measured at a group and individual level. This structure places equal emphasis on the importance of an employee's personal contribution and the results achieved by BP. We operate different bonus plans for those distinct parts of our business where remuneration models in the market are markedly different, such as our trading and marketing businesses.	Annual bonus for executive directors is directly related to the same group performance measures and outcomes as the wider workforce, but without the individual performance element.
Performance shares	We operate a performance share plan with three-year vesting for employees from our professional entry level and above. Operation varies based on seniority in three broad tiers: group leaders (approximately 400); senior leaders (approximately 4,000); and all other professional employees (approximately 35,000 potential participants, of whom 20% will participate). Vesting is subject to group performance outcomes for the group leader population only.	Performance shares for our executive directors are assessed using the same group performance scorecard used for the group leader performance shares.

Group chief executive-to-employee pay ratio

Since 2016 we have disclosed the ratio between our group chief executive's total remuneration and the median remuneration of a comparator group of our UK and US professional and managerial workforce (representing 38% of our global professional workforce). This calculation highlights pay differentials across the concentrated portion of our workforce and thus we have retained this voluntary measure for the purpose of comparison over time.

For 2019, however, we also report the pay ratio based on the new requirements set out in the 2018 regulations. Given the markedly different comparator groups, the voluntary and required pay ratios are not directly comparable. The different ratios arise because of two key differences: the required method includes BP hourly paid retail workforce in its fuels and convenience stations who are employed in roles which attract relatively lower market rates of pay; and the required method excludes the majority of our professional workforce, namely those outside the UK, such as our Houston, Texas campus.

Year	Method	25th percentile pay ratio	50th percentile pay ratio	50th percentile total pay	75th percentile pay ratio
2018	BP voluntary	–	106:1	$136,865	–
2019	BP voluntary	–	89:1[a]	$147,612/ £115,683[a]	–
2019	Option A[b]	543:1[c]	188:1[d][f]	£55,071	82:1[e]

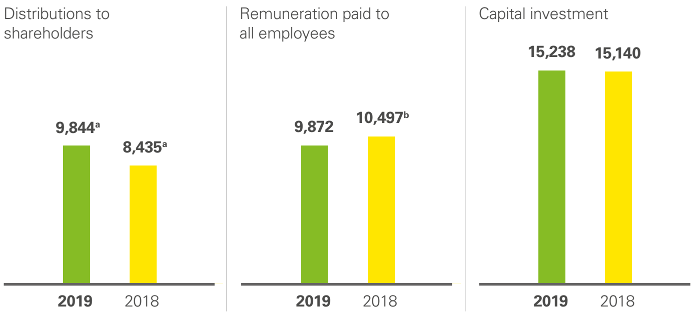
a Remuneration converted from $ to £ at an exchange rate of 1.276.
b Option A has been selected as it is the most accurate approach. Pay and benefits have been calculated using values for the year ended 31 December 2019 and no broadly applicable components of pay or benefits have been omitted. Full-time equivalent remuneration has been calculated by mathematical engrossment.
c The relevant 25th percentile values are £19,108 total pay and benefits, and £18,845 salary.
d The relevant 50th percentile values are £55,071 total pay and benefits, and £38,800 salary.
e The relevant 75th percentile values are £126,085 total pay and benefits, and £74,200 salary.
f The company believes that the 50th percentile pay ratio reflects total pay and benefits values fully in line with reward policies for the group chief executive and the median UK employee respectively, and consequently that the ratio is consistent with policy.

Percentage change comparisons: GCE remuneration versus UK workforce

Comparing 2019 to 2018	Salary	Benefits	Bonus
% change in GCE remuneration	0%	6.3%	66.7%
% change in comparator group remuneration	3.8%	1.0%	16.8%

The comparator group used here is our UK workforce, in line with the required basis for chief executive to employee pay ratio reporting and therefore provides a measure of consistency in reporting.

Relative importance of spend on pay
($ million)



a Distributions to shareholders comprise dividend payments of $8,333 million. ($8,080 million in 2018) and share buybacks at a cost of $1,511 million ($355 million in 2018). See page 299 for details.
b This amount was misstated as $10,494 in our 2018 report.

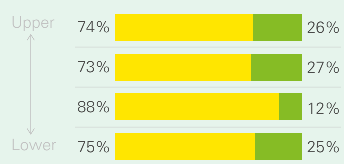
Equal pay and UK gender pay gap reporting

As well as looking at pay structures, the committee has spent time understanding how effectively current pay policies and processes maintain fairness and avoid bias in pay outcomes. We noted BP's 2019 UK gender pay gap reporting, published in March 2020, for the five legal entities covered by the regulations, and the explanations provided in the narrative that accompanied BP's reporting.

Overall the committee feels assured that the anti-discrimination controls written into pay policies, and the quality of processes behind individual pay decision making, are effective in delivering an equal pay environment (like pay for like work) for the wider workforce. While the UK gender pay gap reporting showed pay gaps in favour of men for four out of the five entities, we understand that these gaps result largely from the relative under-representation of women in senior roles, and that the group's primary focus should therefore be on improving representation of women, rather than adjusting pay practices. We are encouraged by the various initiatives taken by management to address these representation concerns and will continue to monitor progress.

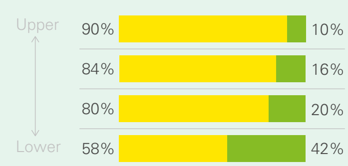
The illustration below, from our 2019 UK gender pay gap reporting (the most recent available), highlights the representation issue and how it relates to the gender pay gap for each entity. For instance, our larger median gender pay gaps relate to BP Exploration and BP p.l.c. where we have the largest differential between representation of women in the top and bottom pay quartiles. By contrast, we reported a negative median pay gap in BP Chemicals (-12.4%), where male to female representation is more balanced.

BP Chemicals Limited
median pay gap -12.4%



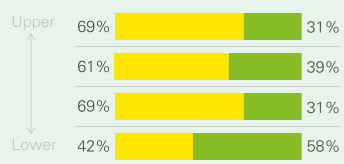
BP Chemicals is our petrochemicals business in the UK, principally our operation in Hull.

BP Exploration Operating Company Limited
median pay gap 24.9%



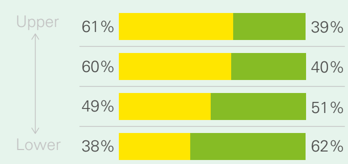
BP Exploration covers Upstream activities in the UK, principally North Sea operations.

BP Oil UK Limited
median pay gap 9.5%



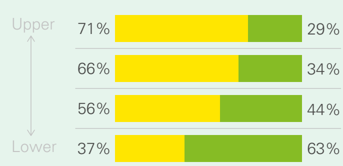
BP Oil represents our Downstream fuels and lubricants businesses.

BP Express Shopping Limited
median pay gap 4.0%



BP Express Shopping is our largest UK employing business, concerned with retail operations supporting our UK-wide network of forecourts.

BP p.l.c.
median pay gap 18.9%



BP p.l.c. predominantly covers employees in corporate business and functions, including our integrated Supply and Trading and Air BP businesses.

Bar charts represent the balance between male (●) and female (●) employees in each total pay quartile of the relevant business.

Stewardship and executive director interests

We believe that our executive directors should have a material interest in the company, both during their tenure and after they leave BP. Our recent shareholding policy therefore required executive directors to build a personal shareholding of five times their salary within five years of their appointment. They were expected to maintain personal shareholdings of at least two and a half times salary for two years post employment. Updates to this policy are proposed as an integral part of our 2020 remuneration policy, as detailed on page 121.

Directors' shareholdings (audited)

The tables below detail the personal shareholdings of each current and recent executive director. Both Bob Dudley and Brian Gilvary significantly exceed the policy requirement at 3 March 2020, with Bernard Looney building towards the policy requirement that applies five years from his appointment on 5 February 2020. These figures include all beneficial and non-beneficial ownership of shares of BP (or calculated equivalents) that have been disclosed to the company.

Director	Ordinary shares or equivalents at 1 Jan 2019	Ordinary shares or equivalents at 31 Dec 2019	Changes from 31 Dec 2019 to 3 Mar 2020	Ordinary shares or equivalents at 3 Mar 2020
Bob Dudley[a]	3,718,284	4,592,208	698,238	5,290,446
Brian Gilvary	2,043,899	2,593,708	492,729	3,086,437

a Held as ADSs.

Director	Appointment date	Value of current shareholding	Multiple of salary achieved
Bob Dudley	October 2010	$28,145,173	15.18 x salary
Brian Gilvary	January 2012	£12,808,714	16.20 x salary

Bob and Brian have interests in both performance shares and deferred bonus shares under the executive directors' incentive plan (EDIP). The share interests are shown in aggregate and by plan in the tables below. These figures show the maximum possible vesting levels. The actual number of shares/ADSs that vest will depend on the extent to which performance conditions are satisfied.

Director	Unvested ordinary shares or equivalents at 1 Jan 2019	Unvested ordinary shares or equivalents as 31 Dec 2019	Changes from 31 Dec 2019 to 3 Mar 2020	Unvested ordinary shares or equivalents at 3 Mar 2020
Bob Dudley[a]	6,825,606[b]	6,639,882	-1,343,142	5,296,740
Brian Gilvary	3,291,614	2,905,764	-845,629	2,060,135

a Held as ADSs.
b This shareholding has been re-based to reflect the 500% of salary grant level of the 2017 policy, in place of the original 550% per the 2014 policy.

Performance shares (audited)

			Share element interests			Interests vested in 2019 and 2020		
			Potential maximum performance shares[a]					
	Performance period	Date of award of performance shares	At 1 Jan 2019	Awarded 2019	At 31 Dec 2019	Number of ordinary shares vested	Vesting date	Face value of award, £
Bob Dudley[b]	2016-18	4 Mar 2016	1,645,074[c]	–	–	1,619,844[d]	3 May 2019[d]	–
	2017-19	19 May 2017	1,571,628	–	1,571,628	1,319,478[e]	18 Feb 2020[e]	–
	2018-20	22 May 2018	1,395,600	–	1,395,600	–	–	8,206,128[f]
	2019-21	19 Feb 2019	–	1,340,766	1,340,766	–	–	7,199,913[g]
Brian Gilvary	2016-18	4 Mar 2016	786,559	–	–	776,611[d]	3 May 2019[d]	–
	2017-19	19 May 2017	722,093	–	722,093	606,347[e]	18 Feb 2020[e]	–
	2018-20	22 May 2018	696,705	–	696,705	–	–	4,096,625[f]
	2019-21	19 Feb 2019	–	654,315	654,315	–	–	3,513,672[g]

a For awards under the 2016-18 plan, performance conditions are measured one third on TSR relative to Chevron, ExxonMobil, Shell and Total ('comparator companies'); one third on operating cash flow; and one third on a balanced scorecard of strategic imperatives. There is no identified overall minimum vesting threshold level but to comply with UK regulations a value of 44.4%, which is conditional on the TSR, operating cash flow, each of the strategic imperatives and strategic progress reaching the minimum threshold, has been calculated.
For awards under the 2017-19 plan, performance conditions are measured 50% on TSR relative to the comparator companies over three years, 30% on ROACE based on performance in 2019, and 20% on strategic progress assessed over the performance period.
For awards under the 2018-2020 plan, performance conditions are measured on the same basis as the 2017-2019 plan, except ROACE which will be based on performance in the last two years of the performance period (i.e. 2019 and 2020).
For awards under the 2019-2021 plan, performance conditions are measured 50% on TSR relative to the comparator companies over three years, 30% on strategic progress assessed over the performance period and 20% ROACE averaged over the full performance period. In the event that no threshhold performance targets are met, no shares would vest unless the committee found reason to exercise discretion.
Each performance period ends on 31 December of the third year.
b Bob Dudley received awards in the form of ADSs. The above numbers reflect calculated equivalents in ordinary shares. One ADS is equivalent to six ordinary shares.
c Bob Dudley has requested that the EDIP performance shares vesting in respect of the performance period 2016-2018 is based on the 500% maximum annual award level which applies under the 2017 directors' remuneration policy, rather than the 550% maximum annual award level which applied under the 2014 directors' remuneration policy.
d Represents vestings of shares made at the end of the relevant performance period based on performance achieved under rules of the plan and includes reinvested dividends on the shares vested. This 2016-2018 award vested on 3 May 2019. The market price of each share at the vesting date was £5.48 and for ADSs was $43.08. Details can be found in the single figure table on page 108.
e Represents vestings of shares made at the end of the relevant performance period based on performance achieved under rules of the plan and includes reinvested dividends on the shares vested. This 2017-2019 award vested on 18 February 2020. The market price of each share at the vesting date was £4.54 and for ADSs was $36.09. Details can be found in the single figure table on page 108.
f The face value has been calculated using the market price at closing of ordinary shares on 22 May 2018 of £5.88.
g The face value has been calculated using the market price at closing of ordinary shares on 19 February 2019 of £5.37.

Deferred shares (audited)[a]

					Deferred share element interests					
					Potential maximum deferred shares			Interests vested in 2019 and 2020		
	Bonus year	Type	Performance period	Date of award of deferred shares	At 1 Jan 2019	Awarded 2019	At 31 Dec 2019	Number of ordinary shares vested	Vesting date	Face value of the award, £
Bob Dudley[bc]	2014	Comp	2015-17	11 Feb 2015	147,054	–	147,054	–	–	655,861[d]
		Vol	2015-17	11 Feb 2015	147,054	–	147,054	–	–	655,861[d]
		Mat	2015-17	11 Feb 2015	294,108	–	294,108	–	–	1,311,722[d]
	2015	Comp	2016-18	04 Mar 2016	275,892	–	275,892	–	–	1,015,283[e]
		Vol	2016-18	04 Mar 2016	275,892	–	275,892	–	–	1,015,283[e]
		Mat	2016-18	04 Mar 2016	551,784	–	551,784	–	–	2,030,565[e]
	2016	Comp	2017-19	19 May 2017	147,642	–	147,642	–	–	696,870[f]
		Mat	2017-19	19 May 2017	147,642	–	147,642	–	–	696,870[f]
	2017	Comp	2018-20	22 May 2018	226,236	–	226,236	–	–	1,330,268[g]
	2018	Comp	2019-21	19 Feb 2019		118,584	118,584	–	–	636,796[h]
Brian Gilvary	2014	Mat	2015-17	11 Feb 2015	176,576	–	176,576	246,359[i]	18 Feb 20	–
	2015	Comp	2016-18	04 Mar 2016	159,021	–	159,021	196,262[j]	19 Feb 19	–
		Vol	2016-18	04 Mar 2016	159,021	–	159,021	196,262[j]	19 Feb 19	–
		Mat	2016-18[k]	04 Mar 2016	318,042	–	318,042	–	–	1,170,395[e]
	2016	Comp	2017-19	19 May 2017	73,070	–	73,070	86,176[i]	18 Feb 20	–
		Mat	2017-19[l]	19 May 2017	73,070	–	73,070	–	–	344,890[f]
	2017	Comp	2018-20	22 May 2018	127,457	–	127,457	–	–	749,447[g]
	2018	Comp	2019-21	19 Feb 2019		64,436	64,436	–	–	346,021[h]

a Since 2010, vesting of the deferred shares has been subject to a safety and environmental sustainability hurdle. If the committee assesses that there has been a material deterioration in safety and environmental performance, or there have been major incidents, either of which reveal underlying weaknesses in safety and environmental management, then it may conclude that shares should vest only in part, or not at all. In reaching its conclusion, the committee will obtain advice from the SESAC. There is no identified minimum vesting threshold level.
b Bob Dudley received awards in the form of ADSs. The above numbers reflect calculated equivalents in ordinary shares. One ADS is equivalent to six ordinary shares.
c Bob Dudley has voluntarily agreed to defer vesting of these awards until the later of one year post employment or the end of the relevant performance period, therefore the performance period will exceed the minimum term of three years.
d The face value has been calculated using the market price of ordinary shares on 11 February 2015 of £4.46.
e The face value has been calculated using the market price of ordinary shares on 4 March 2016 of £3.68.
f The face value has been calculated using the market price of ordinary shares on 19 May 2017 of £4.72.
g The face value has been calculated using the market price of ordinary shares on 22 May 2018 of £5.88.
h The face value has been calculated using the market price of ordinary shares on 19 February 2019 of £5.37
i Represents vestings of shares made at the end of the relevant performance period based on performance achieved under rules of the plan and includes reinvested dividends on the shares vested. The market price of each share used to determine the total value at vesting on the vesting date of 18 February 2020 was £4.54.
j Represents vestings of shares made at the end of the relevant performance period based on performance achieved under rules of the plan and includes reinvested dividends on the shares vested. The market price of each share used to determine the total value at vesting on the vesting date of 19 February 2019 was £5.38. These totals include the accrual of dividends which vested on 3 May 2019.
k Brian Gilvary has voluntarily agreed to defer vesting of these matching awards for a total of five years with a further one-year retention period.
l Brian Gilvary has voluntarily agreed to defer vesting of this matching award to at least one year post employment.

In common with many of our UK employees, Brian Gilvary holds options under the BP group Save As You Earn (SAYE) schemes as shown below. These options are not subject to performance conditions.

Share interests in share option plans (audited)

	Option type	At 1 Jan 2019	Granted	Exercised	At 31 Dec 2019[a]	Option price	Market price at date of exercise	Date from which first exercisable	Expiry date
Brian Gilvary	BP 2011[b]	400,000	–	–	400,000	£3.72	–	07 Sep 14	07 Sep 2021
	SAYE	3,103	–	3,103	–	£2.90	£5.07	01 Sep 19	28 Feb 2020
	SAYE	–	2,064	–	2,064	£4.36		01 Sep 22	28 Feb 2023

a The closing market prices of an ordinary share on 31 December 2019 was £4.72.
During 2019 the highest market price was £5.83 and the lowest market price was £4.62.
b BP 2011 means the BP 2011 plan. These options were granted to Brian Gilvary prior to his appointment as a director and are not subject to performance conditions.

Bob Dudley and Brian Gilvary have no interests in BP preference shares, debentures or option plans (other than as listed above), and no interests in shares or loan stock of any subsidiary company.

No directors or other senior managers own more than 1% of the ordinary shares in issue. At 3 March 2020, our directors and senior managers collectively held interests of 19,004,688 ordinary shares or their calculated equivalents, 7,699,795 restricted share units (with or without conditions) or their calculated equivalents, 8,542,463 performance shares or their calculated equivalents and 4,299,972 options over ordinary shares or their calculated equivalents, under BP group share option schemes.

Post employment share ownership interests

As we reported last year, Bob Dudley and Brian Gilvary will retain significant interests in BP post employment. They have given their personal commitment as executive directors to maintain actual holdings equivalent to two and a half times salary for two years post employment. The commitment is guaranteed by the fact that their anticipated interests in share awards under group plans which remain subject to vesting and/or holding periods at the time they leave BP exceed the two and a half times salary threshold. Although we are instituting a formal post employment share ownership requirement as part of our 2020 policy, given the foregoing, we see no need to modify the commitments of these outgoing executives.

Non-executive director outcomes and interests

The board's remuneration policy for the chairman and non-executive directors (NEDs) was approved at the 2017 AGM and implemented during 2017. There has been no variance of the fees or allowances for the chairman and the NEDs since approval in 2017.

Chairman

The fee structure for the chairman, which has been in place since May 2013, is £785,000 per year. The chairman is not eligible for committee chairmanship and membership fees or intercontinental travel allowance. As chairman throughout 2019, Helge Lund had the use of a fully maintained office for company business, a car and driver, and security advice in London. The table below shows the fees paid for the year ended 31 December 2019.

2019 remuneration (audited)

	Fees		Benefits[a]		Total[b]	
£ thousand	2019	2018	2019	2018	2019	2018
Helge Lund[c]	785	46	95[d]	122[d]	880	169
Carl-Henric Svanberg[e]	–	785	–	24	–	809

a Benefits include travel and other expenses relating to attendance at board and other meetings. Amounts disclosed have been grossed up using a tax rate of 45%, where relevant, as an estimation of tax due.
b Due to rounding, the totals may not agree exactly with the sum of the component parts.
c Appointed as a director on 26 July 2018 and as chairman on 1 January 2019.
d Benefits include relocation expenses.
e Resigned on 31 December 2018.

The figures below include all the beneficial and non-beneficial interests of the chairman in shares of BP (or calculated equivalents) that have been disclosed according to the disclosure guidance and transparency rules in the Financial Conduct Authority handbook ('the DTRs') as at the applicable dates. The chairman's holdings as at 31 December 2019, as a percentage of the shareholding policy, were 361%.

	Ordinary shares or equivalents at 1 Jan 2019	Ordinary shares or equivalents as 31 Dec 2019	Changes from 31 Dec 2019 to 3 Mar 2020	Ordinary shares or equivalents at 3 Mar 2020
Helge Lund	600,000	600,000	–	600,000

Non-executive directors' fee structure

The table below shows the fee structure for non-executive directors, per our 2017 policy.

	Fees £ thousand
Senior independent director[a]	120
Board member	90
Audit, geopolitical, remuneration and SESA committees chairmanship fees[b]	30
Committee membership fee[c]	20
Intercontinental travel allowance	5

a The senior independent director is eligible for committee chairmanship fees and intercontinental travel allowance plus any committee membership fees.
b Committee chairmen do not receive an additional membership fee for the committee they chair.
c For members of the audit, geopolitical, SESA and remuneration committees.

2019 remuneration (audited)

£ thousand	Fees		Benefits[a]		Total[b]	
	2019	2018	2019	2018	2019	2018
Nils Andersen	161	132	11	11	172	144
Alan Boeckmann[c]	68	155	6	10	74	165
Admiral Frank Bowman[c]	74	160	6	14	80	174
Dame Alison Carnwath[d]	115	74	33	47	148	121
Pamela Daley[e]	164	55	37	42	201	97
Sir Ian Davis	165	170	5	2	170	172
Professor Dame Ann Dowling[f]	140	158	3	2	143	159
Melody Meyer	152	160	16	26	168	186
Brendan Nelson	150	150	11	12	161	162
Paula Rosput Reynolds	170	166	36	33	206	200
Sir John Sawers	145	150	1	1	146	151

a Benefits include travel and other expenses relating to the attendance at board and other meetings. Amounts disclosed have been grossed up using a tax rate of 45%, where relevant, as an estimation of tax due.
b Due to rounding, the totals may not agree exactly with the sum of the component parts.
c Resigned on 21 May 2019.
d Appointed 21 May 2018.
e Appointed 26 July 2018.
f Fee includes £25,000 for chairing and being a member of the BP technology advisory council.

Non-executive director fees are reviewed on a regular basis and were last changed in 2012. This year, following a review of the increasing time commitment associated with the role and taking into account non-executive director fees against those of comparable UK listed companies, the fee structure below will be adopted from 1 June 2020.

	Fees £ thousand
Senior independent director[a]	155
Board member	115
Audit, geopolitical, remuneration and SESA committees chairmanship fees[b]	35
Committee membership fee[c]	20

a The senior independent director is eligible for committee chairmanship fees plus any committee membership fees, excluding the nomination and governance committee.
b Committee chairmen do not receive an additional membership fee for the committee they chair.
c A membership fee is not payable for the chairman's committee.

The board has decided to remove the intercontinental travel allowance to simplify the structure of non-executive director fees, although under the proposed policy it retains the flexibility to reintroduce such an allowance. In addition, following a review of the time commitment required, a fee of membership of the nomination and governance committee will be introduced in line with other committee membership fees to compensate for the increased time commitment. The senior independent director will not be eligible for this fee and no fee is payable for chairing the nomination and governance committee.

Non-executive directors' interests

The figures below indicate and include all the beneficial and non-beneficial interests of each non-executive director of the company in shares of BP (or calculated equivalents) that have been disclosed to the company under the DTRs as at the applicable dates.

	Ordinary shares or equivalents at 1 Jan 2019	Ordinary shares or equivalents at 31 Dec 2019	Changes from 31 Dec 2019 to 3 Mar 2020	Ordinary shares or equivalents at 3 Mar 2020	Value of current shareholding[a]	% of policy achieved
Nils Andersen	125,000	125,000	–	125,000	£518,750	576%
Alan Boeckmann[b]	44,812[cd]					
Admiral Frank Bowman[b]	24,864[c]					
Dame Alison Carnwath	17,700	17,700	–	17,700	£73,455	82%
Pamela Daley	17,592[c]	17,592[c]	–	17,592[c]	$93,589	82%
Sir Ian Davis	50,296	52,671	–	52,671	£218,585	243%
Professor Dame Ann Dowling	22,320	22,320	–	22,320	£92,628	103%
Melody Meyer	20,646[c]	20,646[c]	–	20,646[c]	$109,837	96%
Brendan Nelson	11,040	11,040	–	11,040	£45,816	51%
Paula Rosput Reynolds	73,200[c]	73,200[c]	–	73,200[c]	$389,424	339%
Sir John Sawers	15,030	15,506	6,494	22,000	£91,300	101%

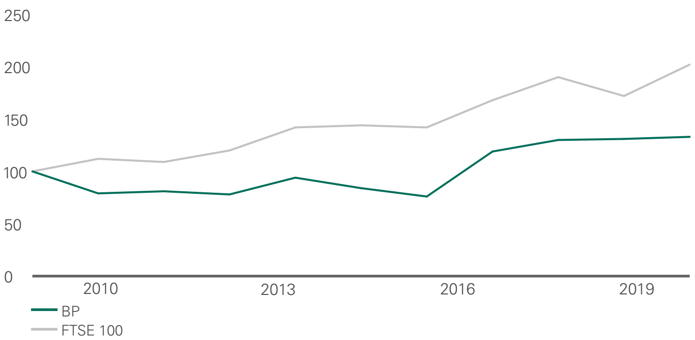
a Based on share and ADS prices at 3 March 2020 of £4.15 and $31.92.
b Resigned on 21 May 2019.
c Held as ADSs.
d Amended from 44,772 as originally disclosed in the 2018 report.

Other disclosures

Payments for loss of office and payments to past directors (audited)

We made no payments for loss of office during or in respect of 2019 to current or former directors. Sir Ian Prosser (who retired as a non-executive director of BP in April 2010) was appointed as a director and non-executive chairman of BP Pension Trustees Limited on 1 October 2010. During 2019, he received £100,000 for this role. Other than this, we made no payment to any past director of BP during 2019 (we have no de minimis threshold for such disclosures).

Historical TSR performance



This graph 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 2009 to 31 December 2019.

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, advice received, and shareholder engagement is set out in the remuneration committee report on page 101.

During 2019 Hannah Ashdown and, from his appointment as company secretary on 7 May 2019, Ben Mathews, both of whom were employed by the company and reported to the chairman 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 Helmut Schuster, executive vice president, group human resources, and Ashok Pillai, vice president, group reward.

PricewaterhouseCoopers LLP ('PwC') continued to provide independent advice to the committee in 2019, following its appointment as independent adviser to the committee in September 2017, following a competitive tender process. None of PwC's consultants advising the BP remuneration committee have any connection with the company's directors. Advice included, for example, support with the remuneration policy review and remuneration benchmarking. PwC is a member of the Remuneration Consulting Group and, as such, operates under the code of conduct in relation to executive remuneration consulting in the UK. The committee is satisfied that the advice received is objective and independent. Total fees or other charges (based on an hourly rate) for the provision of remuneration advice to the committee in 2019 (save in respect of legal advice) were £144,175 to PwC.

Freshfields Bruckhaus Deringer 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. During the year, PwC provided BP with services including: subsidiary company secretarial support; global mobility; internal audit subject matter expertise; cyber security risk reviews; tax modernization; low carbon strategy consulting; digital, data analytics and IT implementation services.

Shareholder engagement

Throughout 2019 we continued to discuss remuneration policy and approach with many of our largest shareholders, as well as investor representative bodies. We plan to continue this dialogue in 2020, as we consider updates to our remuneration policies for 2020 and beyond.

The table below shows the votes on the report for the last three years.

AGM directors' remuneration report vote results

Year	% vote 'for'	% vote 'against'	Votes withheld
2019	95.93%	4.07%	337,586,814
2018	96.42%	3.58%	42,741,541
2017	97.05%	2.95%	63,453,383

The remuneration policy was approved by shareholders at the 2017 AGM on 17 May 2017. The votes on the policy are shown below.

2017 AGM directors' remuneration policy vote results

Year	% vote 'for'	% vote 'against'	Votes withheld
2017	97.28%	2.72%	36,563,886

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 chairman and reported to the board. Any external appointment must not conflict with a director's duties and commitments to BP. Details of appointments as non-executive directors of publicly listed companies during 2019 are shown below.

Director	Appointee company	Additional position held at appointee company	Total fees
Bob Dudley	Rosneft[a]	Director	0
Brian Gilvary	Air Liquide SA	Non-executive director	Euros 77,500

a Bob Dudley holds this appointment as a result of the company's shareholding in Rosneft.

Directors’ remuneration report – the 2020 policy

In this part of our report we set out our directors’ remuneration policy for 2020 and subsequent years (the ‘2020 policy’). We will present this 2020 policy to shareholders at the 2020 annual general meeting and, subject to shareholder approval, it will take effect for the 2020 financial year.

Remuneration principles
In preparation for the review of our directors’ remuneration policy, the committee gave deep consideration to the changing reward frameworks for the wider workforce, alongside our more specific debates on executive remuneration. All of this is in the context of a changing business model as we evolve to meet and contribute to the low carbon energy transition. From this, we have drawn a unifying set of remuneration principles that apply equally to executives, and to employees at all levels of our workforce hierarchy.

Alignment	Our remuneration programmes will align with BP’s strategic priorities, long-term success and shareholders’ experience. In delivering our remuneration programmes across the globe we will reflect the policies and practices of the respective markets in which we operate.
Competitiveness	Total remuneration will be competitive for the role taking into account scale, sector, complexity of responsibility and geography. When setting senior executive pay, we will consider both external pay relativity and wider workforce remuneration and conditions.
Pay for performance	We promote a culture where all employees are accountable for delivering performance . Depending on the level of the individual in the organization, we use variable pay to incentivize delivery against performance. Pay will be delivered with an emphasis on long-term equity in line with seniority. Performance measures and targets will seek to balance collective BP success with clear line of sight for participants. Remuneration outcomes aim to reflect sustained long-term underlying performance of BP. Factors beyond the control of management will be adjusted in determining final outcomes.
Judgement	We will use discretion and judgement to review formulaic performance outcomes to arrive at fair and balanced remuneration outcomes for both BP and employees.
Sustainability	Remuneration programmes will support the development of a long-term sustainable business informed by environmental, societal and other inputs. Performance targets and measures will typically be chosen with due regard to incentives for prudent risk taking. Individual contribution and values and behaviours will be reflected in remuneration outcomes.

Consideration of shareholder views
We have reflected on the valuable shareholder engagement exercise that led to the significant changes from our 2014 to 2017 policy. In our view, those changes have stood up well over the last three years, have delivered remuneration outcomes that align to shareholders’ own experience, and have encouraged strategic decisions appropriate for the long term. Notably, the current 2017 policy also corresponds well to our recently concluded remuneration principles, shown above.

Throughout 2019 we consulted widely with shareholder representatives individually and collectively. In particular through a constructive listening session with our largest shareholders in September 2019, we identified four broad themes for our future policy direction:

- Clear end-to-end alignment from strategy, through measurable performance indicators and reward outcomes, to shareholder experience
- Balance our contribution to the energy transition with delivering shareholder returns. The committee was encouraged to use appropriate discretion, given the complexity of the environment in the energy transition
- Assure that strategic moves align to long-term sustainability, relative to a wide peer group
- Use meaningful and transparent measures to reflect our progress in the energy transition and reductions to our carbon impact.

We have concluded that the strongly performance-oriented reward model that has served us well in recovery from the aftermath of the 2010 Deepwater Horizon oil spill, and particularly the structure of our 2017 policy, broadly remains the right frame as we look ahead to the equally great challenge of reducing our carbon footprint. The 2020 policy set out below therefore retains and builds upon the 2017 policy structure, and thus commands the advantage of being well-understood and accepted by our executives and wider workforce alike.

Policy table – executive directors

Salary and benefits

Purpose

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.

Operation and opportunity

Salary

Salary levels will relate to the nature of the role, performance of the business and the individual, market positioning and pay conditions in the wider BP group. There is no maximum salary under the policy.

When setting salaries, the committee considers practice in other oil and gas majors as well as European and US companies of a similar size, geographic spread and business dynamic to BP. The committee will consider salary increases for the most senior management and the wider workforce. In particular, percentage increases for executive directors will not exceed increases for the broader employee population, 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, for example following a major role change.

Benefits

Executive directors are entitled to receive those benefits available to all BP employees generally, such as participation in all-employee share plans, sickness pay, relocation assistance and parental leave. Benefits are not pensionable.

Executive directors may receive other benefits that are judged to be cost effective and appropriate in terms of the individual's role, time and/or security. These include car-related benefits or cash in lieu, security, assistance with tax return preparation, insurance and medical benefits. The company may meet any tax charges arising on business-related benefits provided to directors, for example security.

The taxable value of benefits provided may fluctuate during the period of this policy, depending on the cost of provision and a director's personal circumstances.

In general, the committee expects to maintain benefits at the current level.

Performance framework

Not applicable

Retirement benefits

Purpose

To recognize competitive practice in home country.

Operation and opportunity

Executive directors normally participate in the company retirement plans that operate in their home country.

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. Specifically, the committee will be sensitive to investor concerns over pensions for directors, and limit pension contribution rates to no more than the median allowance offered to the wider workforce in the UK (as a percentage of salary).

Current executives (including designates) in BP have been employees of the group for a number of years and remain as participants in long-standing arrangements in which other similarly situated employees continue to participate.

UK participants will become deferred pensioners of the company's defined benefit plan. They will receive a cash supplement in lieu of further service accrual under the plan.

Performance framework

Retirement benefits are not directly linked to performance.

Annual bonus

Purpose

To provide variable remuneration dependent on performance against annual financial, operational, safety and environmental measures. 50% of the bonus is paid in cash and 50% is mandatorily deferred and held in BP shares for three years to reinforce the long-term nature of the business and the importance of sustainability.

Operation and opportunity

The bonus is based on performance against annual measures and targets set at the start of the year, evaluated over the financial year and assessed following the year end.

The target annual bonus is half of the maximum available, and relates to delivery of performance in line with targets in the annual plan.

Executive directors may earn a maximum annual bonus of 225% of salary. This maximum level would relate to performance at or above the highest end of the performance scale for every measure. The committee intends to set demanding requirements for maximum payment.

The final bonus outcome, following the formulaic assessment of performance relative to targets, is specifically reserved as a matter for the committee's judgement. Accordingly, the committee may exercise its discretion to adjust the formulaic outcome either upwards or downwards.

Half the bonus is paid in cash, and half is deferred into BP shares for three years. Dividends (or equivalents, including the value of any reinvestment) may accrue in respect of any deferred shares.

Awards are subject to malus and clawback provisions as described on page 123.

Performance framework	The committee determines a scorecard of specific measures, weightings and targets each year to reflect the priorities in the annual plan. The scorecard is designed to deliver the group's strategy.	The scorecard will typically include a balance of financial, operational, environmental and safety measures. Details of the measures and weighting will be reported in advance each year in the annual report on remuneration, while targets will be disclosed retrospectively. The committee holds discretion to choose the specific measures and weightings to be adopted within each of these categories to better reflect the annual plan as agreed with the board.

Performance shares

Purpose	To link the largest part of remuneration opportunity with the long-term performance of the business. The outcome varies with performance against measures of relative total shareholder return (rTSR), return on average capital employed (ROACE) and an assessment related to the low carbon transition.	
Operation and opportunity	The maximum annual award level for the chief executive officer will be 500% of salary and 450% of salary for the chief financial officer. Annual awards of shares will vest based on performance relative to measures and targets that reflect the delivery of BP's strategy over a performance period of typically three years. For each measure, the threshold level at which vesting is first triggered is not expected to yield vesting above 25% of the maximum. The final performance shares outcome, following the formulaic assessment of performance relative to targets, is specifically reserved as a matter for the committee's judgement. Accordingly, the committee may exercise its discretion to adjust the formulaic outcome either upwards or downwards.	The shares that vest are subject to a holding period. The combined length of the performance and holding periods will normally be six years. Dividends (or equivalents, including the value of reinvestment) may accrue in respect of share awards to the extent that they vest. Awards are subject to malus and clawback provisions as described on page 123.
Performance framework	Performance shares vest relative to performance achieved against a combination of financial and strategic measures. For 2020 awards, the measures (weightings) will be: • Relative total shareholder return (40%) assessed relative to Chevron, Eni, Equinor Exxon, Repsol, Shell and Total • Return on average capital employed (30%). This will be assessed on a three-year average basis, with no adjustment for market conditions • Low carbon/energy transition (30%). At the outset of each cycle the committee will review the measures that are to govern the award, along with weightings and targets, to ensure they remain focused on delivering the strategy and are in the interests of shareholders.	For the relative assessment of total shareholder returns, the committee will in time consider broadening the comparator set as our own transition towards low carbon evolves. We expect to outline specific measures for the low carbon / energy transition element later this year. This will follow, and align with, the strategy update planned for our capital markets day later this year. The committee would consult appropriately with major shareholders regarding any material changes to the measures. The committee will assess safety outcomes over the perfomance cycle as an underpin in determining the final vesting percentage.

Shareholding requirements

Purpose	To provide alignment between the interests of executive directors and our other shareholders.	
Operation and opportunity	The chief executive officer is required to build and maintain a minimum shareholding of five times base salary within five years of appointment, and to maintain that minimum shareholding for at least two years post-retirement.	Other executive directors are required to build and maintain a minimum shareholding of four and a half times base salary within five years of appointment, and to maintain that minimum shareholding for at least two years post-retirement.
Performance framework	Not applicable.	

Notes to the policy table

1. New components and key changes from the 2017 policy
While the structure of the 2017 policy has been retained, the committee highlights the following key changes from 2017:

- A new requirement to limit the value of retirement benefits for service as an executive director. In practice, we do not expect to offer pension contribution rates worth more than 15% of salary.
- The minimum shareholding requirement is clearly stated and continues to apply, in full, for two years post employment. This minimum shareholding requirement is now formally adopted as part of the remuneration policy.

2. How is variable pay linked to performance?

Annual bonus	Bonus aligned with annual objectives	50% paid in cash; 50% in BP shares deferred for 3 years
Performance bonus	Share award for meeting three-year targets	6 years; 3 year performance period + 3 year holding period
Share ownership	Long-term shareholding	Built up over 5 years and maintained

The three elements described above provide a balance between focus on short-term, medium-term and long-term performance, while encouraging behaviours which are in the long-term interests of shareholders. The operation of variable pay is supported by a focus on stewardship. There is a requirement that the chief executive officer will build up a holding of five times salary, and other executive directors a holding of four and a half times salary, over a period of five years following appointment and maintain that level during employment and for a further two years post employment.

3. How are performance measures linked to strategy?
Variable pay is linked to performance measures designed to deliver the BP strategy. At the start of each year, the remuneration committee reviews the measures, targets and weightings to ensure they remain consistent with the priorities in the annual plan and the group strategy. For the annual bonus and performance shares, the approach to performance measurement is intended to provide a balance of measures to assess performance reflecting the global scale of the business, the unique characteristics of the oil and gas sector, and the role our enterprise will play in advancing the transition to lower carbon energy. The key changes from our 2017 policy, and a summary of measures for 2020 awards, are shown below:

- Weighting of the environment target in our annual bonus scorecard is doubled to 20%.
- Fewer measures in our annual bonus scorecard (from two to one on safety, from two to one on reliable operations, from three to two on financial performance). Our 2020 financial performance on cash flow changes from operating cash flow to free cash flow.
- Weighting of the rTSR measure in our performance shares scorecard reduced to 40%. The comparator group has been expanded to include Repsol, ENI and Equinor. The low carbon / energy transition category replaces strategic progress and weighting increases to 30%.

New remuneration policy measures for the period commencing in 2020

Annual bonus

Safety	Environment	Operational performance	Financial performance
20%	20%	10%	50%

Performance shares

Relative total shareholder return	Return on average capital employment	Low carbon / energy transition
40%	30%	30%

Underpin: Take into account safety outcomes prior to determining final vesting percentage.

Discretion to reflect shareholder experience, environmental, societal and other inputs.

Robust malus and clawback.

4. How will we use flexibility, judgement and discretion?
The committee reviews BP's performance against specific measures and targets, and in doing so may make both quantitative and qualitative assessments of performance in reaching its decisions. This involves the application of judgement and discretion, in which the committee also seeks relevant input from the board's audit and safety, environment and security assurance committees. Accordingly, the committee may decide to adjust the formulaic outcome derived from the relevant scorecards, either upwards or downwards, to reflect broader considerations. The committee continues to consider that the powers of flexibility, judgement and discretion are critical to the successful execution of the policy.

In framing the policy, the committee has taken care to ensure that these important powers continue to be available:

- Sufficient flexibility to take account of future changes in the industry environment and in remuneration practice generally. This allows the committee to respond to changes in circumstances, for example in applying particular performance measures and/or weightings within the plans, or in broadening the comparator group for the relative returns measure, in order to evolve with the company's strategy, without the need for specific shareholder approval.
- Power to exercise judgement in making a qualitative assessment in certain circumstances. A number of measures are used for annual or long-term incentive awards, many of which are numerical in nature and require a quantitative assessment of performance. Others may require a qualitative assessment, such as the low carbon / energy transition measures in the performance shares plan.
- Scope for the committee to exercise discretion, mainly where it is desirable to vary a formulaic outcome that would otherwise arise from the policy's implementation. The committee considers that the ability to exercise discretion, upwards or downwards, is important to ensure that a particular outcome is fair in light of the director's own performance, the company's overall performance and positioning under particular performance measures and outcomes for shareholders.

The committee intends to provide appropriate disclosure on the use of discretion so that shareholders can understand the basis for its decisions.

5. How will we safeguard against payments for failure?

Performance based pay	A significant portion of remuneration varies with performance – where performance targets are not achieved, lower or no payments will be made under the plans.	
Discretion	The committee may vary formulaic outcomes where these do not suitably reflect performance over the relevant performance period.	
Malus and clawback	The malus provisions enable the committee to reduce the size of award, cancel an unvested award, or impose further conditions on an award made under this policy. The malus provisions may apply if, prior to the vesting or payment of an award, there is a negative event such as: • material failure impacting safety or environmental sustainability • incorrect award outcomes due to miscalculation or based on incorrect information • restatement due to financial reporting failure or misstatement of audited results • material misconduct by the participant • such other exceptional circumstances that the committee consider to be similar in nature.	The clawback provisions enable the committee to require participants to return some or all of an award after payment or vesting. They may be applied under the following circumstances: • incorrect outcomes due to miscalculation or based on incorrect information • restatement due to financial reporting failure or misstatement of audited results • material misconduct by the participant.

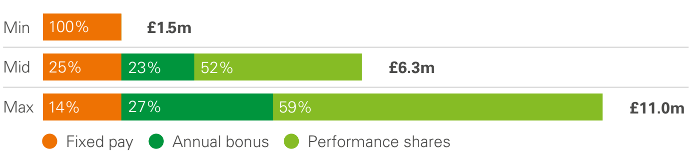
6. Differences from remuneration policy in the wider group

This executive director remuneration policy is structurally similar to remuneration for the majority of the wider workforce, but naturally differs in quantum reflecting market norms for the differing size and complexity of roles. Although performance assessment is a common feature for executive and wider workforce remuneration, the relative importance of different performance measures changes in line with seniority. For instance, executive directors are subject to longer-term measures and no individual performance element, whereas the majority of the wider workforce receive variable pay that is based on annual performance measures, including their own individual performance.

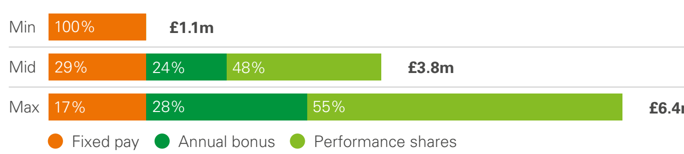
Illustrations of application of remuneration policy

The total remuneration opportunity for executive directors is strongly performance based and weighted to the long term. The charts below provide scenarios for the total remuneration of executive directors at different levels of performance and are calculated as prescribed in UK regulations.

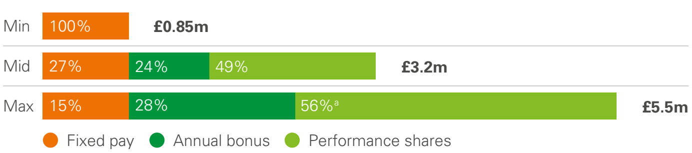
Bernard Looney



Brian Gilvary



Murray Auchincloss



a Due to rounding, the sum of the parts does not equal 100%.

The remuneration outcomes reported above reflect the face value of performance shares and therefore exclude the impact of potential share price growth, as well as dividends. If share prices were to appreciate by 50% from face value, then the maximum remuneration receivable by Bernard Looney, Brian Gilvary and Murray Auchincloss would increase to £14.2m, £8.2m and £7.1m respectively.

Fixed components

For these illustrations salary, benefits and pension are the same in all three scenarios (annual values shown).

Salary	CEO (Looney)	£1,300,000	Bernard Looney's salary from appointment on 5 February 2020.
	CFO (Gilvary)	£790,500	Brian's salary, effective until his retirement from BP on 30 June 2020.
	CFO (Auchincloss)	£695,000	Murray's salary, effective from his appointment on 1 July 2020.
Benefits and pension benefits	CEO (Looney)	£245,000	Based on pension benefits at 15% of salary, with an estimated £50,000 total for other benefits.
	CFO (Gilvary)	£296,150	Based on Brian's 30% cash in lieu of pension, plus the total of other benefits shown in the 2019 single figure table.
	CFO (Auchincloss)	£154,250	Based on pension benefits at 15% of salary, with an estimated £50,000 total for other benefits.

Variable components

Variable pay under the policy comprises annual bonus and performance shares.

Scenario	Minimum	Mid	Maximum
Annual bonus (including cash and deferred elements)	Threshold not met Nil	50% of maximum 112.5% of salary	100% of maximum 225% of salary
Performance shares	Threshold not met CEO – Nil CFO – Nil	50% vesting CEO – 250% of salary CFO – 225% of salary	100% vesting CEO – 500% of salary CFO – 450% of salary

7. Clarity, simplicity, and other considerations related to the Corporate Governance Code

The committee consider the scorecard-based approach to setting targets and measuring outcomes provides great clarity in our ability to engage transparently with shareholders and the wider workforce on remuneration arrangements, and that this is complemented by retaining the simple structure of our 2017 policy; market aligned fixed pay with annual cash and three-year performance share incentives. Risks are managed through a combination of careful setting of performance measures and targets, the many options to apply committee discretion in assessing outcomes, and the robust malus and clawback measures reserved in this policy. The committee also considers that remuneration outcomes are predictable, as shown clearly in the scenario charts at note 6 above, and proportional by virtue of the challenging performance levels required to achieve target pay outcomes. By retaining material weighting in measures related to both safety and the environment, this policy aligns closely with central themes of BP's culture, purpose and ambition.

Recruitment policy

The committee expects any new executive director to be engaged on terms that are consistent with the policy. However it recognizes that it cannot anticipate circumstances in which any new executive director may be recruited. The committee may determine that it is in the interests of the company and shareholders to secure the services of a particular individual which may require it to take account of the terms of that individual's existing employment and/or their personal circumstances.

Accordingly, the committee will ensure that:

- The salary level of any new director is appropriate to their role and the competitive environment at the time of appointment. Where appropriate it may appoint an individual on a lower salary (relative to any previous incumbent), then gradually increase salary levels as the individual gains experience in the role.
- Variable remuneration will be awarded within the parameters of the policy for current executive directors.
- The committee may tailor the vesting criteria for initial incentive awards depending on the specific circumstances.
- Where an existing employee is promoted to the board, the company may honour all existing contractual commitments including any outstanding share awards or pension entitlements.
- The committee would expect any new director to participate in the company pension and benefit schemes that are open to other employees (where appropriate referencing the candidate's home country).
- Where an individual is relocating in order to take up the role, the company may provide certain one-off benefits such as reasonable relocation expenses, accommodation for a period following appointment, assistance with visa applications or other immigration issues and ongoing arrangements such as tax filing assistance, annual flights home and a housing/utilities allowance.
- Where an individual would be forfeiting remuneration or employment terms in order to join the company, the committee may award appropriate compensation. The committee would require reasonable evidence of the nature and value of any forfeited arrangements and would, to the extent practicable, ensure any compensation was of comparable commercial value and capped as appropriate, considering the terms of the previous arrangement being forfeited (for example the form and structure of award, timeframe, performance criteria and likelihood of vesting). Where appropriate, the committee prefers to deliver buy-outs in the form of restricted shares in the company.

In making any decision on the remuneration of a new director, the committee would balance shareholder expectations, current best practice and the circumstances of any new director. It would strive not to pay more than is necessary to recruit the right candidate and would give full details in the next remuneration report.

Service contract

Bob Dudley's service contract is with BP Corporation North America Inc., Bernard Looney's and Brian Gilvary's service contracts are with BP p.l.c., and Murray Auchincloss' service contract will be with BP p.l.c.

Each executive director is entitled to retirement benefits as outlined on page 120.

Each executive director is also entitled to the following contractual benefits:

- If appropriate for security reasons, a company car and driver is provided for business and private use, with the company bearing all normal employment, servicing, insurance and running costs. Alternatively, where not required for security reasons, a cash allowance may be paid instead.
- Medical and dental benefits, sick pay during periods of absence and assistance with the preparation of tax returns.
- Indemnification in accordance with applicable law.
- Participation in bonus or incentive arrangements at the committee's sole discretion.

Each executive director may terminate their employment by giving 12 months' written notice. In this event, for business reasons, the employer may not necessarily hold the executive director to their full notice period.

The employer may lawfully terminate the executive director's employment in the following ways:

- By giving the director 12 months' written notice.
- Without compensation, in circumstances where the employer is entitled to terminate for cause, as defined for the purposes of their service contract.

The company may lawfully terminate employment by making a lump sum payment in lieu of notice equal to 12 months' salary or by monthly instalments rather than as a lump sum.

The lawful termination mechanisms described above are without prejudice to the employer's ability in appropriate circumstances to terminate in breach of the notice period referred to above, and thereby to be liable for damages to the executive director.

In the event of termination by the company, each executive director may have an entitlement to compensation in respect of their statutory rights under employment protection legislation in the UK and potentially elsewhere. Where appropriate the company may also meet a director's reasonable legal expenses in connection with either their appointment or termination of their appointment.

Copies of the executive directors' service contracts, along with the non-executive director appointment letters, are available for inspection at the registered office of BP p.l.c.

Termination payments

In determining overall termination arrangements, the committee will distinguish between types of leaver and the circumstances of their leaving. The committee would also consider all relevant circumstances, including whether a contractual provision in the director's arrangements complied with best practice at the time of termination and the date the provision was agreed, as well as the performance of the director in certain respects.

Where appropriate, the committee may consider providing certain benefits relating to termination including the provision of outplacement support or reasonable costs associated with relocation back to an individual's home country. Should it become necessary to terminate an executive director's employment, and therefore to determine a termination payment, the committee's policy is as follows:

Termination payments	The director's primary entitlement would be a termination payment in respect of their service agreement, as set out above. However the committee will consider mitigation to reduce the termination payment where appropriate to do so, taking into account the circumstances for leaving and the terms of the agreement. Mitigation would not be applicable where a contractual payment in lieu of notice is made.	If the departing director is eligible for an early retirement pension, the committee would consider, if relevant under the terms of the appropriate plan, the extent of any actuarial reduction that should be applied. UK directors who leave in circumstances approved by the committee may have a favourable actuarial reduction applied to their pensions (which to date has been 3%). Departing directors who leave in other circumstances may be subject to a greater reduction.
Annual bonus	The committee would consider whether the director should be entitled to an annual bonus in respect of the financial year in which the termination occurs.	Normally, any such bonus would be restricted to the director's actual period of service in that financial year.
Share awards	Share awards will be treated in accordance with the relevant plan rules. For awards granted under the executive directors' incentive plan (EDIP), the treatment can only be made in accordance with the framework approved by shareholders. The committee would consider whether conditional share awards held by the director should lapse on leaving or should, at the committee's discretion, be preserved. If awards are preserved, the award would normally continue until the vesting date. Awards may be pro-rated based on service over the performance period.	In deciding whether to exercise discretion to preserve EDIP awards, the committee would also consider the proximity of the award to its maturity date. To the extent that any such share award vests, the release of those shares to the former director will be made approximately one year after their date of termination (even if they would have been subject to a longer holding period had the executive remained in employment with BP).

Legacy arrangements and other detailed provisions

Previously the deferred element of the annual bonus in respect of years up to and including 2016 attracted a corresponding award of matching shares. Although the committee no longer grants matching awards in respect of future bonus awards, executives retain interests in legacy awards previously granted under this arrangement under the terms set out in the 2014 policy.

For completeness, the table below summarizes the key terms of the previous matching share element.

Purpose	To reinforce the long-term nature of the business and the importance of sustainability.	
Operation	Previously one third of the annual bonus was subject to compulsory deferral and a further third was subject to voluntary deferral. These deferred shares were matched on a one-for-one basis.	Where shares vest, additional shares representing the value of reinvested dividends are added. All deferred shares are subject to clawback provisions if they are found to have been granted on the basis of a material misstatement of financial or other data.
Performance framework	Both deferred and matching shares must pass an additional hurdle related to safety and environmental sustainability performance in order to vest.	If there has been a material deterioration in safety and environmental metrics, or major incidents revealing underlying weaknesses in safety and environmental management then the committee, with advice from the board's safety, environment and security assurance committee, may conclude that shares vest in part, or not at all.

In addition to the award described above, the committee may continue to satisfy existing remuneration commitments and/or payments for loss of office, including the exercise of any discretion in connection with such payments provided that such terms were agreed:

- before 10 April 2014 when the first approved remuneration policy came into effect
- before the 2020 policy came into effect, provided that the terms of the payment were consistent with the shareholder-approved directors' remuneration policy in force at the time they were agreed
- at a time when the relevant individual was not a director of the company and, in the opinion of the committee, the payment was not in consideration for the individual becoming a director.

Share awards are subject to the terms of the relevant plan rules under which the award has been granted. The committee may adjust or amend awards, but only in accordance with the provisions of the plan rules. This includes making adjustments to awards to reflect one-off corporate events, such as a change in the company's capital structure or treatment of awards in the event of a change of control. In accordance with the plan rules, awards may be settled in cash rather than shares, where the committee considers this appropriate.

The committee may make minor amendments to the policy to aid its operation or implementation without seeking shareholder approval, for example for regulatory, exchange control, tax or administrative purposes or to take account of a change in legislation provided that any such change is not to the material advantage of the directors.

Remuneration in the wider group

The committee considers employment conditions in the BP group when establishing and implementing policy for executive directors to ensure the alignment of and context for principles and approach. In particular, the committee reviews the policy and makes decisions for the most senior leaders (the BP leadership team that reports to the CEO). Decisions regarding remuneration for employees outside the most senior leaders are the responsibility of the chief executive officer. The committee does not consult directly with employees when formulating the policy. However, feedback from employee focus groups and employee surveys, that are regularly reported to the board, provide views on a wide range of employee matters including pay.

The wider employee group participates in performance-based incentives. Throughout the group, salary and benefit levels are set in accordance with the prevailing relevant market conditions and practice in the countries in which employees are based. Differences between executive director pay policy and that of other employees reflect the senior position of the individuals, prevailing market conditions and corporate governance practices in respect of executive director remuneration. The key difference in policy for executive directors is that a greater proportion of total remuneration is delivered as performance-based incentives.

Policy table – non-executive directors

The following table sets out the framework that will be used to determine the fees for non-executive directors during the term of this policy.

Non-executive chairman	
Fees	
Approach	Remuneration is in the form of cash fees, payable monthly. The level and structure of the chairman's remuneration will primarily be compared against UK best practice.
Operation and opportunity	The quantum and structure of the non-executive chairman's remuneration is reviewed annually by the remuneration committee, which makes a recommendation to the board.
Benefits and expenses	
Approach	The chairman is provided with support and reasonable travelling expenses.
Operation and opportunity	The chairman is provided with an office and full-time secretarial and administrative support in London and a contribution to an office and secretarial support in his home country as appropriate. A car and the use of a driver is provided in London, together with security assistance. All reasonable travelling and other expenses (including any relevant tax) incurred in carrying out his duties is reimbursed.
Non-executive directors	
Fees	
Approach	Remuneration is in the form of cash fees, payable monthly. Remuneration practice is consistent with recognized best practice standards for non-executive directors' remuneration and, as a UK-listed company, the level and structure of non-executive directors' remuneration will primarily be compared against UK best practice. Additional fees may be payable to reflect additional board responsibilities, for example, committee chairmanship and membership and for the role of senior independent director.
Operation and opportunity	The level and structure of non-executive directors' remuneration is reviewed by the chairman, the CEO and the company secretary who make a recommendation to the board. Non-executive directors do not vote on their own remuneration. Remuneration for non-executive directors is reviewed annually.
Intercontinental allowance	
Approach	Non-executive directors may receive an allowance to reflect the global nature of the company's business. This allowance would be payable for the purpose of attending board or committee meetings or site visits.
Operation and opportunity	This allowance would be paid in cash following each event of intercontinental travel.
Benefits and expenses	
Approach	Non-executive directors are provided with administrative support and reasonable travelling expenses. Professional fees are reimbursed in the form of cash, payable following the provision of advice and assistance.
Operation and opportunity	Non-executive directors are reimbursed for all reasonable travelling and subsistence expenses (including any relevant tax) incurred in carrying out their duties. Professional fees incurred by non-executive directors based outside the UK in connection with advice and assistance on UK tax compliance matters are reimbursed.
Shareholding guidelines	
Approach	Non-executive directors are encouraged to establish a holding in BP shares of the equivalent value of one year's base fee.
Letters of appointment for chairman and non-executive directors	
Approach	The chairman and non-executive directors each have letters of appointment. There is no term limit on a director's service, as BP proposes all directors for annual re-election by shareholders in line with best governance practice. There are no obligations arising from the non-executive directors' letters of appointment for remuneration or payments for loss of office, except for the chairman whose appointment may be terminated in the following ways: • by either party giving three months' written notice, or • by the company for cause (as set out in the letter of appointment) and without compensation. The company may lawfully terminate the appointment by making a lump sum payment in lieu of notice equal to three months' fees. Copies of the executive directors' service contracts and non-executive directors' letters of appointment are available for inspection at the registered office of the company.

The maximum fees for non-executive directors are set in accordance with the Articles of Association.

This directors' remuneration report was approved by the board and signed on its behalf by Ben J.S. Mathews, company secretary on 18 March 2020.

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 UK 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 European Union (EU) 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).

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 Article 4 of the IAS Regulation 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.

The directors confirm that to the best of their knowledge:

- The consolidated financial statements, prepared in accordance with IFRS as issued by the IASB, IFRS as adopted by the EU and in accordance with the provisions of the Companies Act 2006, 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
Chairman
18 March 2020

Risk management and internal control

Under the UK Corporate Governance Code 2018 (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 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.

Non-operated joint ventures and associates have not been dealt with as part of this board process.

A description of the principal and emerging 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 page 70. During the year, 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 in How we manage risk on page 68.

In assessing the risks faced by the company and monitoring the system of internal control, the board and the audit, safety, environment and security assurance and geopolitical committees requested, received and reviewed reports from executive management, including management of the business segments, corporate activities and functions, at their regular meetings. A report by each of these committees, including its activities during the year, is set out on pages 90-99, 101.

During the year, the committees as relevant also met with management, the group head of audit and other monitoring and assurance functions (including group ethics and 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 appropriate committee or the board.

An audit committee meeting in January 2020 carried out an annual review of the effectiveness of the system of internal control. In considering this system, the audit committee noted that it is 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.

This review included a report from the group head of audit which summarized group audit's consideration of the design and operation of elements of BP's system of internal control over significant risks arising in the categories of strategic and commercial, safety and operational and compliance and control, in addition to considering the control environment for the group. The report also highlighted the results of internal audit work conducted during the year and the remedial actions taken by management in response to failings and weaknesses identified. Where failings or weaknesses were identified, the audit committee was satisfied that these were or are being appropriately addressed by the remedial actions proposed by management.

At its meeting in March 2020, the board 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 322.

Longer-term viability

In accordance with provision 31 of the Code, the directors have assessed the prospects of the company over a period significantly longer than 12 months. The directors believe that a viability assessment period of three years is appropriate based on management's reasonable expectations of the position and performance of the company over this period, taking account of its short-term and longer-range plans, including committed capital investment.

Taking into account the company's current position and its principal risks on page 70, 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 three years.

The directors' assessment included a review of the financial impact of the most severe but plausible scenarios that could threaten the viability of the company and the likely effectiveness of the potential mitigations that management reasonably believes would be available to the company over this period. These scenarios included:

- a significant process safety incident when operating facilities, drilling wells or transportation of hydrocarbons;
- a sustained significant oil price decline;
- a significant cyber-security incident; and
- a loss of a significant market or asset.

The risks associated with the transition to a lower carbon economy and a global pandemic are embedded in these scenarios.

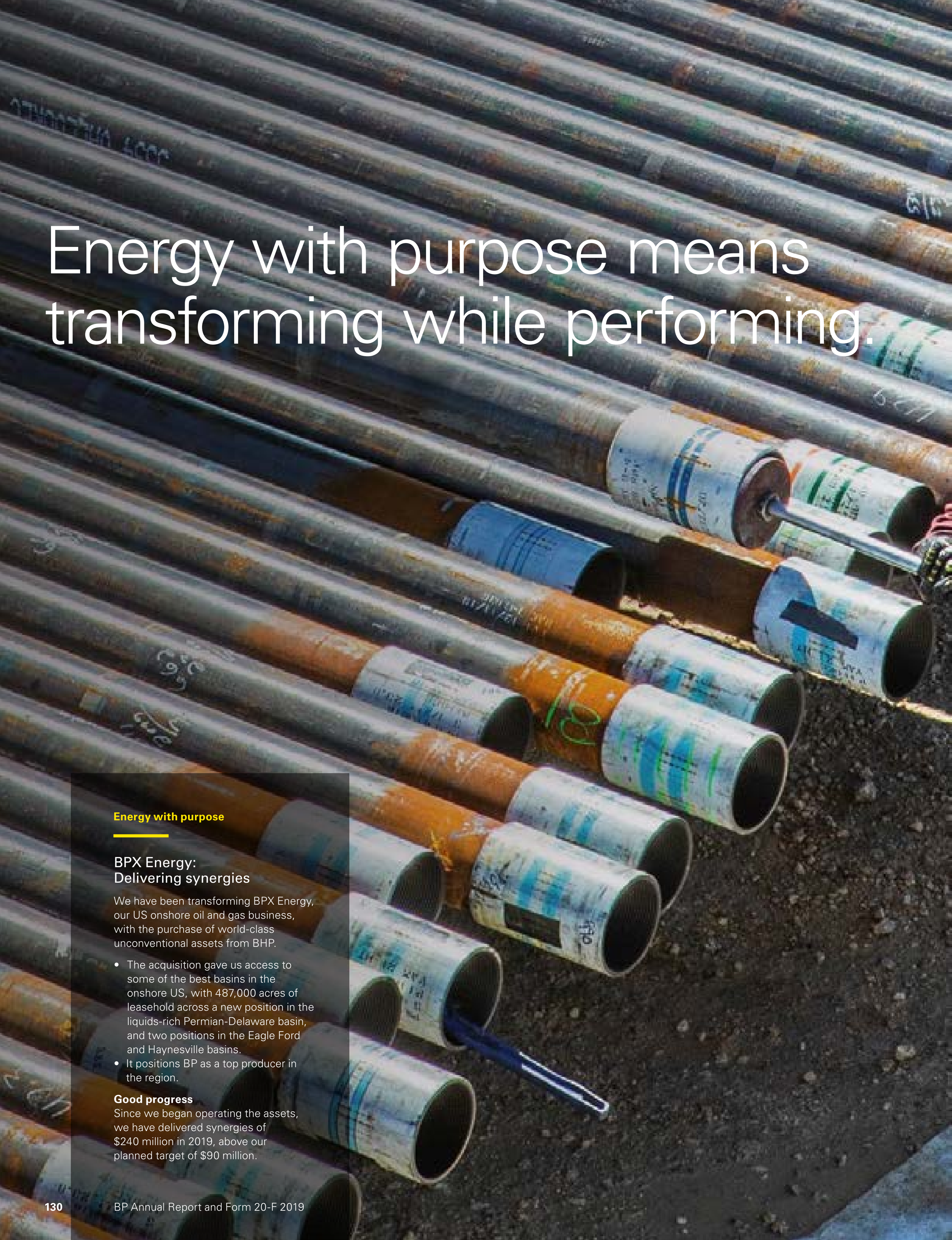
In assessing the prospects of the company, the directors noted that such assessment is subject to a degree of uncertainty that can be expected to increase looking out over time and, accordingly, that future outcomes cannot be guaranteed or predicted with certainty.

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.

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.



Energy with purpose means transforming while performing.

Energy with purpose

BPX Energy: Delivering synergies

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

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

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

Consolidated financial statements of the BP group

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 on the Annual Report and Accounts to the members of BP p.l.c.

Report on the audit of the financial statements

Opinion
In our opinion:

- The financial statements of BP p.l.c. (the 'parent company') and its subsidiaries (the 'group') give a true and fair view of the state of the group's and of the parent company's affairs as at 31 December 2019 and of the group's profit for the year then ended.
- The group financial statements have been properly prepared in accordance with International Financial Reporting Standards (IFRSs) as adopted by the European Union (EU) and IFRSs as issued by the International Accounting Standards Board (IASB).
- The parent company financial statements have been properly prepared in accordance with United Kingdom generally accepted accounting practice including Financial Reporting Standard (FRS) 101 'Reduced Disclosure Framework'.
- The financial statements have been prepared in accordance with the requirements of the Companies Act 2006 and, as regards the group financial statements, Article 4 of the IAS Regulation.

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

- Group income statement;
- Group statement of comprehensive income;
- Group and parent company statements of changes in equity;
- Group and parent company balance sheets;
- Group cash flow statement;
- Group related Notes 1 to 38 to the financial statements, including a summary of significant accounting policies; and
- Parent company related Notes 1 to 14 to the financial statements, including a summary of significant accounting policies.

The financial reporting framework that has been applied in the preparation of the group financial statements is applicable law and IFRSs as adopted by the European Union and as issued by the IASB. The financial reporting framework that has been applied in the preparation of the parent company financial statements is applicable law and United Kingdom Accounting Standards, including FRS 101 "Reduced Disclosure Framework" (United Kingdom Generally Accepted Accounting Practice).

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

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

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

Summary of our audit approach

Key audit matters	The key audit matters that we identified in the current year are as follows: • Potential impact of climate change and the energy transition (impacting PP&E, goodwill, intangible assets and provisions); • Impairment of upstream oil and gas property, plant and equipment (PP&E) assets; • Impairment of exploration and appraisal assets (included within 'intangible assets' in the Group balance sheet); • Accounting for structured commodity transactions (SCTs) within the integrated supply and trading (IST) function, and the valuation of other level 3 financial instruments (potentially impacting all financial statement accounts, in particular finance debt); • IT controls relating to financial systems (potentially impacting all financial statement accounts); and • Management override of controls (potentially impacting all financial statement accounts).
Changes in our key audit matters since the prior year	These key audit matters are consistent with those we identified in the prior year except that: • This year we identified the potential impact of climate change and the energy transition as a key audit matter, given the significant increase in focus on this issue by management and by external stakeholders, and the potential impact on the financial statements as a consequence. • In our report for the year ended 31 December 2018 we identified the accounting for acquisitions and disposals within the upstream segment as a key audit matter, in large part as a consequence of the accounting complexities surrounding the $10.3 billion acquisition of BHP Billiton assets in the US. During the current year, there were no material acquisitions and there were fewer significant accounting complexities and judgements in the disposal transactions undertaken by BP. Accordingly, we did not identify this as a key audit matter for 2019.
Materiality	We have set materiality for the current year at $850 million (2018 $750 million) based on profit before tax, profit before impairment charges and tax, and underlying replacement cost profit before interest and tax.
Scoping	Our scope covered 263 components. Of these, 179 were full-scope audits and the remaining 84 were subject to specific procedures on certain account balances by component audit teams or the group audit team. These covered 81% of group revenue and 75% of PP&E.

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

Conclusions relating to going concern, principal risks and viability statement

Going concern

We have reviewed the directors' statement on page 157 to the financial statements about whether they considered it appropriate to adopt the going concern basis of accounting in preparing them and their identification of any material uncertainties to the group's and company's ability to continue to do so over a period of at least 12 months from the date of approval of the financial statements.

We considered as part of our risk assessment the nature of the group, its business model and related risks including where relevant the impact of Brexit, the requirements of the applicable financial reporting framework and the system of internal control. We evaluated the directors' assessment of the group's ability to continue as a going concern, including challenging the underlying data and key assumptions used to make the assessment, and evaluated the directors' plans for future actions in relation to their going concern assessment.

We are required to state whether we have anything material to add or draw attention to in relation to that statement required by Listing Rule 9.8.6R(3) and report if the statement is materially inconsistent with our knowledge obtained in the audit.

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

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

Principal risks and viability statement

Based solely on reading the directors' statements and considering whether they were consistent with the knowledge we obtained in the course of the audit, including the knowledge obtained in the evaluation of the directors' assessment of the group's and the company's ability to continue as a going concern, we are required to state whether we have anything material to add or draw attention to in relation to:

- the disclosures on pages 68-71 that describe the principal risks, procedures to identify emerging risks, and an explanation of how these are being managed or mitigated;
- the directors' confirmation on page 128 that they have carried out a robust assessment of the principal and emerging risks facing the group, including those that would threaten its business model, future performance, solvency or liquidity; or
- the directors' explanation on page 129 as to how they have assessed the prospects of the group, over what period they have done so and why they consider that period to be appropriate, and their statement as to whether they have a reasonable expectation that the group will be able to continue in operation and meet its liabilities as they fall due over the period of their assessment, including any related disclosures drawing attention to any necessary qualifications or assumptions.

We are also required to report whether the directors' statement relating to the prospects of the group required by Listing Rule 9.8.6R(3) is materially inconsistent with our knowledge obtained in the audit.

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

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

Key audit matters

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial statements of the current period and include the most significant assessed risks of material misstatement (whether or not due to fraud) that we identified. These matters included those which had the greatest effect on: the overall audit strategy; the allocation of resources in the audit; and directing the efforts of the engagement team. All of these matters were considered and discussed with the audit committee as described on page 93.

Throughout the course of our audit we identify risks of material misstatement ('risks'). We consider both the likelihood of a risk and the potential magnitude of a misstatement in making the assessment. Certain risks are classified as 'significant' or 'higher' depending on their severity. The category of the risk determines the level of evidence we seek in providing assurance that the associated financial statement item is not materially misstated.

These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

<table>
<tr><th colspan="2">Potential impact of climate change and the energy transition (impacting PP&E, goodwill, intangible assets and provisions)</th></tr>
<tr><th>Key audit matter description</th><th>How the scope of our audit responded to the key audit matter</th></tr>
<tr><td>
Climate change impacts BP’s business in a number of ways as set out in the strategic report on pages 2-71 of the Annual Report and Accounts.
It represents a strategic challenge with its implications becoming increasingly significant towards 2050 and beyond. Whilst many of BP’s oil and gas properties and refining assets are long-term in nature, none are being amortised over a period that extends beyond this date. At current rates of depreciation, depletion and amortisation (DD&A), the average life of the upstream PP&E is seven years and the downstream PP&E is 13 years. Accordingly, the related principal risks that we have identified for our audit are as follows:

Forecast assumptions used in assessing the value of assets within BP’s balance sheet for impairment testing, particularly oil and gas price assumptions relevant to upstream oil and gas PP&E assets, may not appropriately reflect changes in supply and demand due to climate change and the energy transition (see 'impairment of upstream PP&E' below);
Recoverability of exploration and appraisal (E&A) assets included within BP’s balance sheet where the investment required in order to develop particular projects into producing oil and gas PP&E assets might not be sanctioned by the board in future due to climate change considerations or a potential development may not be considered to be economic due to the impact of climate change and the energy transition on oil and gas prices (see 'impairment of exploration and appraisal assets' below)

Management also assessed the following potential risks that could arise from climate change considerations.

The carrying value of goodwill may no longer be recoverable and therefore may need to be impaired;
The useful economic lives of the group’s PP&E may be shortened as society moves towards 'net zero' emissions targets, such that the DD&A charge is materially understated;
Decommissioning and asset retirement obligations may need to be brought forward with a resulting increase in the present value of the associated liabilities; and
Climate change-related litigation brought against BP, as disclosed in Note 33 to the financial statements and described on page 320 under legal proceedings, may lead to an outflow of funds requiring provision in the current year.

The material upstream goodwill balance is recorded and tested at the segment level. The most significant assumption in the goodwill impairment test affected by climate change relates to future oil and gas prices (see 'impairment of upstream PP&E' below). Given the significant headroom in the goodwill impairment test, management identified no other assumption that could lead to a material misstatement of goodwill due to the energy transition and other climate change factors. Disclosures in relation to sensitivities for goodwill are included within Note 14 on pages 187-188.
The downstream segment has a goodwill balance at 31 December 2019 of $3.9 billion, of which the most significant element is $2.8 billion relating to the Lubricants business. Notwithstanding the expected global transition to electric vehicles, management noted that demand for lubricants is forecast to continue to grow until at least 2040, underpinning the substantial headroom in the most recent impairment test as described in Note 14.
As described on pages 70-71 and in Note 1, the impact of potential changes in DD&A charges, or to decommissioning dates would not have a material impact on the amounts reported in the current period.
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.
</td><td>
Overall response
We held discussions with management, with Deloitte specialists and within the Group engagement team to identify the areas where we felt climate change could have a potential impact on the financial statements.
We also established a climate change steering committee comprising a group of senior partners with specific sustainability and technical audit and accounting expertise within Deloitte to provide an independent challenge to our key decisions and conclusions with respect to this area.
Audit procedures in respect of impairment of upstream oil and gas PP&E assets and exploration and appraisal assets
The audit response related to the two principal risks identified is set out under the key audit matters for impairment of upstream oil and gas PP&E assets on pages 135-136 and the impairment of exploration and appraisal assets on page 137.
Other audit procedures performed
We challenged management’s assertion that the impact of potential changes in DD&A charges, or to decommissioning dates, would not have a material impact on the amounts reported in the current period, by making inquiries of relevant BP personnel outside the finance function, reviewing internal and external documents and conducting sensitivity analysis as part of our audit risk assessment procedures. We obtained third party forecasts of future refined petroleum product demand for those countries which are included in our group full audit scope for downstream, under a range of scenarios including scenarios noted as being consistent with achieving the 2015 COP 21 Paris agreement goal to limit temperature rises to well below 2°C ('Paris 2°C Goal'). These indicated that global demand for such products was expected to remain significant until at least 2040.
We performed procedures to satisfy ourselves that, other than future oil and gas price assumptions, there were no other assumptions in management's goodwill calculations to which reasonably possible changes could cause goodwill to be materially misstated.
We obtained an understanding of the controls identified by management as being relevant to ensuring the completeness and accuracy of litigation and climate change related disclosure within the Annual Report; we performed procedures to test these controls.
With regard to climate change litigation, we designed procedures specifically to respond to the risks that provisions could be understated or that contingent liability disclosures may be omitted or be inaccurate including:

Holding discussions with the group general counsel and other senior BP lawyers regarding climate change matters;
Conducting a search for climate change litigation and claims brought against the group; and
Making written inquiries of, and holding discussions with, external legal counsel advising BP in relation to climate change litigation.

We read the other information included in the Annual Report and considered (a) whether there was any material inconsistency between the other information and the financial statements; or (b) whether there was any material inconsistency between the other information and our understanding of the business based on audit evidence obtained and conclusions reached in the audit.
</td></tr>
</table>

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Key observations	Key observations in relation to oil and gas price assumptions used in upstream oil and gas PP&E assets impairment tests, and the recoverability of exploration and appraisal assets including the impacts of climate change, are set out in the relevant key audit matter below. Based on the audit evidence obtained both from internal and external legal counsel, we were satisfied with management's assertion that no provision should currently be made in respect of climate change litigation. We reviewed management's disclosure of the contingent liabilities in respect of these matters and concluded that the disclosures are appropriate. We were satisfied with the results of our procedures relating to DD&A charges, goodwill and decommissioning. We are satisfied that management's other disclosures in the Annual Report relating to climate change are consistent with the financial statements and our understanding of the business.

Impairment of upstream oil and gas property, plant and equipment (PP&E) assets	
Key audit matter description	**How the scope of our audit responded to the key audit matter**
The group balance sheet includes property, plant and equipment (PP&E) of $133 billion (2018 $135 billion), of which $90 billion (2018 $99 billion) is oil and gas properties within the upstream segment. Management announced an approximately $10 billion disposal programme for 2019 and 2020. As a consequence of this, certain assets identified for disposal have been assessed for impairment in the context of their fair value based on the expected disposal proceeds from third parties, as opposed to their value in use. The transition to a lower carbon global economy may potentially lead to a lower oil and gas price scenario in the future due to declining demand. Management took into account considerations of uncertainty over the pace of the transition to lower-carbon supply and demand and the social, political and environmental actions that will be taken to meet the goals of the Paris climate change agreement when determining their future oil and gas price assumptions and revised the future price assumptions downwards when compared with the prior year assumptions as set out in Note 1 on page 162. As a consequence, they identified a risk of impairment across all upstream CGUs. Accordingly, as required by International Accounting Standard (IAS) 36 'Impairment of Assets', management performed a review of all the upstream cash generating units (CGUs) for indicators of impairment and impairment reversal as at 31 December 2019. Further information has been provided in Note 1. In large part due to the disposal programme, for the year ended 31 December 2019, BP recorded $5,871 million (2018 $400 million) of upstream impairment charges and $129 million (2018 $580 million) of impairment reversals. Through our risk assessment procedures, we have determined that there are three key estimates in management's determination of the level of impairment charge/reversal to record. These are: • **Oil and gas prices** - BP's oil and gas price assumptions have a significant impact on CGU impairment assessments and valuations performed across the portfolio, and are inherently uncertain. Furthermore, as noted above the estimation of future oil and gas prices is subject to increased uncertainty, given climate change and the global energy transition. There is a risk that management's oil and gas price assumptions are not reasonable, leading to a material misstatement. The assumptions are highly judgemental.	We tested management's internal controls over the setting of oil and gas prices, discount rates and reserve estimates, as well as the controls over the performance of the impairment valuation tests. In addition, we conducted the following substantive procedures. **Oil and gas prices** • We independently developed a reasonable range of forecasts based on external data obtained, against which we compared the company's future oil and gas price assumptions in order to challenge whether they are reasonable. • In developing this range we obtained a variety of reputable third party forecasts, peer information and market data. • In challenging management's price assumptions, we considered the extent to which they and each of the forecast pricing scenarios obtained from third parties reflect the impact of lower oil and gas demand due to climate change. We specifically reviewed third party forecasts stated as being, or interpreted by us as being, consistent with achieving the Paris 2°C Goal and considered whether they presented contradictory evidence. • We reviewed and challenged management's disclosures including in relation to the sensitivity of oil and gas price assumptions to reduced demand scenarios whether due to climate change or other reasons. **Discount rates** • We independently evaluated BP's discount rates used in impairment tests with input from Deloitte valuation specialists. • We assessed whether country risks and tax adjustments were appropriately reflected in BP's discount rates. **Reserves estimates** • We reviewed BP's reserves estimation methods and policies, assisted by Deloitte reserves experts. • We assessed, with the assistance of Deloitte reserves experts, how these policies had been applied to a sample of internal reserves estimates. • We reviewed reports provided by external experts and assessed their scope of work and findings.

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<table>
<tr><th colspan="2">Impairment of upstream oil and gas property, plant and equipment (PP&E) assets (continued)</th></tr>
<tr><th>Key audit matter description</th><th>How the scope of our audit responded to the key audit matter</th></tr>
<tr><td>

- **Discount rates** - Given the long timeframes involved, certain recoverable amounts of assets are sensitive to the discount rate applied. There is a risk that discount rates do not reflect the return required by the market and the risks inherent in the cash flows being discounted, leading to a material misstatement. Determination of the appropriate discount rate can be judgemental.
- **Reserves estimates** - A key input to impairment assessments and valuations is the production forecast, in turn closely related to the group's reserves estimates and field development assumptions. CGU-specific estimates are not generally material. However, material misstatements could arise either from systematic flaws in reserves estimation policies, or due to flawed estimates in a particularly material individual impairment test.

We identified and focused on certain individual CGUs with a total carrying value of $12.3 billion (2018 $21.8 billion) which we determined would be most at risk of a material impairment as a result of a reasonably possible change in the key assumptions, particularly the oil and gas price assumptions. Accordingly, we identified these as a significant audit risk. We also focused on assets with a further $33.4 billion (2018 $31.5 billion) of combined CGU carrying value which were less sensitive. We identified these as a higher audit risk as they would be potentially at risk in aggregate to a material impairment by a change in such assumptions. Further information regarding these sensitivities is given in Note 1 to the consolidated financial statements.

</td><td>

- We assessed the competence, capability and objectivity of BP's internal and external reserve experts, through obtaining their relevant professional qualifications and experience.
- We compared hydrocarbon production forecasts used in impairment tests to estimates and reports and our understanding of the life of fields.
- We performed a retrospective review to check for indications of estimation bias over time.

Other procedures

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

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

</td></tr>
<tr><td>Key observations</td><td>

Oil and gas prices

The long-term oil and gas price assumptions used to determine recoverable amount through value-in-use impairment tests are derived from the central case long term price assumption used for investment appraisal purposes (as set out on page 19) and represent management's best estimate of future prices as set out in Note 1. We determined that BP's oil and gas price assumptions are reasonable when compared against the range of third party forecasts we identified as being appropriate for the purpose. In forming this view, we included each forecaster's 'best case', 'central case' or 'most likely' estimate.

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 observed that, as well as publishing a 'best case', 'central case' or 'most likely' estimate, the majority of third party price forecasters publish a number of other future scenarios under different plausible economic assumption sets, and that the price forecasts stated as being or interpreted by us as being 'Paris 2°C Goal' scenarios were the lowest of all scenarios from those forecasters. We observed that for oil, all the prices in third party 'Paris 2°C Goal' scenarios in our sample were lower than BP's oil price assumption from 2023 onwards, and for gas, BP's price assumptions for impairment purposes were close to the highest 'Paris 2°C Goal' scenario.

While these 'Paris 2°C Goal' scenarios indicate that BP's price assumptions for impairment purposes are not consistent with the world being on a path to achieving the Paris 2°C Goal we observed that none of those third party forecasters described their 'Paris 2°C Goal' scenarios as their 'best case', 'central case' or "most likely" estimate.

We reviewed the disclosures included in Note 1 to the accounts in respect of price assumptions, including the sensitivity analysis presented therein. We observed that the second downside sensitivity, in which prices start 15% lower than the best estimate and gradually reduce to 25% lower than the best estimate by 2040, is within the range of third party Paris 2°C Goal forecasts both for oil and for gas albeit towards the upper end for oil.

We are satisfied that the COVID-19 outbreak and the geopolitical factors are both non-adjusting events and accordingly the recent sharp fall in the oil price is a result of conditions that arose after the balance sheet date. As such we concluded that management's future oil and gas price assumptions used in impairment tests to assess the recoverable amount of assets at the balance sheet date should not be adjusted.

Discount rates

BP's post-tax nominal 6% weighted average cost of capital, used as the starting point for setting discount rates used for impairment testing, was within the independent range calculated by our Deloitte valuation specialists.

We were also satisfied with the calculation of country risk premia. When the rates were grossed up for tax as required for impairment testing the rates for a small number of countries fell outside of our reasonable range but there was an insignificant impact in respect of a small number of CGUs. Accordingly, we are satisfied with the discount rates used in the impairment testing.

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Key observations	We reviewed the disclosures included in Note 1 to the accounts in respect of discount rate assumptions used and confirmed that they are consistent with the IFRS disclosure requirements. **Reserves estimates** We concluded that the assumptions used to derive the estimates were reasonable.

Impairment of exploration and appraisal assets (included within intangible assets within the Group balance sheet)	
Key audit matter description	**How the scope of our audit responded to the key audit matter**
The group capitalizes exploration and appraisal (E&A) expenditure on a project-by-project basis in line with IFRS 6 'Exploration for and Evaluation of Mineral Resources'. At the end of 2019, $14 billion (2018 $16 billion) of E&A expenditure was carried in the group balance sheet. E&A activity is inherently risky and a significant proportion of projects fail, requiring the write-off of the related capitalized costs when the relevant criteria in IFRS 6 and BP's accounting policy are met. There is a significant judgement relating to the risk that certain capitalized E&A costs are not written off promptly at the appropriate time, in line with information from, and decisions about E&A activities, and the impairment requirements of IFRS 6. Furthermore, similar to upstream PP&E assets discussed above, E&A assets are also potentially exposed to climate change and the global energy transition. A greater number of projects may be expected not to proceed as a consequence of lower forecast future demand, lower appetite by management and the board to allocate capital to certain projects, or increased objections from stakeholders to the development of certain projects. In response, management has updated its internal controls over its IFRS 6 assessment to reflect the potential impact that climate change and the energy transition may have on E&A assets. In the prior year audit, we had identified this key audit matter as a significant risk primarily on account of uncertainty arising from the potential inability of the Company to secure key license extensions in respect of assets in the Gulf of Mexico and on three licenses in other regions. During the current year, and subsequent to the year end, management have obtained licence extensions in the Gulf of Mexico and other regions such that we have concluded this no longer represents a significant audit risk. Nevertheless, given the inherent uncertainty associated with the development and deployment of these assets, we still consider this area to be a higher risk.	We obtained an understanding of the group's E&A impairment assessment processes and tested management's internal controls, including the new control procedures implemented to address potential climate change considerations. We performed a licence-by-licence risk assessment of the group's E&A balance through to year end, to identify significant carrying amounts with a current period risk of impairment (e.g. new information from exploration activities, or imminent licence expiry). We performed a retrospective review of impairment charges recorded in the period, and assessed whether impairment charges were timely. We reviewed and challenged management's significant IFRS 6 impairment judgements, having regard to the impairment criteria of IFRS 6 and BP's accounting policy. We verified key facts relevant to significant carrying amounts (by obtaining for example evidence of future E&A plans and budgets, and evidence of active dialogue with partners and regulators including negotiations to renew licences or modify key terms). We tested the completeness and accuracy of information used in management's E&A impairment assessment, by reviewing and testing key controls over management's register of E&A licences and agreeing key aspects of this to underlying support (e.g. licence documentation); holding meetings and discussions with operational and finance management; considering adverse changes in management's reserves and resource estimates associated with E&A assets; reviewing correspondence with regulators and joint arrangement partners; and considering the implications of capital allocation decisions. When considering capital allocation decision making, we considered whether the development of any projects would be inconsistent with the elements of BP's current strategy which are designed to ensure it is resilient to the energy transition and climate change considerations or which would otherwise have a prohibitively high environmental or social impact for the directors to sanction the necessary investment.
Key observations	We concluded that the key assumptions had been appropriately determined, the judgements management had made were appropriately supported, and no additional impairments were identified from the work we performed. Where E&A costs were carried in respect of projects where licences had previously expired, we obtained evidence that these licences have been renewed. We also confirmed management's view that they did not consider that the development of any of their E&A assets is inconsistent with BP's current strategy. In that context we particularly considered the Canadian oil sands assets (see Note 1) and concluded that, given low-carbon extraction technologies required to optimise the development of these assets are being researched, continuing to carry the assets was consistent with IFRS6.

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<table>
<tr><th colspan="3">Accounting for structured commodity transactions (SCTs) within the integrated supply and trading function (IST), and the valuation of other level 3 financial instruments, where fraud risks may arise in revenue recognition (potentially impacting all financial statement accounts, in particular finance debt)</th></tr>
<tr><th colspan="2">Key audit matter description</th><th>How the scope of our audit responded to the key audit matter</th></tr>
<tr><td colspan="2">
In the normal course of business, IST enters into a variety of transactions for delivering value across the group's supply chain. The nature of these transactions requires significant audit effort be directed towards challenging management's valuation estimates or the adopted accounting treatment.
Accounting for structured commodity transactions: IST may also enter into a variety of transactions which we refer to as SCTs. We generally consider a SCT to be an arrangement having one of the following features:
a) two or more counterparties with non-standard contractual terms;
b) multiple commodity-based transactions; and/or
c) contractual arrangements entered into in contemplation of each other.
SCTs are often long-dated, can have a significant multi-year financial impact, and may require the use of complex valuation models or unobservable market inputs when determining their fair value, in which case they will be classified as level 3 financial instruments under IFRS 13, Fair Value Measurement.
Accounting for SCTs is often complex and involves significant judgement, as these transactions often feature multiple elements that will have a material impact on the presentation and disclosure of these transactions in the financial statements and on key performance measures, including in particular classification of liabilities as finance debt. We have identified the accounting for SCTs as a significant audit risk.
Level 3 financial instruments: Unlike other financial instruments whose values or inputs are readily observable and therefore more easily independently corroborated, there are certain transactions for which the valuation is inherently more subjective due to the use of either complex valuation models and/or unobservable inputs. These instruments are classified as level 3 financial assets or liabilities under IFRS 13. This degree of subjectivity also gives rise to potential fraud through management incorporating bias in determining fair values. Accordingly, we have identified these as a significant audit risk.
As at 31 December 2019, the group's total financial assets and liabilities measured at fair value were $12.5 billion (2018 $12.8 billion) and $8.8 billion (2018 $8.9 billion), of which level 3 derivative financial assets were $5.3 billion (2018 $3.6 billion) and level 3 derivative financial liabilities were $4.4 billion (2018 $3.1 billion).
</td><td>
Accounting for structured commodity transactions:
For structured commodity transactions, we performed audit procedures to:

Test controls related to the transactions.
Develop an understanding of the commercial rationale of the transactions through review of transaction support documents and executed agreements, and discussions with management.
Perform a detailed accounting analysis for a sample of structured commodity transactions involving significant day 1 profits, deferred working capital arrangements, offtake arrangements and/or commitments.

To assess the appropriateness of the accounting treatment of SCTs, we embedded technical accounting specialists within the audit team. During the year we identified two new SCTs which were subjected to our audit procedures listed above. We also reconsidered the SCTs which were identified during 2018 and which have been subject to ongoing assessment in 2019.
Other level 3 financial instruments:
To address the complexities associated with auditing the value of level 3 financial instruments, the engagement team included valuation specialists having significant quantitative and modelling expertise to assist in performing our audit procedures. Our valuation audit procedures included the following control and substantive procedures:

We tested the group's valuation controls including the:
Model certification control, which is designed to review a model's theoretical soundness and the appropriateness of its valuation methodology; and
Independent price verification control, which is designed to review the appropriateness of valuation inputs that are not observable and are significant to the financial instrument's valuation.

We performed substantive valuation testing procedures at interim and year-end balance sheet dates, including:

Engaging a Deloitte valuations specialist to develop fair value estimates, using independently sourced inputs where these were available, and challenge models to evaluate against management's fair value estimates by evaluating whether the differences between our independent estimates and management's estimates were within a reasonable range. In situations where we utilised management's inputs, these were compared to external data sources to ensure they were reasonable;
Evaluating management's valuation methodologies against standard valuation practice and analysing whether a consistent framework is applied across the business period over period; and
Comparing management's input assumptions against the expected assumptions of other market participants and observable market data.

</td></tr>
<tr><td>Key observations</td><td colspan="2">
We reviewed the features of the SCTs and determined that the accounting adopted for each of these was appropriate and in accordance with IFRS.
We concluded that management's valuations relating to level 3 instruments were appropriate.
We did not identify any indications of fraudulent misrepresentation of revenue recognition in the transactions, valuation estimates or accounting entries that we tested.
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<table>
<tr><th colspan="2">IT controls relating to financial systems (potentially impacting all financial statement accounts)</th></tr>
<tr><th>Key audit matter description</th><th>How the scope of our audit responded to the key audit matter</th></tr>
<tr><td>
The group’s financial systems environment is complex, with 121 separate systems scoped as being relevant for the group audit.
Due to the reliance on financial systems within the group, IT controls which support these systems are critical to maintaining an effective control environment.
We identified IT control deficiencies in two key areas.
User Access Management:
In the prior year, we identified a number of deficiencies relating to user access management, both within the group and at the group’s IT service organizations (together ‘access deficiencies’). Management commenced the implementation of a remediation programme in the prior year, although this programme extends into 2020.
During our 2019 audit we identified a number of additional deficiencies relating to user access management in the IT environment as a result of new systems in scope, the control of highly privileged finance access and the management of segregation of duties.
The access deficiencies identified increase the risk that individuals across BP had inappropriate access during the period. This results in an increased risk that data and reports from the affected systems are not reliable. The access deficiencies impact all components within the scope of our group audit.
Management remediated some of the deficiencies during 2019. For the remaining deficiencies, management implemented mitigating controls to confirm that no inappropriate access had been exploited.
Change Management:
A new change management process and change control ticketing system, ServiceNow, was implemented for 2019. Following the change in process and tool a number of deficiencies were identified by Deloitte and by management around the consistent implementation of the minimum change management controls.
The change management deficiencies identified increase the risk of inappropriate or untested changes being made which could negatively impact the way a system operates and accordingly, the ongoing integrity of the controls, reports and data within key financial systems.
In responding to the identified deficiencies management have implemented retrospective approvals for all exceptions identified. Management also performed a full review of all changes made to all systems in the scope of our group audit to ensure all changes were appropriate and that change management controls were documented. In addition management established a programme to remediate all the identified deficiencies.
The change management issues identified impact all components within the scope of our group audit.
Both the user access management controls and the controls over the management of system change are pervasive to the group’s operations and accordingly the level of risk ascribed to our work in this area is dependent on the nature and complexity of the control itself and the risks addressed by the control.
</td><td>
We obtained an understanding of management’s processes and relevant financial systems, and tested the associated general IT controls and automated business controls. We also tested the integrity of key reports. This testing led us to identify a number of deficiencies, notably in relation to user access and change management.
User Access Management:
In responding to the identified deficiencies in user access, our IT audit specialists performed procedures to:

Test the controls that management has implemented or re-designed in order to remediate the deficiencies;
Assess and test the mitigating controls that management identified, including directly testing those controls operated by IT service organizations; and
Determine the impact that utilizing inappropriate levels of access could feasibly have had on the affected systems including assessing the likelihood of inappropriate user access impacting the financial statements, and test controls implemented by management to identify instances of the use of inappropriate access.

Change Management:
In responding to the identified deficiencies our IT audit specialists performed independent testing over:

The mitigating controls performed by management; and
Key automated business controls and the logic and accuracy of key reports to ensure no changes had impacted their effectiveness.

These procedures were designed to address the likelihood and impact of inappropriate or untested changes being implemented.
</td></tr>
<tr><td>Key observations</td><td>
Our testing confirmed that the remediated controls were operating effectively.
Our testing of the mitigating controls management performed, alongside our independent testing to demonstrate whether the access and change management deficiencies were exploited during the year, did not identify instances of inappropriate access usage or change implementation.
Accordingly, we were satisfied with the results of the remediation to date and the mitigation such that we continued to adopt an audit approach which places reliance on the operating effectiveness of financial controls. Under our methodology, this enables us to apply lower sample sizes in our substantive testing.
Management continues to work to remediate fully the access and change management deficiencies identified.
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<table>
<tr><th colspan="2">Management override of controls (potentially impacting all financial statement accounts)</th></tr>
<tr><th>Key audit matter description</th><th>How the scope of our audit responded to the key audit matter</th></tr>
<tr><td>We conducted an assessment of the fraud risks arising from management override of controls by considering potential areas where the group’s financial statements could be manipulated, including:
• Inappropriate accounting estimates and judgements; and
• Accounting for significant unusual transactions arising from changes to the business.
In performing this assessment we considered pressures or incentives to achieve certain IFRS or non-GAAP measures due to the remuneration arrangements of people in Financial Reporting Oversight Roles (FRORs), including management and senior executives.
During our 2018 audit we identified control deficiencies relating to the posting of accounting journal entries at the components where testing was performed. These control deficiencies remain as of the end of 2019 and extended to other components where testing was performed. There were also other changes to BP’s processes for the posting of certain journals which created further deficiencies. As in the previous year, management directed us to other compensating controls which they considered to mitigate the risks, which we subsequently tested. Management has initiated a remediation programme which will extend into 2020.
This had a significant bearing again this year on the allocation of resources in the audit, and the direction of effort of the audit team globally and was a matter we discussed with the audit committee. Accordingly, we identified this as a key audit matter.</td><td>We tested the relevant primary and, where necessary, compensating controls that management identified as responding to the risk of fraudulent journal entries.
In addition, we:
• Made inquiries of individuals involved in the financial reporting process about inappropriate or unusual activity relating to the processing of journal entries and other adjustments.
• Identified and tested relevant entity-level controls, in particular those related to the BP Code of Conduct, whistleblowing (BP OpenTalk) and controls monitoring financial reporting processes and financial results.
• Used our data analytics tools to select journal entries and other adjustments made at the end of a reporting period or otherwise having characteristics which are associated with common fraud schemes for testing.
• Tested journal entries and other adjustments recorded in the general ledger throughout the period, with a particular focus on adjustments that occur late in the financial close process.
We have reviewed accounting estimates for bias and evaluated whether the circumstances producing the bias, if any, represent a risk of material misstatement due to fraud. A number of the most significant estimates are covered by the other Key Audit Matters set out above. This assessment included:
• Evaluating whether the judgements and decisions made by management in making the accounting estimates included in the financial statements, even if they are individually reasonable, indicate a possible bias on the part of BP's management that may represent a risk of material misstatement due to fraud; and
• Performing a retrospective review of management judgements and assumptions related to significant accounting estimates reflected in the financial statements of the prior year.
We considered whether there were any significant transactions that are outside the normal course of business, or that otherwise appear to be unusual due to their nature, timing or size.
The risks and responses to the revenue recognition risks within the integrated supply and trading function are set out on page 138.</td></tr>
<tr><td>Key observations</td><td>The nature of the identified deficiencies over journal entry controls varies from business to business, so there is no single root cause. Management identified compensating controls to mitigate the risk associated with the design deficiencies identified. These included low-level analytical reviews, controls over closing balances, period-end analytical review controls and certain automated business controls. Our testing of these compensating controls concluded they were, in combination, appropriately designed and implemented and that they were operating effectively for the year.
Our substantive testing of journal entries and other adjustments, selected through the use of our data analytics tools, did not identify any inappropriate items.
We did not identify evidence of overall bias or any significant and unusual transactions for which the business rationale (or the lack thereof) of the transaction suggested that it may have been entered into to engage in fraudulent financial reporting or to conceal misappropriation of assets.
Management is continuing to design and implement appropriate process level controls over journal entries in 2020.</td></tr>
</table>

Our application of materiality

We define materiality as the magnitude of misstatement in the financial statements that makes it probable that the economic decisions of a reasonably knowledgeable person would be changed or influenced. We use materiality both in planning the scope of our audit work and in evaluating the results of our work.

Based on our professional judgement, we determined materiality for the financial statements as a whole as follows:

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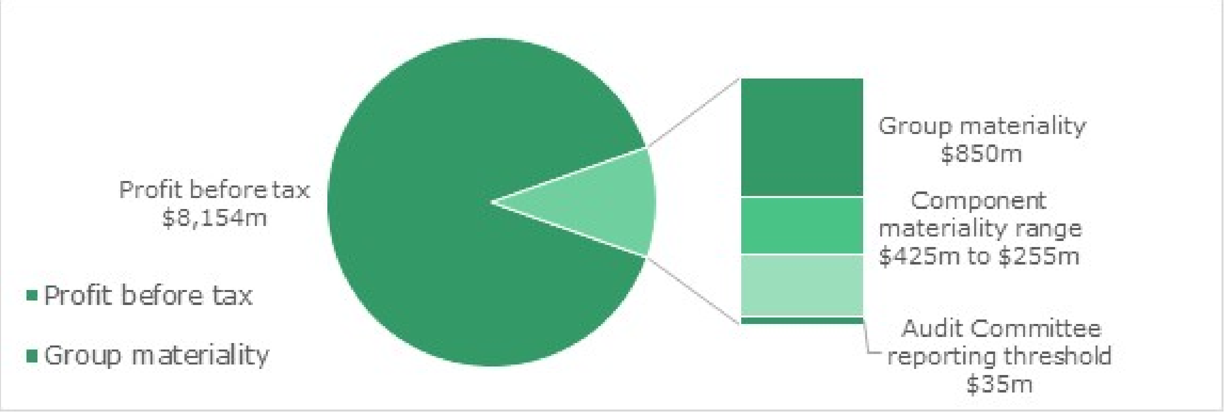
	Group financial statements	Parent company financial statements
Materiality	Materiality has been set at $850 million for the current year. In 2018, we used a materiality of $750 million. The increase is partly due to BP's financial performance in 2019 and also the fact that our 2018 materiality level reflected some conservatism in our first year as auditor.	Materiality has been set at $1,200 million for the current year. (2018 $1,200 million)
Basis for determining materiality	We considered a number of metrics when determining group materiality, including profit before taxation, profit before impairment charges and taxation and underlying replacement cost profit before interest and taxation. Our selected materiality figure represents 10.3% of profit before taxation, 5.7% of profit before impairment charges and taxation, and 5.0% of underlying replacement cost profit before interest and taxation. In 2018, we determined materiality to be $750m which represented 4.5% of profit before taxation and 3.2% of underlying replacement cost profit before interest and taxation. The significant impairment charges of $6,847m recognized in 2019 caused us to place more emphasis on profit before impairment charges and taxation in our determination of materiality this year.	We determined materiality for our audit of the standalone parent using 1% (2018 1%) of net assets.
Rationale for the benchmark applied	We conducted an assessment of which line items are the most important to investors and analysts by reviewing analyst reports and BP's communications to shareholders and lenders, as well as the communications of peer companies. This assessment resulted in us selecting the financial statement line items above. Profit before tax is the benchmark ordinarily considered by us when auditing listed entities. It provides comparability against other companies across all sectors, but has limitations when auditing companies whose earnings are strongly correlated to commodity prices, which can be volatile from one period to the next, and therefore may not be representative of the volume of transactions and the overall size of the business in the year, or where the impact of price volatility may result in material impairment charges or reversals in a particular year. The significant impairment charges recognized in 2019 caused us to place more emphasis on profit before impairment charges and taxation this year. Whilst not a GAAP measure, underlying replacement cost profit before interest and tax is one of the key metrics communicated by management in BP's results announcements. It excludes some of the volatility arising from changes in crude oil, gas and product prices as well as non-operating items.	The materiality determined for the standalone parent company financial statements exceeds the group materiality as it is determined on a different basis given the nature of the parent company operations. As the company is non-trading and operates primarily as a holding company, we believe the net asset position is the most appropriate benchmark to use. Where there were balances and transactions within the parent company accounts that were within the scope of the audit of the group financial statements, our procedures were undertaken using the lower materiality level applying to the group audit components. It was only for the purposes of testing balances not relevant to the group audit, such as intercompany investment balances, that the higher level of materiality applied in practice.



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Performance materiality

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

Error reporting threshold

We agreed with the audit committee that we would report to the committee all audit differences in excess of $35 million (2018 $25 million), as well as differences below that threshold that, in our view, warranted reporting on qualitative grounds. We also report to the audit committee on disclosure matters that we identified when assessing the overall presentation of the financial statements.

An overview of the scope of our audit

Identification and scoping of components

As a result of the highly disaggregated nature of the group, with operations in over 70 countries through approximately 1,000 components, a significant portion of our audit planning effort was ensuring that the scope of our work is appropriate in addressing the identified risks of material misstatement.

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

- The financial significance of an operating unit to BP's revenue and profit before tax, or PP&E, including consideration of the financial significance of specific account balances or transactions.
- The significance of specific risks relating to an operating unit, history of unusual or complex transactions, identification of significant audit issues or the potential for, or a history of, material misstatements.
- The effectiveness of the control environment and monitoring activities, including entity-level controls.
- The findings, observations and audit differences that we noted as a result of our 2018 audit engagement.

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

To ensure we were able to obtain sufficient, appropriate audit evidence for the purposes of our audit of the financial statements, we performed full scope audit procedures for 179 reporting consolidation units ('cons units' or components) (2018 108) which were selected based on their size or risk characteristics. The primary reason for the change in scope is a change in our approach to the global audit of the IST function. We also added to our full scope audit components for 2019 the new businesses acquired in onshore US in 2018 from BHP. Our full-scope audits are in the UK, US, Azerbaijan, Germany and Singapore. One of the full-scope cons units includes the investment in Rosneft, a material associate not controlled by BP.

In addition, component teams performed audit procedures on specified account balances for 55 cons units (2018 16) also covering operations in Angola, Alaska, Trinidad & Tobago and Australia. The group engagement team performed audit procedures on specified account balances by segment teams to component materiality, with certain additional specific procedures performed by component teams, covering an additional 29 cons units (2018 12).

In our assessment of the residual balances, we have considered in particular the risk that there could be a material misstatement within the large number of geographically dispersed businesses, in particular within the downstream segment. This assessment included use of our analytic tools to interrogate data, preparation of trend analysis and comparison of business performance to market benchmark prices. We concluded that through this additional risk assessment, we have reduced the audit risk of such a misstatement arising to a sufficiently low level.

The remaining components are not significant individually and include many small, low risk components and balances. On average, they each represent 0.03% of group revenue (2018 0.06%) and 0.03% of property, plant and equipment (2018 0.08%). For these components, we performed other procedures, including conducting analytical review procedures, making inquiries, and evaluating and testing management's group-wide controls across a range of locations and segments in order to address the risk of residual misstatement on a segment-wide and component basis.

Working with other auditors

The group audit team provides direct oversight, review, and coordination of our component audit teams. The group audit team interacted regularly with the compnent Deloitte teams during each stage of the audit, were responsible for the scope and direction of the audit process and reviewed key working papers. We maintained continuous and open dialogue with our component teams in addition to holding formal meetings quarterly to ensure that we were fully aware of their progress and results of their procedures.

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

We were provided with direct access to Rosneft's auditor in order to evaluate their audit work on the financial statements of Rosneft, used as the basis for BP's equity accounting. We held meetings with Rosneft's auditor throughout the year, issued audit instructions to them, reviewed their written clearance reports responding to these instructions and, through our direct access, were able to exercise appropriate supervision and oversight of their audit work. We also tested directly BP's procedures and controls over its accounting for the investment in Rosneft.

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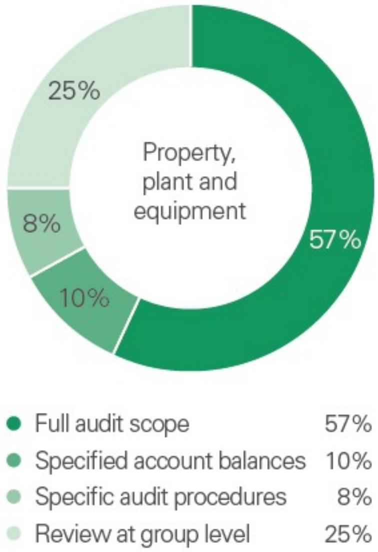

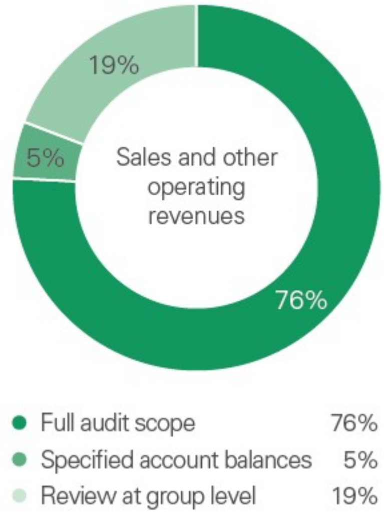

Other information

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

Our opinion on the financial statements does not cover the other information and, except to the extent otherwise explicitly stated in our report, we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

If we identify such material inconsistencies or apparent material misstatements, we are required to determine whether there is a material misstatement in the financial statements or a material misstatement of the other information. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact.

In this context, matters that we are specifically required to report to you as uncorrected material misstatements of the other information include where we conclude that:

- *Fair, balanced and understandable* - the statement given by the directors that they consider the annual report and financial statements taken as a whole is fair, balanced and understandable and provides the information necessary for shareholders to assess the group's position and performance, business model and strategy, is materially inconsistent with our knowledge obtained in the audit; or
- *Audit committee reporting* - the section describing the work of the audit committee does not appropriately address matters communicated by us to the audit committee; or
- *Directors' statement of compliance with the UK Corporate Governance Code* - the parts of the directors' statement required under the Listing Rules relating to the company's compliance with the UK Corporate Governance Code containing provisions specified for review by the auditor in accordance with Listing Rule 9.8.10R(2) do not properly disclose a departure from a relevant provision of the UK Corporate Governance Code.

We have nothing to report in respect of these matters.

Responsibilities of directors

As explained more fully in the directors' responsibilities statement, the directors are responsible for the preparation of the financial statements and for being satisfied that they give a true and fair view, and for such internal control as the directors determine is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, the directors are responsible for assessing the group's and the parent company's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the group or the parent company or to cease operations, or have no realistic alternative but to do so.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs (UK) will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

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

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A further description of our responsibilities for the audit of the financial statements is located on the FRC's website at: *frc.org.uk/auditorsresponsibilities*. This description forms part of our auditor's report.

Extent to which the audit was considered capable of detecting irregularities, including fraud

We identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and then design and perform audit procedures responsive to those risks, including obtaining audit evidence that is sufficient and appropriate to provide a basis for our opinion.

Identifying and assessing potential risks related to irregularities

In identifying and assessing risks of material misstatement in respect of irregularities, including fraud and non-compliance with laws and regulations, we considered the following:

- Our meetings throughout the year with the Group Head of Ethics and Compliance and reviews of BP's internal ethics and compliance reporting summaries, including those concerning investigations;
- Enquiries of management, internal audit, and the audit committee, including obtaining and reviewing supporting documentation, concerning the Group's policies and procedures relating to:
  - identifying, evaluating and complying with laws and regulations and whether they were aware of any instances of non-compliance
  - detecting and responding to the risks of fraud and whether they have knowledge of any actual, suspected or alleged fraud; and
  - the internal controls established to mitigate risks related to fraud or non-compliance with laws and regulations;
- The group's remuneration policies, key drivers for remuneration and bonus levels; and
- Discussions among the engagement team regarding how and where fraud might occur in the financial statements and any potential indicators of fraud. The engagement team includes audit partners and staff who have extensive experience of working with companies in the same sectors as BP operates, and this experience was relevant to the discussion about where fraud risks may arise. The discussions also involved fraud experts from Deloitte's forensic accounting function in the Financial Advisory service line, who advised the engagement team of fraud schemes that had arisen in similar sectors and industries and participated in the initial fraud risk assessment discussions.

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

We also obtained an understanding of the legal and regulatory framework that the group operates in, focusing on provisions of those laws and regulations that had a direct effect on the determination of material amounts and disclosures in the financial statements. The key laws and regulations we considered in this context included the UK Companies Act, UK Corporate Governance Code, IFRS as issued by the IASB and adopted by the EU, FRS 101, US Securities Exchange Act 1934 and relevant SEC regulations, as well as laws and regulations prevailing in each country in which we identified a full-scope component.

In addition, we considered provisions of other laws and regulations that do not have a direct effect on the financial statements but compliance with which may be fundamental to the group's ability to operate or to avoid a material penalty. These included the group's operating licences, environmental regulations etc.

Audit response to risks identified

As a result of performing the above, we did not identify any key audit matters related to the potential risk of fraud or non-compliance with laws and regulations. We did identify two key audit matters relating to fraud risks, as described above, being the accounting for SCTs and Level 3 instruments within IST, and management override of controls. The key audit matters section of our report explains the matters in more detail and also describes the specific procedures we performed in response to those key audit matters.

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

- Reviewing the financial statement disclosures and testing to supporting documentation to assess compliance with provisions of relevant laws and regulations described as having a direct effect on the financial statements;
- Enquiring of management, the audit committee, and both internal and external legal counsel concerning actual and potential litigation and claims;
- Performing analytical procedures to identify any unusual or unexpected relationships that may indicate risks of material misstatement due to fraud;
- Reading minutes of meetings of those charged with governance, reviewing internal audit reports and reviewing correspondence with relevant tax authorities including HMRC and IRS; and
- In addressing the risk of fraud through management override of controls, testing the appropriateness of journal entries and other adjustments; assessing whether the judgements made in making accounting estimates are indicative of a potential bias; and evaluating the business rationale of any significant transactions that are unusual or outside the normal course of business.

We also communicated relevant identified laws and regulations and potential fraud risks to all engagement team members including internal specialists and significant component audit teams, and remained alert to any indications of fraud or non-compliance with laws and regulations throughout the audit.

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Report on other legal and regulatory requirements

Opinions on other matters prescribed by the Companies Act 2006

In our opinion the part of the directors' remuneration report to be audited has been properly prepared in accordance with the Companies Act 2006.

In our opinion, based on the work undertaken in the course of the audit:

- The information given in the strategic report and the directors' report for the financial year for which the financial statements are prepared is consistent with the financial statements; and
- The strategic report and the directors' report have been prepared in accordance with applicable legal requirements.

In the light of the knowledge and understanding of the group and the parent company and their environment obtained in the course of the audit, we have not identified any material misstatements in the strategic report or the directors' report.

Matters on which we are required to report by exception

Adequacy of explanations received and accounting records

Under the Companies Act 2006 we are required to report to you if, in our opinion:

- We have not received all the information and explanations we require for our audit; or
- Adequate accounting records have not been kept by the parent company, or returns adequate for our audit have not been received from branches not visited by us; or
- The parent company financial statements are not in agreement with the accounting records and returns.

We have nothing to report in respect of these matters.

Directors' remuneration

Under the Companies Act 2006 we are also required to report if in our opinion certain disclosures of directors' remuneration have not been made or the part of the directors' remuneration report to be audited is not in agreement with the accounting records and returns.

We have nothing to report in respect of these matters.

Other matters

Auditor tenure

The board appointed Deloitte as the company's auditor with effect from 29 March 2018 to fill the vacancy arising from the resignation of the previous auditor. On 21 May 2019, shareholders resolved at the annual general meeting to reappoint Deloitte as auditor from the conclusion of the meeting until the conclusion of the annual general meeting to be held in 2020 and authorized the directors to set the audit fees.

The first accounting period we audited was the 12 month period ended 31 December 2018. In 2017, we commenced our audit planning procedures. The period of total uninterrupted engagement including previous renewals and reappointments of the firm is accordingly two years.

Consistency of the audit report with the additional report to the audit committee

Our audit opinion is consistent with the additional report to the audit committee we are required to provide in accordance with ISAs (UK).

Use of our report

This report is made solely to the company's members, as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for this report, or for the opinions we have formed.

Douglas King FCA (Senior statutory auditor)
For and on behalf of Deloitte LLP
Statutory Auditor
London, United Kingdom
18 March 2020

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Consolidated financial statements of the BP group

Report of Independent Registered Public Accounting Firm

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

Opinion on the financial statements

We have audited the accompanying consolidated group balance sheets of BP p.l.c. (the company) and subsidiaries (together the group) as at 31 December 2019 and 2018, and the related consolidated group income statements, group statements of comprehensive income, group statements of changes in equity, and group cash flow statements, for each of the two years in the period ended 31 December 2019, and the related notes as well as the legal proceedings described on pages 319-320 (collectively referred to as the 'group financial statements'). In our opinion, the group financial statements present fairly, in all material respects, the financial position of the group as at 31 December 2019 and 2018, and the results of its operations and its cash flows for each of the two years in the period ended 31 December 2019, in conformity with International Financial Reporting Standards (IFRS) as adopted by the European Union and IFRS as issued by the International Accounting Standards Board.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the group's internal control over financial reporting as of 31 December 2019, based on criteria established in the *UK Financial Reporting Council's Guidance on Risk Management, Internal Control and Related Financial and Business Reporting* relating to internal control over financial reporting and our report dated 18 March 2020 expressed an unqualified opinion on the group's internal control over financial reporting.

Basis for opinion

These financial statements are the responsibility of the group's management. Our responsibility is to express an opinion on the group's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the group in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audit provides a reasonable basis for our opinion.

Critical Audit Matters

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

Throughout the course of our audit we identify risks of material misstatement ('risks'). We consider both the likelihood of a risk and the potential magnitude of a misstatement in making the assessment. Certain risks are classified as 'significant' or 'higher' depending on their severity. The category of the risk determines the level of evidence we seek in providing assurance that the associated financial statement item is not materially misstated.

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

Critical Audit Matter Description

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

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

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

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

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

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

b. **Discount rates**- Given the long timeframes involved, certain recoverable amounts of assets are sensitive to the discount rate applied. There is a risk that discount rates do not reflect the return required by the market and the risks inherent in the cash flows being discounted, leading to a material misstatement. Determination of the appropriate discount rate can be judgemental.

c. **Reserves estimates**- A key input to impairment assessments and valuations is the production forecast, in turn closely related to the group's reserves estimates and field development assumptions. CGU-specific estimates are not generally material. However, material misstatements could arise either from systematic flaws in reserves estimation policies, or due to flawed estimates in a particularly material individual impairment test.

We identified and focused on certain individual CGUs with a total carrying value of $12.3 billion which we determined would be most at risk of a material impairment as a result of a reasonably possible change in the key assumptions, particularly the oil and gas price assumptions. Accordingly, we identified these as a significant audit risk. We also focused on assets with a further $33.4 billion of combined CGU carrying value which were less sensitive. We identified these as a higher audit risk as they would be potentially at risk in aggregate to a material impairment by a change in such assumptions. Further information regarding these sensitivities is given in Note 1 to the consolidated financial statements.

How the Critical Audit Matter was addressed in the Audit

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

Oil and gas prices

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

Discount rates

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

Reserves estimates

- We reviewed BP's reserves estimation methods and policies, assisted by Deloitte reserves experts.
- We assessed, with the assistance of Deloitte reserves experts, how these policies had been applied to a sample of internal reserves estimates.
- We reviewed reports provided by external experts and assessed their scope of work and findings.
- We assessed the competence, capability and objectivity of BP's internal and external reserve experts, through obtaining their relevant professional qualifications and experience.
- We compared hydrocarbon production forecasts used in impairment tests to estimates and reports and our understanding of the life of fields.
- We performed a retrospective review to check for indications of estimation bias over time.

Other procedures

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

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

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

Critical Audit Matter Description

The group capitalizes exploration and appraisal (E&A) expenditure on a project-by-project basis in line with IFRS 6 'Exploration for and Evaluation of Mineral Resources'. At the end of 2019, $14 billion of E&A expenditure was carried in the group balance sheet. E&A activity is inherently risky and a significant proportion of projects fail, requiring the write-off of the related capitalized costs when the relevant criteria in IFRS 6 and BP's accounting policy are met.

There is a significant judgement relating to the risk that certain capitalized E&A costs are not written off promptly at the appropriate time, in line with information from, and decisions about, E&A activities and the impairment requirements of IFRS 6.

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

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

How the Critical Audit Matter was addressed in the Audit

We obtained an understanding of the group's E&A impairment assessment processes and tested management's internal controls, including the controls addressing potential climate change considerations.

We performed a licence-by-licence risk assessment of the group's E&A balance through to year end, to identify significant carrying amounts with a current period risk of impairment (e.g. new information from exploration activities, or imminent licence expiry).

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

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

We tested the completeness and accuracy of information used in management's E&A impairment assessment, by reviewing and testing key controls over management's register of E&A licences and agreeing key aspects of this to underlying support (e.g. licence documentation); holding meetings and discussions with operational and finance management; considering adverse changes in management's reserves and resource estimates associated with E&A assets; reviewing correspondence with regulators and joint arrangement partners; and considering the implications of capital allocation decisions. When considering capital allocation decision making, we considered whether the development of any projects would be inconsistent with the elements of BP's current strategy which are designed to ensure it is resilient to the energy transition and climate change considerations or which would otherwise have a prohibitively high environmental or social impact for the directors to sanction the necessary investment.

Accounting for structured commodity transactions (SCTs) within the integrated supply and trading function (IST), and the valuation of other level 3 financial instruments, where fraud risks may arise in revenue recognition (potentially impacting all financial statement accounts, in particular finance debt) - Notes 1, 20, 22, 29 and 30 to the financial statements

Critical Audit Matter Description

In the normal course of business, IST enters into a variety of transactions for delivering value across the group's supply chain. The nature of these transactions requires significant audit effort be directed towards challenging management's valuation estimates or the adopted accounting treatment.

Accounting for structured commodity transactions:
IST may also enter into a variety of transactions which we refer to as SCTs. We generally consider a SCT to be an arrangement having one of the following features:

- Two or more counterparties with non-standard contractual terms;
- Multiple commodity-based transactions; and/or
- Contractual arrangements entered into in contemplation of each other.

SCTs are often long-dated, can have a significant multi-year financial impact, and may require the use of complex valuation models or unobservable inputs when determining their fair value, in which case they will be classified as level 3 financial instruments under IFRS 13, 'Fair Value Measurement'.

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

Level 3 financial instruments:
Unlike other financial instruments whose values or inputs are readily observable and therefore more easily independently corroborated, there are certain transactions for which the valuation is inherently more subjective due to the use of either complex valuation models and/or unobservable inputs. These instruments are classified as level 3 financial assets or liabilities under IFRS 13. This degree of subjectivity also gives rise to potential fraud through management incorporating bias in determining fair values. Accordingly, we have identified these as a significant audit risk.

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

How the Critical Audit Matter was addressed in the Audit

Accounting for SCTs
For structured commodity transactions, we performed audit procedures to:

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

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

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

Other level 3 financial instruments:

To address the complexities associated with auditing the value of level 3 financial instruments, the engagement team included valuation specialists having significant quantitative and modelling expertise to assist in performing our audit procedures. Our valuation audit procedures included the following control and substantive procedures:

- We tested the group's valuation controls including the:

- Model certification control, which is designed to review a model's theoretical soundness and the appropriateness of its valuation methodology; and
- Independent price verification control, which is designed to review the appropriateness of valuation inputs that are not observable and are significant to the financial instrument's valuation.

- We performed substantive valuation testing procedures at interim and year-end balance sheet date, including:
  - Engaging a Deloitte valuations specialist to develop fair value estimates, using independently sourced inputs where these were available, and challenge models to evaluate against management's fair value estimates by evaluating whether the differences between our independent estimates and management's estimates were within a reasonable range. In situations where we utilised management's inputs, these were compared to external data sources to ensure they were reasonable;
  - Evaluating management's valuation methodologies against standard valuation practice and analysing whether a consistent framework is applied across the business period over period; and
  - Comparing management's input assumptions against the expected assumptions of other market participants and observable market data.

/s/ Deloitte LLP

London
United Kingdom
18 March 2020

The first accounting period we audited was the 12 months ended 31 December 2018. In 2017, we commenced our audit planning procedures.

Consolidated financial statements of the BP group

Report of Independent Registered Public Accounting Firm

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

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of BP p.l.c. and subsidiaries (the Company) as at 31 December 2019, based on the criteria established in the UK Financial Reporting Council's Guidance on Risk Management, Internal Control and Related Financial and Business Reporting relating to internal control over financial reporting (UK FRC Guidance). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of 31 December 2019, based on the criteria established in the UK FRC Guidance.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as at and for the year ended 31 December 2019, of the Company and our report dated 18 March 2020, expressed an unqualified opinion on those financial statements.

Basis for opinion

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

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

Definition and limitations of internal control over financial reporting

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

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

/s/ Deloitte LLP
London, United Kingdom
18 March 2020

Consolidated financial statements of the BP group

Report of Independent Registered Public Accounting Firm

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

Opinion on the financial statements

We have audited the accompanying group balance sheet of BP p.l.c. (the Company) as of 31 December 2017, and the related group income statement, group statement of comprehensive income, group statement of changes in equity and group cash flow statement for the period ended 31 December 2017, and the related notes (collectively referred to as the "group financial statements"). In our opinion, the group financial statements present fairly, in all material respects, the financial position of BP p.l.c. at 31 December 2017 and the results of its operations and its cash flows for the period ended 31 December 2017, in conformity with International Financial Reporting Standards (IFRS) as adopted by the European Union and IFRS as issued by the International Accounting Standards Board.

Basis for opinion

These financial statements are the responsibility of BP p.l.c.'s management. Our responsibility is to express an opinion on these financial statements based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to BP p.l.c. in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audit included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audit provides a reasonable basis for our opinion.

/s/ Ernst & Young LLP
We served as the Company's auditor from 1909 to 2018.
London, United Kingdom
29 March 2018

Note that the report set out above is included for the purposes of BP p.l.c.'s Annual Report on Form 20-F for 2019 only and does not form part of BP p.l.c.'s Annual Report and Accounts for 2017.

1. The maintenance and integrity of the BP p.l.c. web site is the responsibility of BP p.l.c.; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the web site.
2. Legislation in the United Kingdom governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

Group income statement

For the year ended 31 December				$ million
	Note	**2019**	2018	2017
Sales and other operating revenues	5	**278,397**	298,756	240,208
Earnings from joint ventures – after interest and tax	16	**576**	897	1,177
Earnings from associates – after interest and tax	17	**2,681**	2,856	1,330
Interest and other income	7	**769**	773	657
Gains on sale of businesses and fixed assets	4	**193**	456	1,210
Total revenues and other income		**282,616**	303,738	244,582
Purchases	19	**209,672**	229,878	179,716
Production and manufacturing expenses		**21,815**	23,005	24,229
Production and similar taxes	5	**1,547**	1,536	1,775
Depreciation, depletion and amortization	5	**17,780**	15,457	15,584
Impairment and losses on sale of businesses and fixed assets	4	**8,075**	860	1,216
Exploration expense	8	**964**	1,445	2,080
Distribution and administration expenses		**11,057**	12,179	10,508
Profit before interest and taxation		**11,706**	19,378	9,474
Finance costs	7	**3,489**	2,528	2,074
Net finance expense relating to pensions and other post-retirement benefits	24	**63**	127	220
Profit before taxation		**8,154**	16,723	7,180
Taxation	9	**3,964**	7,145	3,712
Profit for the year		**4,190**	9,578	3,468
Attributable to				
BP shareholders		**4,026**	9,383	3,389
Non-controlling interests		**164**	195	79
		4,190	9,578	3,468
Earnings per share				
Profit for the year attributable to BP shareholders				
Per ordinary share (cents)				
Basic	11	**19.84**	46.98	17.20
Diluted	11	**19.73**	46.67	17.10
Per ADS (dollars)				
Basic	11	**1.19**	2.82	1.03
Diluted	11	**1.18**	2.80	1.03

Group statement of comprehensive income[a]

For the year ended 31 December	Note	2019	2018	$ million 2017
Profit for the year		**4,190**	9,578	3,468
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss				
Currency translation differences		**1,538**	(3,771)	1,986
Exchange (gains) losses on translation of foreign operations reclassified to gain or loss on sale of businesses and fixed assets		**880**	—	(120)
Available-for-sale investments		**—**	—	14
Cash flow hedges marked to market	30	**(100)**	(126)	197
Cash flow hedges reclassified to the income statement	30	**106**	120	116
Cash flow hedges reclassified to the balance sheet	30	**—**	—	112
Costs of hedging marked to market	30	**(4)**	(244)	—
Costs of hedging reclassified to the income statement	30	**57**	58	—
Share of items relating to equity-accounted entities, net of tax	16, 17	**82**	417	564
Income tax relating to items that may be reclassified	9	**(70)**	4	(196)
		2,489	(3,542)	2,673
Items that will not be reclassified to profit or loss				
Remeasurements of the net pension and other post-retirement benefit liability or asset	24	**328**	2,317	3,646
Cash flow hedges that will subsequently be transferred to the balance sheet	30	**(3)**	(37)	—
Income tax relating to items that will not be reclassified	9	**(157)**	(718)	(1,303)
		168	1,562	2,343
Other comprehensive income		**2,657**	(1,980)	5,016
Total comprehensive income		**6,847**	7,598	8,484
Attributable to				
BP shareholders		**6,674**	7,444	8,353
Non-controlling interests		**173**	154	131
		6,847	7,598	8,484

[a] See Note 32 for further information.

Group statement of changes in equity[a]

$ million

	Share capital and capital reserves	Treasury shares	Foreign currency translation reserve	Fair value reserves	Profit and loss account	BP shareholders' equity	Non-controlling interests	Total equity
At 31 December 2018	**46,352**	**(15,767)**	**(8,902)**	**(987)**	**78,748**	**99,444**	**2,104**	**101,548**
Adjustment on adoption of IFRS 16, net of tax	**—**	**—**	**—**	**—**	**(329)**	**(329)**	**(1)**	**(330)**
At 1 January 2019	**46,352**	**(15,767)**	**(8,902)**	**(987)**	**78,419**	**99,115**	**2,103**	**101,218**
Profit for the year	**—**	**—**	**—**	**—**	**4,026**	**4,026**	**164**	**4,190**
Other comprehensive income	**—**	**—**	**2,407**	**52**	**189**	**2,648**	**9**	**2,657**
Total comprehensive income	**—**	**—**	**2,407**	**52**	**4,215**	**6,674**	**173**	**6,847**
Dividends[b]	**—**	**—**	**—**	**—**	**(6,929)**	**(6,929)**	**(213)**	**(7,142)**
Cash flow hedges transferred to the balance sheet, net of tax	**—**	**—**	**—**	**23**	**—**	**23**	**—**	**23**
Repurchase of ordinary share capital	**—**	**—**	**—**	**—**	**(1,511)**	**(1,511)**	**—**	**(1,511)**
Share-based payments, net of tax	**173**	**1,355**	**—**	**—**	**(809)**	**719**	**—**	**719**
Share of equity-accounted entities' changes in equity, net of tax	**—**	**—**	**—**	**—**	**5**	**5**	**—**	**5**
Transactions involving non-controlling interests, net of tax	**—**	**—**	**—**	**—**	**316**	**316**	**233**	**549**
At 31 December 2019	**46,525**	**(14,412)**	**(6,495)**	**(912)**	**73,706**	**98,412**	**2,296**	**100,708**
At 31 December 2017	46,122	(16,958)	(5,156)	(743)	75,226	98,491	1,913	100,404
Adjustment on adoption of IFRS 9, net of tax	—	—	—	(54)	(126)	(180)	—	(180)
At 1 January 2018	46,122	(16,958)	(5,156)	(797)	75,100	98,311	1,913	100,224
Profit for the year	—	—	—	—	9,383	9,383	195	9,578
Other comprehensive income	—	—	(3,746)	(216)	2,023	(1,939)	(41)	(1,980)
Total comprehensive income	—	—	(3,746)	(216)	11,406	7,444	154	7,598
Dividends[b]	—	—	—	—	(6,699)	(6,699)	(170)	(6,869)
Cash flow hedges transferred to the balance sheet, net of tax	—	—	—	26	—	26	—	26
Repurchase of ordinary share capital	—	—	—	—	(355)	(355)	—	(355)
Share-based payments, net of tax	230	1,191	—	—	(718)	703	—	703
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	14	14	—	14
Transactions involving non-controlling interests, net of tax	—	—	—	—	—	—	207	207
At 31 December 2018	46,352	(15,767)	(8,902)	(987)	78,748	99,444	2,104	101,548
At 1 January 2017	46,122	(18,443)	(6,878)	(1,153)	75,638	95,286	1,557	96,843
Profit for the year	—	—	—	—	3,389	3,389	79	3,468
Other comprehensive income	—	—	1,722	410	2,832	4,964	52	5,016
Total comprehensive income	—	—	1,722	410	6,221	8,353	131	8,484
Dividends[b]	—	—	—	—	(6,153)	(6,153)	(141)	(6,294)
Repurchases of ordinary share capital	—	—	—	—	(343)	(343)	—	(343)
Share-based payments, net of tax	—	1,485	—	—	(798)	687	—	687
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	215	215	—	215
Transactions involving non-controlling interests, net of tax	—	—	—	—	446	446	366	812
At 31 December 2017	46,122	(16,958)	(5,156)	(743)	75,226	98,491	1,913	100,404

[a] See Note 32 for further information.

[b] See Note 10 for further information.

Group balance sheet

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

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

Helge Lund Chairman
B Looney Chief executive officer
18 March 2020

Group cash flow statement

For the year ended 31 December				$ million
	Note	**2019**	2018	2017
Operating activities				
Profit before taxation		**8,154**	16,723	7,180
Adjustments to reconcile profit before taxation to net cash provided by operating activities				
Exploration expenditure written off	8	**631**	1,085	1,603
Depreciation, depletion and amortization	5	**17,780**	15,457	15,584
Impairment and (gain) loss on sale of businesses and fixed assets	4	**7,882**	404	6
Earnings from joint ventures and associates		**(3,257)**	(3,753)	(2,507)
Dividends received from joint ventures and associates		**1,962**	1,535	1,253
Interest receivable		**(441)**	(468)	(304)
Interest received		**416**	348	375
Finance costs	7	**3,489**	2,528	2,074
Interest paid		**(2,870)**	(1,928)	(1,572)
Net finance expense relating to pensions and other post-retirement benefits	24	**63**	127	220
Share-based payments		**730**	690	661
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	24	**(238)**	(386)	(394)
Net charge for provisions, less payments		**(176)**	986	2,106
(Increase) decrease in inventories		**(3,406)**	672	(848)
(Increase) decrease in other current and non-current assets		**(2,335)**	(2,858)	(4,848)
Increase (decrease) in other current and non-current liabilities		**2,823**	(2,577)	2,344
Income taxes paid		**(5,437)**	(5,712)	(4,002)
Net cash provided by operating activities		**25,770**	22,873	18,931
Investing activities				
Expenditure on property, plant and equipment, intangible and other assets		**(15,418)**	(16,707)	(16,562)
Acquisitions, net of cash acquired	3	**(3,562)**	(6,986)	(327)
Investment in joint ventures		**(137)**	(382)	(50)
Investment in associates		**(304)**	(1,013)	(901)
Total cash capital expenditure		**(19,421)**	(25,088)	(17,840)
Proceeds from disposals of fixed assets	4	**500**	940	2,936
Proceeds from disposals of businesses, net of cash disposed	4	**1,701**	1,911	478
Proceeds from loan repayments		**246**	666	349
Net cash used in investing activities		**(16,974)**	(21,571)	(14,077)
Financing activities[a]				
Repurchase of shares		**(1,511)**	(355)	(343)
Lease liability payments		**(2,372)**	(35)	(45)
Proceeds from long-term financing		**8,597**	9,038	8,712
Repayments of long-term financing		**(7,118)**	(7,175)	(6,231)
Net increase (decrease) in short-term debt		**180**	1,317	(158)
Net increase (decrease) in non-controlling interests		**566**	—	1,063
Dividends paid				
BP shareholders	10	**(6,946)**	(6,699)	(6,153)
Non-controlling interests		**(213)**	(170)	(141)
Net cash provided by (used in) financing activities		**(8,817)**	(4,079)	(3,296)
Currency translation differences relating to cash and cash equivalents		**25**	(330)	544
Increase (decrease) in cash and cash equivalents		**4**	(3,107)	2,102
Cash and cash equivalents at beginning of year		**22,468**	25,575	23,484
Cash and cash equivalents at end of year		**22,472**	22,468	25,586

[a] The presentation of financing cash flows for the comparative periods have been amended to align with the current period. See Note 1 for further information.

Notes on financial statements

1. Significant accounting policies, judgements, estimates and assumptions

Authorization of financial statements and statement of compliance with International Financial Reporting Standards

The consolidated financial statements of BP p.l.c and its subsidiaries (collectively referred to as BP or the group) for the year ended 31 December 2019 were approved and signed by the chief executive officer and chairman on 18 March 2020 having been duly authorized to do so by the board of directors. BP p.l.c. is a public limited company incorporated and domiciled in England and Wales. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB), IFRS as adopted by the European Union (EU) and in accordance with the provisions of the UK Companies Act 2006 as applicable to companies reporting under IFRS. IFRS as adopted by the EU differs in certain respects from IFRS as issued by the IASB. The differences have no impact on the group's consolidated financial statements for the years presented. The significant accounting policies and accounting judgements, estimates and assumptions of the group are set out below.

Basis of preparation

The consolidated financial statements have been prepared on a going concern basis and in accordance with IFRS and IFRS Interpretations Committee (IFRIC) interpretations issued and effective for the year ended 31 December 2019. The accounting policies that follow have been consistently applied to all years presented, except where otherwise indicated.

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

Significant accounting policies: use of judgements, estimates and assumptions

Inherent in the application of many of the accounting policies used in preparing the consolidated financial statements is the need for BP management to make judgements, estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities, and the reported amounts of revenues and expenses. Actual outcomes could differ from the estimates and assumptions used. The accounting judgements and estimates that have a significant impact on the results of the group are set out in boxed text below, and should be read in conjunction with the information provided in the Notes on financial statements. The areas requiring the most significant judgement and estimation in the preparation of the consolidated financial statements are: accounting for the investment in Rosneft; exploration and appraisal intangible assets; the recoverability of asset carrying values, including the estimation of reserves; derivative financial instruments; provisions and contingencies; and pensions and other post-retirement benefits. Where an estimate has a significant risk of resulting in a material adjustment to the carrying amounts of assets and liabilities within the next financial year this is specifically noted within the boxed text. The group does not consider income taxes to represent a significant estimate or judgement for 2019, see Income taxes for more information.

Basis of consolidation

The group financial statements consolidate the financial statements of BP p.l.c. and its subsidiaries drawn up to 31 December each year. Subsidiaries are consolidated from the date of their acquisition, being the date on which the group obtains control, and continue to be consolidated until the date that control ceases. The financial statements of subsidiaries are prepared for the same reporting year as the parent company, using consistent accounting policies. Intra-group balances and transactions, including unrealized profits arising from intra-group transactions, have been eliminated. Unrealized losses are eliminated unless the transaction provides evidence of an impairment of the asset transferred. Non-controlling interests represent the equity in subsidiaries that is not attributable, directly or indirectly, to BP shareholders.

Interests in other entities

Business combinations and goodwill

Business combinations are accounted for using the acquisition method. The identifiable assets acquired and liabilities assumed are recognized at their fair values at the acquisition date.

Goodwill is initially measured as the excess of the aggregate of the consideration transferred, the amount recognized for any non-controlling interest and the acquisition-date fair values of any previously held interest in the acquiree over the fair value of the identifiable assets acquired and liabilities assumed at the acquisition date. The amount recognized for any non-controlling interest is measured at the present ownership's proportionate share in the recognized amounts of the acquiree's identifiable net assets. At the acquisition date, any goodwill acquired is allocated to each of the cash-generating units, or groups of cash-generating units, expected to benefit from the combination's synergies. Following initial recognition, goodwill is measured at cost less any accumulated impairment losses. Goodwill arising on business combinations prior to 1 January 2003 is stated at the previous carrying amount under UK generally accepted accounting practice, less subsequent impairments. See Note 14 for further information.

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

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

Interests in joint arrangements

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

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

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

Interests in associates

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

Significant judgement: investment in Rosneft

Judgement is required in assessing the level of control or influence over another entity in which the group holds an interest. For BP, the judgement that the group has significant influence over Rosneft Oil Company (Rosneft), a Russian oil and gas company is significant. As a consequence of this judgement, BP uses the equity method of accounting for its investment and BP's share of Rosneft's oil and natural gas reserves is included in the group's estimated net proved reserves of equity-accounted entities. If significant influence was not present, the investment would be accounted for as an investment in an equity instrument measured at fair value as described under 'Financial assets' below and no share of Rosneft's oil and natural gas reserves would be reported.

Significant influence is defined in IFRS as the power to participate in the financial and operating policy decisions of the investee but is not control or joint control of those policies. Significant influence is presumed when an entity owns 20% or more of the voting power of the investee. Significant influence is presumed not to be present when an entity owns less than 20% of the voting power of the investee.

BP owns 19.75% of the voting shares of Rosneft. The Russian federal government, through its investment company JSC Rosneftegaz, owned 50% plus one share of the voting shares of Rosneft at 31 December 2019. IFRS identifies several indicators that may provide evidence of significant influence, including representation on the board of directors of the investee and participation in policy-making processes. BP's group chief executive, as at 31 December 2019, Bob Dudley, has been a member of the board of directors of Rosneft since 2013 and remains one of BP's nominated directors following his resignation as BP's group chief executive. He is also chairman of the Rosneft board's Strategic Planning Committee. A second BP-nominated director, Guillermo Quintero, has been a member of the Rosneft board and its HR and Remuneration Committee since 2015. BP also holds the voting rights at general meetings of shareholders conferred by its 19.75% stake in Rosneft. BP's management consider, therefore, that the group has significant influence over Rosneft, as defined by IFRS.

The equity method of accounting

Under the equity method, an investment is carried on the balance sheet at cost plus post-acquisition changes in the group's share of net assets of the entity, less distributions received and less any impairment in value of the investment. Loans advanced to equity-accounted entities that have the characteristics of equity financing are also included in the investment on the group balance sheet. The group income statement reflects the group's share of the results after tax of the equity-accounted entity, adjusted to account for depreciation, amortization and any impairment of the equity-accounted entity's assets based on their fair values at the date of acquisition. The group statement of comprehensive income includes the group's share of the equity-accounted entity's other comprehensive income. The group's share of amounts recognized directly in equity by an equity-accounted entity is recognized in the group's statement of changes in equity.

Financial statements of equity-accounted entities are prepared for the same reporting year as the group. Where material differences arise in the accounting policies used by the equity-accounted entity and those used by BP, adjustments are made to those financial statements to bring the accounting policies used into line with those of the group.

Unrealized gains on transactions between the group and its equity-accounted entities are eliminated to the extent of the group's interest in the equity-accounted entity.

The group assesses investments in equity-accounted entities for impairment whenever there is objective evidence that the investment is impaired. If any such objective evidence of impairment exists, the carrying amount of the investment is compared with its recoverable amount, being the higher of its fair value less costs of disposal and value in use. If the carrying amount exceeds the recoverable amount, the investment is written down to its recoverable amount.

Segmental reporting

The group's operating segments are established on the basis of those components of the group that are evaluated regularly by the group chief executive, BP's chief operating decision maker, in deciding how to allocate resources and in assessing performance.

The accounting policies of the operating segments are the same as the group's accounting policies described in this note, except that IFRS requires that the measure of profit or loss disclosed for each operating segment is the measure that is provided regularly to the chief operating decision maker. For BP, this measure of profit or loss is replacement cost profit before interest and tax which reflects the replacement cost of inventories sold in the period and is arrived at by excluding inventory holding gains and losses from profit. Replacement cost profit for the group is not a recognized measure under IFRS. For further information see Note 5.

Foreign currency translation

In individual subsidiaries, joint ventures and associates, transactions in foreign currencies are initially recorded in the functional currency of those entities at the spot exchange rate on the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated into the functional currency at the spot exchange rate on the balance sheet date. Any resulting exchange differences are included in the income statement, unless hedge accounting is applied. Non-monetary assets and liabilities, other than those measured at fair value, are not retranslated subsequent to initial recognition.

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

Non-current assets held for sale

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

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

Property, plant and equipment and intangible assets are not depreciated or amortized once classified as held for sale.

Intangible assets

Intangible assets, other than goodwill, include expenditure on the exploration for and evaluation of oil and natural gas resources, computer software, patents, licences and trademarks and are stated at the amount initially recognized, less accumulated amortization and accumulated impairment losses.

Intangible assets are carried initially at cost unless acquired as part of a business combination. Any such asset is measured at fair value at the date of the business combination and is recognized separately from goodwill if the asset is separable or arises from contractual or other legal rights.

Intangible assets with a finite life, other than capitalized exploration and appraisal costs as described below, are amortized on a straight-line basis over their expected useful lives. For patents, licences and trademarks, expected useful life is the shorter of the duration of the legal agreement and economic useful life, and can range from three to fifteen years. Computer software costs generally have a useful life of three to five years.

The expected useful lives of assets and the amortization method are reviewed on an annual basis and, if necessary, changes in useful lives or the amortization method are accounted for prospectively.

Oil and natural gas exploration, appraisal and development expenditure

Oil and natural gas exploration, appraisal and development expenditure is accounted for using the principles of the successful efforts method of accounting as described below.

Licence and property acquisition costs

Exploration licence and leasehold property acquisition costs are capitalized within intangible assets and are reviewed at each reporting date to confirm that there is no indication that the carrying amount exceeds the recoverable amount. This review includes confirming that exploration drilling is still under way or planned or that it has been determined, or work is under way to determine, that the discovery is economically viable based on a range of technical and commercial considerations, and sufficient progress is being made on establishing development plans and timing. If no future activity is planned, the remaining balance of the licence and property acquisition costs is written off. Lower value licences are pooled and amortized on a straight-line basis over the estimated period of exploration. Upon internal approval for development and recognition of proved reserves of oil and natural gas, the relevant expenditure is transferred to property, plant and equipment.

Exploration and appraisal expenditure

Geological and geophysical exploration costs are recognized as an expense as incurred. Costs directly associated with an exploration well are initially capitalized as an intangible asset until the drilling of the well is complete and the results have been evaluated. These costs include employee remuneration, materials and fuel used, rig costs and payments made to contractors. If potentially commercial quantities of hydrocarbons are not found, the exploration well costs are written off. If hydrocarbons are found and, subject to further appraisal activity, are likely to be capable of commercial development, the costs continue to be carried as an asset. If it is determined that development will not occur then the costs are expensed.

Costs directly associated with appraisal activity undertaken to determine the size, characteristics and commercial potential of a reservoir following the initial discovery of hydrocarbons, including the costs of appraisal wells where hydrocarbons were not found, are initially capitalized as an intangible asset. Upon internal approval for development and recognition of proved reserves, the relevant expenditure is transferred to property, plant and equipment.

The determination of whether potentially economic oil and natural gas reserves have been discovered by an exploration well is usually made within one year of well completion, but can take longer, depending on the complexity of the geological structure. Exploration wells that discover potentially economic quantities of oil and natural gas and are in areas where major capital expenditure (e.g. an offshore platform or a pipeline) would be required before production could begin, and where the economic viability of that major capital expenditure depends on the successful completion of further exploration or appraisal work in the area, remain capitalized on the balance sheet as long as such work is under way or firmly planned.

Development expenditure

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

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

Significant judgement: exploration and appraisal intangible assets

Judgement is required to determine whether it is appropriate to continue to carry costs associated with exploration wells and exploratory-type stratigraphic test wells on the balance sheet. This includes costs relating to exploration licences or leasehold property acquisitions. It is not unusual to have such costs remaining suspended on the balance sheet for several years while additional appraisal drilling and seismic work on the potential oil and natural gas field is performed or while the optimum development plans and timing are established.The costs are carried based on the current regulatory and political environment or any known changes to that environment. All such carried costs are subject to regular technical, commercial and management review on at least an annual basis to confirm the continued intent to develop, or otherwise extract value from, the discovery. Where this is no longer the case, the costs are immediately expensed.

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

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

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

Property, plant and equipment

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

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

Oil and natural gas properties, including certain related pipelines, are depreciated using a unit-of-production method. The cost of producing wells is amortized over proved developed reserves. Licence acquisition, common facilities and future decommissioning costs are amortized over total proved reserves. The unit-of-production rate for the depreciation of common facilities takes into account expenditures incurred to date, together with estimated future capital expenditure expected to be incurred relating to as yet undeveloped reserves expected to be processed through these common facilities. Information on the carrying amounts of the group's oil and natural gas properties, together with the amounts recognized in the income statement as depreciation, depletion and amortization is contained in Note 12 and Note 5 respectively.

Estimates of oil and natural gas reserves determined by applying US Securities and Exchange Commission regulations including the determination of prices using 12-month historical data are used to calculate depreciation, depletion and amortization charges for the group's oil and gas properties. Therefore, the charges are not dependent on management forecasts of future oil and gas prices. The impact of changes in estimated proved reserves is dealt with prospectively by amortizing the remaining carrying value of the asset over the expected future production. Management does not believe that a reasonably possible change in the economic environment would result in a material change to the depreciation and amortization charge for other classes of assets.

The estimation of oil and natural gas reserves and BP's process to manage reserves bookings is described in Supplementary information on oil and natural gas on page 232, which is unaudited. Details on BP's proved reserves and production compliance and governance processes are provided on page 286. The 2019 movements in proved reserves are reflected in the tables showing movements in oil and natural gas reserves by region in Supplementary information on oil and natural gas (unaudited) on page 232.

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

Land improvements	15 to 25 years
Buildings	20 to 50 years
Refineries	20 to 30 years
Petrochemicals plants	20 to 30 years
Pipelines	10 to 50 years
Service stations	15 years
Office equipment	3 to 7 years
Fixtures and fittings	5 to 15 years

The expected useful lives and depreciation method of property, plant and equipment are reviewed on an annual basis and, if necessary, changes in useful lives or the depreciation method are accounted for prospectively.

An item of property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in the income statement in the period in which the item is derecognized.

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

Impairment of property, plant and equipment, intangible assets, and goodwill

The group assesses assets or groups of assets, called cash-generating units (CGUs), for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset or CGU may not be recoverable; for example, changes in the group's business plans, changes in the group's assumptions about commodity prices, low plant utilization, evidence of physical damage or, for oil and gas assets, significant downward revisions of estimated reserves or increases in estimated future development expenditure or decommissioning costs. If any such indication of impairment exists, the group makes an estimate of the asset's or CGU's recoverable amount. Individual assets are grouped into CGUs for impairment assessment purposes at the lowest level at which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. A CGU's recoverable amount is the higher of its fair value less costs of disposal and its value in use. If it is probable that the value of the CGU will be primarily recovered through a disposal transaction, the expected disposal proceeds are considered in determining the recoverable amount. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount.

The business segment plans, which are approved on an annual basis by senior management, are the primary source of information for the determination of value in use. They contain forecasts for oil and natural gas production, refinery throughputs, sales volumes for various types of refined products (e.g. gasoline and lubricants), revenues, costs and capital expenditure. As an initial step in the preparation of these plans, various assumptions regarding market conditions, such as oil prices, natural gas prices, refining margins, refined product margins and cost inflation rates are set by senior management. These assumptions take account of existing prices, global supply-demand equilibrium for oil and natural gas, other macroeconomic factors and historical trends and variability. In assessing value in use, the estimated future cash flows are adjusted for the risks specific to the asset group that are not reflected in the discount rate and are discounted to their present value typically using a pre-tax discount rate that reflects current market assessments of the time value of money.

Fair value less costs of disposal is the price that would be received to sell the asset in an orderly transaction between market participants and does not reflect the effects of factors that may be specific to the group and not applicable to entities in general. In limited circumstances where recent market transactions are not available for reference, discounted cash flow techniques are applied. Where discounted cash flow analyses are used to calculate fair value less costs of disposal, estimates are made about the assumptions market participants would use when pricing the asset, CGU or group of CGUs containing goodwill and the test is performed on a post-tax basis.

An assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such an indication exists, the recoverable amount is estimated. A previously recognized impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognized. If that is the case, the carrying amount of the asset is increased to the lower of its recoverable amount and the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years. Impairment reversals are recognized in profit or loss. After a reversal, the depreciation charge is adjusted in future periods to allocate the asset's revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.

Goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate the recoverable amount of the group of CGUs to which the goodwill relates should be assessed. In assessing whether goodwill has been impaired, the carrying amount of the group of CGUs to which goodwill has been allocated is compared with its recoverable amount. Where the recoverable amount of the group of CGUs is less than the carrying amount (including goodwill), an impairment loss is recognized. An impairment loss recognized for goodwill is not reversed in a subsequent period.

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

Significant judgements and estimates: recoverability of asset carrying values

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

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

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

The estimates for assumptions made in impairment tests in 2019 relating to discount rates and oil and gas properties are discussed below. Changes in the economic environment or other facts and circumstances may necessitate revisions to these assumptions and could result in a material change to the carrying values of the group's assets within the next financial year.

Discount rates

For discounted cash flow calculations, future cash flows are adjusted for risks specific to the CGU. Value-in-use calculations are typically discounted using a pre-tax discount rate based upon the cost of funding the group derived from an established model, adjusted to a pre-tax basis and incorporating a market participant capital structure. Fair value less costs of disposal calculations use the post-tax discount rate.

The discount rates applied in impairment tests are reassessed each year. In 2019 the post-tax discount rate was 6% (2018 6%) and the pre-tax discount rate typically ranged from 7% to 13% (2018 9%) depending on the applicable tax rate in the geographic location of the CGU. Where the CGU is located in a country that is judged to be higher risk an additional premium of 1% to 4% was added to the discount rates (2018 2%). The judgement of classifying a country as higher risk and the applicable premium takes into account various economic and geopolitical factors.

Oil and natural gas properties

For oil and natural gas properties, expected future cash flows are estimated using management's best estimate of future oil and natural gas prices and production and reserves volumes. The estimated future level of production in all impairment tests is based on assumptions about future commodity prices, production and development costs, field decline rates, current fiscal regimes and other factors.

The recoverable amount of oil and gas properties is primarily sensitive to changes in the oil and gas price assumptions. Further sensitivity analysis may be performed if a specific oil and gas property is identified to have low headroom above its carrying amount. In 2019, the group identified oil and gas properties with carrying amounts totalling $25,092 million (2018 $22,000 million) where the headroom, as at the dates of the last impairment test performed on those assets, was less than or equal to 20% of the carrying value, including $1,256 million (2018 $1,345 million) in relation to equity-accounted entities. A change in the discount rate, reserves, resources or the oil and gas price assumptions in the next financial year may result in the recoverable amount of one or more of these assets falling below the current carrying amount.

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

Oil and natural gas prices

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

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

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

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

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

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

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

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

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

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

Oil and natural gas reserves

In addition to oil and natural gas prices, significant technical and commercial assessments are required to determine the group's estimated oil and natural gas reserves. Reserves estimates are regularly reviewed and updated. Factors such as the availability of geological and engineering data, reservoir performance data, acquisition and divestment activity and drilling of new wells all impact on the determination of the group's estimates of its oil and natural gas reserves. BP bases its proved reserves estimates on the requirement of reasonable certainty with rigorous technical and commercial assessments based on conventional industry practice and regulatory requirements.

Reserves assumptions for value-in-use tests reflect the reserves and resources that management currently intend to develop. The recoverable amount of oil and gas properties is determined using a combination of inputs including reserves, resources and production volumes. Risk factors may be applied to reserves and resources which do not meet the criteria to be treated as proved.

Goodwill

Irrespective of whether there is any indication of impairment, BP is required to test annually for impairment of goodwill acquired in business combinations. The group carries goodwill of approximately $11.9 billion on its balance sheet (2018 $12.2 billion), principally relating to the Atlantic Richfield, Burmah Castrol, Devon Energy and Reliance transactions. Sensitivities and additional information relating to impairment testing of goodwill in the Upstream segment are provided in Note 14.

Inventories

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

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

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

Leases

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

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

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

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

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

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

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

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

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

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

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

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

Agreements under which payments are made to owners in return for the right to use a specific asset are accounted for as leases. Leases that transfer substantially all the risks and rewards of ownership are recognized as finance leases. All other leases are accounted for as operating leases.

Finance leases are capitalized at the commencement of the lease term at the fair value of the leased item or, if lower, at the present value of the minimum lease payments. Finance charges are allocated to each period so as to achieve a constant rate of interest on the remaining balance of the liability and are charged directly against income. Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term. Operating lease payments are recognized as an expense on a straight-line basis over the lease term except where capitalized as exploration or appraisal expenditure. See significant accounting policy: Exploration and appraisal expenditure.

Financial assets

Financial assets are recognized initially at fair value, normally being the transaction price. In the case of financial assets not at fair value through profit or loss, directly attributable transaction costs are also included. The subsequent measurement of financial assets depends on their classification, as set out below. The group derecognizes financial assets when the contractual rights to the cash flows expire or the rights to receive cash flows have been transferred to a third party along with either substantially all of the risks and rewards or control of the asset. This includes the derecognition of receivables for which discounting arrangements are entered into.

The group classifies its financial asset debt instruments as measured at amortized cost, fair value through other comprehensive income or fair value through profit or loss. The classification depends on the business model for managing the financial assets and the contractual cash flow characteristics of the financial asset.

Financial assets measured at amortized cost

Financial assets are classified as measured at amortized cost when they are held in a business model the objective of which is to collect contractual cash flows and the contractual cash flows represent solely payments of principal and interest. Such assets are carried at amortized cost using the effective interest method if the time value of money is significant. Gains and losses are recognized in profit or loss when the assets are derecognized or impaired and when interest is recognized using the effective interest method. This category of financial assets includes trade and other receivables.

Financial assets measured at fair value through other comprehensive income

Financial assets are classified as measured at fair value through other comprehensive income when they are held in a business model the objective of which is both to collect contractual cash flows and sell the financial assets, and the contractual cash flows represent solely payments of principal and interest. The group does not have any financial assets classified in this category.

Financial assets measured at fair value through profit or loss

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

Investments in equity instruments

Investments in equity instruments are subsequently measured at fair value through profit or loss unless an election is made on an instrument-by-instrument basis to recognise fair value gains and losses in other comprehensive income. The group does not have any investments for which this election has been made.

Derivatives designated as hedging instruments in an effective hedge

Derivatives designated as hedging instruments in an effective hedge are carried on the balance sheet at fair value. The treatment of gains and losses arising from revaluation is described below in the accounting policy for derivative financial instruments and hedging activities.

Cash equivalents

Cash equivalents are short-term highly liquid investments that are readily convertible to known amounts of cash, are subject to insignificant risk of changes in value and generally have a maturity of three months or less from the date of acquisition. Cash equivalents are classified as financial assets measured at amortized cost or, in the case of certain money market funds, fair value through profit or loss.

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

Impairment of financial assets measured at amortized cost

The group assesses on a forward-looking basis the expected credit losses associated with financial assets classified as measured at amortized cost at each balance sheet date. Expected credit losses are measured based on the maximum contractual period over which the group is exposed to credit risk. As lifetime expected credit losses are recognized for trade receivables and the tenor of substantially all of other in-scope financial assets is less than 12 months there is no significant difference between the measurement of 12-month and lifetime expected credit losses for the group. The measurement of expected credit losses is a function of the probability of default, loss given default and exposure at default. The expected credit loss is estimated as the difference between the asset's carrying amount and the present value of the future cash flows the group expects to receive discounted at the financial asset's original effective interest rate. The carrying amount of the asset is adjusted, with the amount of the impairment gain or loss recognized in the income statement.

A financial asset or group of financial assets classified as measured at amortized cost is considered to be credit-impaired if there is reasonable and supportable evidence that one or more events that have a detrimental impact on the estimated future cash flows of the financial asset (or group of financial assets) have occurred. Financial assets are written off where the group has no reasonable expectation of recovering amounts due.

Financial liabilities

The measurement of financial liabilities depends on their classification, as follows:

Financial liabilities measured at fair value through profit or loss

Financial liabilities that meet the definition of held for trading are classified as measured at fair value through profit or loss. Such liabilities are carried on the balance sheet at fair value with gains or losses recognized in the income statement. Derivatives, other than those designated as effective hedging instruments, are included in this category.

Derivatives designated as hedging instruments in an effective hedge

Derivatives designated as hedging instruments in an effective hedge are carried on the balance sheet at fair value. The treatment of gains and losses arising from revaluation is described below in the accounting policy for derivative financial instruments and hedging activities.

Financial liabilities measured at amortized cost

All other financial liabilities are initially recognized at fair value, net of directly attributable transaction costs. For interest-bearing loans and borrowings this is typically equivalent to the fair value of the proceeds received, net of issue costs associated with the borrowing.

After initial recognition, other financial liabilities are subsequently measured at amortized cost using the effective interest method. Amortized cost is calculated by taking into account any issue costs and any discount or premium on settlement. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognized in interest and other income and finance costs respectively.

This category of financial liabilities includes trade and other payables and finance debt.

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

Derivative financial instruments and hedging activities

The group uses derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates, interest rates and commodity prices, as well as for trading purposes. These derivative financial instruments are recognized initially at fair value on the date on which a derivative contract is entered into and subsequently remeasured at fair value. Derivatives are carried as assets when the fair value is positive and as liabilities when the fair value is negative.

Contracts to buy or sell a non-financial item (for example, oil, oil products, gas or power) that can be settled net in cash, with the exception of contracts that were entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the group's expected purchase, sale or usage requirements, are accounted for as financial instruments. Gains or losses arising from changes in the fair value of derivatives that are not designated as effective hedging instruments are recognized in the income statement.

If, at inception of a contract, the valuation cannot be supported by observable market data, any gain or loss determined by the valuation methodology is not recognized in the income statement but is deferred on the balance sheet and is commonly known as 'day-one gain or loss'. This deferred gain or loss is recognized in the income statement over the life of the contract until substantially all the remaining contract term can be valued using observable market data at which point any remaining deferred gain or loss is recognized in the income statement. Changes in valuation subsequent to the initial valuation at inception of a contract are recognized immediately in the income statement.

For the purpose of hedge accounting, hedges are classified as:

- Fair value hedges when hedging exposure to changes in the fair value of a recognized asset or liability.
- Cash flow hedges when hedging exposure to variability in cash flows that is attributable to either a particular risk associated with a recognized asset or liability or a highly probable forecast transaction.

Hedge relationships are formally designated and documented at inception, together with the risk management objective and strategy for undertaking the hedge. The documentation includes identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged, the existence at inception of an economic relationship and subsequent measurement of the hedging instrument's effectiveness in offsetting the exposure to changes in the hedged item's fair value or cash flows attributable to the hedged risk, the hedge ratio and sources of hedge ineffectiveness. Hedges meeting the criteria for hedge accounting are accounted for as follows:

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

Fair value hedges

The change in fair value of a hedging derivative is recognized in profit or loss. The change in the fair value of the hedged item attributable to the risk being hedged is recorded as part of the carrying value of the hedged item and is also recognized in profit or loss, where it offsets. The group applies fair value hedge accounting when hedging interest rate risk and certain currency risks on fixed rate finance debt.

Fair value hedge accounting is discontinued only when the hedging relationship or a part thereof ceases to meet the qualifying criteria. This includes when the risk management objective changes or when the hedging instrument is sold, terminated or exercised. The accumulated adjustment to the carrying amount of a hedged item at such time is then amortized prospectively to profit or loss as finance interest expense over the hedged item's remaining period to maturity.

Cash flow hedges

The effective portion of the gain or loss on a cash flow hedging instrument is reported in other comprehensive income, while the ineffective portion is recognized in profit or loss. Amounts reported in other comprehensive income are reclassified to the income statement when the hedged transaction affects profit or loss.

Where the hedged item is a highly probably forecast transaction that results in the recognition of a non-financial asset or liability, such as a forecast foreign currency transaction for the purchase of property, plant and equipment, the amounts recognized within other comprehensive income are transferred to the initial carrying amount of the non-financial asset or liability. Where the hedged item is an equity investment, the amounts recognized in other comprehensive income remain in the separate component of equity until the hedged cash flows affect profit or loss. Where the hedged item is recognized directly in profit or loss, the amounts recognized in other comprehensive income are reclassified to production and manufacturing expenses or sales and other operating revenues as appropriate.

Cash flow hedge accounting is discontinued only when the hedging relationship or a part thereof ceases to meet the qualifying criteria. This includes when the designated hedged forecast transaction or part thereof is no longer considered to be highly probable to occur, or when the hedging instrument is sold, terminated or exercised without replacement or rollover. When cash flow hedge accounting is discontinued amounts previously recognized within other comprehensive income remain in equity until the forecast transaction occurs and are reclassified to profit or loss or transferred to the initial carrying amount of a non-financial asset or liability as above. If the forecast transaction is no longer expected to occur, amounts previously recognized within other comprehensive income will be immediately reclassified to profit or loss.

Costs of hedging

The foreign currency basis spread of cross-currency interest rate swaps are excluded from hedge designations and accounted for as costs of hedging. Changes in fair value of the foreign currency basis spread are recognized in other comprehensive income to the extent that they relate to the hedged item. For time-period related hedged items, the amount recognized in other comprehensive income is amortized to profit or loss on a straight line basis over the term of the hedging relationship.

Fair value measurement

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. The group categorizes assets and liabilities measured at fair value into one of three levels depending on the ability to observe inputs employed in their measurement. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are inputs that are observable, either directly or indirectly, other than quoted prices included within level 1 for the asset or liability. Level 3 inputs are unobservable inputs for the asset or liability reflecting significant modifications to observable related market data or BP's assumptions about pricing by market participants.

Significant estimate and judgement: derivative financial instruments

In some cases the fair values of derivatives are estimated using internal models due to the absence of quoted prices or other observable, market-corroborated data. This primarily applies to the group's longer-term derivative contracts. The majority of these contracts are valued using models with inputs that include price curves for each of the different products that are built up from available active market pricing data (including volatility and correlation) and modelled using the maximum available external information. Additionally, where limited data exists for certain products, prices are determined using historical and long-term pricing relationships. The use of alternative assumptions or valuation methodologies may result in significantly different values for these derivatives. A reasonably possible change in the price assumptions used in the models relating to index price would not have a material impact on net assets and the Group income statement primarily as a result of offsetting movements between derivative assets and liabilities. For more information, including the carrying amounts of level 3 derivatives, see Note 30.

In some cases, judgement is required to determine whether contracts to buy or sell commodities meet the definition of a derivative. In particular longer-term contracts to buy and sell LNG are not considered to meet the definition as they are not considered capable of being net settled due to a lack of liquidity in the LNG market and so are accounted for on an accruals basis, rather than as a derivative.

Offsetting of financial assets and liabilities

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

Provisions and contingencies

Provisions are recognized when the group has a present legal or constructive obligation as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where appropriate, the future cash flow estimates are adjusted to reflect risks specific to the liability.

If the effect of the time value of money is material, provisions are determined by discounting the expected future cash flows at a pre-tax risk-free rate that reflects current market assessments of the time value of money. Where discounting is used, the increase in the provision due to the passage of time is recognized within finance costs. Provisions are discounted using a nominal discount rate of 2.5% (2018 3.0%).

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

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

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

Decommissioning

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

An amount equivalent to the decommissioning provision is recognized as part of the corresponding intangible asset (in the case of an exploration or appraisal well) or property, plant and equipment. The decommissioning portion of the property, plant and equipment is subsequently depreciated at the same rate as the rest of the asset. Other than the unwinding of discount on or utilisation of the provision, any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding asset where that asset is generating or is expected to generate future economic benefits.

Environmental expenditures and liabilities

Environmental expenditures that are required in order for the group to obtain future economic benefits from its assets are capitalized as part of those assets. Expenditures that relate to an existing condition caused by past operations that do not contribute to future earnings are expensed.

Liabilities for environmental costs are recognized when a clean-up is probable and the associated costs can be reliably estimated. Generally, the timing of recognition of these provisions coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The amount recognized is the best estimate of the expenditure required to settle the obligation. Provisions for environmental liabilities have been estimated using existing technology, at future prices and discounted using a nominal discount rate.

Significant judgements and estimates: provisions

The group holds provisions for the future decommissioning of oil and natural gas production facilities and pipelines at the end of their economic lives. The largest decommissioning obligations facing BP relate to the plugging and abandonment of wells and the removal and disposal of oil and natural gas platforms and pipelines around the world. Most of these decommissioning events are many years in the future and the precise requirements that will have to be met when the removal event occurs are uncertain. Decommissioning technologies and costs are constantly changing, as are political, environmental, safety and public expectations. The timing and amounts of future cash flows are subject to significant uncertainty and estimation is required in determining the amounts of provisions to be recognized. Any changes in the expected future costs are reflected in both the provision and the asset.

If oil and natural gas production facilities and pipelines are sold to third parties, judgement is required to assess whether the new owner will be unable to meet their decommissioning obligations, whether BP would then be responsible for decommissioning, and if so the extent of that responsibility. The group has assessed that no material decommissioning provisions should be recognized as at 31 December 2019 (2018 no material provisions) for assets sold to third parties where the sale transferred the decommissioning obligation to the new owner.

Decommissioning provisions associated with downstream refineries and petrochemicals facilities are generally not recognized, as the potential obligations cannot be measured, given their indeterminate settlement dates. The group performs periodic reviews of its downstream refineries and petrochemicals long-lived assets for any changes in facts and circumstances that might require the recognition of a decommissioning provision.

The provision for environmental liabilities is estimated based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from current estimates because of changes in laws and regulations, public expectations, prices, discovery and analysis of site conditions and changes in clean-up technology.

The timing and amount of future expenditures relating to decommissioning and environmental liabilities are reviewed annually, together with the interest rate used in discounting the cash flows. The interest rate used to determine the balance sheet obligations at the end of 2019 was a nominal rate of 2.5% (2018 a nominal rate of 3.0%), which was based on long-dated US government bonds. The weighted average period over which decommissioning and environmental costs are generally expected to be incurred is estimated to be approximately 18 years (2018 18 years) and 6 years (2018 6 years) respectively.

Further information about the group's provisions is provided in Note 23. Changes in assumptions in relation to the group's provisions could result in a material change in their carrying amounts within the next financial year. A 0.5% change in the nominal discount rate could have an impact of approximately $1.4 billion (2018 $1.3 billion) on the value of the group's provisions.

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

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

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

Employee benefits

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

Share-based payments

Equity-settled transactions

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

For other equity-settled share-based payment transactions, the goods or services received and the corresponding increase in equity are measured at the fair value of the goods or services received unless their fair value cannot be reliably estimated. If the fair value of the goods and services received cannot be reliably estimated, the transaction is measured by reference to the fair value of the equity instruments granted.

Cash-settled transactions

The cost of cash-settled transactions is recognized as an expense over the vesting period, measured by reference to the fair value of the corresponding liability which is recognized on the balance sheet. The liability is remeasured at fair value at each balance sheet date until settlement, with changes in fair value recognized in the income statement.

Pensions and other post-retirement benefits

The cost of providing benefits under the group's defined benefit plans is determined separately for each plan using the projected unit credit method, which attributes entitlement to benefits to the current period to determine current service cost and to the current and prior periods to determine the present value of the defined benefit obligation. Past service costs, resulting from either a plan amendment or a curtailment (a reduction in future obligations as a result of a material reduction in the plan membership), are recognized immediately when the company becomes committed to a change.

Net interest expense relating to pensions and other post-retirement benefits, which is recognized in the income statement, represents the net change in present value of plan obligations and the value of plan assets resulting from the passage of time, and is determined by applying the discount rate to the present value of the benefit obligation at the start of the year, and to the fair value of plan assets at the start of the year, taking into account expected changes in the obligation or plan assets during the year.

Remeasurements of the defined benefit liability and asset, comprising actuarial gains and losses, and the return on plan assets (excluding amounts included in net interest described above) are recognized within other comprehensive income in the period in which they occur and are not subsequently reclassified to profit and loss.

The defined benefit pension plan surplus or deficit recognized on the balance sheet for each plan comprises the difference between the present value of the defined benefit obligation (using a discount rate based on high quality corporate bonds) and the fair value of plan assets out of which the obligations are to be settled directly. Fair value is based on market price information and, in the case of quoted securities, is the published bid price. Defined benefit pension plan surpluses are only recognized to the extent they are recoverable, either by way of a refund from the plan or reductions in future contributions to the plan.

Contributions to defined contribution plans are recognized in the income statement in the period in which they become payable.

Significant estimate: pensions and other post-retirement benefits

Accounting for defined benefit pensions and other post-retirement benefits involves making significant estimates when measuring the group's pension plan surpluses and deficits. These estimates require assumptions to be made about many uncertainties.

Pensions and other post-retirement benefit assumptions are reviewed by management at the end of each year. These assumptions are used to determine the projected benefit obligation at the year end and hence the surpluses and deficits recorded on the group's balance sheet, and pension and other post-retirement benefit expense for the following year.

The assumptions that are the most significant to the amounts reported are the discount rate, inflation rate, salary growth and mortality levels. Assumptions about these variables are based on the environment in each country. The assumptions used vary from year to year, with resultant effects on future net income and net assets. Changes to some of these assumptions, in particular the discount rate and inflation rate, could result in material changes to the carrying amounts of the group's pension and other post-retirement benefit obligations within the next financial year, in particular for the UK, US and Eurozone plans. Any differences between these assumptions and the actual outcome will also affect future net income and net assets.

The values ascribed to these assumptions and a sensitivity analysis of the impact of changes in the assumptions on the benefit expense and obligation used are provided in Note 24.

Income taxes

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

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

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

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

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

- Where the deferred tax liability arises on the initial recognition of goodwill.
- Where the deferred tax liability arises on the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither accounting profit nor taxable profit or loss.
- In respect of taxable temporary differences associated with investments in subsidiaries and associates and interests in joint arrangements, where the group is able to control the timing of the reversal of the temporary differences and it is probable that the temporary differences will not reverse in the foreseeable future.

Deferred tax assets are recognized for deductible temporary differences, carry-forward of unused tax credits and unused tax losses, to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax credits and unused tax losses can be utilized, except where the deferred tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither accounting profit nor taxable profit or loss. In respect of deductible temporary differences associated with investments in subsidiaries and associates and interests in joint arrangements, deferred tax assets are recognized only to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available against which the temporary differences can be utilized.

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

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

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

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

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

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

Management do not assess there to be a significant risk of a material change to the group’s tax provisioning or recognition of deferred tax assets within the next financial year, however the tax position remains inherently uncertain and therefore subject to change. To the extent that actual outcomes differ from management’s estimates, income tax charges or credits, and changes in current and deferred tax assets or liabilities, may arise in future periods. For more information see Note 9 and Note 33.

Judgement is also required when determining whether a particular tax is an income tax or another type of tax (for example a production tax). Accounting for deferred tax is applied to income taxes as described above, but is not applied to other types of taxes; rather such taxes are recognized in the income statement in accordance with the applicable accounting policy such as Provisions and contingencies. No new significant judgements were made in 2019 in this regard.

Customs duties and sales taxes

Customs duties and sales taxes that are passed on or charged to customers are excluded from revenues and expenses. Assets and liabilities are recognized net of the amount of customs duties or sales tax except:

- Customs duties or sales taxes incurred on the purchase of goods and services which are not recoverable from the taxation authority are recognized as part of the cost of acquisition of the asset.
- Receivables and payables are stated with the amount of customs duty or sales tax included.

The net amount of sales tax recoverable from, or payable to, the taxation authority is included within receivables or payables in the balance sheet.

Own equity instruments – treasury shares

The group’s holdings in its own equity instruments are shown as deductions from shareholders’ equity. Treasury shares represent BP shares repurchased and available for specific and limited purposes. For accounting purposes, shares held in Employee Share Ownership Plans (ESOPs) to meet the future requirements of the employee share-based payment plans are treated in the same manner as treasury shares and are, therefore, included in the consolidated financial statements as treasury shares. The cost of treasury shares subsequently sold or reissued is calculated on a weighted-average basis. Consideration, if any, received for the sale of such shares is also recognized in equity. No gain or loss is recognized in the income statement on the purchase, sale, issue or cancellation of equity shares. Shares repurchased under the share buy-back programme which are immediately cancelled are not shown as treasury shares, but are shown as a deduction from the profit and loss account reserve in the group statement of changes in equity.

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

Revenue and other income

Revenue from contracts with customers is recognized when or as the group satisfies a performance obligation by transferring control of a promised good or service to a customer. The transfer of control of oil, natural gas, natural gas liquids, LNG, petroleum and chemical products, and other items usually coincides with title passing to the customer and the customer taking physical possession. The group principally satisfies its performance obligations at a point in time; the amounts of revenue recognized relating to performance obligations satisfied over time are not significant.

When, or as, a performance obligation is satisfied, the group recognizes as revenue the amount of the transaction price that is allocated to that performance obligation. The transaction price is the amount of consideration to which the group expects to be entitled. The transaction price is allocated to the performance obligations in the contract based on standalone selling prices of the goods or services promised.

Contracts for the sale of commodities are typically priced by reference to quoted prices. Revenue from term commodity contracts is recognized based on the contractual pricing provisions for each delivery. Certain of these contracts have pricing terms based on prices at a point in time after delivery has been made. Revenue from such contracts is initially recognized based on relevant prices at the time of delivery and subsequently adjusted as appropriate. All revenue from these contracts, both that recognized at the time of delivery and that from post-delivery price adjustments, is disclosed as revenue from contracts with customers.

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

Where forward sale and purchase contracts for oil, natural gas or power have been determined to be for short-term trading purposes, the associated sales and purchases are reported net within sales and other operating revenues whether or not physical delivery has occurred.

Physical exchanges with counterparties in the same line of business in order to facilitate sales to customers are reported net, as are sales and purchases made with a common counterparty, as part of an arrangement similar to a physical exchange.

Where the group acts as agent on behalf of a third party to procure or market energy commodities, any associated fee income is recognized but no purchase or sale is recorded.

Interest income is recognized as the interest accrues (using the effective interest rate, that is, the rate that exactly discounts estimated future cash receipts through the expected life of the financial instrument to the net carrying amount of the financial asset).

Dividend income from investments is recognized when the shareholders' right to receive the payment is established.

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

Finance costs

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

Impact of new International Financial Reporting Standards

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

IFRS 16 'Leases'

IFRS 16 'Leases' provides a new model for lessee accounting in which the majority of leases will be accounted for by the recognition on the balance sheet of a right-of-use asset and a lease liability. The subsequent amortization of the right-of-use asset and the interest expense related to the lease liability is recognized in profit or loss over the lease term.

BP elected to apply the modified retrospective transition approach in which the cumulative effect of initial application is recognized in opening retained earnings at the date of initial application with no restatement of comparative periods' financial information. Comparative information in the group balance sheet and group cash flow statement has, however, been re-presented to align with current year presentation, showing lease liabilities and lease liability payments as separate line items. These were previously included within finance debt and repayments of long-term financing line items respectively. Amounts presented in these line items for the comparative periods relate to leases accounted for as finance leases under IAS 17. We do not consider any of the judgements or estimates made on transition to IFRS 16 to be significant.

IFRS 16 introduces a revised definition of a lease. As permitted by the standard, BP elected not to reassess the existing population of leases under the new definition and only applies the new definition for the assessment of contracts entered into after the transition date. On transition the standard permitted, on a lease-by-lease basis, the right-of-use asset to be measured either at an amount equal to the lease liability (as adjusted for prepaid or accrued lease payments), or on a historical basis as if the standard had always applied. BP elected to use the historical asset measurement for its more material leases and used the asset equals liability approach for the remainder of the population. In measuring the right-of-use asset BP applied the transition practical expedient to exclude initial direct costs. BP also elected to adjust the carrying amounts of the right-of-use assets as at 1 January 2019 for onerous lease provisions that had been recognized on the group balance sheet as at 31 December 2018, rather than performing impairment tests on transition.

The effect on the group's balance sheet is set out further below. The presentation and timing of recognition of charges in the income statement has changed following the adoption of IFRS 16. The operating lease expense previously reported under IAS 17, typically on a straight-line basis, has been replaced by depreciation of the right-of-use asset and interest on the lease liability. In the cash flow statement payments are now presented as financing cash flows, representing repayments of principal, and as operating cash flows, representing payments of interest. Variable lease payments that do not depend on an index or rate are not included in the lease liability and will continue to be presented as operating cash flows. In prior years, operating lease payments were principally presented within cash flows from operating activities.

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

The following table provides a reconciliation of the operating lease commitments as at 31 December 2018 to the total lease liability recognized on the group balance sheet in accordance with IFRS 16 as at 1 January 2019, with explanations below.

	$ million
Operating lease commitments at 31 December 2018	11,979
Leases not yet commenced	(1,372)
Leases below materiality threshold	(86)
Short-term leases	(91)
Effect of discounting	(1,512)
Impact on leases in joint operations	836
Variable lease payments	(58)
Redetermination of lease term	(252)
Other	(22)
Total additional lease liabilities recognized on adoption of IFRS 16	9,422
Finance lease obligations at 31 December 2018	667
Adjustment for finance leases in joint operations	(189)
Total lease liabilities at 1 January 2019	9,900

Leases not yet commenced: The operating lease commitments disclosed as at 31 December 2018 include amounts relating to leases entered into by the group that had not yet commenced as at 31 December 2018. In accordance with IFRS 16 assets and liabilities will not be recognized on the group balance sheet in relation to these leases until the dates of commencement of the leases. Commitments for leases not yet commenced as at 31 December 2019 are disclosed in note 28.

Short-term leases and leases below materiality threshold: As part of the transition to IFRS 16, BP elected not to recognize assets and liabilities relating to short-term leases i.e. leases with a term of less than 12 months and also applied a materiality threshold for the recognition of assets and liabilities related to leases. The disclosed operating lease commitments as at 31 December 2018 include amounts related to such leases.

Effect of discounting: The amount of the lease liability recognized in accordance with IFRS 16 is on a discounted basis whereas the operating lease commitments information as at 31 December 2018 is presented on an undiscounted basis. The discount rates used on transition were incremental borrowing rates as appropriate for each lease based on factors such as the lessee legal entity, lease term and currency. The weighted average discount rate used on transition was around 3.5%, with a weighted average remaining lease term of around nine years. For new leases commencing after 1 January 2019 the discount rate used will be the interest rate implicit in the lease, if this is readily determinable, or the incremental borrowing rate if the implicit rate cannot be readily determined.

Impact on leases in joint operations: The operating lease commitments for leases within joint operations as at 31 December 2018 were included on the basis of BP's net working interest, irrespective of whether BP is the operator and whether the lease has been co-signed by the joint operators or not. However, for transition to IFRS 16, the facts and circumstances of each lease in a joint operation were assessed to determine the group's rights and obligations and to recognize assets and liabilities on the group balance sheet accordingly. This relates mainly to leases of drilling rigs within joint operations in the Upstream segment. Where all parties to a joint operation jointly have the right to control the use of the identified asset and all parties have a legal obligation to make lease payments to the lessor, the group's share of the right-of-use asset and its share of the lease liability will be recognized on the group balance sheet. This may arise in cases where the lease is signed by all parties to the joint operation. However, in cases where BP is the only party with the legal obligation to make lease payments to the lessor, the full lease liability will be recognized on the group balance sheet. This may be the case if for example BP, as operator of the joint operation, is the sole signatory to the lease. If, however, the underlying asset is jointly controlled by all parties to the joint operation BP will recognize its net share of the right-of-use asset on the group balance sheet along with a receivable representing the amounts to be recovered from the other parties. If BP is not legally obliged to make lease payments to the lessor but jointly controls the asset, the net share of the right-of-use asset will be recognized on the group balance sheet along with a payable representing amounts to be paid to the other parties.

Variable lease payments: Where there are lease payments that vary depending on an index or rate, the measurement of the operating lease commitments as at 31 December 2018 was based on the variable factor as at inception of the lease and was not updated to reflect subsequent changes in the variable factor. Such subsequent changes in the lease payments were treated as contingent rentals and charged to profit or loss as and when paid. Under IFRS 16 the lease liability is adjusted whenever the lease payments are changed in response to changes in the variable factor, and for transition the liability was measured on the basis of the prevailing variable factor on 1 January 2019.

Redetermination of lease term: Under the transition provisions of IFRS 16, the remaining terms of certain leases were redetermined with the benefit of hindsight, on the basis that BP was reasonably certain to exercise its option to terminate those leases before the full term.

Under IAS 17 finance leases were recognized on the group balance sheet and continue to be recognized in accordance with IFRS 16. The amounts recognized on the group balance sheet as at 1 January 2019 in relation to the right-of-use assets and liabilities for previous finance leases within joint operations are on a net or gross basis as appropriate as described above.

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

In addition to the lease liability, other line items on the group balance sheet adjusted on transition to IFRS 16 include property, plant and equipment for the right-of-use assets, lease related prepayments, receivables from joint operation partners, accruals, payables to operators of joint operations, onerous lease provisions and deferred tax balances, as set out below.

			$ million
	31 December 2018	1 January 2019	Adjustment on adoption of IFRS 16
Non-current assets			
Property, plant and equipment	135,261	143,950	8,689
Trade and other receivables	1,834	2,159	325
Prepayments	1,179	849	(330)
Deferred tax assets	3,706	3,736	30
Current assets			
Trade and other receivables	24,478	24,673	195
Prepayments	963	872	(91)
Current liabilities			
Trade and other payables	46,265	46,209	(56)
Accruals	4,626	4,578	(48)
Lease liabilities	44	2,196	2,152
Finance debt	9,329	9,329	—
Provisions	2,564	2,547	(17)
Non-current liabilities			
Other payables	13,830	14,013	183
Accruals	575	548	(27)
Lease liabilities	623	7,704	7,081
Finance debt	55,803	55,803	—
Deferred tax liabilities	9,812	9,767	(45)
Provisions	17,732	17,657	(75)
Net assets[a]	101,548	101,218	(330)
Equity			
BP shareholders' equity	99,444	99,115	(329)
Non-controlling interests	2,104	2,103	(1)
	101,548	101,218	(330)

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

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

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

Not yet adopted

The following pronouncements from the IASB have not been adopted by the group in these financial statements as they will only become effective for future financial reporting periods. In addition, the group is voluntarily changing certain accounting policies from 1 January 2020 following an IFRIC agenda decision on IFRS 9 '*Financial instruments*'. There are no other standards, amendments or interpretations in issue but not yet adopted that the directors anticipate will have a material effect on the reported income or net assets of the group.

IFRS 17 ' Insurance Contracts'

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

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

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

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

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

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

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

IFRIC agenda decision on IFRS 9

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

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

2. Non-current assets held for sale

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

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

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

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

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

3. Business combinations and other significant transactions

Business combinations

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

BP undertook a number of business combinations in 2018. For the full year, total consideration paid in cash amounted to $7,100 million, offset by cash acquired of $114 million.

On 31 October 2018, BP acquired from BHP Billiton Petroleum (North America) Inc. 100% of the issued share capital of Petrohawk Energy Corporation, a wholly-owned subsidiary of BHP that holds a portfolio of unconventional onshore US oil and gas assets.

The acquisition brings BP extensive oil and gas production and resources in the liquids-rich regions of the Permian and Eagle Ford basins in Texas and in the Haynesville gas basin in Texas and Louisiana.

The total consideration for the transaction, after customary closing adjustments and the effect of discounting deferred payments, was $10,302 million, which was all paid in cash.

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

	$ million
	2018
Assets	
Property, plant and equipment	**10,845**
Intangible assets	**21**
Inventories	**27**
Trade and other receivables	**493**
Cash	**104**
Liabilities	
Trade and other payables	**(659)**
Provisions	**(323)**
Non-controlling interest	**(206)**
Total consideration	**10,302**

An analysis of the cash flows relating to the acquisition included within the cash flow statement for 2018 is provided below.

	$ million
	2018
Transaction costs of the acquisition (included in cash flows from operating activities)	**62**
Interest on deferred payments (included in cash flows from operating activities)	**21**
Cash consideration paid, net of cash acquired (included in cash flows from investing activities)	**6,684**
Total net cash outflow for the acquisition	**6,767**

From the date of acquisition to 31 December 2018, the acquired activities generated revenues of $472 million and profit before tax of $49 million. If the business combination had taken place on 1 January 2018, it is estimated that the acquired activities would have generated revenues of $2,798 million and profit before tax of $431 million.

In addition to the BHP transaction described above, BP undertook a number of other individually insignificant business combinations in 2018.

Other significant transactions

On 18 December 2018, BP purchased an additional 16.5% interest in the Clair field in the North Sea, as part of the agreements with ConocoPhillips in which ConocoPhillips simultaneously purchased BP's entire 39.2% interest in the Greater Kuparuk Area on the North Slope of Alaska. The purchase gives BP a 45.1% interest in Clair in total. Gross payments made and received of $1,739 million and $1,490 million are included in Capital expenditure and Proceeds from disposals of businesses, net of cash acquired, respectively, in the group cash flow statement for 2018. Goodwill of $804 million, resulting from the recognition of a deferred tax liability as part of the transaction accounting, was recognized on the purchase of the interest in the Clair field.

4. Disposals and impairment

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

			$ million
	2019	2018	2017
Gains on sale of businesses and fixed assets			
Upstream	**143**	437	526
Downstream	**50**	15	674
Other businesses and corporate	**—**	4	10
	193	456	1,210

			$ million
	2019	2018	2017
Losses on sale of businesses and fixed assets			
Upstream	**415**	707	127
Downstream	**57**	59	88
Other businesses and corporate	**887**	11	—
	1,359	777	215
Impairment losses			
Upstream	**6,752**	400	1,138
Downstream	**65**	12	69
Other businesses and corporate	**30**	254	32
	6,847	666	1,239
Impairment reversals			
Upstream	**(131)**	(580)	(176)
Downstream	**—**	(2)	(62)
Other businesses and corporate	**—**	(1)	—
	(131)	(583)	(238)
Impairment and losses on sale of businesses and fixed assets	**8,075**	860	1,216

Disposals

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

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

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

Upstream

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

In 2018, gains principally resulted from the disposal of interests in the Bruce, Keith and Rhum fields in the UK North Sea, from the disposal of certain properties in the US, and from adjustments to disposals in prior periods. Losses included $335 million resulting from the disposal of our interest in the Magnus field and associated assets in the UK North Sea, $221 million from the disposal of our interest in the Greater Kuparuk Area in the US (see Note 3 for further information), and adjustments to disposals in prior periods.

In 2017, gains principally resulted from the disposal of a portion of our interest in the Perdido offshore hub in the US, and further gains associated with disposals in the UK.

Downstream

In 2017, gains principally resulted from the disposal of our interest in the SECCO joint venture and the disposal of certain midstream assets in Europe.

4. Disposals and impairment – continued

Other businesses and corporate

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

In 2018 proceeds from disposals were principally in respect of life insurance policies in the US and wind farms within our US wind business.

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

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

The principal transaction categorized as a business disposal in 2018 was the disposal of our interest in the Greater Kuparuk Area in the US- see Note 3 for further information.

The principal transaction categorized as a business disposal in 2017 was the disposal of our interest in the Forties Pipeline System in the North Sea.

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

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

[b] Proceeds are stated net of cash and cash equivalents disposed of $30 million (2018 $15 million and 2017 $25 million).

Impairments

Impairment losses and impairment reversals in each segment are described below. For information on significant estimates and judgements made in relation to impairments see Impairment of property, plant and equipment, intangibles and goodwill within Note 1. See also Note 12, and Note 15 for further information on impairments by asset category.

Upstream

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

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

The 2018 impairment losses of $400 million related to a number of different assets, with the most significant charges arising in Australia and the US. Impairment losses arose primarily as a result of changes to project activity, asset obsolescence and the decision to dispose of certain assets. The 2018 impairment reversals of $580 million related to a number of different assets, with the most significant reversals arising in the North Sea and Angola following a change to decommissioning cost estimates.

The 2017 impairment losses of $1,138 million related to a number of different assets, with the most significant charges arising in BPX Energy (previously known as the US Lower 48 business) and the North Sea. Impairment losses within Upstream arose primarily as a result of changes in reserves estimates and the decision to dispose of certain assets, including the Forties Pipeline System business.

The 2017 impairment reversals of $176 million related to a number of different assets, with the most significant reversals arising in the North Sea.

Downstream

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

Other businesses and corporate

Impairment losses totalling $30 million, $254 million, and $32 million were recognized in 2019, 2018 and 2017 respectively. The amount for 2018 is in respect of assets within our US wind business in advance of their disposal in December 2018.

5. Segmental analysis

The group's organizational structure reflects the various activities in which BP is engaged. At 31 December 2019, BP had three reportable segments: Upstream, Downstream and Rosneft.

Upstream's activities include oil and natural gas exploration, field development and production; midstream transportation, storage and processing; and the marketing and trading of natural gas, including liquefied natural gas (LNG), together with power and natural gas liquids (NGLs).

Downstream's activities include the refining, manufacturing, marketing, transportation, and supply and trading of crude oil, petroleum, petrochemicals products and related services to wholesale and retail customers.

BP's interest in Rosneft is accounted for using the equity method and is reported as a separate operating segment, reflecting the way in which the investment is managed.

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

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

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

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

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

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

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

5. Segmental analysis – continued

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

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

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

By business	Upstream	Downstream	Rosneft	Other businesses and corporate	Consolidation adjustment and eliminations	Total group
						$ million
						2018
Segment revenues						
Sales and other operating revenues	56,399	270,689	—	1,678	(30,010)	298,756
Less: sales and other operating revenues between segments	(28,565)	(574)	—	(871)	30,010	—
Third party sales and other operating revenues	27,834	270,115	—	807	—	298,756
Earnings from joint ventures and associates – after interest and tax	951	589	2,283	(70)	—	3,753
Segment results						
Replacement cost profit (loss) before interest and taxation	14,328	6,940	2,221	(3,521)	211	20,179
Inventory holding gains (losses)[a]	(6)	(862)	67	—	—	(801)
Profit (loss) before interest and taxation	14,322	6,078	2,288	(3,521)	211	19,378
Finance costs						(2,528)
Net finance expense relating to pensions and other post-retirement benefits						(127)
Profit before taxation						16,723
Other income statement items						
Depreciation, depletion and amortization						
US	4,211	900	—	59	—	5,170
Non-US	8,907	1,177	—	203	—	10,287
Charges for provisions, net of write-back of unused provisions, including change in discount rate	355	834	—	1,557	—	2,746
Segment assets						
Investments in joint ventures and associates	12,785	2,772	10,074	689	—	26,320
Additions to non-current assets[b c]	24,266	3,609	—	477	—	28,352

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

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

[c] Amounts have been restated to include acquisitions

5. Segmental analysis – continued

By business	Upstream	Downstream	Rosneft	Other businesses and corporate	Consolidation adjustment and eliminations	Total group
						$ million
						2017
Segment revenues						
Sales and other operating revenues	45,440	219,853	—	1,469	(26,554)	240,208
Less: sales and other operating revenues between segments	(24,179)	(1,800)	—	(575)	26,554	—
Third party sales and other operating revenues	21,261	218,053	—	894	—	240,208
Earnings from joint ventures and associates – after interest and tax	930	674	922	(19)	—	2,507
Segment results						
Replacement cost profit (loss) before interest and taxation	5,221	7,221	836	(4,445)	(212)	8,621
Inventory holding gains (losses)[a]	8	758	87	—	—	853
Profit (loss) before interest and taxation	5,229	7,979	923	(4,445)	(212)	9,474
Finance costs						(2,074)
Net finance expense relating to pensions and other post-retirement benefits						(220)
Profit before taxation						7,180
Other income statement items						
Depreciation, depletion and amortization						
US	4,631	875	—	65	—	5,571
Non-US	8,637	1,141	—	235	—	10,013
Charges for provisions, net of write-back of unused provisions, including change in discount rate	220	304	—	2,902	—	3,426

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

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

[a] Non-US region includes UK $63,194 million

[b] Non-US region includes UK $22,881 million

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

By geographical area	US	Non-US	Total
			$ million
			2018
Revenues			
Third party sales and other operating revenues[a]	98,066	200,690	298,756
Other income statement items			
Production and similar taxes	369	1,167	1,536
Non-current assets			
Non-current assets[b c]	68,188	124,060	192,248

[a] Non-US region includes UK $65,630 million.

[b] Non-US region includes UK $19,426 million.

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

5. Segmental analysis – continued

By geographical area	US	Non-US	$ million 2017 Total
Revenues			
Third party sales and other operating revenues[a]	83,269	156,939	240,208
Other income statement items			
Production and similar taxes	52	1,723	1,775

[a] Non-US region includes UK $48,837 million.

6. Revenue from contracts with customers

The amounts shown in the table below are included in Sales and other operating revenues in the group income statement. An analysis of total sales and other operating revenues by segment and region is provided in Note 5.

Revenue from contracts with customers, by product

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

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

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

7. Income statement analysis

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

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

[b] Included within production and manufacturing expenses.

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

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

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

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

The following financial information represents the amounts included within the group totals relating to activity associated with the exploration for and evaluation of oil and natural gas resources. All such activity is recorded within the Upstream segment.

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

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

[a] 2018 includes $447 million in the deepwater Gulf of Mexico principally relating to licence expiries. 2017 included write-offs in Angola of $574 million in relation to licence relinquishment and Egypt of $208 million following a determination that no commercial hydrocarbons had been found. 2017 also included a $145-million write-off in relation to the value ascribed to certain licences in the deepwater Gulf of Mexico as part of the accounting for the acquisition of upstream assets from Devon Energy in 2011. For further information see Upstream – Exploration on page 53.

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

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

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

9. Taxation

Tax on profit

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

[a] The adjustments in respect of prior years reflect the reassessment of the current tax balances for prior years in light of changes in facts and circumstances during the year.

[b] Origination and reversal of temporary differences in the current year include the impact of tax rate changes on deferred tax balances. 2018 includes a credit of $121 million (2017 $859 million charge) in respect of the reduction in the US federal corporate income tax rate from 35% to 21%, effective from 1 January 2018. The adjustments in respect of prior years reflect the reassessment of deferred tax balances for prior periods in light of all other changes in facts and circumstances during the year.

In 2019, the total tax charge recognized within other comprehensive income was $227 million (2018 $714 million charge and 2017 $1,499 million charge), primarily comprising the deferred tax impact of the remeasurements of the net pension and other post-retirement benefit liability or asset. See Note 32 for further information.

The total tax charge recognized directly in equity was $37 million (2018 $17 million charge and 2017 $263 million charge).

Reconciliation of the effective tax rate

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

9. Taxation – continued

			$ million
	2019	2018	2017
Profit before taxation	**8,154**	16,723	7,180
Tax charge on profit	**3,964**	7,145	3,712
Effective tax rate	**49%**	43%	52%

Tax rate computed at the weighted average statutory rate[a]	**52**	43	44
Increase (decrease) resulting from			
Tax reported in equity-accounted entities	**(7)**	(5)	(7)
Deferred tax not recognized[b]	**(2)**	1	6
Tax incentives for investment	**(3)**	(2)	(6)
Foreign exchange	**1**	3	(4)
Items not deductible for tax purposes	**4**	1	5
Impact of US tax reform[c]	**—**	(1)	12
Other[b]	**4**	3	2
Effective tax rate	**49**	43	52

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

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

[c] Relates to the deferred tax impact of the reduction in the US federal corporate income tax rate from 35% to 21%, effective from 1 January 2018.

Deferred tax

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

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

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

[c] 2018 relates primarily to the purchase of an additional 16.5% interest in the Clair field. See Note 3- Other significant transactions for further information.

9. Taxation – continued

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

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

[a] The 2017 and 2018 income statement and 2018 balance sheet are impacted by the reduction in US federal corporate income tax rate from 35% to 21%, effective from 1 January 2018.

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

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

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

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

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

[a] For 2019 these losses expire in the period 2020-2039 with applicable tax rates ranging from 3% to 12%.

[b] The majority of the unused tax losses have no fixed expiry date.

[c] The UK unused tax credits arise predominantly in overseas branches of UK entities based in jurisdictions with higher statutory corporate income tax rates than the UK. No deferred tax asset has been recognized on these tax credits as they are unlikely to have value in the future; UK taxes on these overseas branches are largely mitigated by double tax relief in respect of overseas tax. These tax credits have no fixed expiry date.

[d] For 2019 the US unused tax credits expire in the period 2020-2029.

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

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

10. Dividends

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

	Pence per share			Cents per share			$ million		
	2019	2018	2017	**2019**	2018	2017	**2019**	2018	2017
Dividends announced and paid in cash									
Preference shares							**1**	1	1
Ordinary shares									
March	**7.7380**	7.1691	8.1587	**10.25**	10.00	10.00	**1,435**	1,828	1,303
June	**8.0660**	7.4435	7.7563	**10.25**	10.00	10.00	**1,779**	1,727	1,546
September	**8.3480**	7.9296	7.6213	**10.25**	10.25	10.00	**1,656**	1,409	1,676
December	**7.8250**	8.0251	7.4435	**10.25**	10.25	10.00	**2,075**	1,734	1,627
	31.9770	30.5673	30.9798	**41.00**	40.50	40.00	**6,946**	6,699	6,153
Dividend announced, paid in March 2020				**10.50**			**2,120**		

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

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

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

11. Earnings per share

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

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

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

The weighted average number of shares outstanding includes certain shares that will be issuable in the future under employee share-based payment plans and excludes treasury shares, which includes shares held by the Employee Share Ownership Plan trusts (ESOPs).

For the diluted earnings per share calculation, the weighted average number of shares outstanding during the year is adjusted for the average number of shares that are potentially issuable in connection with employee share-based payment plans. If the inclusion of potentially issuable shares would decrease loss per share, the potentially issuable shares are excluded from the weighted average number of shares outstanding used to calculate diluted earnings per share.

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

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

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

11. Earnings per share – continued

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

Employee share-based payment plans

The group operates share and share option plans for directors and certain employees to obtain ordinary shares and ADSs in the company. Information on these plans for directors is shown in the Directors remuneration report on pages 100-127.

The following table shows the number of shares potentially issuable under equity-settled employee share option plans, including the number of options outstanding, the number of options exercisable at the end of each year, and the corresponding weighted average exercise prices. The dilutive effect of these plans at 31 December is also shown.

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

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

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

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

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

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

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

12. Property, plant and equipment

$ million

	Land and land improvements	Buildings	Oil and gas properties[a]	Plant, machinery and equipment	Fittings, fixtures and office equipment	Transportation[b]	Oil depots, storage tanks and service stations	Total
Cost- owned property, plant and equipment (PP&E)								
At 1 January 2019	**3,562**	**1,502**	**232,684**	**45,721**	**2,747**	**10,183**	**8,866**	**305,265**
Exchange adjustments	**(22)**	**5**	**—**	**(158)**	**15**	**(3)**	**(69)**	**(232)**
Additions	**88**	**93**	**13,237**	**2,433**	**172**	**274**	**644**	**16,941**
Acquisitions	**51**	**—**	**—**	**—**	**—**	**—**	**8**	**59**
Transfers from intangible assets	**—**	**—**	**1,885**	**—**	**—**	**—**	**—**	**1,885**
Reclassified as assets held for sale	**(26)**	**—**	**(22,602)**	**—**	**(76)**	**(6,708)**	**—**	**(29,412)**
Deletions	**(44)**	**(178)**	**(10,852)**	**(1,272)**	**(326)**	**(272)**	**(755)**	**(13,699)**
At 31 December 2019	**3,609**	**1,422**	**214,352**	**46,724**	**2,532**	**3,474**	**8,694**	**280,807**
Depreciation- owned PP&E								
At 1 January 2019	**626**	**697**	**133,687**	**20,512**	**2,041**	**7,819**	**5,146**	**170,528**
Exchange adjustments	**(4)**	**5**	**—**	**(63)**	**12**	**(3)**	**(45)**	**(98)**
Charge for the year	**44**	**59**	**13,012**	**1,705**	**168**	**173**	**420**	**15,581**
Impairment losses	**1**	**1**	**5,871**	**64**	**1**	**404**	**4**	**6,346**
Impairment reversals	**—**	**—**	**(129)**	**—**	**—**	**(2)**	**—**	**(131)**
Reclassified as assets held for sale	**—**	**—**	**(17,764)**	**—**	**(69)**	**(5,478)**	**—**	**(23,311)**
Deletions	**(86)**	**(65)**	**(9,911)**	**(691)**	**(147)**	**(169)**	**(660)**	**(11,729)**
At 31 December 2019	**581**	**697**	**124,766**	**21,527**	**2,006**	**2,744**	**4,865**	**157,186**
Owned PP&E- net book amount at 31 December 2019	**3,028**	**725**	**89,586**	**25,197**	**526**	**730**	**3,829**	**123,621**
Right-of-use assets- net book amount at 31 December 2019[c]	**—**	**1,196**	**128**	**1,241**	**16**	**3,385**	**3,055**	**9,021**
Total PP&E- net book amount at 31 December 2019	**3,028**	**1,921**	**89,714**	**26,438**	**542**	**4,115**	**6,884**	**132,642**
Cost								
At 1 January 2018	3,474	1,573	226,054	46,662	2,853	10,774	8,748	300,138
Exchange adjustments	(168)	(58)	—	(892)	(73)	(43)	(501)	(1,735)
Additions	233	40	9,712	2,323	204	(112)	736	13,136
Acquisitions	163	4	10,882	9	1	2	36	11,097
Remeasurements[b]	—	—	17	—	—	—	—	17
Transfers from intangible assets	—	—	901	—	—	—	—	901
Deletions	(140)	(45)	(14,699)	(1,810)	(238)	(128)	(146)	(17,206)
At 31 December 2018	3,562	1,514	232,867	46,292	2,747	10,493	8,873	306,348
Depreciation								
At 1 January 2018	683	818	133,326	20,996	2,136	7,523	5,185	170,667
Exchange adjustments	(25)	(24)	—	(460)	(52)	(27)	(279)	(867)
Charge for the year	92	52	12,342	1,820	189	252	384	15,131
Impairment losses	2	—	86	253	—	178	2	521
Impairment reversals	—	—	(564)	(1)	—	(17)	—	(582)
Deletions	(126)	(139)	(11,333)	(1,733)	(232)	(75)	(145)	(13,783)
At 31 December 2018	626	707	133,857	20,875	2,041	7,834	5,147	171,087
Net book amount at 31 December 2018	2,936	807	99,010	25,417	706	2,659	3,726	135,261
Assets held under finance leases at net book amount included above[d]								
At 31 December 2018	—	2	12	207	—	295	6	522
Assets under construction included above								
At 31 December 2019								**23,897**
At 31 December 2018								22,522
Depreciation charge for the year on right-of-use assets								
2019		**220**	**31**	**671**	**9**	**784**	**526**	**2,241**

[a] For information on significant estimates and judgements made in relation to the estimation of oil and natural reserves see Property, plant and equipment within Note 1.

[b] Includes adjustments to decommissioning provisions; see Note 1 for further information.

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

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

13. Capital commitments

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

14. Goodwill and impairment review of goodwill

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

[a] 2018 principally relates to the purchase of an additional 16.5% share in the Clair field in the North Sea. See Note 3 - Other significant transactions for further information.

Impairment review of goodwill

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

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

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

Upstream

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

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

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

The value in use is based on the cash flows expected to be generated by the projected oil or natural gas production profiles up to the expected dates of cessation of production of each producing field, based on current estimates of reserves and resources, appropriately risked. Midstream and supply and trading activities and equity-accounted entities are generally not included in the impairment review of goodwill, because they are not part of the grouping of cash-generating units to which the goodwill relates and which is used to monitor the goodwill for internal management purposes. Where such activities form part of a wider Upstream cash-generating unit, they are reflected in the test. As the production profile and related cash flows can be estimated from BP's past experience, management believes that the cash flows generated over the estimated life of field is the appropriate basis upon which to assess goodwill and individual assets for impairment. The estimated date of cessation of production depends on the interaction of a number of variables, such as the recoverable quantities of hydrocarbons, the production profile of the hydrocarbons, the cost of the development of the infrastructure necessary to recover the hydrocarbons, production costs, the contractual duration of the production concession and the selling price of the hydrocarbons produced. As each producing field has specific reservoir characteristics and economic circumstances, the cash flows of the fields are computed using appropriate individual economic models and key assumptions agreed by BP management. Capital expenditure, operating costs and expected hydrocarbon production profiles are derived from the business segment plan adjusted for assumptions reflecting the price environment at the time that the test was performed. Estimated production volumes and cash flows up to the date of cessation of production on a field-by-field basis are consistent with this. The production profiles used are consistent with the reserve and resource volumes approved as part of BP's centrally controlled process for the estimation of proved and probable reserves and total resources.

14. Goodwill and impairment review of goodwill – continued

The most recent review for impairment was carried out in the fourth quarter. The key assumptions used in the value-in-use calculation are oil and natural gas prices, production volumes and the discount rate. Oil and gas price assumptions and discount rate assumptions used were as disclosed in Note 1. The value-in-use calculation has been prepared solely for the purposes of determining whether the goodwill balance was impaired. Estimated future cash flows were prepared on the basis of certain assumptions prevailing at the time of the test. The actual outcomes may differ from the assumptions made. For example, reserves and resources estimates and production forecasts are subject to revision as further technical information becomes available and economic conditions change. Due to economic developments, regulatory change and emissions reduction activity arising from climate concern and other factors, future commodity prices and other assumptions may differ from the forecasts used in the calculations.

Sensitivities to different variables have been estimated using certain simplifying assumptions. For example, lower oil and gas price sensitivities do not fully reflect the specific impacts for each contractual arrangement and will not capture all favourable impacts that may arise from cost deflation. A detailed calculation at any given price or production profile may, therefore, produce a different result.

It is estimated that no reasonable sustained fall in the oil or gas price assumption over the next 20 years would individually cause the recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets of the segment.

Estimated production volumes are based on detailed data for each field and take into account development plans agreed by management as part of the long-term planning process. The average production for the purposes of goodwill impairment testing over the next 15 years is 829 mmboe per year (2018 829 mmboe per year). It is estimated that no reasonably possible change in production volumes would cause the recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets of the segment.

It is estimated that no reasonably possible change in the pre-tax discount rate would cause the recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets of the segment. The weighted average discount rate used in the test is 12%.

Downstream

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

Cash flows for each cash-generating unit are derived from the business segment plans, which cover a period of up to five years. To determine the value in use for each of the cash-generating units, cash flows for a period of 10 years are discounted and aggregated with a terminal value.

Lubricants

As permitted by IAS 36, the detailed calculations of Lubricants' recoverable amount performed in the most recent detailed calculation in 2018 was used as the basis for the tests in 2019 as the criteria of IAS 36 were considered satisfied: the headroom was substantial in 2018; there have been no significant changes in the assets and liabilities; and the likelihood that the recoverable amount would be less than the carrying amount is remote.

The key assumptions to which the calculation of value in use for the Lubricants unit is most sensitive are operating unit margins, sales volumes, and discount rate. Operating margin and sales volumes assumptions used in the detailed impairment review of goodwill calculation are consistent with the assumptions used in the Lubricants unit's business plan and values assigned to these key assumptions reflect past experience. No reasonably possible change in any of these key assumptions would cause the unit's carrying amount to exceed its recoverable amount. Cash flows beyond the plan period are extrapolated using a nominal 2.8% growth rate.

15. Intangible assets

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

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

16. Investments in joint ventures

The following table provides aggregated summarized financial information relating to the group's share of joint ventures. In December 2019, BP and Bunge both contributed their Brazilian biofuels and biopower businesses into a new joint venture, BP Bunge Bioenergia. BP owns 50% of the new entity.

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

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

						$ million
Sales to joint ventures		**2019**		2018		2017
Product	**Sales**	**Amount receivable at 31 December**	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
LNG, crude oil and oil products, natural gas	**4,884**	**431**	4,603	251	3,578	352

						$ million
Purchases from joint ventures		**2019**		2018		2017
Product	**Purchases**	**Amount payable at 31 December**	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December
LNG, crude oil and oil products, natural gas, refinery operating costs, plant processing fees	**1,812**	**225**	1,336	300	1,257	176

The terms of the outstanding balances receivable from joint ventures are typically 30 to 45 days. The balances are unsecured and will be settled in cash. There are no significant provisions for doubtful debts relating to these balances and no significant expense recognized in the income statement in respect of bad or doubtful debts. Dividends receivable are not included in the table above.

17. Investments in associates

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

					$ million
			Income statement		Balance sheet
			Earnings from associates - after interest and tax		Investments in associates
	2019	2018	2017	**2019**	2018
Rosneft	**2,295**	2,283	922	**12,927**	10,074
Other associates	**386**	573	408	**7,407**	7,599
	2,681	2,856	1,330	**20,334**	17,673

The associate that is material to the group at both 31 December 2019 and 2018 is Rosneft.

BP owns 19.75% of the voting shares of Rosneft which are listed on the MICEX stock exchange in Moscow and its global depository receipts are listed on the London Stock Exchange. The Russian federal government, through its investment company JSC Rosneftegaz, owned 50.0% plus one share of the voting shares of Rosneft at 31 December 2019.

BP classifies its investment in Rosneft as an associate because, in management's judgement, BP has significant influence over Rosneft; see Interests in other entities within Note 1 for further information. The group's investment in Rosneft is a foreign operation whose functional currency is the Russian rouble. The increase in the group's equity-accounted investment balance for Rosneft at 31 December 2019 compared with 31 December 2018 principally relates to earnings from Rosneft and foreign exchange effects, which have been recognized in other comprehensive income, offset by dividends.

17. Investments in associates – continued

The value of BP's 19.75% shareholding in Rosneft based on the quoted market share price of $7.21 per share (2018 $6.18 per share) was $15,090 million at 31 December 2019 (2018 $12,934 million).

The following table provides summarized financial information relating to Rosneft. This information is presented on a 100% basis and reflects adjustments made by BP to Rosneft's own results in applying the equity method of accounting. BP adjusts Rosneft's results for the accounting required under IFRS relating to BP's purchase of its interest in Rosneft and the amortization of the deferred gain relating to the disposal of BP's interest in TNK-BP. These adjustments have increased the reported profit for 2019, as shown in the table below, compared with the amounts reported in Rosneft's IFRS financial statements. In particular, in 2018 these adjustments resulted in BP reporting a lower amount relating to impairment charges of downstream goodwill than the equivalent amounts reported by Rosneft.

			$ million
			Gross amount
	2019	2018	2017
Sales and other operating revenues	**134,046**	131,322	103,028
Profit before interest and taxation	**17,473**	18,886	9,949
Finance costs	**1,281**	2,785	2,228
Profit before taxation	**16,192**	16,101	7,721
Taxation	**3,058**	2,957	1,742
Non-controlling interests	**1,514**	1,585	1,311
Profit for the year	**11,620**	11,559	4,668
Other comprehensive income	**572**	2,086	2,810
Total comprehensive income	**12,192**	13,645	7,478
Non-current assets	**161,327**	137,038	
Current assets	**38,657**	43,438	
Total assets	**199,984**	180,476	
Current liabilities	**44,459**	41,311	
Non-current liabilities	**79,327**	78,754	
Total liabilities	**123,786**	120,065	
Net assets	**76,198**	60,411	
Less: non-controlling interests	**10,744**	9,403	
	65,454	51,008	

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

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

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

[a] From 1 October 2014, Rosneft adopted hedge accounting in relation to a portion of highly probable future export revenue denominated in US dollars over a five-year period. Foreign exchange gains and losses arising on the retranslation of borrowings denominated in currencies other than the Russian rouble and designated as hedging instruments are recognized initially in other comprehensive income, and are reclassified to the income statement as the hedged revenue is recognized.

17. Investments in associates – continued

Transactions between the group and its associates are summarized below.

Sales to associates						$ million
		2019		2018		2017
Product	**Sales**	**Amount receivable at 31 December**	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
LNG, crude oil and oil products, natural gas	**1,544**	**243**	2,064	393	1,612	216

Purchases from associates						$ million
		2019		2018		2017
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	**9,503**	**1,641**	14,112	2,069	11,613	1,681

In addition to the transactions shown in the table above, in 2018 BP acquired a 49% stake in LLC Kharampurneftegaz, a Rosneft subsidiary, which develops resources within the Kharampurskoe and Festivalnoye licence areas in Yamalo-Nenets in northern Russia. BP's interest in LLC Kharampurneftegaz is accounted for as an associate.

The terms of the outstanding balances receivable from associates are typically 30 to 45 days. The balances are unsecured and will be settled in cash. There are no significant provisions for doubtful debts relating to these balances and no significant expense recognized in the income statement in respect of bad or doubtful debts. Dividends receivable are not included in the table above.

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

BP has commitments amounting to $11,198 million (2018 $11,303 million), primarily in relation to contracts with its associates for the purchase of transportation capacity. For information on capital commitments in relation to associates see Note 13.

18. Other investments

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

[a] The majority of equity investments are unlisted.

Other investments includes $598 million relating to contingent consideration amounts arising on disposals (2018 $893 million) which are financial assets classified as measured at fair value through profit or loss. The fair value is determined using an estimate of discounted future cash flows that are expected to be received and is considered a level 3 valuation under the fair value hierarchy. Future cash flows are estimated based on inputs including oil and natural gas prices, production volumes and operating costs related to the disposed operations. The discount rate used is based on a risk-free rate adjusted for asset-specific risks.

19. Inventories

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

The inventory valuation at 31 December 2019 is stated net of a provision of $650 million (2018 $1,009 million) to write down inventories to their net realizable value, of which $290 million (2018 $604 million) relates to hydrocarbon inventories. The net credit to the income statement in the year in respect of inventory net realizable value provisions was $348 million (2018 $552 million charge), of which $309 million credit (2018 $553 million charge) related to hydrocarbon inventories.

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

20. Trade and other receivables

$ million

	2019		2018	
	Current	**Non-current**	Current	Non-current
Financial assets				
Trade receivables	**19,424**	**22**	19,414	7
Amounts receivable from joint ventures and associates	**672**	**2**	642	2
Other receivables	**3,325**	**826**	3,275	740
	23,421	**850**	23,331	749
Non-financial assets				
Gulf of Mexico oil spill trust fund reimbursement asset	**201**	**—**	214	—
Sales taxes and production taxes	**640**	**538**	790	482
Other receivables	**180**	**759**	143	603
	1,021	**1,297**	1,147	1,085
	24,442	**2,147**	24,478	1,834

In both 2019 and 2018 the group entered into non-recourse arrangements to discount certain receivables in support of supply and trading activities and the management of credit risk.

Trade and other receivables are predominantly non-interest bearing. See Note 29 for further information.

21. Valuation and qualifying accounts

$ million

	2019		2018		2017	
	Trade and other receivables	**Fixed asset investments**	Trade and other receivables	Fixed asset investments	Trade and other receivables	Fixed asset investments
At 1 January – IAS 39	**416**	**235**	335	314	392	335
Adjustment on adoption of IFRS 9	**—**	**—**	115	(85)	—	—
At 1 January – IFRS 9	**416**	**235**	450	229	392	335
Charged to costs and expenses	**206**	**28**	30	10	68	47
Charged to other accounts[a]	**(2)**	**—**	(12)	(1)	13	3
Deductions	**(111)**	**(14)**	(52)	(3)	(138)	(71)
At 31 December	**509**	**249**	416	235	335	314

[a] Principally exchange adjustments.

Valuation and qualifying accounts relating to trade and other receivables comprise expected credit loss allowances in 2019 and 2018 and impairment provisions recognized on an incurred loss basis in 2017. The adjustment on adoption of IFRS 9 relates to the additional loss allowance required by IFRS 9's expected credit loss model. The expected credit loss allowance comprises $414 million (2018 $327 million) relating to receivables that were credit-impaired at the end of the year and $95 million (2018 $89 million) relating to receivables that were not credit-impaired at the end of the year. There were no significant changes to the gross carrying amounts of trade and other receivables during the year that affected the estimation of the loss allowance at 31 December 2019.

Valuation and qualifying accounts relating to fixed asset investments comprise impairment provisions for investments in equity-accounted entities in 2019 and 2018. This includes expected credit loss allowances of $2 million (2018 $44 million) relating to loans that form part of the net investment in equity-accounted entities. The adjustment on adoption of IFRS 9 primarily relates to amounts provided against investments in equity instruments that were held at cost less impairment losses under IAS 39 but that are classified as measured at fair value through profit or loss under IFRS 9.

In addition to the amounts presented above, expected loss allowances on cash and cash equivalents classified as measured at amortized cost totalled $11 million (2018 $11 million). For further information on the group's credit risk management policies and how the group recognizes and measures expected losses see Note 29.

Valuation and qualifying accounts are deducted in the balance sheet from the assets to which they apply.

22. Trade and other payables

	2019 Current	2019 Non-current	2018 Current	$ million 2018 Non-current
Financial liabilities				
Trade payables	**30,538**	**—**	26,252	—
Amounts payable to joint ventures and associates	**1,866**	**—**	2,369	—
Payables for capital expenditure and acquisitions[a]	**3,868**	**1,196**	7,325	1,345
Payables related to the Gulf of Mexico oil spill	**1,617**	**10,863**	2,279	11,922
Other payables	**5,810**	**133**	4,980	318
	43,699	**12,192**	43,205	13,585
Non-financial liabilities				
Sales taxes, customs duties, production taxes and social security	**2,381**	**33**	2,272	35
Other payables	**749**	**401**	788	210
	3,130	**434**	3,060	245
	46,829	**12,626**	46,265	13,830

[a] 2018 includes $3,514 million deferred consideration relating to the acquisition of Petrohawk Energy Corporation from BHP Billiton Petroleum (North America) Inc. See Note 3 for further information.

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

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

Payables related to the Gulf of Mexico oil spill include amounts payable under the 2016 consent decree and settlement agreement with the United States and five Gulf coast states, including amounts payable for natural resource damages, state claims and Clean Water Act penalties. On a discounted basis the amounts included in other payables for these elements of the agreements are $5,166 million payable over 13 years, $2,742 million payable over 14 years and $3,782 million payable over 13 years respectively at 31 December 2019. Reported within net cash provided by operating activities in the group cash flow statement is a net cash outflow of $2,694 million (2018 outflow of $3,531 million, 2017 outflow of $5,336 million) related to the Gulf of Mexico oil spill, which includes payments made in relation to these agreements. For 2018 and 2017 payments under the 2012 agreement with the US government to resolve all federal criminal claims arising from the incident are also included. For full details of these agreements, see *BP Annual Report and Form 20-F 2015*.

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

23. Provisions

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

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

The decommissioning provision comprises the future cost of decommissioning oil and natural gas wells, facilities and related pipelines. The environmental provision includes provisions for costs related to the control, abatement, clean-up or elimination of environmental pollution relating to soil, groundwater, surface water and sediment contamination. The litigation and claims category includes provisions for matters related to, for example, commercial disputes, product liability, and allegations of exposures of third parties to toxic substances. Included within the other category at 31 December 2019 are provisions for deferred employee compensation of $311 million (2018 $338 million).

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

23. Provisions – continued

Gulf of Mexico oil spill

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

Litigation and claims- PSC settlements

The Economic and Property Damages Settlement Agreement (EPD Settlement Agreement) with the Plaintiff's Steering Committee (PSC) provides for a court-supervised settlement programme ,the DHCSSP, which commenced operation on 4 June 2012. A separate claims administrator was appointed to pay medical claims and to implement other aspects of the Medical Benefits Class Action Settlement. For further information on the PSC settlements, see Legal proceedings on page 319.

The litigation and claims provision reflects the latest estimate for the remaining costs associated with the PSC settlements. These costs relate predominantly to business economic loss (BEL) claims and associated administration costs. Only a very small number of claims remained to be determined by the end of 2019 however certain BEL claims determined by the DHCSSP have been and continue to be appealed by BP and/or the claimants. Claims under appeal will ultimately only be resolved once the full judicial appeals process has been concluded, including appeals to the Federal District Court and Fifth Circuit, as may be the case, or when settlements are reached with individual claimants. Depending upon the ultimate resolution of these claims, the amounts payable may differ from those currently provided. Payments to resolve outstanding claims under the PSC settlements are expected to be made over the next couple of years. The timing of payments, however, is uncertain, and, in particular, will be impacted by how long it takes to resolve claims that have been appealed and may be appealed in the future.

24. Pensions and other post-retirement benefits

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

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

The primary pension arrangement in the UK is a funded final salary pension plan under which retired employees draw the majority of their benefit as an annuity. This pension plan is governed by a corporate trustee whose board is composed of four member-nominated directors, four company-nominated directors, an independent director and an independent chairman nominated by the company. The trustee board is required by law to act in the best interests of the plan participants and is responsible for setting certain policies, such as investment policies of the plan. The UK plan is closed to new joiners but remains open to ongoing accrual for current members. New joiners in the UK are eligible for membership of a defined contribution plan.

In the US, all pension benefits now accrue under a cash balance formula. Benefits previously accrued under final salary formulas are legally protected. Retiring US employees typically take their pension benefit in the form of a lump sum payment upon retirement. The plan is funded and its assets are overseen by a fiduciary Investment Committee. During 2019 the committee was composed of six BP employees appointed by the president of BP Corporation North America Inc. (the appointing officer). A seventh BP employee was added to the committee on 1 January 2020. The Investment Committee is required by law to act in the best interests of the plan participants and is responsible for setting certain policies, such as the investment policies of the plan. US employees are also eligible to participate in a defined contribution (401k) plan in which employee contributions are matched with company contributions. In the US, group companies also provide post-retirement healthcare to retired employees and their dependants (and, in certain cases, life insurance coverage); the entitlement to these benefits is usually based on the employee remaining in service until a specified age and completion of a minimum period of service.

In the Eurozone, there are defined benefit pension plans in Germany, France, the Netherlands and other countries. In Germany and France, the majority of the pensions are unfunded, in line with market practice. In Germany, the group's largest Eurozone plan, employees receive a pension and also have a choice to supplement their core pension through salary sacrifice. For employees who joined since 2002, the core pension benefit is a career average plan with retirement benefits based on such factors as an employee's pensionable salary and length of service. The returns on the notional contributions made by both the company and employees are based on the interest rate which is set out in German tax law. Retired German employees take their pension benefit typically in the form of an annuity. The German plans are governed by legal agreements between BP and the works council or between BP and the trade union.

The level of contributions to funded defined benefit plans is the amount needed to provide adequate funds to meet pension obligations as they fall due. During 2019 the aggregate level of contributions was $349 million (2018 $610 million and 2017 $637 million). The aggregate level of contributions in 2020 is expected to be approximately $550 million, and includes contributions in all countries that we expect to be required to make contributions by law or under contractual agreements, as well as an allowance for discretionary funding.

For the primary UK plan there is a funding agreement between the group and the trustee. On an annual basis the latest funding position is reviewed and a schedule of contributions is agreed covering the next five years. Contractually committed funding amounted to $1,276 million at 31 December 2019, all of which relates to future service. This amount is included in the group's committed cash flows relating to pensions and other post-retirement benefit plans as set out in the table of contractual obligations on page 302.

The surplus relating to the primary UK pension plan is recognized on the balance sheet on the basis that the company is entitled to a refund of any remaining assets once all members have left the plan.

Pension contributions in the US are determined by legislation and are supplemented by discretionary contributions. No contributions were made into the primary US pension plan in 2019 and no statutory funding requirement is expected in the next 12 months.

The surplus relating to the primary US fund is recognized on the balance sheet on the basis that economic benefit can be gained from the surplus through a reduction in future contributions.

There was no minimum funding requirement for the US plan, and no significant minimum funding requirements in other countries at 31 December 2019.

24. Pensions and other post-retirement benefits – continued

The obligation and cost of providing pensions and other post-retirement benefits is assessed annually using the projected unit credit method. The date of the most recent actuarial review was 31 December 2019. The UK plans are subject to a formal actuarial valuation every three years; valuations are required more frequently in many other countries. The most recent formal actuarial valuation of the UK pension plans was as at 31 December 2017. A valuation of the US plan and largest Eurozone plans are carried out annually.

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

									%
Financial assumptions used to determine benefit obligation			UK			US			Eurozone
	2019	2018	2017	**2019**	2018	2017	**2019**	2018	2017
Discount rate for plan liabilities	**2.1**	2.9	2.5	**3.1**	4.1	3.5	**1.3**	2.0	1.9
Rate of increase in salaries	**3.4**	3.8	4.1	**3.9**	3.9	4.1	**3.1**	3.1	3.0
Rate of increase for pensions in payment	**2.7**	3.0	2.9	**—**	—	—	**1.5**	1.5	1.4
Rate of increase in deferred pensions	**2.7**	3.0	2.9	**—**	—	—	**0.5**	0.5	0.6
Inflation for plan liabilities	**2.7**	3.1	3.1	**1.5**	1.5	1.7	**1.7**	1.7	1.6

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

The discount rate assumptions are based on third-party AA corporate bond indices and for our largest plans in the UK, US and the Eurozone we use yields that reflect the maturity profile of the expected benefit payments. The inflation rate assumptions for our UK and US plans are based on the difference between the yields on index-linked and fixed-interest long-term government bonds. In other countries, including the Eurozone, we use this approach, or advice from the local actuary depending on the information available. The inflation assumptions are used to determine the rate of increase for pensions in payment and the rate of increase in deferred pensions where there is such an increase.

The assumptions for the rate of increase in salaries are based on the inflation assumption plus an allowance for expected long-term real salary growth. These include an allowance for promotion-related salary growth, of up to 0.8% depending on country.

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

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

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

A significant proportion of the assets are held in equities, which are expected to generate a higher level of return over the long term, with an acceptable level of risk. In order to provide reasonable assurance that no single security or type of security has an unwarranted impact on the total portfolio, the investment portfolios are highly diversified.

The trustee's long-term investment objective for the primary UK plan as it matures is to invest in assets whose value changes in the same way as the plan liabilities, in order to reduce the level of funding risk. To move towards this objective, the UK plan uses a liability driven investment (LDI) approach for part of the portfolio, investing primarily in government bonds to achieve this matching effect for the most significant plan liability assumptions of interest rate and inflation rate. This is partly funded by short-term sale and repurchase agreements, whereby the plan borrows money using existing bonds as security and which will be bought back at a specified price at an agreed future date. The funds raised are used to invest in further bonds to increase the proportion of assets which match the plan liabilities. The borrowings are shown separately in the analysis of pension plan assets in the table below.

For the primary UK pension plan there is an agreement with the trustee to increase the proportion of assets with liability matching characteristics over time primarily by reducing the proportion of plan assets held as equities and increasing the proportion held as bonds. There is a similar agreement in place for the primary US plan. During 2019, the UK and the US plans switched 2% and nil of plan assets respectively from equities to bonds (2018 12.5% and 10% respectively).

24. Pensions and other post-retirement benefits – continued

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

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

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

Some of the group's pension plans in the Eurozone and other countries use derivative financial instruments as part of their asset mix to manage the level of risk. The fair value of these instruments are included in other assets in the table below. The UK and US plans do not use derivative financial instruments.

The group's main pension plans do not invest directly in either securities or property/real estate of the company or of any subsidiary.

The fair values of the various categories of assets held by the defined benefit plans at 31 December are presented in the table below, including the effects of derivative financial instruments. Movements in the fair value of plan assets during the year are shown in detail in the table on page 197.

					$ million
	UK[a]	US[b]	Eurozone	Other	Total
Fair value of pension plan assets					
At 31 December 2019					
Listed equities – developed markets	**6,285**	**1,290**	**495**	**371**	**8,441**
– emerging markets	**1,096**	**124**	**61**	**64**	**1,345**
Private equity[c]	**2,675**	**1,474**	**—**	**3**	**4,152**
Government issued nominal bonds[d]	**4,884**	**2,100**	**959**	**572**	**8,515**
Government issued index-linked bonds[d]	**19,462**	**—**	**100**	**—**	**19,562**
Corporate bonds[d]	**6,132**	**2,304**	**569**	**256**	**9,261**
Property[e]	**2,507**	**—**	**96**	**27**	**2,630**
Cash	**426**	**289**	**33**	**93**	**841**
Other	**98**	**74**	**30**	**26**	**228**
Debt (repurchase agreements) used to fund liability driven investments	**(7,436)**	**—**	**—**	**—**	**(7,436)**
	36,129	**7,655**	**2,343**	**1,412**	**47,539**
At 31 December 2018					
Listed equities – developed markets	5,191	1,238	413	306	7,148
– emerging markets	950	63	65	56	1,134
Private equity[c]	2,792	1,495	—	4	4,291
Government issued nominal bonds[d]	4,263	2,072	895	533	7,763
Government issued index-linked bonds[d]	17,491	—	102	—	17,593
Corporate bonds[d]	4,606	2,184	506	243	7,539
Property[e]	2,311	6	57	25	2,399
Cash	376	73	42	83	574
Other	116	64	32	40	252
Debt (repurchase agreements) used to fund liability driven investments	(6,011)	—	—	—	(6,011)
	32,085	7,195	2,112	1,290	42,682
At 31 December 2017					
Listed equities – developed markets	9,548	2,158	537	376	12,619
– emerging markets	2,220	220	83	53	2,576
Private equity[c]	2,679	1,461	—	—	4,140
Government issued nominal bonds[d]	2,663	1,777	941	545	5,926
Government issued index-linked bonds[d]	16,177	—	2	—	16,179
Corporate bonds[d]	4,682	2,024	546	272	7,524
Property[e]	2,211	6	71	30	2,318
Cash	390	80	21	98	589
Other	104	53	23	45	225
Debt (repurchase agreements) used to fund liability driven investments	(5,583)	—	—	—	(5,583)
	35,091	7,779	2,224	1,419	46,513

[a] Bonds held by the UK pension plans are denominated in sterling. Property held by the UK pension plans is in the United Kingdom.

[b] Bonds held by the US pension plans are denominated in US dollars.

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

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

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

24. Pensions and other post-retirement benefits – continued

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

[a] The costs of managing plan investments are offset against the investment return, the costs of administering pension plan benefits are generally included in current service cost and the costs of administering other post-retirement benefit plans are included in the benefit obligation.

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

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

[d] The benefit payments amount shown above comprises $2,304 million benefits and $346 million settlements, plus $37 million of plan expenses incurred in the administration of the benefit.

[e] The benefit obligation for the US is made up of $7,789 million for pension liabilities and $2,330 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $4,567 million for pension liabilities in Germany which is largely unfunded.

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

[g] The fair value of plan assets includes borrowings related to the LDI programme as described on page 196.

24. Pensions and other post-retirement benefits – continued

					$ million
					2018
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit or loss					
Current service cost[a]	295	299	84	43	721
Past service cost[b]	15	—	9	4	28
Settlement[b]	—	—	17	—	17
Operating charge relating to defined benefit plans	310	299	110	47	766
Payments to defined contribution plans	38	178	5	40	261
Total operating charge	348	477	115	87	1,027
Interest income on plan assets[a]	(868)	(262)	(44)	(45)	(1,219)
Interest on plan liabilities	774	369	136	67	1,346
Other finance (income) expense	(94)	107	92	22	127
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	(722)	(256)	(69)	(36)	(1,083)
Change in financial assumptions underlying the present value of the plan liabilities	1,770	945	14	65	2,794
Change in demographic assumptions underlying the present value of the plan liabilities	123	(9)	(42)	7	79
Experience gains and losses arising on the plan liabilities	520	41	(43)	9	527
Remeasurements recognized in other comprehensive income	1,691	721	(140)	45	2,317
Movements in benefit obligation during the year					
Benefit obligation at 1 January	31,513	10,820	7,275	1,873	51,481
Exchange adjustments	(1,589)	—	(303)	(113)	(2,005)
Operating charge relating to defined benefit plans	310	299	110	47	766
Interest cost	774	369	136	67	1,346
Contributions by plan participants[c]	21	—	2	7	30
Benefit payments (funded plans)[d]	(1,780)	(597)	(84)	(83)	(2,544)
Benefit payments (unfunded plans)[d]	(6)	(218)	(301)	(17)	(542)
Disposals	—	—	—	(14)	(14)
Remeasurements	(2,413)	(977)	71	(81)	(3,400)
Benefit obligation at 31 December[a e]	26,830	9,696	6,906	1,686	45,118
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	35,091	7,779	2,224	1,419	46,513
Exchange adjustments	(1,883)	—	(93)	(73)	(2,049)
Interest income on plan assets[a f]	868	262	44	45	1,219
Contributions by plan participants[c]	21	—	2	7	30
Contributions by employers (funded plans)	490	7	88	25	610
Benefit payments (funded plans)[d]	(1,780)	(597)	(84)	(83)	(2,544)
Disposals	—	—	—	(14)	(14)
Remeasurements[f]	(722)	(256)	(69)	(36)	(1,083)
Fair value of plan assets at 31 December[g]	32,085	7,195	2,112	1,290	42,682
Surplus (deficit) at 31 December	5,255	(2,501)	(4,794)	(396)	(2,436)
Represented by					
Asset recognized	5,473	418	29	35	5,955
Liability recognized	(218)	(2,919)	(4,823)	(431)	(8,391)
	5,255	(2,501)	(4,794)	(396)	(2,436)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	5,473	396	(152)	(97)	5,620
Unfunded	(218)	(2,897)	(4,642)	(299)	(8,056)
	5,255	(2,501)	(4,794)	(396)	(2,436)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(26,612)	(6,799)	(2,264)	(1,387)	(37,062)
Unfunded	(218)	(2,897)	(4,642)	(299)	(8,056)
	(26,830)	(9,696)	(6,906)	(1,686)	(45,118)

[a] The costs of managing plan investments are offset against the investment return, the costs of administering pension plan benefits are generally included in current service cost and the costs of administering other post-retirement benefit plans are included in the benefit obligation.

[b] Past service costs and settlements have arisen from restructuring programmes and represent charges for special termination benefits representing the increased liability arising as a result of early retirements mostly in the UK and Eurozone.

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

[d] The benefit payments amount shown above comprises $3,046 million benefits and $2 million settlements, plus $38 million of plan expenses incurred in the administration of the benefit.

[e] The benefit obligation for the US is made up of $7,290 million for pension liabilities and $2,406 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $4,328 million for pension liabilities in Germany which is largely unfunded.

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

[g] The fair value of plan assets includes borrowings related to the LDI programme as described on page 196.

24. Pensions and other post-retirement benefits – continued

					$ million
					2017
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit or loss					
Current service cost[a]	357	292	85	46	780
Past service cost[b]	12	—	5	(1)	16
Settlement	—	—	13	—	13
Operating charge relating to defined benefit plans	369	292	103	45	809
Payments to defined contribution plans	31	191	7	38	267
Total operating charge	400	483	110	83	1,076
Interest income on plan assets[a]	(845)	(266)	(37)	(48)	(1,196)
Interest on plan liabilities	831	393	121	71	1,416
Other finance (income) expense	(14)	127	84	23	220
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	2,396	826	30	43	3,295
Change in financial assumptions underlying the present value of the plan liabilities	(236)	(514)	336	(47)	(461)
Change in demographic assumptions underlying the present value of the plan liabilities	734	72	—	(23)	783
Experience gains and losses arising on the plan liabilities	91	(40)	(36)	14	29
Remeasurements recognized in other comprehensive income	2,985	344	330	(13)	3,646

[a] The costs of managing plan investments are offset against the investment return, the costs of administering pension plan benefits are generally included in current service cost and the costs of administering other post-retirement benefit plans are included in the benefit obligation.

[b] Past service costs have arisen from restructuring programmes and represent a combination of credits as a result of the curtailment in the pension arrangements of a number of employees mostly in the US and charges for special termination benefits representing the increased liability arising as a result of early retirements mostly in the UK and Eurozone.

Sensitivity analysis

The discount rate, inflation, salary growth and the mortality assumptions all have a significant effect on the amounts reported. A one-percentage point change, in isolation, in certain assumptions as at 31 December 2019 for the group's pensions and other post-retirement benefit expense would have had the effects shown in the tables below. The effects shown for the expense in 2020 comprise the total of current service cost and net finance income or expense.

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

[a] The amounts presented reflect that the discount rate is used to determine the asset interest income as well as the interest cost on the obligation.

[b] The amounts presented reflect the total impact of an inflation rate change on the assumptions for rate of increase in salaries, pensions in payment and deferred pensions.

			$ million
			One year increase
	UK	**US**	**Eurozone**
Longevity			
Effect on expense in 2020	**31**	**6**	**9**
Effect on obligation at 31 December 2019	**1,140**	**147**	**306**

Estimated future benefit payments and the weighted average duration of defined benefit obligations

The expected benefit payments, which reflect expected future service, as appropriate, but exclude plan expenses, up until 2029 and the weighted average duration of the defined benefit obligations at 31 December 2019 are as follows:

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

25. Cash and cash equivalents

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

Cash and cash equivalents comprise cash in hand; current balances with banks and similar institutions; term deposits of three months or less with banks and similar institutions; money market funds and commercial paper. The carrying amounts of cash and term bank deposits approximate their fair values. Substantially all of the other cash equivalents are categorized within level 1 of the fair value hierarchy.

Cash and cash equivalents at 31 December 2019 includes $1,676 million (2018 $1,350 million) that is restricted. The restricted cash balances include amounts required to cover initial margin on trading exchanges and certain cash balances which are subject to exchange controls.

The group holds $4,678 million (2018 $4,693 million) of cash and cash equivalents outside the UK and it is not expected that any significant tax will arise on repatriation.

26. Finance debt

						$ million
			2019			2018
	Current	**Non-current**	**Total**	Current	Non-current	Total
Borrowings	**10,487**	**57,237**	**67,724**	9,329	55,803	65,132

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

The main elements of current borrowings are the current portion of long-term borrowings that is due to be repaid in the next 12 months of $8,166 million (2018 $7,175 million) and issued commercial paper of $2,279 million (2018 $2,040 million). Finance debt does not include accrued interest, which is reported within other payables.

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

	Fixed rate debt			**Floating rate debt**		**Total**
	Weighted average interest rate %	**Weighted average time for which rate is fixed Years**	**Amount $ million**	**Weighted average interest rate %**	**Amount $ million**	**Amount $ million**
						2019
US dollar	**4**	**5**	**25,634**	**3**	**41,871**	**67,505**
Other currencies	**6**	**10**	**183**	**7**	**36**	**219**
			25,817		**41,907**	**67,724**
						2018
US dollar	4	4	17,264	4	47,461	64,725
Other currencies	5	5	323	8	84	407
			17,587		47,545	65,132

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

Fair values

The estimated fair value of finance debt is shown in the table below together with the carrying amount as reflected in the balance sheet.

Long-term borrowings in the table below include the portion of debt that matures in the 12 months from 31 December 2019, whereas in the group balance sheet the amount is reported within current finance debt.

The carrying amount of the group's short-term borrowings, comprising mainly of commercial paper, approximates their fair value. The fair values of the significant majority of the group's long-term borrowings are determined using quoted prices in active markets, and so fall within level 1 of the fair value hierarchy. Where quoted prices are not available, quoted prices for similar instruments in active markets are used and such measurements are therefore categorized in level 2 of the fair value hierarchy.

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

27. Capital disclosures and net debt

The group defines capital as total equity. We maintain our financial framework to support the pursuit of value growth for shareholders, while ensuring a secure financial base.

The group monitors capital on basis of gearing (previously termed 'net debt ratio'), that is, the ratio of net debt to net debt plus equity. Net debt is calculated as finance debt, as shown in the balance sheet, plus the fair value of associated derivative financial instruments that are used to hedge foreign exchange and interest rate risks relating to finance debt for which hedge accounting is applied, less cash and cash equivalents. Net debt and gearing are non-GAAP measures. BP believes these measures provide useful information to investors. Net debt enables investors to see the economic effect of finance debt, related hedges and cash and cash equivalents in total. Gearing enables investors to see how significant net debt is relative to equity from shareholders. The derivatives are reported on the balance sheet within the headings 'Derivative financial instruments'. All components of equity are included in the denominator of the calculation.

We aim to manage the gearing within a 20-30% band and maintain a significant liquidity buffer. At 31 December 2019, gearing was 31.1% (2018 30.0%).

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

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

[a] Derivative financial instruments entered into for the purpose of managing interest rate and foreign currency exchange risk associated with net debt with a fair value liability position of $601 million (2018 liability of $827 million) are not included in the calculation of net debt shown above as hedge accounting was not applied for these instruments. The movement in the year is attributable to a net cash out flow of $286 million (2018 net cash flow $nil) and fair value loss of $60 million (2018 fair value losses of $193 million).

Net debt including leases is shown in the table below.

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

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

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

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

28. Leases

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

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

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

[a] Comparative information represents finance leases accounted for under IAS 17

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

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

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

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

29. Financial instruments and financial risk factors

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

					$ million
At 31 December 2019	**Note**	**Measured at amortized cost**	**Mandatorily measured at fair value through profit or loss**	**Derivative hedging instruments**	**Total carrying amount**
Financial assets					
Other investments	**18**	**—**	**1,445**	**—**	**1,445**
Loans		**906**	**63**	**—**	**969**
Trade and other receivables	**20**	**24,271**	**—**	**—**	**24,271**
Derivative financial instruments	**30**	**—**	**9,984**	**483**	**10,467**
Cash and cash equivalents	**25**	**18,183**	**4,289**	**—**	**22,472**
Financial liabilities					
Trade and other payables	**22**	**(55,891)**	**—**	**—**	**(55,891)**
Derivative financial instruments	**30**	**—**	**(8,122)**	**(676)**	**(8,798)**
Accruals		**(6,062)**	**—**	**—**	**(6,062)**
Lease liabilities	**28**	**(9,722)**	**—**	**—**	**(9,722)**
Finance debt[a]	**26**	**(67,724)**	**—**	**—**	**(67,724)**
		(96,039)	**7,659**	**(193)**	**(88,573)**

$ million

At 31 December 2018	Note	Measured at amortized cost	Mandatorily measured at fair value through profit or loss	Derivative hedging instruments	Total carrying amount
Financial assets					
Other investments	18	—	1,563	—	1,563
Loans		839	124	—	963
Trade and other receivables	20	24,080	—	—	24,080
Derivative financial instruments	30	—	8,564	427	8,991
Cash and cash equivalents	25	20,366	2,102	—	22,468
Financial liabilities					
Trade and other payables	22	(56,790)	—	—	(56,790)
Derivative financial instruments	30	—	(7,685)	(1,248)	(8,933)
Accruals		(5,201)	—	—	(5,201)
Lease liabilities	28	(667)	—	—	(667)
Finance debt[a]	26	(65,132)	—	—	(65,132)
		(82,505)	4,668	(821)	(78,658)

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

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

Information on gains and losses on derivative financial assets and financial liabilities classified as measured at fair value through profit or loss is provided in the derivative gains and losses section of Note 30. Fair value gains and losses related to other assets and liabilities classified as measured at fair value through profit or loss totalled a net loss of $129 million. Dividend income of $20 million (2018 $8 million) from investments in equity instruments classified as measured at fair value through profit or loss is presented within other income - see Note 7.

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

Financial risk factors

The group is exposed to a number of different financial risks arising from natural business exposures as well as its use of financial instruments including market risks relating to commodity prices; foreign currency exchange rates and interest rates; credit risk; and liquidity risk.

The group financial risk committee (GFRC) advises the group chief financial officer (CFO) who oversees the management of these risks. The GFRC is chaired by the CFO and consists of a group of senior managers including the group treasurer and the heads of the group finance, tax and the integrated supply and trading functions. The purpose of the committee is to advise on financial risks and the appropriate financial risk governance framework for the group. The committee provides assurance to the CFO and the group chief executive (GCE), and via the GCE to the board, that the group's financial risk-taking activity is governed by appropriate policies and procedures and that financial risks are identified, measured and managed in accordance with group policies and group risk appetite.

The group's trading activities in the oil, natural gas, LNG and power markets are managed within the integrated supply and trading function. Treasury holds foreign exchange and interest-rate products in the financial markets to hedge group exposures related to debt issuance; the compliance, control, and risk management processes for these activities are managed within the treasury function. All other foreign exchange and interest rate activities within financial markets are performed within the integrated supply and trading function and are also underpinned by the compliance, control and risk management infrastructure common to the activities of BP's integrated supply and trading function. All derivative activity is carried out by specialist teams that have the appropriate skills, experience and supervision. These teams are subject to close financial and management control.

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

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

(a) Market risk

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

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

29. Financial instruments and financial risk factors – continued

(i) Commodity price risk

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

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

(ii) Foreign currency exchange risk

Since BP has global operations, fluctuations in foreign currency exchange rates can have a significant effect on the group's reported results and future expenditure commitments. The effects of most exchange rate fluctuations are absorbed in business operating results through changing cost competitiveness, lags in market adjustment to movements in rates and translation differences accounted for on specific transactions. For this reason, the total effect of exchange rate fluctuations is not identifiable separately in the group's reported results. The main underlying economic currency of the group's cash flows is the US dollar. This is because BP's major product, oil, is priced internationally in US dollars. BP's foreign currency exchange management policy is to limit economic and material transactional exposures arising from currency movements against the US dollar. The group co-ordinates the handling of foreign currency exchange risks centrally, by netting off naturally-occurring opposite exposures wherever possible and then managing any material residual foreign currency exchange risks.

Most of the group's borrowings are in US dollars or are hedged with respect to the US dollar. At 31 December 2019, the total foreign currency borrowings not swapped into US dollars amounted to $219 million (2018 $407 million excludes leases).

The group manages the net residual foreign currency exposures by constantly reviewing the foreign currency economic value at risk and aims to manage such risk to keep the 12-month foreign currency value at risk below $400 million. At no point over the past three years did the value at risk exceed the maximum risk limit. A continuous assessment is made in respect to the group's foreign currency exposures to capture hedging requirements.

During the year, hedge accounting was applied to foreign currency exposure to highly probable forecast capital expenditure commitments. The group fixes the US dollar cost of non-US dollar supplies by using currency forwards for the highly probable forecast capital expenditure; the exposures are in sterling, euro, Australian dollar and Korean won. At 31 December 2019 the most significant open contracts in place were for $106 million sterling (2018 $434 million sterling).

Where the group enters into foreign currency exchange contracts for entrepreneurial trading purposes the activity is controlled using trading value-at-risk techniques as explained in (i) commodity price risk above.

(iii) Interest rate risk

BP is also exposed to interest rate risk from the possibility that changes in interest rates will affect future cash flows or the fair values of its financial instruments, principally finance debt. While the group issues debt in a variety of currencies based on market opportunities, it uses derivatives to swap the debt to a floating rate exposure, mainly to US dollar floating, but in certain defined circumstances maintains a US dollar fixed rate exposure for a proportion of debt. The proportion of floating rate debt net of interest rate swaps at 31 December 2019 was 62% of total finance debt outstanding (2018 73% excludes leases). The weighted average interest rate on finance debt at 31 December 2019 was 3% (2018 4%) and the weighted average maturity of fixed rate debt was five years (2018 four years excludes leases).

The group's earnings are sensitive to changes in interest rates on the floating rate element of the group's finance debt. If the interest rates applicable to floating rate instruments were to have changed by one percentage point on 1 January 2020, it is estimated that the group's finance costs for 2020 would change by approximately $419 million (2018 $475 million).

(b) Credit risk

Credit risk is the risk that a customer or counterparty to a financial instrument will fail to perform or fail to pay amounts due causing financial loss to the group and arises from cash and cash equivalents, derivative financial instruments and deposits with financial institutions and principally from credit exposures to customers relating to outstanding receivables. Credit exposure also exists in relation to guarantees issued by group companies under which the outstanding exposure incremental to that recognized on the balance sheet at 31 December 2019 was $692 million (2018 $696 million) in respect of liabilities of joint ventures and associates and $523 million (2018 $432 million) in respect of liabilities of other third parties.

The group has a credit policy, approved by the CFO that is designed to ensure that consistent processes are in place throughout the group to measure and control credit risk. Credit risk is considered as part of the risk-reward balance of doing business. On entering into any business contract the extent to which the arrangement exposes the group to credit risk is considered. Key requirements of the policy include segregation of credit approval authorities from any sales, marketing or trading teams authorized to incur credit risk; the establishment of credit systems and processes to ensure that all counterparty exposure is rated and that all counterparty exposure and limits can be monitored and reported; and the timely identification and reporting of any non-approved credit exposures and credit losses. While each segment is responsible for its own credit risk management and reporting consistent with group policy, the treasury function holds group-wide credit risk authority and oversight responsibility for exposure to banks and financial institutions.

29. Financial instruments and financial risk factors – continued

For the purposes of financial reporting the group calculates expected loss allowances based on the maximum contractual period over which the group is exposed to credit risk. Lifetime expected credit losses are recognized for trade receivables and the credit risk associated with the significant majority of financial assets measured at amortized cost is considered to be low. Since the tenor of substantially all of the group's in-scope financial assets is less than 12 months there is no significant difference between the measurement of 12-month and lifetime expected credit losses. Expected loss allowances for financial guarantee contracts are typically lower than their fair value less, where appropriate, amortization. Financial assets are considered to be credit-impaired when there is reasonable and supportable evidence that one or more events that have a detrimental impact on the estimated future cash flows of the financial asset have occurred. This includes observable data concerning significant financial difficulty of the counterparty; a breach of contract; concession being granted to the counterparty for economic or contractual reasons relating to the counterparty's financial difficulty, that would not otherwise be considered; it becoming probable that the counterparty will enter bankruptcy or other financial re-organization or an active market for the financial asset disappearing because of financial difficulties. The group also applies a rebuttable presumption that an asset is credit-impaired when contractual payments are more than 30 days past due. Where the group has no reasonable expectation of recovering a financial asset in its entirety or a portion thereof, for example where all legal avenues for collection of amounts due have been exhausted, the financial asset (or relevant portion) is written off.

The measurement of expected credit losses is a function of the probability of default, loss given default (i.e. the magnitude of the loss after recovery if there is a default) and the exposure at default (i.e. the asset's carrying amount). The group allocates a credit risk rating to exposures based on data that is determined to be predictive of the risk of loss, including but not limited to external ratings. Probabilities of default derived from historical, current and future-looking market data are assigned by credit risk rating with a loss given default based on historical experience and relevant market and academic research applied by exposure type. Experienced credit judgement is applied to ensure probabilities of default are reflective of the credit risk associated with the group's exposures. Credit enhancements that would reduce the group's credit losses in the event of default are reflected in the calculation when they are considered integral to the related asset.

The maximum credit exposure associated with financial assets is equal to the carrying amount. The group does not aim to remove credit risk entirely but expects to experience a certain level of credit losses. As at 31 December 2019, the group had in place credit enhancements designed to mitigate approximately $7.0 billion (2018 $7.3 billion) of credit risk, of which substantially all relates to assets in the scope of IFRS 9's impairment requirements. Credit enhancements include standby and documentary letters of credit, bank guarantees, insurance and liens which are typically taken out with financial institutions who have investment grade credit ratings, or are liens over assets held by the counterparty of the related receivables. Reports are regularly prepared and presented to the GFRC that cover the group's overall credit exposure and expected loss trends, exposure by segment, and overall quality of the portfolio.

Management information used to monitor credit risk, which reflects the impact of credit enhancements, indicates that the risk profile of financial assets which are subject to review for impairment under IFRS 9 is as set out below.

		%
As at 31 December	2019	2018
AAA to AA-	**16%**	22%
A+ to A-	**51%**	41%
BBB+ to BBB-	**13%**	16%
BB+ to BB-	**7%**	8%
B+ to B-	**11%**	11%
CCC+ and below	**2%**	2%

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

Financial instruments subject to offsetting, enforceable master netting arrangements and similar agreements

The following table shows the amounts recognized for financial assets and liabilities which are subject to offsetting arrangements on a gross basis, and the amounts offset in the balance sheet.

Amounts which cannot be offset under IFRS, but which could be settled net under the terms of master netting agreements if certain conditions arise, and collateral received or pledged, are also presented in the table to show the total net exposure of the group.

				Related amounts not set off in the balance sheet		$ million
At 31 December 2019	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	**13,191**	**(2,724)**	**10,467**	**(1,971)**	**(206)**	**8,290**
Derivative liabilities	**(11,445)**	**2,724**	**(8,721)**	**1,971**	**—**	**(6,750)**
Trade and other receivables	**10,661**	**(5,211)**	**5,450**	**(961)**	**(190)**	**4,299**
Trade and other payables	**(10,266)**	**5,211**	**(5,055)**	**961**	**—**	**(4,094)**
At 31 December 2018						
Derivative assets	11,502	(2,511)	8,991	(2,079)	(299)	6,613
Derivative liabilities	(11,337)	2,511	(8,826)	2,079	—	(6,747)
Trade and other receivables	11,296	(5,390)	5,906	(1,020)	(169)	4,717
Trade and other payables	(10,797)	5,390	(5,407)	1,020	—	(4,387)

29. Financial instruments and financial risk factors – continued

(c) Liquidity risk

Liquidity risk is the risk that suitable sources of funding for the group's business activities may not be available. The group's liquidity is managed centrally with operating units forecasting their cash and currency requirements to the central treasury function. Unless restricted by local regulations, generally subsidiaries pool their cash surpluses to the treasury function, which will then arrange to fund other subsidiaries' requirements, or invest any net surplus in the market or arrange for necessary external borrowings, while managing the group's overall net currency positions.

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

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

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

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

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

During 2019, $8 billion (2018 $9 billion) of long-term taxable bonds were issued with terms ranging from one to thirty years. Commercial paper is issued at competitive rates to meet short-term borrowing requirements as and when needed.

As a further liquidity measure, the group continues to maintain suitable levels of cash and cash equivalents, amounting to $22.5 billion at 31 December 2019 (2018 $22.5 billion), primarily invested with highly rated banks or money market funds and readily accessible at immediate and short notice. At 31 December 2019, the group had substantial amounts of undrawn borrowing facilities available, consisting of $7,625 million (2018 $7,625 million) of standby facilities, all of which is available to draw and repay up to the first half of 2022. These facilities are with 25 international banks, and borrowings under them would be at pre-agreed rates. On 13th March the group entered into a committed $10,000 million credit facility which is available for two years at pre-agreed margins.

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

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

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

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

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

29. Financial instruments and financial risk factors – continued

The table below shows the timing of cash outflows for derivative financial instruments entered into for the purpose of managing interest rate and foreign currency exchange risk associated with finance debt, whether or not hedge accounting is applied, based upon contractual payment dates. The amounts reflect the gross settlement amount where the pay leg of a derivative will be settled separately from the receive leg, as in the case of cross-currency swaps hedging non-US dollar finance debt. The swaps are with high investment-grade counterparties and therefore the settlement-day risk exposure is considered to be negligible. Not shown in the table are the gross settlement amounts (inflows) for the receive leg of derivatives that are settled separately from the pay leg, which amount to $24,787 million at 31 December 2019 (2018 $22,453 million) to be received on the same day as the related cash outflows. For further information on our derivative financial instruments, see Note 30.

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

30. Derivative financial instruments

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

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

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

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

Over-the-counter (OTC) financial swaps and physical commodity sale and purchase contracts are generally valued using readily available information in the public markets and quotations provided by brokers and price index developers. These quotes are corroborated with market data and are categorized within level 2 of the fair value hierarchy.

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

30. Derivative financial instruments – continued

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

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

Derivatives held for trading

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

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

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

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

							$ million
							2018
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	48	12	9	—	—	—	69
Oil price derivatives	1,916	363	53	25	4	—	2,361
Natural gas price derivatives	1,333	708	542	452	352	1,400	4,787
Power price derivatives	540	276	158	79	55	132	1,240
Other derivatives	—	—	—	—	107	—	107
	3,837	1,359	762	556	518	1,532	8,564

30. Derivative financial instruments – continued

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

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

							$ million
							2018
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(299)	(71)	(256)	(171)	(3)	(98)	(898)
Oil price derivatives	(1,560)	(232)	(43)	(12)	(2)	—	(1,849)
Natural gas price derivatives	(1,030)	(557)	(391)	(338)	(285)	(1,287)	(3,888)
Power price derivatives	(401)	(213)	(95)	(54)	(47)	(133)	(943)
	(3,290)	(1,073)	(785)	(575)	(337)	(1,518)	(7,578)

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

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

							$ million
							2018
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Fair value of derivative assets							
Level 1	111	14	3	—	—	—	128
Level 2	5,000	1,362	504	262	120	72	7,320
Level 3	491	385	353	331	427	1,640	3,627
	5,602	1,761	860	593	547	1,712	11,075
Less: netting by counterparty	(1,765)	(402)	(98)	(37)	(29)	(180)	(2,511)
	3,837	1,359	762	556	518	1,532	8,564
Fair value of derivative liabilities							
Level 1	(156)	(11)	(2)	(2)	—	—	(171)
Level 2	(4,562)	(1,161)	(576)	(308)	(67)	(163)	(6,837)
Level 3	(337)	(303)	(305)	(302)	(299)	(1,535)	(3,081)
	(5,055)	(1,475)	(883)	(612)	(366)	(1,698)	(10,089)
Less: netting by counterparty	1,765	402	98	37	29	180	2,511
	(3,290)	(1,073)	(785)	(575)	(337)	(1,518)	(7,578)
Net fair value	547	286	(23)	(19)	181	14	986

30. Derivative financial instruments – continued

Level 3 derivatives

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

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

					$ million
	Oil price	Natural gas price	Power price	Other	Total
Fair value contracts at 1 January 2018	67	65	(226)	115	21
Gains (losses) recognized in the income statement	58	(26)	209	(8)	233
Settlements	(107)	(32)	(97)	—	(236)
Transfers out of level 3	5	(20)	(34)	—	(49)
Net fair value of contracts at 31 December 2018	23	(13)	(148)	107	(31)
Deferred day-one gains (losses)					577
Derivative asset (liability)					546

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

Derivative gains and losses

The group enters into derivative contracts including futures, options, swaps and certain forward sales and forward purchases contracts, relating to both currency and commodity trading activities. Gains or losses arise on contracts entered into for risk management purposes, optimization activity and entrepreneurial trading. They also arise on certain contracts that are for normal procurement or sales activity for the group but that are required to be fair valued under accounting standards. These gains and losses are included within sales and other operating revenues in the income statement. Also included within this line item are gains and losses on inventory held for trading purposes. The total amount relating to all these items was a net gain of $2,153 million (2018 $2,504 million net gain and 2017 $1,983 million net gain). This number does not include gains and losses on realized physical derivative contracts that have been reflected gross in the income statement within sales and purchases or the change in value of transportation and storage contracts which are not recognized under IFRS, but does include the associated financially settled contracts. The net amounts for actual gains and losses relating to these derivative contracts and all related items therefore differ significantly from the amounts disclosed above.

The group also enters into derivative contracts relating to foreign currency risk management activities. Gains and losses on these contracts are included within production and manufacturing expenses in the income statement. The change in the unrealized value of these contracts was a net gain of $160 million (2018 $351 million net loss and 2017 $1,420 million net gain), however the gains and losses in each year are largely offset by opposing net foreign exchange differences on retranslation of the associated non-US dollar debt. The net amounts for actual gains and losses relating to these derivative contracts and all related items therefore differ significantly from the amounts disclosed above.

Cash flow hedges

(i) Foreign currency risk of highly probable forecast capital expenditure

At 31 December 2019, the group held currency forwards designated as hedging instruments in cash flow hedge relationships of highly probable forecast non-US dollar capital expenditure. Note 29 outlines the group's approach to foreign currency exchange risk management. When the highly probable forecast capital expenditure designated as a hedged item occurs, a non-financial asset is recognized and is presented within the fixed asset section of the balance sheet.

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

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

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

- counterparty's credit risk, the group mitigates counterparty credit risk by entering into derivative transactions with high credit quality counterparties; and
- differences in settlement timing between the derivative and hedged items. The latter impacts the discount factor used in the calculation of the hedge ineffectiveness. The group mitigates differences in timing between the derivatives and hedged items by applying a rolling strategy and by hedging currency pairs from stable economies (i.e. sterling/US dollar, Euro/US dollar, Korean won/US dollar). The group's cash flow hedge designations are highly effective as the sources of ineffectiveness identified are expected to result in minimal hedge ineffectiveness.

The group has not designated any net positions as hedged items in cash flow hedges of foreign currency risk.

30. Derivative financial instruments – continued

(ii) Commodity price risk of highly probable forecast sales

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

The group is exposed to the variability in the gas price, but only applied hedge accounting to the risk of Henry Hub price movements for a percentage of future gas sales from its BPX Energy business (previously known as US Lower 48 business).

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

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

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

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

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

	Carrying amount of hedging instrument		**Nominal amounts of hedging instruments**	
	Assets	**Liabilities**		
At 31 December 2019	**$ million**	**$ million**	**$ million**	**mmBtu**
Cash flow hedges				
Foreign exchange risk				
Highly probable forecast capital expenditure	**1**	**(4)**	**150**	
At 31 December 2018				
Cash flow hedges				
Foreign exchange risk				
Highly probable forecast capital expenditure	5	(14)	386	
Commodity price risk				
Highly probable forecast sales	2	—		145

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

Of the nominal amount of hedging instruments at 31 December relating to highly probably forecast capital expenditure $150 million (2018 $304 million) matures within 12 months and $nil (2018 $82 million) within one to two years. All of the hedging instruments relating to highly probable forecast sales at 31 December 2018 matured in 2019.

30. Derivative financial instruments – continued

The table below summarizes the weighted average exchange rates and the weighted average sales price in relation to the derivatives designated as hedging instruments in cash flow hedge relationships at 31 December.

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

Fair value hedges

At 31 December 2019, the group held interest rate and cross-currency interest rate swap contracts as fair value hedges of the interest rate risk and foreign currency risk arising from group fixed rate debt issuances. The interest rate swaps are used to convert US dollar denominated fixed rate borrowings into floating rate debt. The cross-currency interest rate swaps are used to convert sterling, euro, Swiss franc, Canadian dollar and Norwegian krone denominated fixed rate borrowings into US dollar floating rate debt. The group manages all risks derived from debt issuance, such as credit risk, however, the group applies hedge accounting only to certain components of interest rate and foreign currency risk in order to minimize hedge ineffectiveness. Note 29 outlines the group's approach to interest rate and foreign currency exchange risk management.

The interest rate and foreign currency exposures are identified and hedged on an instrument-by-instrument basis. For interest rate exposures, the group designates as a fair value hedge the benchmark interest rate component only. This is an observable and reliably measurable component of interest rate risk. For foreign currency exposures, the group excludes from the designation the foreign currency basis spread component implicit in the cross-currency interest rate swaps. This is separately calculated at hedge designation, is recognized in other comprehensive income over the life of the hedge and amortized to the income statement on a straight-line basis, in accordance with the group's policy on costs of hedging.

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

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

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

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

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

30. Derivative financial instruments – continued

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

			$ million
	Carrying amount of hedging instrument		Nominal amounts of hedging instruments
At 31 December 2019	Assets	Liabilities	
Fair value hedges			
Interest rate risk on finance debt	**138**	**(35)**	**13,442**
Interest rate and foreign currency risk on finance debt	**344**	**(637)**	**21,296**
At 31 December 2018			
Fair value hedges			
Interest rate risk on finance debt	262	(445)	24,513
Interest rate and foreign currency risk on finance debt	158	(789)	16,580

All hedging instruments are presented within derivative financial instruments on the group balance sheet. Ineffectiveness arising on fair value hedges is included within the production and manufacturing expenses section of the income statement.

The tables below summarize the profile by tenor of the nominal amount of the derivatives designated as hedging instruments in fair value hedge relationships at 31 December. The weighted average floating interest rate of these interest rate swaps and cross-currency interest rate swaps was 2.36% (2018 3.04%) and 3.27% (2018 4.07%) respectively.

								$ million
At 31 December 2019	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	**3,000**	**2,576**	**4,039**	**1,200**	**206**	**2,421**	**—**	**13,442**
Interest rate and foreign currency risk on finance debt	**882**	**672**	**1,400**	**2,777**	**3,109**	**10,216**	**2,240**	**21,296**
At 31 December 2018								
Fair value hedges								
Interest rate risk on finance debt	2,694	2,324	2,597	4,923	1,700	10,275	—	24,513
Interest rate and foreign currency risk on finance debt	—	1,245	1,167	707	2,921	10,254	286	16,580

The tables below summarize the carrying amount, and the accumulated fair value adjustments included within the carrying amount, of the hedged items designated in fair value hedge relationships at 31 December.

					$ million
	Carrying amount of hedged item		Accumulated fair value adjustment included in the carrying amount of hedged items		
At 31 December 2019	Assets	Liabilities	Assets	Liabilities	Discontinued hedges
Fair value hedges					
Interest rate risk on finance debt	**—**	**(13,441)**	**—**	**(100)**	**(714)**
Interest rate and foreign currency risk on finance debt	**—**	**(21,240)**	**—**	**(525)**	**—**
At 31 December 2018					
Fair value hedges					
Interest rate risk on finance debt	—	(24,747)	175	—	(360)
Interest rate and foreign currency risk on finance debt	—	(16,883)	—	(62)	—

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

30. Derivative financial instruments – continued

Movement in reserves related to hedge accounting

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

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

					$ million
	Cash flow hedge reserve			Costs of hedging reserve	
	Highly probable forecast capital expenditure	Highly probable forecast sales	Purchase of equity[a]	Interest rate and foreign currency risk on finance debt	Total
At 31 December 2017	(10)	—	(651)	—	(661)
Adjustment on adoption of IFRS 9	—	—	—	(37)	(37)
At 1 January 2018	(10)	—	(651)	(37)	(698)
Recognized in other comprehensive income					
Cash flow hedges marked to market	(37)	(126)	—	—	(163)
Cash flow hedges reclassified to the income statement- hedged item affected profit or loss	—	120	—	—	120
Costs of hedging marked to market	—	—	—	(244)	(244)
Costs of hedging reclassified to the income statement	—	—	—	58	58
	(37)	(6)	—	(186)	(229)
Cash flow hedges transferred to the balance sheet	26	—	—	—	26
At 31 December 2018	(21)	(6)	(651)	(223)	(901)

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

Substantially all of the cash flow hedge reserve balances and all of the amounts reclassified into profit or loss during the year relate to continuing hedge relationships. Amounts deferred in the cash flow hedge reserve that have been reclassified to profit or loss are presented in sales and other operating revenues in the income statement.

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

31. Called-up share capital

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

	2019		2018		2017	
Issued	**Shares thousand**	**$ million**	Shares thousand	$ million	Shares thousand	$ million
8% cumulative first preference shares of £1 each[a]	**7,233**	**12**	7,233	12	7,233	12
9% cumulative second preference shares of £1 each[a]	**5,473**	**9**	5,473	9	5,473	9
		21		21		21
Ordinary shares of 25 cents each						
At 1 January	**21,525,464**	**5,381**	21,288,193	5,322	21,049,696	5,263
Issue of new shares for the scrip dividend programme	**208,927**	**52**	195,305	49	289,789	72
Issue of new shares for employee share-based payment plans	**37,400**	**9**	92,168	23	—	—
Issue of new shares – other	**—**	**—**	—	—	—	—
Repurchase of ordinary share capital	**(235,951)**	**(59)**	(50,202)	(13)	(51,292)	(13)
At 31 December	**21,535,840**	**5,383**	21,525,464	5,381	21,288,193	5,322
		5,404		5,402		5,343

[a] The nominal amount of 8% cumulative first preference shares and 9% cumulative second preference shares that can be in issue at any time shall not exceed £10,000,000 for each class of preference shares.

Voting on substantive resolutions tabled at a general meeting is on a poll. On a poll, shareholders present in person or by proxy have two votes for every £5 in nominal amount of the first and second preference shares held and one vote for every ordinary share held. On a show-of-hands vote on other resolutions (procedural matters) at a general meeting, shareholders present in person or by proxy have one vote each.

In the event of the winding up of the company, preference shareholders would be entitled to a sum equal to the capital paid up on the preference shares, plus an amount in respect of accrued and unpaid dividends and a premium equal to the higher of (i) 10% of the capital paid up on the preference shares and (ii) the excess of the average market price of such shares on the London Stock Exchange during the previous six months over par value.

During 2019 the company repurchased 236 million ordinary shares for a total consideration of $1,511 million, including transaction costs of $8 million, as part of the share repurchase programme announced on 31 October 2017. All shares purchased were for cancellation. The repurchased shares represented 1.1% of ordinary share capital. A further 120 million of shares have been repurchased in January 2020 at a total cost of $776 million. The number of shares in issue is reduced when shares are repurchased.

Treasury shares[a]

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

[a] See Note 32 for definition of treasury shares.

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

For each year presented, the balance at 1 January represents the maximum number of shares held in treasury by BP during the year, representing 5.9% (2018 6.9% and 2017 7.5%) of the called-up ordinary share capital of the company.

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

32. Capital and reserves

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

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

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2017	5,284	12,219	1,413	27,206	46,122
Profit (loss) for the year	—	—	—	—	—
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including reclassifications)	—	—	—	—	—
Available-for-sale investments (including reclassifications)	—	—	—	—	—
Cash flow hedges (including reclassifications)	—	—	—	—	—
Share of items relating to equity-accounted entities, net of tax[a]	—	—	—	—	—
Other	—	—	—	—	—
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	—	—	—	—	—
Total comprehensive income	—	—	—	—	—
Dividends	72	(72)	—	—	—
Repurchases of ordinary share capital	(13)	—	13	—	—
Share-based payments, net of tax[b]	—	—	—	—	—
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	—
Transactions involving non-controlling interests, net of tax[d]	—	—	—	—	—
At 31 December 2017	5,343	12,147	1,426	27,206	46,122

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

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

32. Capital and reserves – continued

$ million

Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Costs of hedging	Total fair value reserves	Profit and loss account	BP shareholders' equity	Non-controlling interests	Total equity
(15,767)	**(8,902)**	**—**	**(777)**	**(210)**	**(987)**	**78,748**	**99,444**	**2,104**	**101,548**
—	**—**	**—**	**—**	**—**	**—**	**(329)**	**(329)**	**(1)**	**(330)**
(15,767)	**(8,902)**	**—**	**(777)**	**(210)**	**(987)**	**78,419**	**99,115**	**2,103**	**101,218**
—	**—**	**—**	**—**	**—**	**—**	**4,026**	**4,026**	**164**	**4,190**
—	**2,407**	**—**	**—**	**—**	**—**	**—**	**2,407**	**9**	**2,416**
—	**—**	**—**	**5**	**50**	**55**	**—**	**55**	**—**	**55**
—	**—**	**—**	**—**	**—**	**—**	**82**	**82**	**—**	**82**
—	**—**	**—**	**—**	**—**	**—**	**(64)**	**(64)**	**—**	**(64)**
—	**—**	**—**	**—**	**—**	**—**	**171**	**171**	**—**	**171**
—	**—**	**—**	**(3)**	**—**	**(3)**	**—**	**(3)**	**—**	**(3)**
—	**2,407**	**—**	**2**	**50**	**52**	**4,215**	**6,674**	**173**	**6,847**
—	**—**	**—**	**—**	**—**	**—**	**(6,929)**	**(6,929)**	**(213)**	**(7,142)**
—	**—**	**—**	**23**	**—**	**23**	**—**	**23**	**—**	**23**
—	**—**	**—**	**—**	**—**	**—**	**(1,511)**	**(1,511)**	**—**	**(1,511)**
1,355	**—**	**—**	**—**	**—**	**—**	**(809)**	**719**	**—**	**719**
—	**—**	**—**	**—**	**—**	**—**	**5**	**5**	**—**	**5**
—	**—**	**—**	**—**	**—**	**—**	**316**	**316**	**233**	**549**
(14,412)	**(6,495)**	**—**	**(752)**	**(160)**	**(912)**	**73,706**	**98,412**	**2,296**	**100,708**
(16,958)	(5,156)	17	(760)	—	(743)	75,226	98,491	1,913	100,404
—	—	(17)	—	(37)	(54)	(126)	(180)	—	(180)
(16,958)	(5,156)	—	(760)	(37)	(797)	75,100	98,311	1,913	100,224
—	—	—	—	—	—	9,383	9,383	195	9,578
—	(3,746)	—	—	—	—	—	(3,746)	(41)	(3,787)
—	—	—	(6)	(173)	(179)	—	(179)	—	(179)
—	—	—	—	—	—	417	417	—	417
—	—	—	—	—	—	7	7	—	7
—	—	—	—	—	—	1,599	1,599	—	1,599
—	—	—	(37)	—	(37)	—	(37)	—	(37)
—	(3,746)	—	(43)	(173)	(216)	11,406	7,444	154	7,598
—	—	—	—	—	—	(6,699)	(6,699)	(170)	(6,869)
—	—	—	26	—	26	—	26	—	26
—	—	—	—	—	—	(355)	(355)	—	(355)
1,191	—	—	—	—	—	(718)	703	—	703
—	—	—	—	—	—	14	14	—	14
—	—	—	—	—	—	—	—	207	207
(15,767)	(8,902)	—	(777)	(210)	(987)	78,748	99,444	2,104	101,548
(18,443)	(6,878)	3	(1,156)	—	(1,153)	75,638	95,286	1,557	96,843
—	—	—	—	—	—	3,389	3,389	79	3,468
—	1,722	—	—	—	—	(3)	1,719	52	1,771
—	—	14	—	—	14	—	14	—	14
—	—	—	396	—	396	—	396	—	396
—	—	—	—	—	—	564	564	—	564
—	—	—	—	—	—	(72)	(72)	—	(72)
—	—	—	—	—	—	2,343	2,343	—	2,343
—	1,722	14	396	—	410	6,221	8,353	131	8,484
—	—	—	—	—	—	(6,153)	(6,153)	(141)	(6,294)
—	—	—	—	—	—	(343)	(343)	—	(343)
1,485	—	—	—	—	—	(798)	687	—	687
—	—	—	—	—	—	215	215	—	215
—	—	—	—	—	—	446	446	366	812
(16,958)	(5,156)	17	(760)	—	(743)	75,226	98,491	1,913	100,404

[c] Principally relates to the sale of a 49% interest in BP's retail property portfolio in Australia.
[d] Principally relates to the initial public offering of common units in BP Midstream Partners LP for which net proceeds of $811 million were received.

32. Capital and reserves – continued

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

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

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

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

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

Foreign currency translation reserve
The foreign currency translation reserve records exchange differences arising from the translation of the financial statements of foreign operations. Upon disposal of foreign operations, the related accumulated exchange differences are reclassified to the income statement.

Available-for-sale investments
This reserve recorded the changes in fair value of investments classified as available-for-sale under IAS 39 except for impairment losses, foreign exchange gains or losses, or changes arising from revised estimates of future cash flows. On adoption of IFRS 9 the balance in this reserve was transferred to the profit and loss account reserve. Under the new standard the group recognizes fair value gains and losses on these investments in profit or loss.

Cash flow hedges
This reserve records the portion of the gain or loss on a hedging instrument in a cash flow hedge that is determined to be an effective hedge. It includes $651 million relating to the acquisition of an 18.5% interest in Rosneft in 2013 which will only be reclassified to the income statement if the investment in Rosneft is either sold or impaired. For further information on the accounting for cash flow hedges see Note 1 - Derivative financial instruments and hedging activities.

Costs of hedging
This reserve records the change in fair value of the foreign currency basis spread of financial instruments to which cost of hedge accounting has been applied. The accumulated amount relates to time-period related hedged items and is amortized to profit or loss over the term of the hedging relationship.

Prior to the group's adoption of IFRS 9 changes in the fair value of such foreign currency basis spreads were recognized in profit or loss. On adoption of the new standard a transfer from the profit and loss account reserve to the costs of hedging reserve was made in order to reflect the opening reserves position for relevant hedging instruments existing on transition. For further information on the accounting for costs of hedging see Note 1 - Derivative financial instruments and hedging activities.

Profit and loss account
The balance held on this reserve is the accumulated retained profits of the group.

32. Capital and reserves – continued

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

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

			$ million
			2018
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including reclassifications)	(3,771)	(16)	(3,787)
Cash flow hedges (including reclassifications)	(6)	—	(6)
Costs of hedging (including reclassifications)	(186)	13	(173)
Share of items relating to equity-accounted entities, net of tax	417	—	417
Other	—	7	7
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	2,317	(718)	1,599
Cash flow hedges that will subsequently be transferred to the balance sheet	(37)	—	(37)
Other comprehensive income	(1,266)	(714)	(1,980)

			$ million
			2017
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including reclassifications)	1,866	(95)	1,771
Available-for-sale investments (including reclassifications)	14	—	14
Cash flow hedges (including reclassifications)	425	(29)	396
Share of items relating to equity-accounted entities, net of tax	564	—	564
Other	—	(72)	(72)
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	3,646	(1,303)	2,343
Other comprehensive income	6,515	(1,499)	5,016

33. Contingent liabilities

There were contingent liabilities at 31 December 2019 in respect of guarantees and indemnities entered into as part of the ordinary course of the group's business. No material losses are likely to arise from such contingent liabilities. Further information on financial guarantees is included in Note 29.

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

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

33. Contingent liabilities – continued

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

If oil and natural gas production facilities and pipelines are sold to third parties and the subsequent owner is unable to meet their decommissioning obligations it is possible that, in certain circumstances, BP could be partially or wholly responsible for decommissioning. While the amounts associated with decommissioning provisions reverting to the group could be significant and could be material, BP is not currently aware of any such cases that have a greater than remote chance of reverting to the group. Furthermore, as described in Provisions and contingencies within Note 1, decommissioning provisions associated with downstream and petrochemical facilities are not generally recognized as the potential obligations cannot be measured given their indeterminate settlement dates.

See also Legal proceedings on pages 319-320.

Contingent liabilities related to the Gulf of Mexico oil spill

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

34. Remuneration of senior management and non-executive directors

Remuneration of directors

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

[a] Excludes amounts relating to past directors.

Emoluments

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

Pension contributions

During 2019 one executive director participated in a UK final salary pension plan in respect of service prior to 1 April 2011. During 2019, one executive director participated in retirement savings plans established for US employees and in a US defined benefit pension plan in respect of service prior to 1 September 2016.

Further information

Full details of individual directors' remuneration are given in the Directors' remuneration report on page 100. See also Related-party transactions on page 321.

Remuneration of directors and senior management

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

Senior management comprises members of the executive team, see pages 78-79 for further information.

Short-term employee benefits

These amounts comprise fees and benefits paid to the non-executive chairman and non-executive directors, as well as salary, benefits and cash bonuses for senior management. Deferred annual bonus awards, to be settled in shares, are included in share-based payments. Short term employee benefits includes compensation for loss of office of $nil in 2019 (2018 $nil and 2017 $nil).

Pensions and other post-retirement benefits

The amounts represent the estimated cost to the group of providing pensions and other post-retirement benefits to senior management in respect of the current year of service measured in accordance with IAS 19 'Employee Benefits'.

Share-based payments

This is the cost to the group of senior management's participation in share-based payment plans, as measured by the fair value of options and shares granted, accounted for in accordance with IFRS 2 'Share-based Payments'.

35. Employee costs and numbers

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

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

[a] Includes termination costs of $182 million (2018 $493 million and 2017 $189 million).

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

[c] Reported to the nearest 100.

[d] Includes 18,100 (2018 17,100 and 2017 16,500) service station staff.

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

36. Auditor's remuneration

Fees	2019	2018	$ million 2017
The audit of the company annual accounts[a]	**32**	25	26
The audit of accounts of subsidiaries of the company	**11**	10	11
Total audit	**43**	35	37
Audit-related assurance services[b]	**4**	4	7
Total audit and audit-related assurance services	**47**	39	44
Non-audit and other assurance services	**1**	2	3
Total non-audit or non-audit-related assurance services	**1**	2	3
Services relating to BP pension plans	**1**	1	—
	49	42	47

[a] Fees in respect of the audit of the accounts of BP p.l.c. including the group's consolidated financial statements.

[b] Includes interim reviews and audit of internal control over financial reporting and non-statutory audit services.

With effect from 2018, following a competitive tender process, Deloitte LLP (Deloitte) was appointed as auditor of the Company, replacing Ernst & Young LLP (EY). In the table above, auditor's remuneration for services provided during the years ended 31 December 2019 and 31 December 2018 thus relates to Deloitte and for the year ended 31 December 2017 EY.

2019 includes $3.6 million of additional fees for 2018. In addition to the amounts shown in the table above, in 2018 $0.75 million of additional fees were paid to EY in respect of their audit for 2017. Auditor's remuneration is included in the income statement within distribution and administration expenses.

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

The audit committee has established pre-approval policies and procedures for the engagement of Deloitte to render audit and certain assurance and other services. The audit fees payable to Deloitte were considered as part of the audit tender process in 2016 and challenged by the audit committee through comparison with the audit pricing proposals of the other bidding firms, before being approved. Deloitte performed further assurance services that were not prohibited by regulatory or other professional requirements and were pre-approved by the Committee. Deloitte is engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit-related or assurance nature.

Under SEC regulations, the remuneration of the auditor of $49 million (2018 $42 million and 2017 $47 million) is required to be presented as follows: audit $43 million (2018 $35 million and 2017 $37 million); other audit-related $4 million (2018 $4 million and 2017 $7 million); tax $nil (2018 $nil and 2017 $nil); and all other fees $3 million (2018 $3 million and 2017 $3 million).

37. Subsidiaries, joint arrangements and associates

The more important subsidiaries and associates of the group at 31 December 2019 and the group percentage of ordinary share capital (to nearest whole number) are set out below. There are no individually significant incorporated joint arrangements. The group's share of the assets and liabilities of the more important unincorporated joint arrangements are held by subsidiaries listed in the table below. Those subsidiaries held directly by the parent company are marked with an asterisk (*), the percentage owned being that of the group unless otherwise indicated. A complete list of undertakings of the group is included in Note 14 in the parent company financial statements of BP p.l.c. which are filed with the Registrar of Companies in the UK, along with the group's annual report.

Subsidiaries	%	Country of incorporation	Principal activities
International			
BP Corporate Holdings	100	England & Wales	Investment holding
BP Exploration Operating Company	100	England & Wales	Exploration and production
*BP Global Investments	100	England & Wales	Investment holding
*BP International	100	England & Wales	Integrated oil operations
BP Oil International	100	England & Wales	Integrated oil operations
*Burmah Castrol	100	Scotland	Lubricants
Angola			
BP Exploration (Angola)	100	England & Wales	Exploration and production
Azerbaijan			
BP Exploration (Caspian Sea)	100	England & Wales	Exploration and production
BP Exploration (Azerbaijan)	100	England & Wales	Exploration and production
Canada			
*BP Holdings Canada	100	England & Wales	Investment holding
Egypt			
BP Exploration (Delta)	100	England & Wales	Exploration and production
Germany			
BP Europa SE	100	Germany	Refining and marketing
India			
BP Exploration (Alpha)	100	England & Wales	Exploration and production
Trinidad & Tobago			
BP Trinidad and Tobago	70	US	Exploration and production
UK			
BP Capital Markets	100	England & Wales	Finance
US			
*BP Holdings North America	100	England & Wales	Investment holding
Atlantic Richfield Company	100	US	
BP America	100	US	
BP America Production Company	100	US	
BP Company North America	100	US	Exploration and production, refining and marketing
BP Corporation North America	100	US	
BP Exploration (Alaska)	100	US	
BP Products North America	100	US	
Standard Oil Company	100	US	
BP Capital Markets America	100	US	Finance

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

38. Condensed consolidating information on certain US subsidiaries

BP p.l.c. fully and unconditionally guarantees the payment obligations of its 100%-owned subsidiary BP Exploration (Alaska) Inc. under the BP Prudhoe Bay Royalty Trust. As described in Note 2, in 2020 BP expects, subject to governmental authorizations, to complete the sale of all of its Alaska operations, including its interest in BP Exploration (Alaska) Inc., to Hilcorp Energy. Following completion of the sale, BP will continue to fully and unconditionally guarantee the payment obligations of BP Exploration (Alaska) Inc. to the BP Prudhoe Bay Royalty Trust. The following financial information for BP p.l.c., BP Exploration (Alaska) Inc. and all other subsidiaries on a condensed consolidating basis is intended to provide investors with meaningful and comparable financial information about BP p.l.c. and its subsidiary issuers of registered securities and is provided pursuant to Rule 3-10 of Regulation S-X in lieu of the separate financial statements of each subsidiary issuer of public debt securities. Non-current assets for BP p.l.c. includes investments in subsidiaries recorded under the equity method for the purposes of the condensed consolidating financial information. Equity-accounted income of subsidiaries is the group's share of profit related to such investments. The eliminations and reclassifications column includes the necessary amounts to eliminate the intercompany balances and transactions between BP p.l.c., BP Exploration (Alaska) Inc. and other subsidiaries. The financial information presented in the following tables for BP Exploration (Alaska) Inc. incorporates subsidiaries of BP Exploration (Alaska) Inc. using the equity method of accounting and excludes the BP group's midstream operations in Alaska that are reported through different legal entities and that are included within the 'other subsidiaries' column in these tables. BP p.l.c. also fully and unconditionally guarantees securities issued by BP Capital Markets p.l.c. and BP Capital Markets America Inc. These companies are 100%-owned finance subsidiaries of BP p.l.c.

Income statement

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

38. Condensed consolidating information on certain US subsidiaries – continued

Income statement continued

$ million

					2018
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	4,315	—	298,620	(4,179)	298,756
Earnings from joint ventures- after interest and tax	—	—	897	—	897
Earnings from associates- after interest and tax	—	—	2,856	—	2,856
Equity-accounted income of subsidiaries- after interest and tax	—	10,942	—	(10,942)	—
Interest and other income	42	373	2,081	(1,723)	773
Gains on sale of businesses and fixed assets	—	—	456	—	456
Total revenues and other income	4,357	11,315	304,910	(16,844)	303,738
Purchases	1,507	—	232,550	(4,179)	229,878
Production and manufacturing expenses	1,015	—	21,990	—	23,005
Production and similar taxes	282	—	1,254	—	1,536
Depreciation, depletion and amortization	377	—	15,080	—	15,457
Impairment and losses on sale of businesses and fixed assets	66	—	794	—	860
Exploration expense	—	—	1,445	—	1,445
Distribution and administration expenses	22	642	11,673	(158)	12,179
Profit (loss) before interest and taxation	1,088	10,673	20,124	(12,507)	19,378
Finance costs	8	1,326	2,759	(1,565)	2,528
Net finance (income) expense relating to pensions and other post-retirement benefits	—	(95)	222	—	127
Profit (loss) before taxation	1,080	9,442	17,143	(10,942)	16,723
Taxation	164	59	6,922	—	7,145
Profit (loss) for the year	916	9,383	10,221	(10,942)	9,578
Attributable to					
BP shareholders	916	9,383	10,026	(10,942)	9,383
Non-controlling interests	—	—	195	—	195
	916	9,383	10,221	(10,942)	9,578

Income statement continued

$ million

					2017
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	3,264	—	240,177	(3,233)	240,208
Earnings from joint ventures- after interest and tax	—	—	1,177	—	1,177
Earnings from associates- after interest and tax	—	—	1,330	—	1,330
Equity-accounted income of subsidiaries- after interest and tax	—	4,436	—	(4,436)	—
Interest and other income	11	369	1,470	(1,193)	657
Gains on sale of businesses and fixed assets	71	9	1,139	(9)	1,210
Total revenues and other income	3,346	4,814	245,293	(8,871)	244,582
Purchases	1,010	—	181,939	(3,233)	179,716
Production and manufacturing expenses	1,156	—	23,073	—	24,229
Production and similar taxes[a]	(18)	—	1,793	—	1,775
Depreciation, depletion and amortization	735	—	14,849	—	15,584
Impairment and losses on sale of businesses and fixed assets	—	—	1,216	—	1,216
Exploration expense	—	—	2,080	—	2,080
Distribution and administration expenses	19	616	10,022	(149)	10,508
Profit (loss) before interest and taxation	444	4,198	10,321	(5,489)	9,474
Finance costs	6	826	2,286	(1,044)	2,074
Net finance (income) expense relating to pensions and other post-retirement benefits	—	(15)	235	—	220
Profit (loss) before taxation	438	3,387	7,800	(4,445)	7,180
Taxation	(392)	(11)	4,115	—	3,712
Profit (loss) for the year	830	3,398	3,685	(4,445)	3,468
Attributable to					
BP shareholders	830	3,398	3,606	(4,445)	3,389
Non-controlling interests	—	—	79	—	79
	830	3,398	3,685	(4,445)	3,468

[a] Includes revised non-cash provision adjustments; actual cash payments for Production and similar taxes remain in line with prior year.

38. Condensed consolidating information on certain US subsidiaries – continued

Statement of comprehensive income

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

Statement of comprehensive income continued

	Issuer	Guarantor			$ million 2018
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Profit (loss) for the year	916	9,383	10,221	(10,942)	9,578
Other comprehensive income					
Items that may be reclassified subsequently to profit or loss					
Currency translation differences	—	(296)	(3,475)	—	(3,771)
Cash flow hedges (including reclassifications)	—	—	(6)	—	(6)
Costs of hedging (including reclassifications)	—	—	(186)	—	(186)
Share of items relating to equity-accounted entities, net of tax	—	—	417	—	417
Income tax relating to items that may be reclassified	—	—	4	—	4
	—	(296)	(3,246)	—	(3,542)
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	—	1,689	628	—	2,317
Cash flow hedges that will subsequently be transferred to the balance sheet	—	—	(37)	—	(37)
Income tax relating to items that will not be reclassified	—	(511)	(207)	—	(718)
	—	1,178	384	—	1,562
Other comprehensive income	—	882	(2,862)	—	(1,980)
Equity-accounted other comprehensive income of subsidiaries	—	(2,821)	—	2,821	—
Total comprehensive income	916	7,444	7,359	(8,121)	7,598
Attributable to					
BP shareholders	916	7,444	7,205	(8,121)	7,444
Non-controlling interests	—	—	154	—	154
	916	7,444	7,359	(8,121)	7,598

38. Condensed consolidating information on certain US subsidiaries – continued

Statement of comprehensive income continued

	Issuer	Guarantor			$ million 2017
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Profit (loss) for the year	830	3,398	3,685	(4,445)	3,468
Other comprehensive income					
Items that may be reclassified subsequently to profit or loss					
Currency translation differences	—	166	1,820	—	1,986
Exchange (gains) losses on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets	—	—	(120)	—	(120)
Available-for-sale investments marked to market	—	—	14	—	14
Cash flow hedges marked to market	—	—	197	—	197
Cash flow hedges reclassified to the income statement	—	—	116	—	116
Cash flow hedges reclassified to the balance sheet	—	—	112	—	112
Share of items relating to equity-accounted entities, net of tax	—	—	564	—	564
Income tax relating to items that may be reclassified	—	—	(196)	—	(196)
	—	166	2,507	—	2,673
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	—	2,984	662	—	3,646
Income tax relating to items that will not be reclassified	—	(1,169)	(134)	—	(1,303)
	—	1,815	528	—	2,343
Other comprehensive income	—	1,981	3,035	—	5,016
Equity-accounted other comprehensive income of subsidiaries	—	2,983	—	(2,983)	—
Total comprehensive income	830	8,362	6,720	(7,428)	8,484
Attributable to					
BP shareholders	830	8,362	6,589	(7,428)	8,353
Non-controlling interests	—	—	131	—	131
	830	8,362	6,720	(7,428)	8,484

38. Condensed consolidating information on certain US subsidiaries – continued

Balance sheet

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

38. Condensed consolidating information on certain US subsidiaries – continued

Balance sheet continued

	Issuer	Guarantor			$ million 2018
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Non-current assets					
Property, plant and equipment	4,445	—	130,816	—	135,261
Goodwill	—	—	12,204	—	12,204
Intangible assets	598	—	16,686	—	17,284
Investments in joint ventures	—	—	8,647	—	8,647
Investments in associates	—	2	17,671	—	17,673
Other investments	—	—	1,341	—	1,341
Subsidiaries- equity-accounted basis	—	166,311	—	(166,311)	—
Fixed assets	5,043	166,313	187,365	(166,311)	192,410
Loans	—	—	32,402	(31,765)	637
Trade and other receivables	—	2,600	1,834	(2,600)	1,834
Derivative financial instruments	—	—	5,145	—	5,145
Prepayments	—	—	1,179	—	1,179
Deferred tax assets	—	—	3,706	—	3,706
Defined benefit pension plan surpluses	—	5,473	482	—	5,955
	5,043	174,386	232,113	(200,676)	210,866
Current assets					
Loans	—	—	326	—	326
Inventories	302	—	17,686	—	17,988
Trade and other receivables	2,536	151	38,931	(17,140)	24,478
Derivative financial instruments	—	—	3,846	—	3,846
Prepayments	7	—	956	—	963
Current tax receivable	—	—	1,019	—	1,019
Other investments	—	—	222	—	222
Cash and cash equivalents	—	13	22,455	—	22,468
	2,845	164	85,441	(17,140)	71,310
Total assets	7,888	174,550	317,554	(217,816)	282,176
Current liabilities					
Trade and other payables	413	14,634	48,358	(17,140)	46,265
Derivative financial instruments	—	—	3,308	—	3,308
Accruals	89	31	4,506	—	4,626
Lease liabilities	—	—	44	—	44
Finance debt	—	—	9,329	—	9,329
Current tax payable	310	—	1,791	—	2,101
Provisions	1	—	2,563	—	2,564
	813	14,665	69,899	(17,140)	68,237
Non-current liabilities					
Other payables	—	31,800	16,395	(34,365)	13,830
Derivative financial instruments	—	—	5,625	—	5,625
Accruals	—	—	575	—	575
Lease liabilities	—	—	623	—	623
Finance debt	—	—	55,803	—	55,803
Deferred tax liabilities	586	1,907	7,319	—	9,812
Provisions	670	—	17,062	—	17,732
Defined benefit pension plan and other post-retirement benefit plan deficits	—	184	8,207	—	8,391
	1,256	33,891	111,609	(34,365)	112,391
Total liabilities	2,069	48,556	181,508	(51,505)	180,628
Net assets	5,819	125,994	136,046	(166,311)	101,548
Equity					
BP shareholders' equity	5,819	125,994	133,942	(166,311)	99,444
Non-controlling interests	—	—	2,104	—	2,104
	5,819	125,994	136,046	(166,311)	101,548

38. Condensed consolidating information on certain US subsidiaries – continued

Cash flow statement

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

38. Condensed consolidating information on certain US subsidiaries – continued

Cash flow statement continued

	Issuer	Guarantor			$ million 2018
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Operating activities					
Profit (loss) before taxation	1,080	9,442	17,143	(10,942)	16,723
Adjustments to reconcile profit (loss) before taxation to net cash provided by operating activities					
Exploration expenditure written off	—	—	1,085	—	1,085
Depreciation, depletion and amortization	377	—	15,080	—	15,457
Impairment and (gain) loss on sale of businesses and fixed assets	66	—	338	—	404
Earnings from joint ventures and associates	—	—	(3,753)	—	(3,753)
Dividends received from joint ventures and associates	—	—	1,535	—	1,535
Equity accounted income of subsidiaries- after interest and tax	—	(10,942)	—	10,942	—
Dividends received from subsidiaries	—	3,490	—	(3,490)	—
Interest receivable	(42)	(215)	(1,776)	1,565	(468)
Interest received	42	215	1,656	(1,565)	348
Finance costs	8	1,326	2,759	(1,565)	2,528
Interest paid	(8)	(1,326)	(2,159)	1,565	(1,928)
Net finance expense relating to pensions and other post-retirement benefits	—	(95)	222	—	127
Share-based payments	—	671	19	—	690
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	—	(183)	(203)	—	(386)
Net charge for provisions, less payments	33	—	953	—	986
(Increase) decrease in inventories	(62)	—	734	—	672
(Increase) decrease in other current and non-current assets	(72)	165	(951)	(2,000)	(2,858)
Increase (decrease) in other current and non-current liabilities	(491)	4,509	(6,595)	—	(2,577)
Income taxes paid	(133)	—	(5,579)	—	(5,712)
Net cash provided by operating activities	798	7,057	20,508	(5,490)	22,873
Investing activities					
Expenditure on property, plant and equipment, intangible and other assets	(273)	—	(16,434)	—	(16,707)
Acquisitions, net of cash acquired	—	—	(6,986)	—	(6,986)
Investment in joint ventures	—	—	(382)	—	(382)
Investment in associates	—	—	(1,013)	—	(1,013)
Total cash capital expenditure	(273)	—	(24,815)	—	(25,088)
Proceeds from disposals of fixed assets	—	—	940	—	940
Proceeds from disposals of businesses, net of cash disposed	1,475	—	436	—	1,911
Proceeds from loan repayments	—	—	666	—	666
Net cash provided by (used in) investing activities	1,202	—	(22,773)	—	(21,571)
Financing activities					
Repurchase of shares	—	(355)	—	—	(355)
Lease liability payments	—	—	(35)	—	(35)
Proceeds from long-term financing	—	—	9,038	—	9,038
Repayments of long-term financing	—	—	(7,175)	—	(7,175)
Net increase (decrease) in short-term debt	—	—	1,317	—	1,317
Dividends paid					
BP shareholders	(2,000)	(6,699)	(3,490)	5,490	(6,699)
Non-controlling interests	—	—	(170)	—	(170)
Net cash provided by (used in) financing activities	(2,000)	(7,054)	(515)	5,490	(4,079)
Currency translation differences relating to cash and cash equivalents	—	—	(330)	—	(330)
Increase (decrease) in cash and cash equivalents	—	3	(3,110)	—	(3,107)
Cash and cash equivalents at beginning of year	—	10	25,565	—	25,575
Cash and cash equivalents at end of year	—	13	22,455	—	22,468

38. Condensed consolidating information on certain US subsidiaries – continued

Cash flow statement continued

	Issuer	Guarantor			$ million 2017
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Operating activities					
Profit (loss) before taxation	438	3,387	7,800	(4,445)	7,180
Adjustments to reconcile profit (loss) before taxation to net cash provided by operating activities					
Exploration expenditure written off	—	—	1,603	—	1,603
Depreciation, depletion and amortization	735	—	14,849	—	15,584
Impairment and (gain) loss on sale of businesses and fixed assets	(71)	(9)	77	9	6
Earnings from joint ventures and associates	—	—	(2,507)	—	(2,507)
Dividends received from joint ventures and associates	—	—	1,253	—	1,253
Equity accounted income of subsidiaries- after interest and tax	—	(4,436)	—	4,436	—
Dividends received from (paid to) subsidiaries	—	3,183	—	(3,183)	—
Interest receivable	(11)	(220)	(1,117)	1,044	(304)
Interest received	11	220	1,188	(1,044)	375
Finance costs	6	826	2,286	(1,044)	2,074
Interest paid	(6)	(826)	(1,784)	1,044	(1,572)
Net finance expense relating to pensions and other post-retirement benefits	—	(15)	235	—	220
Share-based payments	—	595	66	—	661
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	—	(145)	(249)	—	(394)
Net charge for provisions, less payments	(128)	—	2,234	—	2,106
(Increase) decrease in inventories	(25)	—	(823)	—	(848)
(Increase) decrease in other current and non-current assets	108	522	(5,478)	—	(4,848)
Increase (decrease) in other current and non-current liabilities	(830)	3,374	(200)	—	2,344
Income taxes paid	—	—	(4,002)	—	(4,002)
Net cash provided by operating activities	227	6,456	15,431	(3,183)	18,931
Investing activities					
Expenditure on property, plant and equipment, intangible and other assets	(321)	—	(16,241)	—	(16,562)
Acquisitions, net of cash acquired	—	—	(327)	—	(327)
Investment in joint ventures	—	—	(50)	—	(50)
Investment in associates	—	—	(901)	—	(901)
Total cash capital expenditure	(321)	—	(17,519)	—	(17,840)
Proceeds from disposals of fixed assets	94	—	2,842	—	2,936
Proceeds from disposals of businesses, net of cash disposed	—	—	478	—	478
Proceeds from loan repayments	—	—	349	—	349
Net cash provided by (used in) investing activities	(227)	—	(13,850)	—	(14,077)
Financing activities					
Net issue (repurchase) of shares	—	(343)	—	—	(343)
Lease liability payments	—	—	(45)	—	(45)
Proceeds from long-term financing	—	—	8,712	—	8,712
Repayments of long-term financing	—	—	(6,231)	—	(6,231)
Net increase (decrease) in short-term debt	—	—	(158)	—	(158)
Net increase (decrease) in non-controlling interests	—	—	1,063	—	1,063
Dividends paid					
BP shareholders	—	(6,153)	(3,183)	3,183	(6,153)
Non-controlling interests	—	—	(141)	—	(141)
Net cash provided by (used in) financing activities	—	(6,496)	17	3,183	(3,296)
Currency translation differences relating to cash and cash equivalents	—	—	544	—	544
Increase (decrease) in cash and cash equivalents	—	(40)	2,142	—	2,102
Cash and cash equivalents at beginning of year	—	50	23,434	—	23,484
Cash and cash equivalents at end of year	—	10	25,576	—	25,586

Supplementary information on oil and natural gas (unaudited)

The regional analysis presented below is on a continent basis, with separate disclosure for countries that contain 15% or more of the total proved reserves (for subsidiaries plus equity-accounted entities), in accordance with SEC and FASB requirements.

Oil and gas reserves – certain definitions

Unless the context indicates otherwise, the following terms have the meanings shown below:

Proved oil and gas reserves

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any; and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favourable than in the reservoir as a whole, the operation of an installed programme in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or programme was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Undeveloped oil and gas reserves

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Developed oil and gas reserves

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

For details on BP's proved reserves and production compliance and governance processes, see pages 308-313.

Oil and natural gas exploration and production activities

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

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

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

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

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

[e] Includes property taxes and other government take. The UK region includes a $361-million gain which is offset by corresponding charges primarily in the US region, relating to the group self-insurance programme.

[f] Excludes the unwinding of the discount on provisions and payables amounting to $439 million which is included in finance costs in the group income statement.

[g] Midstream and other activities excludes inventory holding gains and losses.

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

Oil and natural gas exploration and production activities – continued

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

[a] Amounts reported for Russia in this table include BP's share of Rosneft's worldwide activities, including insignificant amounts outside Russia. The amounts reported include the corresponding amounts for their equity-accounted entities.

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

[c] Costs of decommissioning are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

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

[e] The amounts shown reflect BP's share of equity-accounted entities' costs incurred, and not the costs incurred by BP in acquiring an interest in equity-accounted entities.

[f] Presented net of sales tax.

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

										$ million
										2018
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
Capitalized costs at 31 December[a b]										
Gross capitalized costs										
Proved properties	29,730	—	89,069	3,385	14,269	51,980	—	38,315	6,119	232,867
Unproved properties	451	—	3,602	2,667	2,742	3,870	—	3,153	568	17,053
	30,181	—	92,671	6,052	17,011	55,850	—	41,468	6,687	249,920
Accumulated depreciation	16,809	—	47,051	420	8,517	38,324	—	20,173	3,626	134,920
Net capitalized costs	13,372	—	45,620	5,632	8,494	17,526	—	21,295	3,061	115,000
Costs incurred for the year ended 31 December[a b]										
Acquisition of properties										
Proved	1,933	—	10,650	—	—	(1)	—	36	—	12,618
Unproved	—	—	35	—	100	50	—	(5)	—	180
	1,933	—	10,685	—	100	49	—	31	—	12,798
Exploration and appraisal costs[c]	238	—	216	139	245	283	5	148	24	1,298
Development	817	—	3,429	46	591	2,340	—	2,458	236	9,917
Total costs	2,988	—	14,330	185	936	2,672	5	2,637	260	24,013
Results of operations for the year ended 31 December[a]										
Sales and other operating revenues[d]										
Third parties	619	—	1,306	105	2,074	3,228	—	1,430	1,410	10,172
Sales between businesses	2,255	—	11,656	1	195	3,928	—	7,793	665	26,493
	2,874	—	12,962	106	2,269	7,156	—	9,223	2,075	36,665
Exploration expenditure	105	—	509	146	252	405	5	20	3	1,445
Production costs	646	—	2,729	120	430	1,066	—	951	138	6,080
Production taxes	(269)	—	369	—	357	—	—	1,010	69	1,536
Other costs (income)[e]	(331)	(2)	2,379	43	165	133	42	94	223	2,746
Depreciation, depletion and amortization	1,199	—	3,921	101	1,023	3,635	—	2,165	298	12,342
Net impairments and (gains) losses on sale of businesses and fixed assets	(226)	—	203	10	—	(141)	—	21	136	3
	1,124	(2)	10,110	420	2,227	5,098	47	4,261	867	24,152
Profit (loss) before taxation[f]	1,750	2	2,852	(314)	42	2,058	(47)	4,962	1,208	12,513
Allocable taxes[g]	446	—	454	(95)	314	1,184	13	3,509	508	6,333
Results of operations	1,304	2	2,398	(219)	(272)	874	(60)	1,453	700	6,180
Upstream and Rosneft segments replacement cost profit (loss) before interest and tax										
Exploration and production activities – subsidiaries (as above)	1,750	2	2,852	(314)	42	2,058	(47)	4,962	1,208	12,513
Midstream and other activities – subsidiaries[h]	(20)	265	188	(111)	135	(58)	5	463	6	873
Equity-accounted entities[i j]	(2)	130	28	—	209	207	2,346	245	—	3,163
Total replacement cost profit (loss) before interest and tax	1,728	397	3,068	(425)	386	2,207	2,304	5,670	1,214	16,549

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

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

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

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

[e] Includes property taxes, other government take and the fair value gain on embedded derivatives of $17 million. The UK region includes a $384-million gain which is offset by corresponding charges primarily in the US region, relating to the group self-insurance programme.

[f] Excludes the unwinding of the discount on provisions and payables amounting to $208 million which is included in finance costs in the group income statement.

[g] US region includes the deferred tax impact of the reduction in the US Federal corporate income tax rate from 35% to 21% enacted in December 2017.

[h] Midstream and other activities excludes inventory holding gains and losses.

[i] The profits of equity-accounted entities are included after interest and taxes.

[j] From 16 December 2017, BP entered into a new 50:50 joint venture Pan American Energy Group (PAEG). Prior to this, Pan American Energy (PAE) was owned 60% by BP and 40% by Bridas Corporation.

Oil and natural gas exploration and production activities – continued

$ million

2018

	Europe UK	Europe Rest of Europe	North America US	North America Rest of North America	South America	Africa	Asia Russia[a]	Asia Rest of Asia	Australasia	Total
Equity-accounted entities (BP share)										
Capitalized costs at 31 December[b c]										
Gross capitalized costs										
Proved properties	—	3,439	—	—	9,643	—	24,052	3,646	—	40,780
Unproved properties	—	657	—	—	86	—	828	26	—	1,597
	—	4,096	—	—	9,729	—	24,880	3,672	—	42,377
Accumulated depreciation	—	670	—	—	4,665	—	6,749	3,672	—	15,756
Net capitalized costs	—	3,426	—	—	5,064	—	18,131	—	—	26,621
Costs incurred for the year ended 31 December[b d e]										
Acquisition of properties[c]										
Proved	—	—	—	—	—	—	425	—	—	425
Unproved	—	137	—	—	—	—	148	—	—	285
	—	137	—	—	—	—	573	—	—	710
Exploration and appraisal costs[d]	—	67	—	—	25	—	207	—	—	299
Development	—	251	—	—	575	—	3,255	212	—	4,293
Total costs	—	455	—	—	600	—	4,035	212	—	5,302
Results of operations for the year ended 31 December[b]										
Sales and other operating revenues[f]										
Third parties	—	1,114	—	—	1,792	—	—	353	—	3,259
Sales between businesses	—	—	—	—	—	—	15,901	—	—	15,901
	—	1,114	—	—	1,792	—	15,901	353	—	19,160
Exploration expenditure	—	89	—	—	7	—	112	—	—	208
Production costs	—	207	—	—	438	—	1,487	39	—	2,171
Production taxes	—	—	—	—	361	—	7,634	94	—	8,089
Other costs (income)	—	21	—	—	55	—	638	—	—	714
Depreciation, depletion and amortization	—	290	—	—	416	—	1,627	212	—	2,545
Net impairments and losses on sale of businesses and fixed assets	—	6	—	—	—	—	47	1	—	54
	—	613	—	—	1,277	—	11,545	346	—	13,781
Profit (loss) before taxation	—	501	—	—	515	—	4,356	7	—	5,379
Allocable taxes	—	350	—	—	321	—	849	—	—	1,520
Results of operations[g]	—	151	—	—	194	—	3,507	7	—	3,859
Upstream and Rosneft segments replacement cost profit (loss) before interest and tax from equity-accounted entities										
Exploration and production activities – equity-accounted entities after tax (as above)	—	151	—	—	194	—	3,507	7	—	3,859
Midstream and other activities after tax[h]	(2)	(21)	28	—	15	207	(1,161)	238	—	(696)
Total replacement cost profit (loss) after interest and tax	(2)	130	28	—	209	207	2,346	245	—	3,163

[a] Amounts reported for Russia in this table include BP's share of Rosneft's worldwide activities, including insignificant amounts outside Russia. The amounts reported include the corresponding amounts for their equity-accounted entities.

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

[c] Costs of decommissioning are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

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

[e] The amounts shown reflect BP's share of equity-accounted entities' costs incurred, and not the costs incurred by BP in acquiring an interest in equity-accounted entities.

[f] Presented net of sales taxes.

[g] From 16 December 2017, BP entered into a new 50:50 joint venture Pan American Energy Group (PAEG). Prior to this, Pan American Energy (PAE) was owned 60% by BP and 40% by Bridas Corporation.

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

Oil and natural gas exploration and production activities – continued

										$ million
										2017
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
Capitalized costs at 31 December[a b]										
Gross capitalized costs										
Proved properties	34,208	—	83,449	3,518	13,581	49,795	—	35,519	5,984	226,054
Unproved properties	481	—	3,957	2,561	2,905	4,013	—	3,407	562	17,886
	34,689	—	87,406	6,079	16,486	53,808	—	38,926	6,546	243,940
Accumulated depreciation	21,793	—	48,462	367	7,495	34,870	—	18,007	3,192	134,186
Net capitalized costs	12,896	—	38,944	5,712	8,991	18,938	—	20,919	3,354	109,754
Costs incurred for the year ended 31 December[a b]										
Acquisition of properties										
Proved	—	—	22	—	—	564	—	1,187	—	1,773
Unproved	13	—	13	—	330	374	—	228	—	958
	13	—	35	—	330	938	—	1,415	—	2,731
Exploration and appraisal costs[c]	336	—	102	52	264	682	11	190	18	1,655
Development	995	—	2,776	58	911	2,972	—	2,760	223	10,695
Total costs	1,344	—	2,913	110	1,505	4,592	11	4,365	241	15,081
Results of operations for the year ended 31 December[a]										
Sales and other operating revenues[d]										
Third parties	204	—	724	171	1,134	2,211	—	1,276	967	6,687
Sales between businesses	1,745	—	9,117	2	327	4,022	—	6,394	487	22,094
	1,949	—	9,841	173	1,461	6,233	—	7,670	1,454	28,781
Exploration expenditure	331	—	282	39	83	1,346	11	(29)	17	2,080
Production costs	629	—	2,256	116	573	979	—	904	157	5,614
Production taxes	(37)	—	52	—	86	—	—	1,618	56	1,775
Other costs (income)[e]	(272)	2	1,655	34	71	280	39	311	349	2,469
Depreciation, depletion and amortization	1,190	—	4,258	96	742	3,586	—	2,147	366	12,385
Net impairments and (gains) losses on sale of businesses and fixed assets	133	(12)	87	(1)	(31)	—	—	(10)	13	179
	1,974	(10)	8,590	284	1,524	6,191	50	4,941	958	24,502
Profit (loss) before taxation[f]	(25)	10	1,251	(111)	(63)	42	(50)	2,729	496	4,279
Allocable taxes[g]	(104)	—	(1,811)	(28)	155	788	(19)	1,505	146	632
Results of operations	79	10	3,062	(83)	(218)	(746)	(31)	1,224	350	3,647
Upstream and Rosneft segments replacement cost profit (loss) before interest and tax										
Exploration and production activities – subsidiaries (as above)	(25)	10	1,251	(111)	(63)	42	(50)	2,729	496	4,279
Midstream and other activities – subsidiaries[h]	(185)	97	(176)	(111)	140	(80)	3	315	11	14
Equity-accounted entities[i j]	—	71	25	—	381	205	837	245	—	1,764
Total replacement cost profit (loss) before interest and tax	(210)	178	1,100	(222)	458	167	790	3,289	507	6,057

[a] These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries, which includes our share of oil and natural gas exploration and production activities of joint operations. They do not include any costs relating to the Gulf of Mexico oil spill. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction and transportation operations are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK, Asia and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the South Caucasus Pipeline, the Forties Pipeline System and the Baku-Tbilisi-Ceyhan pipeline. The Forties Pipeline System was divested on 31 October 2017. Major LNG activities are located in Trinidad, Indonesia, Australia and Angola.

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

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

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

[e] Includes property taxes, other government take and the fair value gain on embedded derivatives of $32 million. The UK region includes a $343-million gain which is offset by corresponding charges primarily in the US region, relating to the group self-insurance programme.

[f] Excludes the unwinding of the discount on provisions and payables amounting to $120 million which is included in finance costs in the group income statement.

[g] US region includes the deferred tax impact of the reduction in the US Federal corporate income tax rate from 35% to 21% enacted in December 2017.

[h] Midstream and other activities excludes inventory holding gains and losses.

[i] The profits of equity-accounted entities are included after interest and tax.

[j] From 16 December 2017, BP entered into a new 50:50 joint venture Pan American Energy Group (PAEG). Prior to this, Pan American Energy (PAE) was owned 60% by BP and 40% by Bridas Corporation. Of BP's initial 60% interest in PAE, 10% was classified as held for sale on 9 September 2017. For September, only 9 days of income was reported for the full 60%. After this equity accounting continued for the 50% not classified as held for sale. BP accounted for 50% of the enlarged entity from 16 December 2017.

										$ million
										2017
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		
Equity-accounted entities (BP share)										
Capitalized costs at 31 December[b c]										
Gross capitalized costs										
Proved properties	—	3,187	—	—	9,096	—	24,686	3,434	—	40,403
Unproved properties	—	481	—	—	68	—	907	26	—	1,482
	—	3,668	—	—	9,164	—	25,593	3,460	—	41,885
Accumulated depreciation	—	400	—	—	4,249	—	6,207	3,460	—	14,316
Net capitalized costs	—	3,268	—	—	4,915	—	19,386	—	—	27,569
Costs incurred for the year ended 31 December[b d e]										
Acquisition of properties[c]										
Proved	—	323	—	—	—	—	653	—	—	976
Unproved	—	152	—	—	20	—	416	—	—	588
	—	475	—	—	20	—	1,069	—	—	1,564
Exploration and appraisal costs[d]	—	49	—	—	43	—	194	—	—	286
Development	—	199	—	—	576	—	3,361	446	—	4,582
Total costs	—	723	—	—	639	—	4,624	446	—	6,432
Results of operations for the year ended 31 December[b]										
Sales and other operating revenues[f]										
Third parties	—	773	—	—	1,750	—	—	988	—	3,511
Sales between businesses	—	—	—	—	—	—	11,537	—	—	11,537
	—	773	—	—	1,750	—	11,537	988	—	15,048
Exploration expenditure	—	68	—	—	—	—	59	—	—	127
Production costs	—	157	—	—	592	—	1,424	117	—	2,290
Production taxes	—	—	—	—	336	—	5,712	426	—	6,474
Other costs (income)	—	67	—	—	11	—	409	(5)	—	482
Depreciation, depletion and amortization	—	328	—	—	458	—	1,539	446	—	2,771
Net impairments and losses on sale of businesses and fixed assets	—	6	—	—	27	—	54	—	—	87
	—	626	—	—	1,424	—	9,197	984	—	12,231
Profit (loss) before taxation	—	147	—	—	326	—	2,340	4	—	2,817
Allocable taxes	—	54	—	—	(18)	—	457	—	—	493
Results of operations[g]	—	93	—	—	344	—	1,883	4	—	2,324
Upstream and Rosneft segments replacement cost profit (loss) before interest and tax from equity-accounted entities										
Exploration and production activities – equity-accounted entities after tax (as above)	—	93	—	—	344	—	1,883	4	—	2,324
Midstream and other activities after tax[h]	—	(22)	25	—	37	205	(1,046)	241	—	(560)
Total replacement cost profit (loss) after interest and tax	—	71	25	—	381	205	837	245	—	1,764

[a] Amounts reported for Russia in this table include BP's share of Rosneft's worldwide activities, including insignificant amounts outside Russia. The amounts reported include the corresponding amounts for their equity-accounted entities.

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

[c] Costs of decommissioning are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

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

[e] The amounts shown reflect BP's share of equity-accounted entities' costs incurred, and not the costs incurred by BP in acquiring an interest in equity-accounted entities.

[f] Presented net of sales taxes.

[g] From 16 December 2017, BP entered into a new 50:50 joint venture Pan American Energy Group (PAEG). Prior to this, Pan American Energy (PAE) was owned 60% by BP and 40% by Bridas Corporation. Of BP's initial 60% interest in PAE, 10% was classified as held for sale on 9 September 2017. For September, only 9 days of income was reported for the full 60%. After this equity accounting continued for the 50% not classified as held for sale. BP accounted for 50% of the enlarged entity from 16 December 2017.

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

Movements in estimated net proved reserves

										million barrels
Crude oil[a b]										2019
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	223	—	962	43	8	223	—	1,126	30	2,615
Undeveloped	243	—	802	190	5	36	—	482	5	1,763
	466	—	1,764	234	14	259	—	1,608	34	4,378
Changes attributable to										
Revisions of previous estimates	(23)	—	72	(8)	1	39	—	104	2	187
Improved recovery	—	—	189	1	—	—	—	—	—	191
Purchases of reserves-in-place	—	—	—	—	—	—	—	1	—	1
Discoveries and extensions	—	—	34	—	—	—	—	11	—	45
Production	(36)	—	(143)	(9)	(3)	(57)	—	(125)	(6)	(378)
Sales of reserves-in-place	—	—	(12)	—	—	(45)	—	—	—	(57)
	(59)	—	141	(16)	(2)	(63)	—	(9)	(4)	(12)
At 31 December[e]										
Developed	206	—	1,063	40	7	156	—	1,074	26	2,572
Undeveloped	200	—	842	179	5	40	—	525	4	1,794
	406	—	1,905	218	12	196	—	1,599	30	4,367
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	—	57	—	—	293	1	3,190	—	—	3,541
Undeveloped	—	100	—	19	259	—	2,414	—	—	2,792
	—	157	—	19	552	1	5,604	—	—	6,333
Changes attributable to										
Revisions of previous estimates	—	2	—	1	(13)	1	158	—	—	147
Improved recovery	—	4	—	—	—	—	—	—	—	4
Purchases of reserves-in-place	—	—	—	—	—	—	7	—	—	7
Discoveries and extensions	—	—	—	—	33	—	277	—	—	310
Production	—	(13)	—	—	(24)	—	(345)	—	—	(382)
Sales of reserves-in-place	—	—	—	—	—	—	(6)	—	—	(6)
	—	(7)	—	1	(4)	1	91	—	—	81
At 31 December[g h]										
Developed	—	115	—	—	291	2	3,159	—	—	3,567
Undeveloped	—	35	—	20	257	—	2,535	—	—	2,847
	—	150	—	20	548	2	5,695	—	—	6,415
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	223	57	962	43	302	224	3,190	1,126	30	6,156
Undeveloped	243	100	802	209	264	36	2,414	482	5	4,555
	466	157	1,764	253	566	260	5,604	1,608	34	10,711
At 31 December										
Developed	206	115	1,063	40	298	158	3,159	1,074	26	6,140
Undeveloped	200	35	842	198	262	40	2,535	525	4	4,642
	406	150	1,905	238	560	198	5,695	1,599	30	10,781

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

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

[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 4.5 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

[d] Includes 362 million barrels of crude oil associated with Assets Held for Sale in the USA.

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

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

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

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

Movements in estimated net proved reserves- continued

million barrels

Natural gas liquids[a b]										2019
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	8	—	266	—	2	14	—	—	5	295
Undeveloped	6	—	246	—	25	4	—	—	—	280
	14	—	511	—	27	18	—	—	5	576
Changes attributable to										
Revisions of previous estimates	—	—	(46)	—	(1)	—	—	—	—	(47)
Improved recovery	1	—	62	—	—	—	—	—	—	63
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	1	—	—	—	—	—	—	1
Production[d]	(1)	—	(33)	—	(3)	(3)	—	—	(1)	(41)
Sales of reserves-in-place	—	—	(17)	—	—	—	—	—	—	(17)
	(1)	—	(32)	—	(4)	(3)	—	—	(1)	(41)
At 31 December[e]										
Developed	8	—	229	—	2	12	—	—	4	255
Undeveloped	5	—	250	—	21	4	—	—	—	280
	13	—	479	—	23	16	—	—	4	535
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	—	4	—	—	—	7	103	—	—	114
Undeveloped	—	3	—	—	—	—	51	—	—	54
	—	7	—	—	—	7	154	—	—	169
Changes attributable to										
Revisions of previous estimates	—	—	—	—	3	5	(11)	—	—	(3)
Improved recovery	—	1	—	—	—	—	—	—	—	1
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Production	—	(1)	—	—	—	(2)	(2)	—	—	(4)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	—	—	—	2	4	(13)	—	—	(7)
At 31 December[g h]										
Developed	—	5	—	—	2	11	89	—	—	107
Undeveloped	—	3	—	—	—	—	52	—	—	55
	—	7	—	—	2	11	141	—	—	162
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	8	4	266	—	2	22	103	—	5	409
Undeveloped	6	3	246	—	25	4	51	—	—	335
	14	7	511	—	27	26	154	—	5	744
At 31 December										
Developed	8	5	229	—	4	23	89	—	4	363
Undeveloped	5	3	250	—	21	4	52	—	—	334
	13	7	479	—	25	27	141	—	4	697

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

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

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

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

[e] Includes 7 million barrels of NGL in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

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

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

Movements in estimated net proved reserves - continued

Total liquids[a b]										million barrels 2019
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	231	—	1,228	43	10	237	—	1,126	35	2,910
Undeveloped	249	—	1,048	190	30	40	—	482	5	2,044
	480	—	2,276	234	41	277	—	1,608	39	4,954
Changes attributable to										
Revisions of previous estimates	(24)	—	26	(8)	—	40	—	104	2	140
Improved recovery	1	—	252	1	—	—	—	—	—	254
Purchases of reserves-in-place	—	—	—	—	—	—	—	1	—	1
Discoveries and extensions	—	—	35	—	—	—	—	11	—	46
Production[e]	(38)	—	(176)	(9)	(6)	(60)	—	(125)	(7)	(420)
Sales of reserves-in-place	—	—	(28)	—	—	(45)	—	—	—	(74)
	(60)	—	109	(16)	(6)	(65)	—	(9)	(5)	(52)
At 31 December[f]										
Developed	214	—	1,292	40	9	168	—	1,074	30	2,828
Undeveloped	205	—	1,092	179	26	43	—	525	4	2,074
	420	—	2,384	218	35	212	—	1,599	34	4,902
Equity-accounted entities (BP share)[g]										
At 1 January										
Developed	—	60	—	—	293	8	3,293	—	—	3,655
Undeveloped	—	104	—	19	259	—	2,465	—	—	2,846
	—	164	—	19	552	8	5,758	—	—	6,502
Changes attributable to										
Revisions of previous estimates	—	2	—	1	(11)	7	146	—	—	145
Improved recovery	—	5	—	—	—	—	—	—	—	5
Purchases of reserves-in-place	—	—	—	—	—	—	7	—	—	7
Discoveries and extensions	—	—	—	—	33	—	277	—	—	310
Production	—	(14)	—	—	(24)	(2)	(346)	—	—	(386)
Sales of reserves-in-place	—	—	—	—	—	—	(6)	—	—	(6)
	—	(7)	—	1	(1)	5	78	—	—	75
At 31 December[h i]										
Developed	—	120	—	—	293	13	3,248	—	—	3,675
Undeveloped	—	37	—	20	257	—	2,588	—	—	2,902
	—	157	—	20	550	13	5,836	—	—	6,576
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	231	60	1,228	44	303	245	3,293	1,126	35	6,565
Undeveloped	249	104	1,048	209	289	40	2,465	482	5	4,890
	480	164	2,276	253	593	285	5,758	1,608	39	11,456
At 31 December										
Developed	214	120	1,292	40	302	181	3,248	1,074	30	6,502
Undeveloped	205	37	1,092	198	283	43	2,588	525	4	4,976
	420	157	2,384	238	585	224	5,836	1,599	34	11,478

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

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

[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 4.5 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

[d] Includes 456 million barrels associated with Assets Held for Sale in the USA.

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

[f] Also includes 11 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

[h] Includes 357 million barrels in respect of the non-controlling interest in Rosneft, including 26 mmboe held through BP's interests in Russia other than Rosneft.

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

Movements in estimated net proved reserves – continued

billion cubic feet

Natural gas[a b]										2019
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	439	—	6,270	—	2,168	1,313	—	3,599	2,630	16,420
Undeveloped	343	—	5,056	—	3,073	1,067	—	3,218	1,179	13,936
	782	—	11,326	—	5,241	2,380	—	6,817	3,809	30,355
Changes attributable to										
Revisions of previous estimates	(34)	—	(1,877)	1	(263)	(4)	—	285	(129)	(2,022)
Improved recovery	9	—	307	—	—	—	—	—	—	315
Purchases of reserves-in-place	—	—	—	—	—	—	—	50	—	50
Discoveries and extensions	—	—	11	—	178	—	—	299	—	488
Production[d]	(57)	—	(923)	(1)	(729)	(450)	—	(383)	(291)	(2,834)
Sales of reserves-in-place	—	—	(386)	—	—	(21)	—	—	—	(406)
	(82)	—	(2,869)	—	(814)	(475)	—	251	(420)	(4,410)
At 31 December[e]										
Developed	493	—	6,330	—	2,192	1,163	—	3,667	2,256	16,101
Undeveloped	207	—	2,127	—	2,235	742	—	3,401	1,132	9,844
	700	—	8,458	—	4,427	1,905	—	7,068	3,389	25,946
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	—	107	—	—	1,207	391	7,798	12	—	9,515
Undeveloped	—	55	—	4	446	143	8,719	4	—	9,369
	—	161	—	4	1,653	534	16,517	15	—	18,884
Changes attributable to										
Revisions of previous estimates	—	9	—	3	(120)	38	789	—	—	718
Improved recovery	—	15	—	—	—	—	—	—	—	15
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	—	—	180	—	534	—	—	714
Production[d]	—	(22)	—	—	(135)	(65)	(448)	(5)	—	(676)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	2	—	3	(75)	(27)	874	(5)	—	772
At 31 December[g h]										
Developed	—	108	—	—	1,130	507	9,324	10	—	11,079
Undeveloped	—	56	—	6	447	—	8,067	—	—	8,576
	—	164	—	6	1,577	507	17,391	10	—	19,656
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	439	107	6,270	—	3,375	1,704	7,798	3,610	2,630	25,934
Undeveloped	343	55	5,056	4	3,519	1,210	8,719	3,221	1,179	23,305
	782	161	11,326	4	6,894	2,914	16,517	6,832	3,809	49,239
At 31 December										
Developed	493	108	6,330	—	3,323	1,670	9,324	3,677	2,256	27,181
Undeveloped	207	56	2,127	6	2,682	742	8,067	3,401	1,132	18,421
	700	164	8,458	6	6,004	2,412	17,391	7,078	3,389	45,601

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

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

[c] Includes 3,054 billion cubic feet of natural gas associated with Assets Held for Sale in the USA.

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

[e] Includes 1,330 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

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

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

Movements in estimated net proved reserves – continued

Total hydrocarbons[a b]										million barrels of oil equivalent[c] 2019
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[d e]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	307	—	2,309	43	384	464	—	1,746	488	5,741
Undeveloped	308	—	1,919	190	560	224	—	1,037	208	4,447
	615	—	4,228	234	944	687	—	2,783	696	10,188
Changes attributable to										
Revisions of previous estimates	(29)	—	(297)	(8)	(45)	39	—	153	(21)	(208)
Improved recovery	3	—	305	1	—	—	—	—	—	309
Purchases of reserves-in-place	—	—	—	—	—	—	—	10	—	10
Discoveries and extensions	—	—	36	—	31	—	—	63	—	130
Production[f g]	(48)	—	(335)	(9)	(131)	(137)	—	(191)	(57)	(908)
Sales of reserves-in-place	—	—	(95)	—	—	(49)	—	—	—	(144)
	(74)	—	(386)	(16)	(146)	(147)	—	35	(78)	(813)
At 31 December[h]										
Developed	300	—	2,384	40	387	369	—	1,707	419	5,604
Undeveloped	241	—	1,459	179	411	171	—	1,111	199	3,771
	540	—	3,842	218	798	540	—	2,818	618	9,375
Equity-accounted entities (BP share)[i]										
At 1 January										
Developed	—	79	—	—	501	76	4,638	2	—	5,296
Undeveloped	—	113	—	20	336	25	3,968	1	—	4,462
	—	192	—	20	837	101	8,605	3	—	9,757
Changes attributable to										
Revisions of previous estimates	—	4	—	1	(31)	13	282	—	—	269
Improved recovery	—	7	—	—	—	—	—	—	—	7
Purchases of reserves-in-place	—	—	—	—	—	—	7	—	—	7
Discoveries and extensions	—	—	—	—	64	—	369	—	—	434
Production[f]	—	(17)	—	—	(47)	(13)	(424)	(1)	—	(503)
Sales of reserves-in-place	—	—	—	—	—	—	(6)	—	—	(6)
	—	(6)	—	1	(14)	—	229	(1)	—	208
At 31 December[j k]										
Developed	—	139	—	—	488	100	4,856	2	—	5,585
Undeveloped	—	47	—	21	334	—	3,978	—	—	4,381
	—	186	—	21	822	100	8,834	2	—	9,965
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	307	79	2,309	44	885	539	4,638	1,749	488	11,037
Undeveloped	308	113	1,919	210	896	249	3,968	1,037	208	8,908
	615	192	4,228	253	1,781	788	8,605	2,786	696	19,945
At 31 December										
Developed	300	139	2,384	40	875	469	4,856	1,708	419	11,189
Undeveloped	241	47	1,459	199	746	171	3,978	1,112	199	8,152
	540	186	3,842	239	1,621	640	8,834	2,820	618	19,341

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

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

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

[d] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 4.5 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

[e] Includes 982 million barrels of oil equivalent associated with Assets Held for Sale in the USA.

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

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

[h] Includes 240 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

[j] Includes 603 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft, including 124 mmboe held through BP's interests in Russia other than Rosneft.

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

Movements in estimated net proved reserves – continued

										million barrels
Crude oil[a b]										2018
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	245	—	932	54	10	281	—	1,040	31	2,592
Undeveloped	164	—	492	195	6	28	—	642	11	1,537
	409	—	1,423	248	16	309	—	1,682	42	4,129
Changes attributable to										
Revisions of previous estimates	22	—	116	(6)	1	11	—	40	(2)	183
Improved recovery	—	—	51	—	—	1	—	—	—	52
Purchases of reserves-in-place	93	—	412	—	—	—	—	—	—	504
Discoveries and extensions	15	—	17	—	—	13	—	—	—	46
Production	(37)	—	(137)	(9)	(3)	(75)	—	(114)	(6)	(381)
Sales of reserves-in-place	(37)	—	(118)	—	—	—	—	—	—	(155)
	57	—	341	(15)	(2)	(50)	—	(74)	(8)	249
At 31 December[d e]										
Developed	223	—	962	43	8	223	—	1,126	30	2,615
Undeveloped	243	—	802	190	5	36	—	482	5	1,763
	466	—	1,764	234	14	259	—	1,608	34	4,378
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	—	56	—	—	285	1	3,124	6	—	3,473
Undeveloped	—	89	—	—	263	—	2,251	—	—	2,603
	—	145	—	—	548	1	5,374	6	—	6,076
Changes attributable to										
Revisions of previous estimates	—	11	—	—	7	—	150	—	—	168
Improved recovery	—	13	—	—	—	—	—	—	—	13
Purchases of reserves-in-place	—	—	—	—	—	—	89	—	—	89
Discoveries and extensions	—	—	—	19	21	—	326	—	—	366
Production	—	(13)	—	—	(25)	—	(335)	(6)	—	(379)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	12	—	19	4	(1)	229	(6)	—	257
At 31 December[g]										
Developed	—	57	—	—	293	1	3,190	—	—	3,541
Undeveloped	—	100	—	19	259	—	2,414	—	—	2,792
	—	157	—	19	552	1	5,604	—	—	6,333
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	245	56	932	54	295	282	3,124	1,047	31	6,064
Undeveloped	164	89	492	195	269	28	2,251	642	11	4,140
	409	145	1,423	249	564	310	5,374	1,688	42	10,205
At 31 December										
Developed	223	57	962	43	302	224	3,190	1,126	30	6,156
Undeveloped	243	100	802	209	264	36	2,414	482	5	4,555
	466	157	1,764	253	566	260	5,604	1,608	34	10,711

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

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

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

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

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

[f] Includes 344 million barrels of crude oil in respect of the 6.28% non-controlling interest in Rosneft, including 24 mmbbl held through BP's interests in Russia other than Rosneft.

[g] Total proved crude oil reserves held as part of our equity interest in Rosneft is 5,539 million barrels, comprising less than 1 million barrels in Vietnam and Canada, 58 million barrels in Venezuela and 5,481 million barrels in Russia.

Movements in estimated net proved reserves – continued

										million barrels
Natural gas liquids[a b]										2018
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	11	—	177	—	2	21	—	—	5	216
Undeveloped	3	—	69	—	28	—	—	—	1	102
	14	—	246	—	30	21	—	—	6	318
Changes attributable to										
Revisions of previous estimates	1	—	20	—	—	(3)	—	—	—	17
Improved recovery	—	—	16	—	—	2	—	—	—	18
Purchases of reserves-in-place	—	—	253	—	—	—	—	—	—	253
Discoveries and extensions	3	—	1	—	—	3	—	—	—	7
Production[c]	(2)	—	(25)	—	(3)	(3)	—	—	(1)	(34)
Sales of reserves-in-place	(3)	—	—	—	—	—	—	—	—	(3)
	—	—	265	—	(3)	(2)	—	—	(1)	258
At 31 December[d]										
Developed	8	—	266	—	2	14	—	—	5	295
Undeveloped	6	—	246	—	25	4	—	—	—	280
	14	—	511	—	27	18	—	—	5	576
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	—	4	—	—	—	10	82	—	—	97
Undeveloped	—	4	—	—	—	—	49	—	—	53
	—	8	—	—	—	10	131	—	—	149
Changes attributable to										
Revisions of previous estimates	—	—	—	—	—	(1)	25	—	—	23
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Production	—	(1)	—	—	—	(1)	(2)	—	—	(4)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	(1)	—	—	—	(3)	23	—	—	19
At 31 December[f]										
Developed	—	4	—	—	—	7	103	—	—	114
Undeveloped	—	3	—	—	—	—	51	—	—	54
	—	7	—	—	—	7	154	—	—	169
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	11	4	177	—	2	31	82	—	5	313
Undeveloped	3	4	69	—	28	—	49	—	1	154
	14	8	246	—	30	31	131	—	6	467
At 31 December										
Developed	8	4	266	—	2	22	103	—	5	409
Undeveloped	6	3	246	—	25	4	51	—	—	335
	14	7	511	—	27	26	154	—	5	744

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

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

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

[d] Includes 8 million barrels of NGL in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

[f] Includes 12 million barrels of NGLs in respect of the 7.82% non-controlling interest in Rosneft.

[g] Total proved NGL reserves held as part of our equity interest in Rosneft is 154 million barrels, comprising less than 1 million barrels in Venezuela, Vietnam and Canada, and 154 million barrels in Russia.

Movements in estimated net proved reserves – continued

										million barrels
Total liquids[a b]										2018
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	256	—	1,108	54	12	301	—	1,040	36	2,808
Undeveloped	167	—	561	195	34	28	—	642	12	1,639
	424	—	1,669	248	46	329	—	1,682	48	4,447
Changes attributable to										
Revisions of previous estimates	23	—	136	(6)	1	8	—	40	(2)	200
Improved recovery	—	—	67	—	—	3	—	—	—	70
Purchases of reserves-in-place	93	—	665	—	—	—	—	—	—	758
Discoveries and extensions	18	—	18	—	—	16	—	—	—	52
Production[d]	(39)	—	(162)	(9)	(6)	(79)	—	(114)	(7)	(415)
Sales of reserves-in-place	(40)	—	(118)	—	—	—	—	—	—	(158)
	56	—	606	(15)	(5)	(52)	—	(74)	(9)	507
At 31 December[e]										
Developed	231	—	1,228	43	10	237	—	1,126	35	2,910
Undeveloped	249	—	1,048	190	30	40	—	482	5	2,044
	480	—	2,276	234	41	277	—	1,608	39	4,954
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	—	60	—	—	285	11	3,206	6	—	3,569
Undeveloped	—	93	—	—	263	—	2,300	—	—	2,656
	—	153	—	—	548	12	5,505	6	—	6,225
Changes attributable to										
Revisions of previous estimates	—	11	—	—	7	(2)	175	—	—	191
Improved recovery	—	13	—	—	—	—	—	—	—	13
Purchases of reserves-in-place	—	—	—	—	—	—	89	—	—	89
Discoveries and extensions	—	—	—	19	21	—	326	—	—	366
Production	—	(13)	—	—	(25)	(2)	(337)	(6)	—	(383)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	11	—	19	4	(3)	253	(6)	—	277
At 31 December[g h]										
Developed	—	60	—	—	293	8	3,293	—	—	3,655
Undeveloped	—	104	—	19	259	—	2,465	—	—	2,846
	—	164	—	19	552	8	5,758	—	—	6,502
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	256	60	1,108	54	297	313	3,206	1,047	36	6,377
Undeveloped	167	93	561	195	297	28	2,300	642	12	4,295
	424	153	1,669	249	594	341	5,505	1,688	48	10,672
At 31 December										
Developed	231	60	1,228	44	303	245	3,293	1,126	35	6,565
Undeveloped	249	104	1,048	209	289	40	2,465	482	5	4,890
	480	164	2,276	253	593	285	5,758	1,608	39	11,456

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

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

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

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

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

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

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

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

Movements in estimated net proved reserves – continued

Natural gas[a b]										billion cubic feet 2018
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	523	—	5,238	(1)	2,862	1,159	—	2,755	2,730	15,266
Undeveloped	320	—	3,086	—	3,330	1,510	—	4,245	1,505	13,997
	843	—	8,323	(1)	6,193	2,670	—	7,000	4,235	29,263
Changes attributable to										
Revisions of previous estimates	84	—	10	3	(195)	(444)	—	140	(123)	(524)
Improved recovery	—	—	1,315	—	—	—	—	—	—	1,315
Purchases of reserves-in-place	40	—	2,655	—	—	—	—	—	—	2,695
Discoveries and extensions	60	—	11	—	31	578	—	—	—	680
Production[c]	(66)	—	(751)	(3)	(788)	(423)	—	(324)	(303)	(2,658)
Sales of reserves-in-place	(178)	—	(237)	—	—	—	—	—	—	(416)
	(61)	—	3,003	1	(951)	(290)	—	(184)	(426)	1,092
At 31 December[d]										
Developed	439	—	6,270	—	2,168	1,313	—	3,599	2,630	16,420
Undeveloped	343	—	5,056	—	3,073	1,067	—	3,218	1,179	13,936
	782	—	11,326	—	5,241	2,380	—	6,817	3,809	30,355
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	—	112	—	—	1,274	476	6,077	17	—	7,955
Undeveloped	—	69	—	—	450	146	7,173	3	—	7,841
	—	180	—	—	1,724	622	13,250	20	—	15,796
Changes attributable to										
Revisions of previous estimates	—	2	—	—	(50)	(39)	805	2	—	719
Improved recovery	—	—	—	—	1	—	—	—	—	1
Purchases of reserves-in-place	—	—	—	—	—	—	2,413	—	—	2,413
Discoveries and extensions	—	—	—	4	122	—	512	—	—	638
Production[c]	—	(22)	—	—	(145)	(48)	(464)	(6)	—	(685)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	(19)	—	3	(71)	(87)	3,267	(5)	—	3,087
At 31 December[f g]										
Developed	—	107	—	—	1,207	391	7,798	12	—	9,515
Undeveloped	—	55	—	4	446	143	8,719	4	—	9,369
	—	161	—	4	1,653	534	16,517	15	—	18,884
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	523	112	5,238	—	4,136	1,635	6,077	2,771	2,730	23,221
Undeveloped	320	69	3,086	—	3,781	1,656	7,173	4,249	1,505	21,838
	843	180	8,323	—	7,917	3,291	13,250	7,020	4,235	45,060
At 31 December										
Developed	439	107	6,270	—	3,375	1,704	7,798	3,610	2,630	25,934
Undeveloped	343	55	5,056	4	3,519	1,210	8,719	3,221	1,179	23,305
	782	161	11,326	4	6,894	2,914	16,517	6,832	3,809	49,239

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

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

[c] Includes 181 billion cubic feet of natural gas consumed in operations, 139 billion cubic feet in subsidiaries, 42 billion cubic feet in equity-accounted entities.

[d] Includes 1,573 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

[f] Includes 1,211 billion cubic feet of natural gas in respect of the 8.60% non-controlling interest in Rosneft including 480 billion cubic feet held through BP's interests in Russia other than Rosneft.

[g] Total proved gas reserves held as part of our equity interest in Rosneft is 14,325 billion cubic feet, comprising 0 billion cubic feet in Canada, 26 billion cubic feet in Venezuela, 15 billion cubic feet in Vietnam, 200 billion cubic feet in Egypt and 14,084 billion cubic feet in Russia.

Movements in estimated net proved reserves – continued

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

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

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

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

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

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

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

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

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

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

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

Movements in estimated net proved reserves – continued

Crude oil[a b]										million barrels 2017
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	155	—	826	42	9	317	—	1,107	32	2,487
Undeveloped	274	—	497	209	11	42	—	245	14	1,291
	429	—	1,322	251	20	358	—	1,352	46	3,778
Changes attributable to										
Revisions of previous estimates	15	—	208	5	1	35	—	407	2	673
Improved recovery	—	—	12	—	—	2	—	—	—	14
Purchases of reserves-in-place	3	—	1	—	—	1	—	—	—	5
Discoveries and extensions	—	—	12	—	—	—	—	42	—	53
Production	(29)	—	(131)	(7)	(5)	(88)	—	(119)	(6)	(384)
Sales of reserves-in-place	(9)	—	—	—	—	—	—	—	—	(9)
	(20)	—	101	(2)	(4)	(50)	—	330	(4)	351
At 31 December[d e]										
Developed	245	—	932	54	10	281	—	1,040	31	2,592
Undeveloped	164	—	492	195	6	28	—	642	11	1,537
	409	—	1,423	248	16	309	—	1,682	42	4,129
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	—	45	—	—	321	1	3,162	43	—	3,573
Undeveloped	—	69	—	—	325	—	2,134	1	—	2,529
	—	114	—	—	646	1	5,296	44	—	6,101
Changes attributable to										
Revisions of previous estimates	—	2	—	—	1	—	102	(1)	—	104
Improved recovery	—	11	—	—	4	—	—	—	—	16
Purchases of reserves-in-place	—	34	—	—	—	—	37	—	—	71
Discoveries and extensions	—	1	—	—	22	—	264	—	—	288
Production	—	(11)	—	—	(28)	—	(325)	(36)	—	(401)
Sales of reserves-in-place	—	(5)	—	—	(98)	—	—	—	—	(103)
	—	31	—	—	(98)	—	78	(37)	—	(25)
At 31 December[g]										
Developed	—	56	—	—	285	1	3,124	6	—	3,473
Undeveloped	—	89	—	—	263	—	2,251	—	—	2,603
	—	145	—	—	548	1	5,374	6	—	6,076
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	155	45	826	42	330	318	3,162	1,150	32	6,060
Undeveloped	274	69	497	209	336	42	2,134	246	14	3,819
	429	114	1,322	251	666	360	5,296	1,395	46	9,879
At 31 December										
Developed	245	56	932	54	295	282	3,124	1,047	31	6,064
Undeveloped	164	89	492	195	269	28	2,251	642	11	4,140
	409	145	1,423	249	564	310	5,374	1,688	42	10,205

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

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

[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 9 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

[d] Includes 5 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

[f] Includes 337 million barrels of crude oil in respect of the 6.31% non-controlling interest in Rosneft, including 6 mmbbl held through BP's equity accounted interest in Taas-Yuryakh Neftegazodobycha.

[g] Total proved crude oil reserves held as part of our equity interest in Rosneft is 5,402 million barrels, comprising less than 1 million barrels in Vietnam and Canada, 59 million barrels in Venezuela and 5,342 million barrels in Russia.

Movements in estimated net proved reserves – continued

										million barrels
Natural gas liquids[a b]										2017
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	13	—	226	—	5	13	—	—	9	266
Undeveloped	3	—	73	—	28	1	—	—	2	107
	16	—	299	—	33	14	—	—	11	373
Changes attributable to										
Revisions of previous estimates	2	—	(44)	—	—	11	—	—	(4)	(36)
Improved recovery	—	—	15	—	—	—	—	—	—	15
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	1	—	—	—	—	—	—	1
Production[c]	(3)	—	(24)	—	(3)	(4)	—	—	(1)	(35)
Sales of reserves-in-place	(1)	—	—	—	—	—	—	—	—	(1)
	(2)	—	(52)	—	(3)	7	—	—	(5)	(55)
At 31 December[d]										
Developed	11	—	177	—	2	21	—	—	5	216
Undeveloped	3	—	69	—	28	—	—	—	1	102
	14	—	246	—	30	21	—	—	6	318
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	—	3	—	—	—	11	50	—	—	65
Undeveloped	—	2	—	—	—	—	15	—	—	17
	—	5	—	—	—	11	65	—	—	81
Changes attributable to										
Revisions of previous estimates	—	—	—	—	—	1	68	—	—	69
Improved recovery	—	1	—	—	—	—	—	—	—	1
Purchases of reserves-in-place	—	2	—	—	—	—	—	—	—	2
Discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Production	—	(1)	—	—	—	(1)	(2)	—	—	(4)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	3	—	—	—	(1)	66	—	—	68
At 31 December[f]										
Developed	—	4	—	—	—	10	82	—	—	97
Undeveloped	—	4	—	—	—	—	49	—	—	53
	—	8	—	—	—	10	131	—	—	149
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	13	3	226	—	5	24	50	—	9	331
Undeveloped	3	2	73	—	28	1	15	—	2	123
	16	5	299	—	33	25	65	—	11	454
At 31 December										
Developed	11	4	177	—	2	31	82	—	5	313
Undeveloped	3	4	69	—	28	—	49	—	1	154
	14	8	246	—	30	31	131	—	6	467

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

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

[c] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 2 thousand barrels per day for equity-accounted entities.

[d] Includes 9 million barrels of NGL in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

[f] Total proved NGL reserves held as part of our equity interest in Rosneft is 131 million barrels, comprising less than 1 million barrels in Venezuela, Vietnam and Canada, and 131 million barrels in Russia.

Movements in estimated net proved reserves – continued

Total liquids[a b]										million barrels 2017
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	168	—	1,051	42	14	330	—	1,107	42	2,753
Undeveloped	277	—	569	209	39	43	—	245	16	1,398
	445	—	1,621	251	53	372	—	1,352	57	4,151
Changes attributable to										
Revisions of previous estimates	17	—	164	5	1	45	—	407	(2)	637
Improved recovery	—	—	27	—	—	2	—	—	—	29
Purchases of reserves-in-place	3	—	1	—	—	1	—	—	—	5
Discoveries and extensions	—	—	12	—	—	—	—	42	—	54
Production[d]	(32)	—	(155)	(7)	(8)	(92)	—	(119)	(7)	(419)
Sales of reserves-in-place	(10)	—	—	—	—	—	—	—	—	(10)
	(22)	—	49	(2)	(7)	(43)	—	330	(9)	296
At 31 December[e]										
Developed	256	—	1,108	54	12	301	—	1,040	36	2,808
Undeveloped	167	—	561	195	34	28	—	642	12	1,639
	424	—	1,669	248	46	329	—	1,682	48	4,447
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	—	48	—	—	321	12	3,213	43	—	3,637
Undeveloped	—	71	—	—	325	—	2,148	1	—	2,545
	—	119	—	—	646	12	5,361	44	—	6,183
Changes attributable to										
Revisions of previous estimates	—	2	—	—	1	1	170	(1)	—	174
Improved recovery	—	13	—	—	4	—	—	—	—	17
Purchases of reserves-in-place	—	36	—	—	—	—	37	—	—	72
Discoveries and extensions	—	1	—	—	22	—	264	—	—	288
Production	—	(12)	—	—	(28)	(2)	(327)	(36)	—	(405)
Sales of reserves-in-place	—	(6)	—	—	(98)	—	—	—	—	(104)
	—	34	—	—	(98)	(1)	144	(37)	—	43
At 31 December[g h]										
Developed	—	60	—	—	285	11	3,206	6	—	3,569
Undeveloped	—	93	—	—	263	—	2,300	—	—	2,656
	—	153	—	—	548	12	5,505	6	—	6,225
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	168	48	1,051	42	335	342	3,213	1,150	42	6,390
Undeveloped	277	71	569	209	364	43	2,148	246	16	3,943
	445	119	1,621	251	699	385	5,361	1,395	57	10,333
At 31 December										
Developed	256	60	1,108	54	297	313	3,206	1,047	36	6,377
Undeveloped	167	93	561	195	297	28	2,300	642	12	4,295
	424	153	1,669	249	594	341	5,505	1,688	48	10,672

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

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

[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 9 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

[d] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 2 thousand barrels per day for equity-accounted entities.

[e] Also includes 14 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

[g] Includes 338 million barrels in respect of the non-controlling interest in Rosneft, including 6 mmboe held through BP's equity accounted interest in Taas-Yuryakh Neftegazodobycha.

[h] Total proved liquid reserves held as part of our equity interest in Rosneft is 5,533 million barrels, comprising less than 1 million barrels in Canada, 59 million barrels in Venezuela, less than 1 million barrels in Vietnam and 5,473 million barrels in Russia.

Movements in estimated net proved reserves – continued

Natural gas[a b]	Europe UK	Europe Rest of Europe	North America US	North America Rest of North America	South America	Africa	Asia Russia	Asia Rest of Asia	Australasia	Total
										billion cubic feet 2017
Subsidiaries										
At 1 January										
Developed	499	—	5,447	—	1,784	767	—	1,890	3,012	13,398
Undeveloped	350	—	2,567	—	4,970	2,191	—	3,769	1,643	15,490
	848	—	8,014	—	6,755	2,958	—	5,659	4,654	28,888
Changes attributable to										
Revisions of previous estimates	50	—	(38)	3	(677)	(450)	—	258	(129)	(983)
Improved recovery	—	—	1,002	—	—	1	—	6	—	1,009
Purchases of reserves-in-place	25	—	—	—	—	527	—	—	—	552
Discoveries and extensions	—	—	10	—	829	14	—	1,229	—	2,082
Production[c]	(77)	—	(664)	(3)	(714)	(380)	—	(152)	(291)	(2,281)
Sales of reserves-in-place	(4)	—	—	—	—	—	—	—	—	(4)
	(5)	—	309	—	(562)	(288)	—	1,342	(420)	376
At 31 December[d]										
Developed	523	—	5,238	(1)	2,862	1,159	—	2,755	2,730	15,266
Undeveloped	320	—	3,086	—	3,330	1,510	—	4,245	1,505	13,997
	843	—	8,323	(1)	6,193	2,670	—	7,000	4,235	29,263
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	—	89	—	—	1,546	412	5,544	26	—	7,617
Undeveloped	—	21	—	—	534	—	6,304	4	—	6,863
	—	110	—	1	2,080	412	11,847	30	—	14,480
Changes attributable to										
Revisions of previous estimates	—	19	—	—	47	5	1,556	(2)	—	1,625
Improved recovery	—	37	—	—	55	—	—	—	—	92
Purchases of reserves-in-place	—	39	—	—	—	237	10	—	—	286
Discoveries and extensions	—	1	—	—	67	—	324	—	—	392
Production[c]	—	(19)	—	—	(178)	(32)	(488)	(8)	—	(726)
Sales of reserves-in-place	—	(6)	—	—	(347)	—	—	—	—	(353)
	—	70	—	—	(356)	210	1,403	(10)	—	1,316
At 31 December[f g]										
Developed	—	112	—	—	1,274	476	6,077	17	—	7,955
Undeveloped	—	69	—	—	450	146	7,173	3	—	7,841
	—	180	—	—	1,724	622	13,250	20	—	15,796
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	499	89	5,447	—	3,330	1,179	5,544	1,916	3,012	21,015
Undeveloped	350	21	2,567	—	5,505	2,191	6,304	3,772	1,643	22,353
	848	110	8,014	—	8,835	3,370	11,847	5,688	4,654	43,368
At 31 December										
Developed	523	112	5,238	—	4,136	1,635	6,077	2,771	2,730	23,221
Undeveloped	320	69	3,086	—	3,781	1,656	7,173	4,249	1,505	21,838
	843	180	8,323	—	7,917	3,291	13,250	7,020	4,235	45,060

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

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

[c] Includes 180 billion cubic feet of natural gas consumed in operations, 131 billion cubic feet in subsidiaries, 49 billion cubic feet in equity-accounted entities.

[d] Includes 1,860 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

[f] Includes 306 billion cubic feet of natural gas in respect of the 2.30% non-controlling interest in Rosneft including 2 billion cubic feet held through BP's equity accounted interest in Taas-Yuryakh Neftegazodobycha.

[g] Total proved gas reserves held as part of our equity interest in Rosneft is 13,522 billion cubic feet, comprising 0 billion cubic feet in Canada, 28 billion cubic feet in Venezuela, 19 billion cubic feet in Vietnam, 237 billion cubic feet in Egypt and 13,237 billion cubic feet in Russia.

Movements in estimated net proved reserves – continued

Total hydrocarbons[a b]	Europe		North America		South America	Africa	Asia		Australasia	Total
									million barrels of oil equivalent[c] 2017	
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	254	—	1,990	42	321	462	—	1,433	561	5,063
Undeveloped	338	—	1,012	209	896	420	—	895	299	4,068
	592	—	3,002	251	1,217	882	—	2,327	860	9,131
Changes attributable to										
Revisions of previous estimates	25	—	157	5	(116)	(32)	—	451	(24)	467
Improved recovery	—	—	200	—	—	2	—	1	—	203
Purchases of reserves-in-place	8	—	1	—	—	92	—	—	—	100
Discoveries and extensions	—	—	14	—	143	3	—	254	—	413
Production[e f]	(45)	—	(270)	(8)	(131)	(157)	—	(145)	(57)	(812)
Sales of reserves-in-place	(11)	—	—	—	—	—	—	—	—	(11)
	(23)	—	102	(2)	(104)	(93)	—	562	(81)	361
At 31 December[g]										
Developed	347	—	2,011	54	505	501	—	1,515	507	5,440
Undeveloped	222	—	1,093	195	608	288	—	1,374	272	4,052
	569	—	3,104	248	1,114	790	—	2,889	779	9,492
Equity-accounted entities (BP share)[h]										
At 1 January										
Developed	—	63	—	—	588	83	4,168	47	—	4,951
Undeveloped	—	75	—	—	417	—	3,235	1	—	3,729
	—	138	—	—	1,005	83	7,404	49	—	8,679
Changes attributable to										
Revisions of previous estimates	—	5	—	—	9	2	439	(1)	—	454
Improved recovery	—	19	—	—	14	—	—	—	—	33
Purchases of reserves-in-place	—	42	—	—	—	41	38	—	—	122
Discoveries and extensions	—	1	—	—	34	—	320	—	—	355
Production[e]	—	(15)	—	—	(58)	(7)	(411)	(38)	—	(530)
Sales of reserves-in-place	—	(7)	—	—	(158)	—	—	—	—	(165)
	—	46	—	—	(159)	35	386	(39)	—	269
At 31 December[i j]										
Developed	—	80	—	—	505	93	4,254	9	—	4,941
Undeveloped	—	105	—	—	341	25	3,536	1	—	4,008
	—	184	—	—	846	119	7,790	10	—	8,949
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	254	63	1,990	42	909	545	4,168	1,480	561	10,014
Undeveloped	338	75	1,012	209	1,313	420	3,235	896	299	7,797
	592	138	3,002	251	2,222	966	7,404	2,376	860	17,810
At 31 December										
Developed	347	80	2,011	54	1,010	595	4,254	1,524	507	10,381
Undeveloped	222	105	1,093	195	949	314	3,536	1,374	272	8,060
	569	184	3,104	249	1,959	908	7,790	2,899	779	18,441

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

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

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

[d] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 9 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

[e] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 2 thousand barrels per day for equity-accounted entities.

[f] Includes 31 million barrels of oil equivalent of natural gas consumed in operations, 23 million barrels of oil equivalent in subsidiaries, 8 million barrels of oil equivalent in equity-accounted entities.

[g] Includes 335 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

[i] Includes 391 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft, including 7 mmboe held through BP's equity accounted interest in Taas-Yuryakh Neftegazodobycha.

[j] Total proved reserves held as part of our equity interest in Rosneft is 7,864 million barrels of oil equivalent, comprising less than 1 million barrels of oil equivalent in Canada, 64 million barrels of oil equivalent in Venezuela, 3 million barrels of oil equivalent in Vietnam, 41 million barrels of oil equivalent in Egypt and 7,755 million barrels of oil equivalent in Russia.

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

The following tables set out the standardized measure of discounted future net cash flows, and changes therein, relating to crude oil and natural gas production from the group's estimated proved reserves. This information is prepared in compliance with FASB Oil and Gas Disclosures requirements.

Future net cash flows have been prepared on the basis of certain assumptions which may or may not be realized. These include the timing of future production, the estimation of crude oil and natural gas reserves and the application of average crude oil and natural gas prices and exchange rates from the previous 12 months. Furthermore, both proved reserves estimates and production forecasts are subject to revision as further technical information becomes available and economic conditions change. BP cautions against relying on the information presented because of the highly arbitrary nature of the assumptions on which it is based and its lack of comparability with the historical cost information presented in the financial statements.

										$ million
										2019
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December										
Subsidiaries										
Future cash inflows[a]	**28,600**	**—**	**135,900**	**7,400**	**11,500**	**21,200**	**—**	**135,800**	**24,000**	**364,400**
Future production cost[b]	**13,700**	**—**	**59,200**	**3,400**	**5,700**	**6,700**	**—**	**53,200**	**6,100**	**148,000**
Future development cost[b]	**1,700**	**—**	**16,400**	**1,200**	**2,000**	**1,300**	**—**	**16,700**	**2,700**	**42,000**
Future taxation[c]	**5,200**	**—**	**8,700**	**200**	**1,300**	**3,300**	**—**	**46,000**	**5,300**	**70,000**
Future net cash flows	**8,000**	**—**	**51,600**	**2,600**	**2,500**	**9,900**	**—**	**19,900**	**9,900**	**104,400**
10% annual discount[d]	**2,700**	**—**	**23,100**	**1,400**	**600**	**2,300**	**—**	**7,200**	**4,400**	**41,700**
Standardized measure of discounted future net cash flows[e f]	**5,300**	**—**	**28,500**	**1,200**	**1,900**	**7,600**	**—**	**12,700**	**5,500**	**62,700**
Equity-accounted entities (BP share)[g]										
Future cash inflows[a]	**—**	**10,300**	**—**	**—**	**36,800**	**—**	**322,000**	**—**	**—**	**369,100**
Future production cost[b]	**—**	**3,500**	**—**	**—**	**14,900**	**—**	**222,600**	**—**	**—**	**241,000**
Future development cost[b]	**—**	**700**	**—**	**—**	**3,900**	**—**	**21,800**	**—**	**—**	**26,400**
Future taxation[c]	**—**	**4,700**	**—**	**—**	**4,100**	**—**	**13,300**	**—**	**—**	**22,100**
Future net cash flows	**—**	**1,400**	**—**	**—**	**13,900**	**—**	**64,300**	**—**	**—**	**79,600**
10% annual discount[d]	**—**	**400**	**—**	**—**	**8,200**	**—**	**37,100**	**—**	**—**	**45,700**
Standardized measure of discounted future net cash flows[h i]	**—**	**1,000**	**—**	**—**	**5,700**	**—**	**27,200**	**—**	**—**	**33,900**
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows[j]	**5,300**	**1,000**	**28,500**	**1,200**	**7,600**	**7,600**	**27,200**	**12,700**	**5,500**	**96,600**

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

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

[a] The marker prices used were Brent \$62.74/bbl, Henry Hub \$2.58/mmBtu.

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

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

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

[e] In certain situations, revenues and costs are included in the standardized measure of discounted future net cash flows valuation and excluded from the determination of proved reserves and vice versa. This can result in the standardized measure of discounted future net cash flows being negative.

[f] Non-controlling interests in BP Trinidad and Tobago LLC amounted to \$600 million.

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

[h] Non-controlling interests in Rosneft amounted to \$2,100 million in Russia.

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

[j] Includes future net cash flows for assets held for sale at 31 December 2019.

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

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

										$ million 2018
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December										
Subsidiaries										
Future cash inflows[a]	39,700	—	160,000	4,100	17,500	30,400	—	147,500	30,000	429,200
Future production cost[b]	15,000	—	57,600	3,400	7,200	8,500	—	55,800	7,600	155,100
Future development cost[b]	2,100	—	17,800	1,100	2,800	2,600	—	16,400	2,500	45,300
Future taxation[c]	8,900	—	16,600	—	3,200	5,300	—	51,100	6,900	92,000
Future net cash flows	13,700	—	68,000	(400)	4,300	14,000	—	24,200	13,000	136,800
10% annual discount[d]	5,000	—	29,900	(200)	700	3,300	—	9,400	5,800	53,900
Standardized measure of discounted future net cash flows[e f]	8,700	—	38,100	(200)	3,600	10,700	—	14,800	7,200	82,900
Equity-accounted entities (BP share)[g]										
Future cash inflows[a]	—	12,800	—	—	38,500	—	356,800	—	—	408,100
Future production cost[b]	—	4,200	—	—	16,100	—	238,400	—	—	258,700
Future development cost[b]	—	800	—	—	3,600	—	19,300	—	—	23,700
Future taxation[c]	—	5,900	—	—	4,400	—	17,700	—	—	28,000
Future net cash flows	—	1,900	—	—	14,400	—	81,400	—	—	97,700
10% annual discount[d]	—	600	—	—	8,500	—	48,100	—	—	57,200
Standardized measure of discounted future net cash flows[h i]	—	1,300	—	—	5,900	—	33,300	—	—	40,500
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	8,700	1,300	38,100	(200)	9,500	10,700	33,300	14,800	7,200	123,400

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

			$ million
	Subsidiaries	Equity-accounted entities (BP share)	Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	(18,800)	(8,000)	(26,800)
Development costs for the current year as estimated in previous year	8,500	4,300	12,800
Extensions, discoveries and improved recovery, less related costs	5,800	3,300	9,100
Net changes in prices and production cost	41,000	13,100	54,100
Revisions of previous reserves estimates	(2,100)	2,000	(100)
Net change in taxation	(17,000)	(4,600)	(21,600)
Future development costs	1,000	(3,500)	(2,500)
Net change in purchase and sales of reserves-in-place	7,600	400	8,000
Addition of 10% annual discount	5,200	3,100	8,300
Total change in the standardized measure during the year[j]	31,200	10,100	41,300

[a] The marker prices used were Brent $71.43/bbl, Henry Hub $3.10/mmBtu.

[b] Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included. 2018 comparative for Russia equity-accounted entity future production cost has been restated from $232,100 million to maintain consistency with 2019 presentation.

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

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

[e] In certain situations, revenues and costs are included in the standardized measure of discounted future net cash flows valuation and excluded from the determination of proved reserves and vice versa. This can result in the standardized measure of discounted future net cash flows being negative.

[f] Non-controlling interests in BP Trinidad and Tobago LLC amounted to $1,100 million.

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

[h] Non-controlling interests in Rosneft amounted to $2,500 million in Russia.

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

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

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

										$ million
										2017
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December										
Subsidiaries										
Future cash inflows[a]	26,300	—	99,200	7,100	15,200	27,000	—	118,800	26,200	319,800
Future production cost[b]	13,800	—	46,700	4,100	7,100	8,600	—	52,600	8,400	141,300
Future development cost[b]	1,700	—	12,100	1,100	2,400	3,400	—	18,200	3,200	42,100
Future taxation[c]	4,200	—	6,500	—	1,700	3,800	—	33,200	4,800	54,200
Future net cash flows	6,600	—	33,900	1,900	4,000	11,200	—	14,800	9,800	82,200
10% annual discount[d]	2,100	—	13,100	1,100	500	3,400	—	5,500	4,800	30,500
Standardized measure of discounted future net cash flows[e]	4,500	—	20,800	800	3,500	7,800	—	9,300	5,000	51,700
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	—	9,000	—	—	32,900	—	205,100	400	—	247,400
Future production cost[b]	—	4,100	—	—	15,500	—	114,900	300	—	134,800
Future development cost[b]	—	800	—	—	3,400	—	17,600	100	—	21,900
Future taxation[c]	—	3,100	—	—	3,100	—	12,400	—	—	18,600
Future net cash flows	—	1,000	—	—	10,900	—	60,200	—	—	72,100
10% annual discount[d]	—	400	—	—	6,400	—	34,900	—	—	41,700
Standardized measure of discounted future net cash flows[g h]	—	600	—	—	4,500	—	25,300	—	—	30,400
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	4,500	600	20,800	800	8,000	7,800	25,300	9,300	5,000	82,100

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

			$ million
	Subsidiaries	Equity-accounted entities (BP share)	Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	(12,800)	(5,500)	(18,300)
Development costs for the current year as estimated in previous year	9,800	4,200	14,000
Extensions, discoveries and improved recovery, less related costs	2,300	1,300	3,600
Net changes in prices and production cost	33,100	7,300	40,400
Revisions of previous reserves estimates	2,800	1,000	3,800
Net change in taxation	(12,500)	(1,500)	(14,000)
Future development costs	3,000	(4,600)	(1,600)
Net change in purchase and sales of reserves-in-place	800	(600)	200
Addition of 10% annual discount	2,300	2,600	4,900
Total change in the standardized measure during the year[i]	28,800	4,200	33,000

[a] The marker prices used were Brent $54.36/bbl, Henry Hub $2.96/mmBtu.

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

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

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

[e] Non-controlling interests in BP Trinidad and Tobago LLC amounted to $1,100 million.

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

[g] Non-controlling interests in Rosneft amounted to $1,963 million in Russia.

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

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

Operational and statistical information

The following tables present operational and statistical information related to production, drilling, productive wells and acreage. Figures include amounts attributable to assets held for sale.

Crude oil and natural gas production

The following table shows crude oil, natural gas liquids and natural gas production for the years ended 31 December 2019, 2018 and 2017.

Production for the year[a b]

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia[c]	Rest of Asia		
Subsidiaries[d]										
Crude oil[e]										thousand barrels per day
2019	**100**	**—**	**400**	**24**	**7**	**156**	**—**	**343**	**17**	**1,046**
2018	101	—	385	24	7	204	—	313	17	1,051
2017	80	—	370	20	12	241	—	325	17	1,064
Natural gas liquids										thousand barrels per day
2019	**3**	**—**	**81**	**—**	**9**	**8**	**—**	**—**	**2**	**104**
2018	5	—	60	—	9	11	—	—	2	88
2017	6	—	56	—	10	10	—	—	2	85
Natural gas[f]										million cubic feet per day
2019	**129**	**—**	**2,358**	**2**	**1,977**	**1,138**	**—**	**976**	**786**	**7,366**
2018	152	—	1,900	7	2,136	1,061	—	826	819	6,900
2017	182	—	1,659	9	1,936	949	—	371	783	5,889
Equity-accounted entities (BP share)										
Crude oil[e]										thousand barrels per day
2019	**—**	**35**	**—**	**—**	**56**	**1**	**955**	**—**	**—**	**1,047**
2018	—	34	—	—	55	1	933	16	—	1,040
2017	—	31	—	—	63	1	905	99	—	1,099
Natural gas liquids										thousand barrels per day
2019	**—**	**2**	**—**	**—**	**1**	**8**	**3**	**—**	**—**	**14**
2018	—	2	—	—	—	6	4	—	—	12
2017	—	2	—	—	—	6	4	—	—	12
Natural gas[f]										million cubic feet per day
2019	**—**	**56**	**—**	**—**	**314**	**87**	**1,279**	**—**	**—**	**1,736**
2018	—	59	—	—	335	80	1,286	—	—	1,760
2017	—	53	—	—	418	77	1,308	—	—	1,855

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

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

[c] Amounts reported for Russia include BP's share of Rosneft worldwide activities, including insignificant amounts outside Russia.

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

[e] Crude oil includes condensate.

[f] Natural gas production excludes gas consumed in operations.

Productive oil and gas wells and acreage

The following tables show the number of gross and net productive oil and natural gas wells and total gross and net developed and undeveloped oil and natural gas acreage in which the group and its equity-accounted entities had interests as at 31 December 2019. A 'gross' well or acre is one in which a whole or fractional working interest is owned, while the number of 'net' wells or acres is the sum of the whole or fractional working interests in gross wells or acres. Productive wells are producing wells and wells capable of production. Developed acreage is the acreage within the boundary of a field, on which development wells have been drilled, which could produce the reserves; while undeveloped acres are those on which wells have not been drilled or completed to a point that would permit the production of commercial quantities, whether or not such acres contain proved reserves.

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

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

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

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

[d] Includes approximately 2,618 gross (1,265 net) multiple completion wells. If one of the multiple completions in a well is an oil completion, the well is classified as an oil well.

[e] Undeveloped acreage includes leases and concessions.

Net oil and gas wells completed or abandoned

The following table shows the number of net productive and dry exploratory and development oil and natural gas wells completed or abandoned in the years indicated by the group and its equity-accounted entities. Productive wells include wells in which hydrocarbons were encountered and the drilling or completion of which, in the case of exploratory wells, has been suspended pending further drilling or evaluation. A dry well is one found to be incapable of producing hydrocarbons in sufficient quantities to justify completion.

	Europe		North America		South America	Africa	Asia		Australasia	Total[a]
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
2019										
Exploratory										
Productive	**—**	**0.2**	**0.8**	**0.8**	**3.5**	**2.3**	**11.6**	**5.2**	**—**	**24.4**
Dry	**1.0**	**0.3**	**1.6**	**0.5**	**1.1**	**0.3**	**0.5**	**0.4**	**0.2**	**5.9**
Development										
Productive	**1.7**	**2.4**	**193.0**	**0.2**	**110.7**	**6.0**	**230.8**	**49.6**	**0.4**	**594.8**
Dry	**—**	**0.3**	**10.0**	**—**	**0.6**	**—**	**—**	**1.0**	**—**	**11.9**
2018										
Exploratory										
Productive	0.3	—	1.7	—	2.0	—	15.0	5.0	—	24.0
Dry	—	—	—	0.5	2.0	2.4	—	—	—	4.9
Development										
Productive	1.4	0.6	142.7	5.0	103.9	14.4	137.3	53.5	1.3	460.1
Dry	—	—	6.8	—	3.6	—	—	2.6	—	13.0
2017										
Exploratory										
Productive	2.8	0.1	1.5	1.2	3.2	2.6	9.4	1.4	—	22.2
Dry	2.4	—	—	—	—	2.9	—	1.0	—	6.3
Development										
Productive	2.5	0.5	124.0	8.0	103.7	16.5	282.7	43.6	1.1	582.6
Dry	—	—	0.5	—	1.6	2.1	—	0.8	—	5.0

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

Operational and statistical information – continued

Drilling and production activities in progress

The following table shows the number of exploratory and development oil and natural gas wells in the process of being drilled by the group and its equity-accounted entities as of 31 December 2019. Suspended development wells and long-term suspended exploratory wells are also included in the table.

	Europe		North America		South America	Africa	Asia		Australasia	Total[a]
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December 2019										
Exploratory										
Gross	**—**	**—**	**8.0**	**—**	**2.0**	**4.0**	**—**	**5.0**	**—**	**19.0**
Net	**—**	**—**	**4.9**	**—**	**0.5**	**1.6**	**—**	**0.5**	**—**	**7.5**
Development										
Gross	**6.0**	**3.6**	**213.0**	**6.0**	**13.0**	**26.0**	**—**	**216.0**	**2.0**	**485.6**
Net	**2.0**	**1.1**	**140.0**	**3.0**	**4.1**	**14.5**	**—**	**29.1**	**0.8**	**194.6**

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

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

Company balance sheet

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

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

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

B Looney Chief executive officer

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

Company statement of changes in equity[a]

$ million

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Treasury shares	Foreign currency translation reserve	Profit and loss account	Total equity
At 1 January 2019	**5,402**	**12,305**	**1,439**	**26,509**	**(15,767)**	**(366)**	**96,430**	**125,952**
Profit for the year	**—**	**—**	**—**	**—**	**—**	**—**	**4,470**	**4,470**
Other comprehensive income	**—**	**—**	**—**	**—**	**—**	**200**	**401**	**601**
Total comprehensive income	**—**	**—**	**—**	**—**	**—**	**200**	**4,871**	**5,071**
Dividends	**52**	**(52)**	**—**	**—**	**—**	**—**	**(6,929)**	**(6,929)**
Repurchases of ordinary share capital	**(59)**	**—**	**59**	**—**	**—**	**—**	**(1,511)**	**(1,511)**
Share-based payments, net of tax	**9**	**164**	**—**	**—**	**1,355**	**—**	**(790)**	**738**
At 31 December 2019	**5,404**	**12,417**	**1,498**	**26,509**	**(14,412)**	**(166)**	**92,071**	**123,321**
At 1 January 2018	5,343	12,147	1,426	26,509	(16,958)	(70)	101,078	129,475
Profit for the year	—	—	—	—	—	—	1,931	1,931
Other comprehensive income	—	—	—	—	—	(296)	1,178	882
Total comprehensive income	—	—	—	—	—	(296)	3,109	2,813
Dividends	49	(49)	—	—	—	—	(6,699)	(6,699)
Repurchases of ordinary share capital	(13)	—	13	—	—	—	(355)	(355)
Share-based payments, net of tax	23	207	—	—	1,191	—	(703)	718
At 31 December 2018	5,402	12,305	1,439	26,509	(15,767)	(366)	96,430	125,952

[a] See Note 8 for further information.

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

Notes on financial statements

1. Significant accounting policies, judgements, estimates and assumptions

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

The financial statements of BP p.l.c. for the year ended 31 December 2019 were approved and signed by the chief executive officer on 18 March 2020 having been duly authorized to do so by the board of directors. The company meets the definition of a qualifying entity under Financial Reporting Standard 100 'Application of Financial Reporting Requirements' (FRS 100) issued by the Financial Reporting Council. Accordingly, these financial statements have been prepared in accordance with FRS 101 and in accordance with the provisions of the UK Companies Act 2006.

Basis of preparation

The financial statements have been prepared on a going concern basis and in accordance with the Companies Act 2006 and applicable UK accounting standards.

The financial statements have been prepared under the historical cost convention. Historical cost is generally based on the fair value of the consideration given in exchange for the assets.

As permitted by FRS 101, the company has taken advantage of the disclosure exemptions available in relation to:

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

(b) the requirements of paragraphs 10(d), 10(f), 16, 38A, 38B, 38C, 38D, 40A, 40B, 40C, 40D, 111 and 134 to 136 of IAS 1 'Presentation of Financial Statements';

(c) the requirements in paragraph 38 of IAS 1 'Presentation of Financial Statements' to present comparative information in respect of paragraph 79(a)(iv) of IAS 1.

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

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

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

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

(h) the requirement of the second sentence of paragraph 110 and paragraphs 113(a), 114,115, 118, 119(a) to (c), 120 to 127 and 129 of IFRS 15 'Revenue from Contracts with Customers'.

Where required, equivalent disclosures are given in the consolidated financial statements of BP p.l.c.

As permitted by Section 408 of the Companies Act 2006, the income statement of the company is not presented as part of these financial statements.

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

Significant accounting policies: use of judgements, estimates and assumptions

Inherent in the application of many of the accounting policies used in preparing the financial statements is the need for management to make judgements, estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities, and the reported amounts of revenues and expenses. Actual outcomes could differ from the estimates and assumptions used. The accounting judgements and estimates that have a significant impact on the results of the company are set out in boxed text below, and should be read in conjunction with the information provided in the Notes on financial statements.

Investments

Investments in subsidiaries are recorded at cost. The company assesses investments for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If any such indication of impairment exists, the company makes an estimate of its recoverable amount. Where the carrying amount of an investment exceeds its recoverable amount, the investment is considered impaired and is written down to its recoverable amount. Where these circumstances have reversed, the impairment previously made is reversed to the extent of the original cost of the investment.

Foreign currency translation

The functional and presentation currency of the financial statements is US dollars. Transactions in foreign currencies are initially recorded in the functional currency by applying the spot exchange rate on the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated into the functional currency at the spot exchange rate on the balance sheet date. Any resulting exchange differences are included in the income statement. Non-monetary assets and liabilities, other than those measured at fair value, are not retranslated subsequent to initial recognition.

Exchange adjustments arising when the opening net assets and the profits for the year retained by a non-US dollar functional currency branch are translated into US dollars are recognized in a separate component of equity and reported in other comprehensive income. Income statement transactions are translated into US dollars using the average exchange rate for the reporting period.

Financial guarantees

The company enters into financial guarantee contracts with its subsidiaries. At the inception of a financial guarantee contract, a liability is recognized initially at fair value and then subsequently at the higher of the estimated loss and amortized cost. Where a guarantee is issued for a premium, a receivable of an amount equal to the liability is initially recognized. Subsequently, the liability and receivable reduce by the amount of consideration received, which is recognized in the income statement. Where a guarantee is issued without a premium, the fair value is recognized as additional investment in the entity to which the guarantee relates.

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

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

Share-based payments

Equity-settled transactions

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

For other equity-settled share-based payment transactions, the goods or services received and the corresponding increase in equity are measured at the fair value of the goods or services received, unless their fair value cannot be reliably estimated. If the fair value of the goods and services received cannot be reliably estimated, the transaction is measured by reference to the fair value of the equity instruments granted.

Cash-settled transactions

The cost of cash-settled transactions is recognized as an expense over the vesting period, measured by reference to the fair value of the corresponding liability which is recognized on the balance sheet. The liability is remeasured at fair value at each balance sheet date until settlement, with changes in fair value recognized in the income statement.

Pensions

The defined benefit pension plans are plans that share risks between entities under common control. In each instance BP p.l.c. is the principal employer and carries the whole plan surplus or deficit on its balance sheet. The cost of providing benefits under the company's defined benefit plans is determined separately for each plan using the projected unit credit method, which attributes entitlement to benefits to the current period to determine current service cost and to the current and prior periods to determine the present value of the defined benefit obligation. Past service costs, resulting from either a plan amendment or a curtailment (a reduction in future obligations as a result of a material reduction in the plan membership), are recognized immediately when the company becomes committed to a change.

Net interest expense relating to pensions, which is recognized in the income statement, represents the net change in present value of plan obligations and the value of plan assets resulting from the passage of time, and is determined by applying the discount rate to the present value of the benefit obligation at the start of the year, and to the fair value of plan assets at the start of the year, taking into account expected changes in the obligation or plan assets during the year.

Remeasurements of the defined benefit liability and asset, comprising actuarial gains and losses, and the return on plan assets (excluding amounts included in net interest described above) are recognized within other comprehensive income in the period in which they occur and are not subsequently reclassified to profit and loss.

The defined benefit pension plan surplus or deficit recognized on the balance sheet for each plan comprises the difference between the present value of the defined benefit obligation (using a discount rate based on high quality corporate bonds) and the fair value of plan assets out of which the obligations are to be settled directly. Fair value is based on market price information and, in the case of quoted securities, is the published bid price. Defined benefit pension plan surpluses are only recognized to the extent they are recoverable, typically by way of refund.

Contributions to defined contribution plans are recognized in the income statement in the period in which they become payable.

Significant estimate: pensions

Accounting for defined benefit pensions involves making significant estimates when measuring the company's pension plan surpluses and deficits. These estimates require assumptions to be made about many uncertainties.

Pension assumptions are reviewed by management at the end of each year. These assumptions are used to determine the projected benefit obligation at the year end and hence the surpluses and deficits recorded on the company's balance sheet, and pension expense for the following year. The assumptions used are provided in Note 4.

The assumptions that are the most significant to the amounts reported are the discount rate, inflation rate, salary growth and mortality levels. Assumptions about these variables are based on the environment in each country. The assumptions used vary from year to year, with resultant effects on future net income and net assets. Changes to some of these assumptions, in particular the discount rate and inflation rate, could result in material changes to the carrying amounts of the company's pension obligations within the next financial year for the UK plan. Any differences between these assumptions and the actual outcome will also affect future net income and net assets.

The values ascribed to these assumptions and a sensitivity analysis of the impact of changes in the assumptions on the benefit expense and obligation used are provided in Note 4.

Income taxes

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

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

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

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

Deferred tax assets are only recognized to the extent that it is probable that they will be realized in the future.

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

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

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the period when the asset is realized or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the balance sheet date. Deferred tax assets and liabilities are not discounted. See note 6 for further details.

Financial assets

The company determines the classification of its financial assets at initial recognition. Financial assets are recognized initially at fair value, normally being the transaction price plus directly attributable transaction costs. The subsequent measurement of financial assets depends on their classification, as set out below. The company derecognizes financial assets when the contractual rights to the cash flows expire or the rights to receive cash flows have been transferred to a third party along with substantially all of the risks and rewards or control of the asset.

Financial assets measured at amortized cost

Financial assets are classified as measured at amortized cost when they are held in a business model the objective of which is to collect contractual cash flows and the contractual cash flows represent solely payments of principal and interest. Such assets are carried at amortized cost using the effective interest method if the time value of money is significant. Gains and losses are recognized in profit or loss when the assets are derecognized or impaired and when interest is recognized using the effective interest method. This category of financial assets includes trade and other receivables.

Cash equivalents

Cash equivalents are short-term highly liquid investments that are readily convertible to known amounts of cash, are subject to insignificant risk of changes in value and generally have a maturity of three months or less from the date of acquisition. Cash equivalents are classified as financial assets measured at amortized cost.

Financial liabilities

All financial liabilities held by the company are classified as financial liabilities measured at amortized cost. Financial liabilities include other payables, accruals, and finance debt. The company determines the classification of its financial liabilities at initial recognition.

Financial liabilities measured at amortized cost

All financial liabilities are initially recognized at fair value, net of directly attributable transaction costs. For interest-bearing loans and borrowings this is typically equivalent to the fair value of the proceeds received, net of issue costs associated with the borrowing.

After initial recognition, financial liabilities are subsequently measured at amortized cost using the effective interest method. Amortized cost is calculated by taking into account any issue costs and any discount or premium on settlement. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognized in interest and other income and finance costs respectively.

Impact of new International Financial Reporting Standards

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

2. Investments

			$ million
	Subsidiaries	Associates	
	Shares	Shares	Total
Cost			
At 1 January 2019	**166,302**	**2**	**166,304**
Additions	**—**	**—**	**—**
Disposals	**(15)**	**—**	**(15)**
At 31 December 2019	**166,287**	**2**	**166,289**
Amounts provided			
At 1 January 2019	**33**	**—**	**33**
At 31 December 2019	**33**	**—**	**33**
Cost			
At 1 January 2018	166,307	2	166,309
Additions	270	—	270
Disposals	(275)	—	(275)
At 31 December 2018	166,302	2	166,304
Amounts provided			
At 1 January 2018	33	—	33
At 31 December 2018	33	—	33
At 31 December 2019	**166,254**	**2**	**166,256**
At 31 December 2018	166,269	2	166,271

The more important subsidiaries of the company at 31 December 2019 and the percentage holding of ordinary share capital (to the nearest whole number) are set out below. For a full list of related undertakings see Note 14.

Subsidiaries	%	Country of incorporation	Principal activities
International			
BP Global Investments	100	England & Wales	Investment holding
BP International	100	England & Wales	Integrated oil operations
Burmah Castrol	100	Scotland	Lubricants
Canada			
BP Holdings Canada	100	England & Wales	Investment holding
US			
BP Holdings North America	100	England & Wales	Investment holding

The carrying value of the investment in BP International Limited at 31 December 2019 was $76,152 million (2018 $76,152 million).

3. Receivables

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

[a] Non-current receivables includes a promissory note issued by BP (Abu Dhabi) Limited in 2016 in consideration for the issue of BP p.l.c. ordinary shares to the government of Abu Dhabi.

4. Pensions

The primary pension arrangement is a funded final salary pension plan in the UK under which retired employees draw the majority of their benefit as an annuity. This pension plan is governed by a corporate trustee whose board is composed of four member-nominated directors, four company-nominated directors, an independent director, and an independent chairman nominated by the company. The trustee board is required by law to act in the best interests of the plan participants and is responsible for setting certain policies, such as investment policies of the plan. The plan is closed to new joiners but remains open to ongoing accrual for current members. New joiners are eligible for membership of a defined contribution plan.

The level of contributions to funded defined benefit plans is the amount needed to provide adequate funds to meet pension obligations as they fall due. During 2019 the aggregate level of contributions was $236 million (2018 $490 million). The aggregate level of contributions in 2020 is expected to be approximately $255 million, and includes contributions we expect to be required to make by law or under contractual agreements, as well as an allowance for discretionary funding.

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

4. Pensions – continued

For the primary UK plan there is a funding agreement between the company and the trustee. On an annual basis the latest funding position is reviewed and a schedule of contributions is agreed covering the next five years. Contractually committed funding amounted to $1,276 million at 31 December 2019, all of which relates to future service. The surplus relating to the primary UK pension plan is recognized on the balance sheet on the basis that the company is entitled to a refund of any remaining assets once all members have left the plan.

The obligation and cost of providing the pension benefits is assessed annually using the projected unit credit method. The date of the most recent actuarial review was 31 December 2019. The principal plans are subject to a formal actuarial valuation every three years in the UK. The most recent formal actuarial valuation of the main pension plan was as at 31 December 2017.

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

Financial assumptions used to determine benefit obligation		%
	2019	2018
Discount rate for pension plan liabilities	**2.1**	2.9
Rate of increase in salaries	**3.4**	3.8
Rate of increase for pensions in payment	**2.7**	3.0
Rate of increase in deferred pensions	**2.7**	3.0
Inflation for pension plan liabilities	**2.7**	3.1

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

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

The assumption for the rate of increase in salaries is based on our inflation assumption plus an allowance for expected long-term real salary growth. This comprises of an allowance for promotion-related salary growth of 0.7%.

In addition to the financial assumptions, we regularly review the demographic and mortality assumptions. The mortality assumptions reflect best practice in the UK and have been chosen with regard to the latest available published tables adjusted to reflect the experience of the plans and an extrapolation of past longevity improvements into the future. For the main pension plan the mortality assumptions are as follows:

Mortality assumptions		Years
	2019	2018
Life expectancy at age 60 for a male currently aged 60	**27.3**	27.4
Life expectancy at age 60 for a male currently aged 40	**28.9**	28.9
Life expectancy at age 60 for a female currently aged 60	**28.7**	28.8
Life expectancy at age 60 for a female currently aged 40	**30.5**	30.6

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

A significant proportion of the assets are held in equities, owing to a higher expected level of return over the long term of such assets with an acceptable level of risk. In order to provide reasonable assurance that no single security or type of security has an unwarranted impact on the total portfolio, the investment portfolios are highly diversified.

The trustee's long-term investment objective for the primary UK plan as it matures is to invest in assets whose value changes in the same way as the plan liabilities, in order to reduce the level of funding risk. To move towards this objective, the UK plan uses a liability driven investment (LDI) approach for part of the portfolio, investing primarily in government bonds to achieve this matching effect for the most significant plan liability assumptions of interest rate and inflation rate. This is partly funded by short-term sale and repurchase agreements, whereby the plan borrows money using existing bonds as security and which will be bought back at a specified price at an agreed future date. The funds raised are used to invest in further bonds to increase the proportion of assets which match the plan liabilities. The borrowings are shown separately in the analysis of pension plan assets in the table below.

For the primary UK pension plan there is an agreement with the trustee to increase the proportion of assets with liability matching characteristics over time primarily by reducing the proportion of plan assets held as equities and increasing the proportion held as bonds. During 2019, the plan switched 2% from equities to bonds (2018 12.5%).

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

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

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

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4. Pensions – continued

The primary plan does not invest directly in either securities or property/real estate of the company or of any subsidiary.

The fair values of the various categories of assets held by the defined benefit plans at 31 December are presented in the table below, including the effects of derivative financial instruments. Movements in the fair value of plan assets during the year are shown in detail in the table on page 268.

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

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

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

[c] Property held is all located in the United Kingdom and are valued based on an analysis of recent market transactions supported by market knowledge derived from third-party valuers.

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

[a] The costs of managing the fund's investments are treated as being part of the investment return, the costs of administering our pensions plan benefits are included in current service cost.

[b] Past service cost represents the increased liability arising as a result of early retirements occurring as part of restructuring programmes.

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

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4. Pensions – continued

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

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

[b] The benefit payments amount shown above comprises $1,194 million benefits (2018 $1,764 million) plus $18 million (2018 $20 million) of plan expenses incurred in the administration of the benefit.

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

[d] Reflects $35,811 million of assets held in the BP Pension Fund (2018 $31,818 million) and $251 million held in the BP Global Pension Trust (2018 $203 million), as well as $53 million representing the company's share of Merchant Navy Officers Pension Fund (2018 $51 million) and $14 million of Merchant Navy Ratings Pension Fund (2018 $13 million).

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

Sensitivity analysis

The discount rate, inflation, salary growth and the mortality assumptions all have a significant effect on the amounts reported. A one-percentage point change, in isolation, in certain assumptions as at 31 December 2019 for the company's plans would have had the effects shown in the table below. The effects shown for the expense in 2020 comprise the total of current service cost and net finance income or expense.

		$ million
	One percentage point	
	Increase	Decrease
Discount rate[a]		
Effect on pension expense in 2020	**(274)**	**227**
Effect on pension obligation at 31 December 2019	**(4,725)**	**6,359**
Inflation rate[b]		
Effect on pension expense in 2020	**171**	**(134)**
Effect on pension obligation at 31 December 2019	**4,711**	**(3,890)**
Salary growth		
Effect on pension expense in 2020	**42**	**(36)**
Effect on pension obligation at 31 December 2019	**604**	**(525)**

[a] The amounts presented reflect that the discount rate is used to determine the asset interest income as well as the interest cost on the obligation.

[b] The amounts presented reflect the total impact of an inflation rate change on the assumptions for rate of increase in salaries, pensions in payment and deferred pensions.

One additional year of longevity in the mortality assumptions would increase the 2020 pension expense by $31 million and the pension obligation at 31 December 2019 by $1,130 million.

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4. Pensions – continued

Estimated future benefit payments and the weighted average duration of defined benefit obligations

The expected benefit payments, which reflect expected future service, as appropriate, but exclude plan expenses, up until 2028 and the weighted average duration of the defined benefit obligations at 31 December 2019 are as follows:

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

5. Payables

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

Included in non-current amounts payable to subsidiaries is an interest-bearing payable of $4,236 million (2018 $4,236 million) with BP International Limited, with interest being charged based on a 3-month USD LIBOR rate plus 55 basis points and a maturity date of December 2021. Also included is an interest-bearing payable of $27,100 million (2018 $27,100 million) with BP International Limited, with interest being charged based on a 3-month USD LIBOR rate plus 65 basis points and a maturity date of May 2023. Current amounts payable to subsidiaries also includes an interest-bearing payable of $5,031 million (2018 $5,000 million) with BP Finance plc, with interest being charged based on a 1-year USD LIBOR rate and a maturity date of April 2020, callable upon demand.

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

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

6. Taxation

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

At 31 December 2019, deferred tax assets of $467 million on other temporary differences, $9 million relating to pensions, $67 million relating to income losses and $391 million relating to other deductible temporary differences (2018 $258 million relating to other temporary differences, $7 million relating to pensions, $67 million relating to income losses and $184 million relating to other deductible temporary differences) were not recognized as it is not considered probable that suitable taxable profits will be available in the company from which the future reversal of the underlying temporary differences can be deducted. There is no fixed expiry date for the unrecognized temporary differences.

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7. Called-up share capital

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

	2019		2018	
Issued	Shares thousand	$ million	Shares thousand	$ million
8% cumulative first preference shares of £1 each[a]	**7,233**	**12**	7,233	12
9% cumulative second preference shares of £1 each[a]	**5,473**	**9**	5,473	9
		21		21
Ordinary shares of 25 cents each				
At 1 January	**21,525,464**	**5,381**	21,288,193	5,322
Issue of new shares for the scrip dividend programme	**208,927**	**52**	195,305	49
Issue of new shares for employee share-based payment plans	**37,400**	**9**	92,168	23
Repurchase of ordinary share capital	**(235,951)**	**(59)**	(50,202)	(13)
At 31 December	**21,535,840**	**5,383**	21,525,464	5,381
		5,404		5,402

[a] The nominal amount of 8% cumulative first preference shares and 9% cumulative second preference shares that can be in issue at any time shall not exceed £10,000,000 for each class of preference shares.

Voting on substantive resolutions tabled at a general meeting is on a poll. On a poll, shareholders present in person or by proxy have two votes for every £5 in nominal amount of the first and second preference shares held and one vote for every ordinary share held. On a show-of-hands vote on other resolutions (procedural matters) at a general meeting, shareholders present in person or by proxy have one vote each.

In the event of the winding-up of the company, preference shareholders would be entitled to a sum equal to the capital paid up on the preference shares, plus an amount in respect of accrued and unpaid dividends and a premium equal to the higher of (i) 10% of the capital paid up on the preference shares and (ii) the excess of the average market price of such shares on the London Stock Exchange during the previous six months over par value.

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

Treasury shares[a]

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

[a] See Note 8 for definition of treasury shares.

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

For each year presented, the balance at 1 January represents the maximum number of shares held in treasury by BP during the year, representing 5.9% (2018 6.9%) of the called-up ordinary share capital of the company.

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

8. Capital and reserves

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

Share capital

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

Share premium account

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

Capital redemption reserve

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

Merger reserve

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

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

8. Capital and reserves – continued

Treasury shares

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

Foreign currency translation reserve

The foreign currency translation reserve records exchange differences arising from the translation of the financial information of the foreign currency branch. Upon disposal of foreign operations, the related accumulated exchange differences are recycled to the income statement.

Profit and loss account

The balance held on this reserve is the accumulated retained profits of the company.

The profit and loss account reserve includes $24,107 million (2018 $24,107 million), the distribution of which is limited by statutory or other restrictions.

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

9. Financial guarantees

The company has issued guarantees under which the maximum aggregate liabilities at 31 December 2019 were $78,586 million (2018 $77,965 million), the majority of which relate to finance debt of subsidiaries. Also included are guarantees of subsidiaries' liabilities under the Consent Decree between the United States, the Gulf states and BP and under the settlement agreement with the Gulf states in relation to the Gulf of Mexico oil spill. The company has also issued uncapped indemnities and guarantees, including a guarantee of subsidiaries' liabilities under the Plaintiffs' Steering Committee agreement relating to the Gulf of Mexico oil spill. Uncapped indemnities and guarantees are also issued in relation to potential losses arising from environmental incidents involving ships leased and operated by a subsidiary.

10. Share-based payments

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

		$ million
	2019	2018
Total expense recognized for equity-settled share-based payment transactions	**433**	429
Total (credit) expense recognized for cash-settled share-based payment transactions	**(1)**	(9)
Total expense recognized for share-based payment transactions	**432**	420
Closing balance of liability for cash-settled share-based payment transactions	**17**	27
Total intrinsic value for vested cash-settled share-based payments	**16**	23

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

11. Auditor's remuneration

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

12. Directors' remuneration

		$ million
Remuneration of directors	**2019**	2018
Total for all directors		
Emoluments	**9**	8
Amounts awarded under incentive schemes[a]	**20**	16
Total	**29**	24

[a] Excludes amounts relating to past directors.

Emoluments

These amounts comprise fees paid to the non-executive chairman and the non-executive directors and, for executive directors, salary and benefits earned during the relevant financial year, plus cash bonuses awarded for the year. Further information is provided in the Directors' remuneration report on page 100.

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

13. Employee costs and numbers

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

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

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

14. Related undertakings of the group

In accordance with Section 409 of the Companies Act 2006, a full list of related undertakings, the registered office address and the percentage of equity owned as at 31 December 2019 is disclosed below.

Unless otherwise stated, the share capital disclosed comprises ordinary shares or common stock (or local equivalent thereof) which are indirectly held by BP p.l.c.

All subsidiary undertakings are controlled by the group and their results are fully consolidated in the group's financial statements.

The percentage of equity owned by the group is 100% unless otherwise noted below.

The stated ownership percentages represent the effective equity owned by the group.

Subsidiaries

200 PS Overseas Holdings Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
563916 Alberta Ltd. (99.90%)[a]	240- 4th Avenue SW, Calgary AB T2P 4H4, Canada
ACP (Malaysia), Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Actomat B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
Advance Petroleum Holdings Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
Advance Petroleum Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
AE Cedar Creek Holdings LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
AE Goshen II Holdings LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
AE Goshen II Wind Farm LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
AE Power Services LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
AE Wind PartsCo LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Air BP Albania SHA	Air BP Albania Sh.A., Aeroporti Nderkombetar i Tiranes, "Nene Tereza", Post Box 2933 in Tirana, Albania
Air BP Brasil Ltda.	Avenida Rouxinol, 55 , Offices 501-514 , Moema Office Tower, São Paulo, 04516- 000, Brazil
Air BP Canada LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Air BP Croatia d.o.o.	Savska cesta 32, Zagreb, Croatia
Air BP Finland Oy	Öljytie 4, 01530 Vantaa, Finland
Air BP Iceland	Armula 24, 108, Reykjavik, Iceland
Air BP Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Air BP Norway AS	Drammensveien 167, Oslo, 0277, Norway
Air BP Sales Romania S.R.L.	59 Aurel Vlaicu Street, Otopeni, Ilfov County, Romania
Air BP Sweden AB	Box 8107, 10420, Stockholm, Sweden
Air Refuel Pty Ltd[c]	17 Level, 717 Bourke Street, Docklands, Melbourne VIC 3008, Australia
Allgreen Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
AM/PM International Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
American Oil Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco (Fiddich) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Amoco (U.K.) Exploration Company, LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Bolivia Petroleum Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Bolivia Services Company Inc.	Craigmuir Chambers, P.O. Box 71, Road Town, Tortola, British Virgin Islands
Amoco Canada International Holdings B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
Amoco Capline Pipeline Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Chemical (Europe) S.A.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Chemicals (FSC) B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
Amoco Cypress Pipeline Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Destin Pipeline Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Environmental Services Company[d]	Bank of America Center, 16th Floor, 1111 East Main Street, Richmond VA 23219, United States
Amoco Exploration Holdings B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
Amoco Guatemala Petroleum Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco International Finance Corporation	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco International Petroleum Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Leasing Corporation	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Amoco Louisiana Fractionator Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Main Pass Gathering Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Marketing Environmental Services Company	400 East Court Avenue, Des Moines ID 50309, United States
Amoco MB Fractionation Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco MBF Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Netherlands Petroleum Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Nigeria Exploration Company Limited[e]	188, Awolowo Road, S. W. Ikoyi, Lagos, Nigeria
Amoco Nigeria Oil Company Limited[e]	188, Awolowo Road, S. W. Ikoyi, Lagos, Nigeria
Amoco Nigeria Petroleum Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Nigeria Petroleum Company Limited	188, Awolowo Road, S. W. Ikoyi, Lagos, Nigeria
Amoco Norway Oil Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Oil Holding Company	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Amoco Olefins Corporation	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Overseas Exploration Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Pipeline Asset Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States

14. Related undertakings of the group – continued

Amoco Pipeline Holding Company	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Amoco Properties Incorporated	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Remediation Management Services Corporation	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Research Operating Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Rio Grande Pipeline Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Somalia Petroleum Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco Sulfur Recovery Company	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Amoco Trinidad Gas B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
Amoco Tri-States NGL Pipeline Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Amoco U.K. Petroleum Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
AmProp Finance Company	251 East Ohio Street, Suite 500, Indianapolis IN 46204, United States
Amprop Illinois I Limited Partnership[f]	801 Adlai Stevenson Drive, Springfield, IL, 62703, United States
Amprop, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Anaconda Arizona, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Arabian Production And Marketing Lubricants Company (50.00%)	Riyadh Airport Road, Business Gate, Building C2, 2nd Floor. , Saudi Arabia
Aral Aktiengesellschaft	Wittener Straße 45, 44789 Bochum, Germany
Aral Luxembourg S.A.	Bâtiment B, 36route de Longwy, L-8080 Bertrange, Luxembourg
Aral Services Luxembourg Sarl	Autoroute A3/E25, L-3325 Berchem Ouest, Luxembourg
Aral Tankstellen Services Sarl	Bâtiment B, 36route de Longwy, L-8080 Bertrange, Luxembourg
ARCO British International, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO British Limited, LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO Coal Australia Inc.	Level 17, 717 Bourke Street, Docklands VIC, Australia
ARCO El-Djazair Holdings Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO Environmental Remediation, L.L.C.[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO Exploration, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO Gaviota Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO International Investments Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO International Services Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Arco Mediterraneo Inversiones, S.L	Federico García Lorca, 43, entreplanta, 04004, Almería, Spain
ARCO Midcon LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
ARCO Oil Company Nigeria Unlimited[b]	8/10, Broad Street, Lagos, Nigeria
ARCO Oman Inc.	Trident Corporate Services (Bahamas) Limited, Providence House, East Hill Street, P.O.Box N-3944, Nassau, Bahamas, Bahamas
ARCO Resources Limited	Level 17, 717 Bourke Street, Docklands VIC, Australia
ARCO Trinidad Exploration and Production Company Limited	2 Bayside Executive Park, West Bay, Nassau, Bahamas
ARCO Unimar Holdings LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Areas Noriega S.L.	Ronda de Poniente 3, 1ªPlanta, 28760 Tres Cantos, Madrid, Spain
Areas Singulares Reyes S.L.	Cl Velázquez 18 4ªPlanta 28001 , Madrid, Spain
Aspac Lubricants (Malaysia) Sdn. Bhd. (63.03%)	Level 9, Tower 5, Avenue 7, The Horizon Bangsar South City, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur, Malaysia
Atlantic 2/3 UK Holdings Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Atlantic Richfield Company[d]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Autino Holdings Limited (88.85%)[g]	Abbey Gardens, 7th Floor, 4 Abbey Street, Reading, RG1 3BA, United Kingdom
Autino Limited (88.85%)	Abbey Gardens, 7th Floor, 4 Abbey Street, Reading, RG1 3BA, United Kingdom
Auwahi Wind Energy Holdings LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
B2Mobility GmbH	Wittener Straße 45, 44789 Bochum, Germany
Bahia de Bizkaia Electridad, S.L. (75.00%)	Atraque Punta Lucero, Explanada Punta Ceballos s/n, Ziérbena (Vizcaya), Spain
Baltimore Ennis Land Company, Inc.	4400 Easton Commons Way , Suite 125, Columbus OH 43219, United States
BASS Management Pty Ltd (51.00%)	Level 17, 717 Bourke Street, Docklands VIC, Australia
Black Lake Pipe Line Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP- Castrol (Thailand) Limited (57.59%)[h]	23rd Fl. Rajanakarn Bldg, 3 South Sathon Road, Yannawa South Sathon, Bangkok 10120, Thailand
BP (Abu Dhabi) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP (Barbados) Holding SRL	Erin Court, Bishop's Court Hill, St. Michael , Barbados
BP (Barbican) Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP (China) Holdings Limited[b]	Room 2101, 21F Youyou International Plaza, 76 Pujian Road, Pudong, Shanghai Pilot Free Trade Zone, PRC
BP (China) Industrial Lubricants Limited[b]	No.9 Bin Jiang South Road, Petrochemical Industrial Park, Taicang Gangkou Development Zone, Jiangsu Province, China
BP (Gibraltar) Limited[j]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP (GTA Mauritania) Finance Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP (GTA Senegal) Finance Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP (Guangzhou) Advanced Mobility Limited[b]	Room 1218, Building 3, No. 6 Hanxing San jie, Zhongcun Street, Panyu District, Guangzhou, Guangdong Province , China
BP (Hunan) Petroleum Company Limited[b]	Room 1001, 10th Floor, Building A2, Xiangjiang Times Business Square, No.179 Xiandao Road, Yuelu District, Changsha, Hunan, China
BP (Indian Agencies) Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom

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

14. Related undertakings of the group – continued

BP (Shandong) Petroleum Co., Ltd[b]	Room 1-2201, Sijian Meilin Mansion, No. 48-15 Wuyingshan Middle Road, Tianqiao District, Ji'nan, Shandong, China
BP (Shanghai) Trading Limited[b]	Room 2105, No. 28 Maji Road, Donghua Financial Building, China (Shanghai) Pilot Free Trade, Shanghai, 200131, China
BP Absheron Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Advanced Mobility Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Africa Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Africa Oil Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Akaryakit Ortakligi (70.00%)[f]	Degirmen yolu cad. No:28 , Asia OfisPark K:3 İcerenkoy-Atasehir, Istanbul, 34752, Turkey
BP Alaska LNG LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Alternative Energy Holdings Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Alternative Energy Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Alternative Energy North America Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Alternative Energy Trinidad and Tobago Limited	5-5A Queen's Park West, Port-of-Spain, Trinidad and Tobago
BP America Chembel Holding LLC	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP America Chemicals Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP America Foreign Investments Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP America Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP America Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP America Production Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP AMI Leasing, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Amoco Chemical Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Amoco Chemical Holding Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Amoco Chemical Indonesia Limited	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
BP Amoco Chemical Malaysia Holding Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Amoco Exploration (Faroes) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Amoco Exploration (In Amenas) Limited	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
BP Andaman II Ltd	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Angola (Block 18) B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Argentina Exploration Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Argentina Holdings LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Aromatics Holdings Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Aromatics Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Asia Limited	Unit 807, Tower B, Manulife Financial Centre, 223 Wai Yip Street, Kwun Tong, Hong Kong
BP Asia Pacific (Malaysia) Sdn. Bhd.	Level 9, Tower 5, Avenue 7, The Horizon Bangsar South City, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur, Malaysia
BP Asia Pacific Holdings Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Asia Pacific Pte Ltd[i]	7 Straits View #26-01, Marina One East Tower, Singapore, 018936, Singapore
BP Australia Capital Markets Limited	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Australia Employee Share Plan Proprietary Limited	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Australia Group Pty Ltd[e]	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Australia Investments Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Australia Nominees Proprietary Limited	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Australia Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Australia Shipping Pty Ltd[k]	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Australia Swaps Management Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Aviation A/S	c/o Danish Refuelling Services, I/SKøbenhavns Lufthavn 1, 2770 Kastrup, Denmark
BP Benevolent Fund Trustees Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Berau Ltd.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Biocombustíveis S.A. (96.53%)	Avenida das Nações Unidas, 12399, 4fl, Sao Paulo, Brazil
BP Bioenergia Campina Verde Ltda. (96.53%)	Rua Principal, Fazenda Recanto, Zona Rural, Caixa Postal 01, Ituiutaba, Minas Gerais, 38.300-898, Brazil
BP Bioenergia Ituiutaba Ltda. (96.53%)	Fazenda Recanto, Zona Rural, CEP 38.300-898, Ituiutaba, Minas Gerais, Brazil
BP Bioenergia Itumbiara S.A. (96.53%)	Estrada Municipal Itumbiara / Chacoeira Dourada, Fazenda Jandaia, Gleba B, Itumbiara, Goiás, 75516-126, Brazil
BP Bioenergia Tropical S.A. (97.46%)	Rodovia GO 410, km 51 à esquerda, Fazenda Canadá, s/n, Zona Rural, Edéia, Goiás, 75940-000, Brazil
BP Biofuels Advanced Technology Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Biofuels Brazil Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Biofuels Louisiana LLC[b]	5615 Corporate Blvd., Suite 400B, Baton Rouge LA 70808, United States
BP Biofuels North America LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Biofuels Trading Comércio, Importação e Exportação Ltda. (96.53%)	Avenida das Nações Unidas, 12399, 4fl, Sao Paulo, Brazil
BP Bomberai Ltd.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Brasil Ltda.	Avenida das Américas, no. 3434, Salas 301 a 308, Barra da Tijuca, Rio de Janeiro, RJ, 22640-102, Brazil
BP Brazil Tracking L.L.C.[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Bulwer Island Pty Ltd[l]	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Business Service Centre Asia Sdn Bhd	Level 9, Tower 5, Avenue 7, The Horizon Bangsar South City, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur, Malaysia

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

14. Related undertakings of the group – continued

BP Business Service Centre KFT[b]	BP Business Service Centre KFT, 32-34 Soroksári út, H-1095 Budapest, Hungary
BP Canada Energy Development Company	Stewart McKelvey, Attention: Lawrence J. Stordy, 900, 1959 Upper Water Street, Halifax NS B3J 3N2, Canada
BP Canada Energy Group ULC	Stewart McKelvey, Attention: Lawrence J. Stordy, 900, 1959 Upper Water Street, Halifax NS B3J 3N2, Canada
BP Canada Energy Marketing Corp.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Canada International Holdings B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Canada Investments Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Capellen Sarl	Aire de Capellen, L-8309 Capellen, Luxembourg
BP Capital Markets America Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Capital Markets p.l.c.	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Car Fleet Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Caribbean Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Castrol KK (64.84%)	East Tower 20F, Gate City Ohsaki, 1-11-2 Osaki, Shinagawa-ku, Tokyo, Japan
BP Castrol Lubricants (Malaysia) Sdn. Bhd. (63.03%)	Level 9, Tower 5, Avenue 7, The Horizon Bangsar South City, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur, Malaysia
BP Central Pipelines LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Chembel	Amocolaan 2 2440 Geel , Belgium
BP Chemicals (Korea) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Chemicals East China Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Chemicals Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Chemicals Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP China Exploration and Production Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP CIV Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Comercializadora de Energia Ltda.	Avenida das Nações Unidas, 12399, rooms 62,63 and 64 size B, 6th floor, Landmark Building, São Paulo, 04578-000, Brazil
BP Commodities Trading Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Commodity Supply B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Company North America Inc.[m]	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
BP Containment Response Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Containment Response System Holdings LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Continental Holdings Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Corporate Holdings Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Corporation North America Inc.	150 West Market Street, Suite 800, Indianapolis IN 46204, United States
BP D230 Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Danmark A/S	Arne Jacobsens Allé 7, 5th Floor, 2300, Copenhagen, Denmark
BP D-B Pipeline Company LLC (54.37%)[f]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Developments Australia Pty. Ltd.	Level 15, 240 St Georges Terrace, Perth WA 6000, Australia
BP Dogal Gaz Ticaret Anonim Sirketi	Degirmen yolu cad. No:28 , Asia OfisPark K:3 İcerenkoy-Atasehir, Istanbul, 34752, Turkey
BP East Kalimantan CBM Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Eastern Mediterranean Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Egypt Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Egypt East Delta Marine Corporation	Craigmuir Chambers, P.O. Box 71, Road Town, Tortola, British Virgin Islands
BP Egypt East Tanka B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Egypt Production B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Egypt Ras El Barr B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Egypt West Mediterranean (Block B) B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Energía México, S. de R.L. de C.V.	Avenida Santa Fe 505, Col. Cruz Manca Santa Fe, Delegacion Cuajimalpa, Mexico
BP Energy Asia Pte. Limited	7 Straits View #26-01, Marina One East Tower, Singapore, 018936, Singapore
BP Energy Colombia Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Energy Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Energy do Brasil Ltda.	Avenida das Américas, no. 3434, Salas 301 a 308, Barra da Tijuca, Rio de Janeiro, RJ, 22640-102, Brazil
BP Energy Europe Limited	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
BP Energy Solutions B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Espana, S.A. Unipersonal[n]	Avenida de Barajas 30, Madrid, Madrid, Spain
BP Estaciones y Servicios Energéticos, Sociedad Anónima de Capital Variable[c]	Avenida Santa Fe 505, Piso 10, Distrito Federal , MEXICO C.P. 0534, Mexico
BP Europa SE[o]	Überseeallee 1, 20457, Hamburg, Hamburg, Germany
BP Exploracion de Venezuela S.A.	Av. Francisco de Miranda, con primera avenida de Los Palos , Grandes, Edif Cavendes, piso 9, ofi 903, Los Palos Grandes, Chacao / Caracas, Caracas / Miranda, 1060, Venezuela, Bolivarian Republic of
BP Exploration & Production Inc.[d]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Exploration (Absheron) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Alaska) Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Exploration (Algeria) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Alpha) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Angola) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Azerbaijan) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Canada) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom

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

14. Related undertakings of the group – continued

BP Exploration (Caspian Sea) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (D230) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Delta) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (El Djazair) Limited	PricewaterhouseCoopers (Bahamas) Limited, Providence House, East Hill Street, P.O. Box N-3910, Nassau, Bahamas
BP Exploration (Epsilon) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Gambia) Limited	3 Kairaba Avenue, 3rd Floor Centenary, Serekunda West, Kanifing Municipality, Gambia
BP Exploration (Greenland) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Madagascar) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Morocco) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Namibia) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Nigeria Finance) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Nigeria) Limited	1, Oyinka Abayomi Drive, Ikoyi, Lagos, Nigeria
BP Exploration (Psi) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Shafag-Asiman) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Shah Deniz) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (South Atlantic) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (STP) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration (Xazar) Pte. Ltd.	7 Straits View #26-01, Marina One East Tower, Singapore, 018936, Singapore
BP Exploration Angola (Kwanza Benguela) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Argentina Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Australia Pty Ltd	Level 15, 240 St Georges Terrace, Perth WA 6000, Australia
BP Exploration Beta Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration China Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Company (Middle East) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Company Limited	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
BP Exploration Indonesia Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Libya Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Mexico Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Mexico, S.A. De C.V.[c]	Av. Santa Fe No. 505 Piso 10, Col. Cruz Manca Santa Fe, Deleg. CuajimalpaC.P., 05349 México D.F., Mexico
BP Exploration North Africa Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Operating Company Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Orinoco Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Personnel Company Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Exploration Peru Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Express Shopping Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Finance Australia Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Finance p.l.c.	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Foundation Incorporated[b]	251 East Ohio Street, Suite 500, Indianapolis IN 46204, United States
BP France	Campus Saint Christophe, Bâtiment Galilée 3, 10 Avenue de l'Entreprise, 95863, Cergy Saint Christophe, Cergy Pontoise, France
BP Fuels & Lubricants AS	Drammensveien 167, Oslo, 0277, Norway
BP Fuels Deutschland GmbH	Wittener Straße 45, 44789 Bochum, Germany
BP Gas & Power Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Gas Europe, S.A.U.	Avenida de la Transición Española 30, Parque Empresarial Omega, Edificio D. 28108 Alcobendas, Madrid, Spain
BP Gas Marketing Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Gas Supply (Angola) LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Ghana Limited	Number 12, Aviation Road, Una Home 3rd Floor, Airport City , Accra, Greater Accra, PMB CT 42, Ghana
BP Global Investments Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Global Investments Salalah & Co LLC	PO Box 2309, Salalah, 211, Oman
BP Global West Africa Limited	Heritage Place, 7th Floor, Left Wing, 21 Lugard Avenue, Ikoyi, Lagos, Nigeria
BP GOM Logistics LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Greece Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Guangdong Limited (90.00%)[b]	Rm 2710Guangfa Bank Plaza, No. 83 Nonglin Xia Road, Yuexiu District, Guangzhou, China
BP High Density Polyethylene- France	Campus Saint Christophe, Bâtiment Galilée 3, 10 Avenue de l'Entreprise, 95863, Cergy Saint Christophe, Cergy Pontoise, France
BP Holdings (Thailand) Limited (81.18%)[p]	39/77-78 Moo 2 Rama II Road, Tambon Bangkrachao, Amphur Muang, Samutsakorn 74000, Thailand
BP Holdings B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Holdings Canada Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Holdings International B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Holdings North America Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Hong Kong Limited	Unit 807, Tower B, Manulife Financial Centre, 223 Wai Yip Street, Kwun Tong, Hong Kong
BP India Private Limited (88.65%)	Technopolis Knowledge Park, Mahakali Caves Road, Andheri (East), Mumbai 400093, India
BP Indonesia Investment Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP International Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP International Services Company	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States

14. Related undertakings of the group – continued

BP Investment Management Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Investments Asia Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Iran Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Iraq N.V.	Amocolaan 2 2440 Geel , Belgium
BP Italia SpA	Via Verona 12, Cornaredo, 20010, Milan, Italy
BP Japan K.K.	15th Fl. Roppongi Hills Mori Tower, 10-1 Roppongi 6-chome, Minato-ku, Tokyo106-6115, Japan
BP Korea Limited	2nd Floor, 306, Banpo-daero, Seocho-gu, Seoul 06509, Republic of Korea
BP Kuwait Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Latin America LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Latin America Upstream Services Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP LNG Shipping Limited	Washington House, 4th Floor, 16 Church Street, Hamilton HM 11 , Bermuda
BP Lubricants KK (64.84%)	East Tower 20F, Gate City Ohsaki, 1-11-2 Osaki, Shinagawa-ku, Tokyo, Japan
BP Lubricants USA Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Luxembourg S.A.	Aire de Capellen, L-8309 Capellen, Luxembourg
BP Malaysia Holdings Sdn. Bhd. (70.00%)	Level 9, Tower 5, Avenue 7, The Horizon Bangsar South City, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur, Malaysia
BP Management International B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Management Netherlands B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Marine Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Mariner Holding Company LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Maritime Services (Singapore) Pte. Limited	7 Straits View #26-01, Marina One East Tower, Singapore, 018936, Singapore
BP Marketing Egypt LLC	Plot 28 , North 90 Road , Housing & Construction Bank Building, New Cairo, Cairo, 11835, Egypt
BP Mauritania Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Mauritius Limited (in liquidation)	5th Floor, Ebene Esplanade, 24 Cybercity, Ebene, Mauritius
BP Middle East Enterprises Corporation	Craigmuir Chambers, P.O. Box 71, Road Town, Tortola, British Virgin Islands
BP Middle East Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Middle East LLC	P.O.Box 1699, Dubai, 1699, United Arab Emirates
BP Midstream Partners GP LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Midstream Partners Holdings LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Midstream Partners LP (54.37%)[q]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Midwest Product Pipelines Holdings LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Mocambique Limitada	Society and Geography Avenue, Plot No. 269 , Third floor, Maputo, Mozambique
BP Mocambique Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Muturi Holdings B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Nederland Holdings BV	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Netherlands Upstream B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP New Ventures Middle East Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP New Zealand Holdings Limited	Watercare House, 73 Remuera Road, Newmarket, Auckland, 1050, New Zealand
BP New Zealand Share Scheme Limited	Watercare House, 73 Remuera Road, Newmarket, Auckland, 1050, New Zealand
BP Nutrition Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Offshore Gathering Systems Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Offshore Pipelines Company LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Offshore Response Company LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Oil (Thailand) Limited (90.40%)[r]	39/77-78 Moo 2 Rama II Road, Tambon Bangkrachao, Amphur Muang, Samutsakorn 74000, Thailand
BP Oil Australia Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Oil Espana, S.A. Unipersonal	Polígono Industrial "El Serrallo", s/n 12100 Grao de Castellón, Castellón de la Plana, Spain
BP Oil Hellenic S.A.	26A Apostolopoulou, Halandri, Athens, Attica, 152 31, Greece
BP Oil International Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Oil Kent Refinery Limited (in liquidation)	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Oil Llandarcy Refinery Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Oil Logistics UK Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Oil New Zealand Limited	Watercare House, 73 Remuera Road, Newmarket, Auckland, 1050, New Zealand
BP Oil Pipeline Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Oil Senegal S.A.	Route de Ouakam x Corniche Ouest, Immeuble Alphadio Barry, Dakar, Senegal
BP Oil Shipping Company, USA	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Oil UK Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Oil Venezuela Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Oil Vietnam Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Oil Yemen Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Olex Fanal Mineralol GmbH	Überseeallee 1, 20457, Hamburg, Hamburg, Germany
BP One Pipeline Company LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Pacific Investments Ltd	Watercare House, 73 Remuera Road, Newmarket, Auckland, 1050, New Zealand
BP Pakistan (Badin) Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Pakistan Exploration and Production, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Pension Escrow Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Pension Trustees Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Pensions (Overseas) Limited[j]	Albert House, South Esplanade, St. Peter Port, GY1 1AW, Guernsey
BP Pensions Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom

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

14. Related undertakings of the group – continued

BP Petrochemicals India Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Petroleo y Gas, S.A.	Av. Francisco de Miranda, con primera avenida de Los Palos , Grandes, Edif Cavendes, piso 9, ofi 903, Los Palos Grandes, Chacao / Caracas, Caracas / Miranda, 1060, Venezuela, Bolivarian Republic of
BP Petrolleri Anonim Sirketi	Degirmen yolu cad. No:28 , Asia OfisPark K:3 İcerenkoy-Atasehir, Istanbul, 34752, Turkey
BP Pipelines (Alaska) Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Pipelines (BTC) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Pipelines (North America) Inc.	45 Memorial Circle, Augusta ME 04330, United States
BP Pipelines (SCP) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Pipelines (TANAP) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Pipelines TAP Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Polska Services Sp. z o.o.	Ul. Jasnogórska 1, 31-358 Kraków, Malopolskie, Poland
BP Portugal-Comercio de Combustiveis e Lubrificantes SA	Lagoas Park, Edificio 3, Porto Salvo, Oeiras, Portugal
BP Poseidon Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Products North America Inc.	The Corporation Trust Incorporated, 351 West Camden Street, Baltimore MD 21201, United States
BP Properties Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Raffinaderij Rotterdam B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP Refinery (Kwinana) Proprietary Limited	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP Regional Australasia Holdings Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP River Rouge Pipeline Company LLC (54.37%)[f]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Russian Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Russian Ventures Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP SC Holdings LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Scale Up Factory Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Senegal Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Services International Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Servicios de Combustibles S.A. de C.V.	Avenida Santa Fe 505, Col. Cruz Manca Santa Fe, Delegacion Cuajimalpa, Mexico
BP Servicios territoriales, S.A. de C.V.	Avenida Santa Fe 505, Col. Cruz Manca Santa Fe, Delegacion Cuajimalpa, Mexico
BP Shafag-Asiman Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Shipping Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Singapore Pte. Limited	7 Straits View #26-01, Marina One East Tower, Singapore, 018936, Singapore
BP Solar Energy North America LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Solar Espana, S.A. Unipersonal[c]	Avenida de la Transición Española 30, Parque Empresarial Omega, Edificio D. 28108 Alcobendas, Madrid, Spain
BP Solar International Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Solar Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
BP South America Holdings Ltd	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Southern Africa Proprietary Limited (75.00%)	199 Oxford Road, Oxford Parks, Dunkeld, Johannesburg, Gauteng, 2196, South Africa
BP Southern Cone Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Subsea Well Response (Brazil) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Subsea Well Response Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Taiwan Marketing Limited	7FNo. 71Sec. 3Min Sheng East Road, Taipei, Taiwan
BP Technology Ventures Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Technology Ventures Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Train 2/3 Holding SRL	Erin Court, Bishop's Court Hill, St. Michael , Barbados
BP Transportation (Alaska) Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Trinidad and Tobago LLC (70.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Trinidad Processing Limited	5-5A Queen's Park West, Port-of-Spain, Trinidad and Tobago
BP Turkey Refining Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Two Pipeline Company LLC (54.37%)[f]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP UK Retained Holdings Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Venezuela Investments B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BP West Aru I Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP West Aru II Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP West Papua I Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP West Papua III Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Wind Energy North America Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP Wiriagar Ltd.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP World-Wide Technical Services Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BP Zhuhai Chemical Company Limited (91.90%)[b]	Da Ping Harbour, Lin Gang Industrial Zone, Zhuhai City, Guangdong Province, China
BP+Amoco International Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
BPA Investment Holding Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP-AIOC Exploration (TISA) LLC (65.88%)[b]	153 Neftchilar Avenue, Baku, AZ1010, Azerbaijan
BPNE International B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
BPRY Caribbean Ventures LLC (70.00%)[b]	RL&F Service Corp, 920 North King Street, 2nd Floor, Wilmington DE 19801, United States
BPX (Eagle Ford) Gathering LLC (75.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BPX (Karnes) Gathering LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BPX (KCS Resources) LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States

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

BPX (Permian) Gathering LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BPX (WSF Operating) Inc.	5615 Corporate Blvd., Suite 400B, Baton Rouge LA 70808, United States
BPX Energy Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BPX Midstream LLC[b]	The Corporation Company, 1833 South Morgan Road, Oklahoma City OK 73128, United States
BPX Operating Company	350 North St. Paul Street, Suite 2900, Dallas, Texas 75201, United States
BPX Production Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BPX Properties (GP) LLC[b]	CT Corporation System, 1021 Main Street, Suite 1150, Houston, Texas 77002, United States
BPX Properties (LP) LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BPX Properties (NA) LP[f]	1999 Bryan St., STE 900, Dallas TX 75201, United States
Brian Jasper Nominees Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
Britannic Energy Trading Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Britannic Investments Iraq Limited (90.00%)	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Britannic Marketing Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Britannic Strategies Limited	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
Britannic Trading Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
British Pipeline Agency Limited (50.00%)[s]	5-7 Alexandra Road, Hemel Hempstead, Herts., HP2 5BS, United Kingdom
Britoil Limited	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
BTC Pipeline Holding Company Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Burmah Castrol Australia Pty Ltd[t]	Level 17, 717 Bourke Street, Docklands VIC, Australia
Burmah Castrol Holdings Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Burmah Castrol PLC[i]	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
Burmah Castrol South Africa (Pty) Limited[u]	199 Oxford Road, Oxford Parks, Dunkeld, Johannesburg, Gauteng, 2196, South Africa
Burmah Chile SpA	José Musalen Saffie, Huerfanos N° 770 Of. 301, Santiago, Chile
BXL Plastics Limited[v]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Cadman DBP Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Casitas Pipeline Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Castrol (China) Limited	Unit 807, Tower B, Manulife Financial Centre, 223 Wai Yip Street, Kwun Tong, Hong Kong
Castrol (Ireland) Limited	One Spencer Dock, North Wall Quay, Dublin 1, Ireland
Castrol (Shanghai) Management Co., Ltd[b]	Floor 3, Building 5, 255 Guiqiao Road, Shanghai Pilot Free Trade Zone, China
Castrol (Shenzhen) Company Limited[b]	No.1120 Mawan Road, Nanshan District, Shenzhen, China
Castrol (Tianjin) Lubricants Co., Ltd[b]	South of NanGang Industrial Area, and East of Hai Gang Road, Tianjin Economic Development Area, Tianjin, China, China
Castrol (U.K.) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Castrol Australia Pty. Limited	Level 17, 717 Bourke Street, Docklands VIC, Australia
CASTROL Austria GmbH[b]	Straße 6, Objekt 17, Industriezentrum NÖ-Süd,, 2355 Wr. Neudorf, Austria
Castrol B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
Castrol BP Petco Limited Liability Company (65.00%)[b]	9th Floor, 22-36 Nguyen Hue Street, 57-69F Dong Khoi Street, District 1, Ho Chi Minh City, Vietnam
Castrol Brasil Ltda.	Avenida das Américas, no. 3434, Salas 301 a 308, Barra da Tijuca, Rio de Janeiro, RJ, 22640-102, Brazil
Castrol Caribbean & Central America Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Castrol Colombia Ltda.	Calle 81, No 11- 42, Oficina 901, Torre Sur, Bogota, Colombia
Castrol Del Peru S.A. (99.49%)	Av. Camino Real, 111 Torre B Oficina, 603 San Isidro, Lima, Peru
Castrol Egypt Lubricants S.A.E. (51.00%)	First floor of building located at Plot 28- the first Sector, City Center, New Cairo, Cairo, Egypt
Castrol India Limited (51.00%)	Technopolis Knowledge Park, Mahakali Caves Road, Andheri (East), Mumbai 400093, India
Castrol Industrie und Service GmbH	Erkelenzer Straße 20, 41179 Mönchengladbach, Germany
Castrol KK (64.84%)	East Tower 20F, Gate City Ohsaki, 1-11-2 Osaki, Shinagawa-ku, Tokyo, Japan
Castrol Limited	Technology Centre, Whitchurch Hill, Pangbourne, Reading, RG8 7QR, United Kingdom
Castrol Lubricants RO S.R.L	5th Floor, 92-96 Izvor St, 5th District, Bucharest, Romania
Castrol Mexico, S.A. de C.V.[c]	Av. Santa Fe No. 505 Piso 10, Col. Cruz Manca Santa Fe, Deleg. CuajimalpaC.P., 05349 México D.F., Mexico
Castrol Namibia (Pty) Limited	24 Orban Street, Klein Windhoek, Windhoek, Namibia
Castrol Offshore Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Castrol Pakistan (Private) Limited	D-67/1, Block # 4, Scheme # 5, Clifton, Karachi, Pakistan
Castrol Philippines, Inc.	32/F LKG Tower, Ayala Avenue, Makati City, 6801, Philippines
Castrol Servicos Ltda.	Avenida Tamboré, 448, Barueri, Sao Paulo, Brazil
Castrol Ukraine LLC[b]	2A Kostiantynivska Street, Kyiv, 04071, Ukraine
Castrol Zimbabwe (Private) Limited	Barking Road, Willowvale, Harare, Zimbabwe
Centrel Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
Charge Your Car Limited[c]	500, Capability Green, Luton, LU1 3LS, United Kingdom
Chargemaster (Europe) GmbH	Bischof-von-Henle-Straße 2a, Regensburg, 93051, Germany
Chargemaster Limited	500, Capability Green, Luton, LU1 3LS, United Kingdom
Charging Solutions Limited	500, Capability Green, Luton, LU1 3LS, United Kingdom
CH-Twenty, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Clarisse Holdings Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
Coastwise Trading Company, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Consolidada de Energia y Lubricantes, (CENERLUB) C.A.	Avenida Eugenio Mendoza / San Felipe Edificio Centro Letonia, Torre Ing-Bank, Piso 12, Oficina 124-B, La Castellana, Caracas, 1060, Venezuela, Bolivarian Republic of
Conti Cross Keys Inn, Inc.	Easton and Swamp Roads, Buckinham Township, Bucks County, Pennsylvania, United States
Coro Trading NZ Limited	Watercare House, 73 Remuera Road, Newmarket, Auckland, 1050, New Zealand

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14. Related undertakings of the group – continued

Cuyama Pipeline Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Dermody Developments Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
Dermody Holdings Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
Dermody Investments Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
Dermody Petroleum Pty. Ltd.	Level 17, 717 Bourke Street, Docklands VIC, Australia
DHC Solvent Chemie GmbH	Timmerhellstsr. 28, 45478, Mülheim/Ruhr, Germany
Dome Beaufort Petroleum Limited	240- 4th Avenue SW, Calgary AB T2P 4H4, Canada
Dome Wallis (1980) Limited Partnership (92.50%)[f]	240- 4th Avenue SW, Calgary AB T2P 4H4, Canada
Dradnats, Inc.	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Dualez 16, S.L.	Avenida de la Transición Espanola 30, Alcobendas, 28108, Madrid, Spain
ECM Markets SA (Pty) Ltd (75.00%)	199 Oxford Road, Oxford Parks, Dunkeld, Johannesburg, Gauteng, 2196, South Africa
Elektromotive Limited	500, Capability Green, Luton, LU1 3LS, United Kingdom
Elite Customer Solutions Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
Elm Holdings Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Energy Global Investments (USA) Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Enstar LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Estacion de Servicio Alto Campoo, S.L.	Avenida de la Transición Espanola 30, Alcobendas, 28108, Madrid, Spain
Estacion de Servicio Ganzo 10, S.L.	Avenida de la Transición Espanola 30, Alcobendas, 28108, Madrid, Spain
Estacion de Servicio Reocin 9, S.L.	Avenida de la Transición Espanola 30, Alcobendas, 28108, Madrid, Spain
Estacion de Servicio Santillana II, S.L.	Avenida de la Transición Espanola 30, Alcobendas, 28108, Madrid, Spain
Estacion de Servicio Sardinero, S.L.	Avenida de la Transición Espanola 30, Alcobendas, 28108, Madrid, Spain
Estonian Aviation Fuelling Services (50.00%)	Harju maakond, Lasnamäe linnaosa, Väike-Sõjamäe tn 12a, Tallinn, 11415, Estonia
Europa Oil NZ Limited	Watercare House, 73 Remuera Road, Newmarket, Auckland, 1050, New Zealand
Exomet, Inc.	4400 Easton Commons Way , Suite 125, Columbus OH 43219, United States
Expandite Contract Services Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Exploration (Luderitz Basin) Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Exploration Service Company Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Flat Ridge 2 Holdings LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Flat Ridge Wind Energy, LLC[b]	112 SW 7th Street, Suite 3C, Topeka, Kansas, 66603
Foseco Holding International B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
Foseco Holding, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Foseco, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Fosroc Expandite Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Fowler Ridge Holdings LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Fowler Ridge I Land Investments LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Fowler Ridge II Holdings LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Fowler Ridge III Wind Farm LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
FreeBees B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
Fuel & Retail Avia[t]ion Sweden AB	Box 8107, 10420, Stockholm, Sweden
Fuelplane- Sociedade Abastecedora De Aeronaves, Unipessoal, Lda	Lagoas Park, Edificio 3, Porto Salvo, Oeiras, Portugal
FWK (2017) Limited[w]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
FWK Holdings (2017) LTD[w]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Gardena Holdings Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Gelsenkirchen Raffinerie Netz GmbH	Alexander-von-Humboldt-Straße 1, Gelsenkirchen, 45896, Germany
GOAM 1 C.I S. A .S	Calle 80 No.11-42, Bogota, 110111, Colombia
Grampian Aviation Fuelling Services Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Guangdong Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Highlands Ethanol, LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Hosteleria Noriega S.L.	Ronda de Poniente 3, 1ªPlanta, 28760 Tres Cantos, Madrid, Spain
IGI Resources, Inc.	921 S. Orchard St. Ste G, Boise ID 83705, United States
Insight Analytics Solutions Holdings Limited (74.50%)	Romax Technology Centre, University of Nottingham Innovation Park, Triumph Road, Nottingham, NG7 2TU, United Kingdom
Insight Analytics Solutions Limited (74.50%)	Romax Technology Centre, University of Nottingham Innovation Park, Triumph Road, Nottingham, NG7 2TU, United Kingdom
Insight Analytics Solutions USA, Inc (74.50%)	2108 55th Street, Suite 105, Boulder CO 80301, United States
International Bunker Supplies Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
Iraq Petroleum Company Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Jupiter Insurance Limited	Albert House, South Esplanade, St. Peter Port, GY1 1AW, Guernsey
Ken-Chas Reserve Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Kenilworth Oil Company Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Kingbook Inversiones Socimi, S.A.	Calle Velázquez 18, 28001 Madrid, Spain
Latin Energy Argentina S.A.	Av. Cordoba 315 Piso 8, Buenos Aires, 1054, Argentina
Lebanese Aviation Technical Services S.A.L.	P O Box- 11-5814c/o Coral Oil Building, 583Avenue de Gaulle, Raoucheh, Beirut, Lebanon
Limited Liability Company BP Toplivnaya Kompania[b]	Novinskiy blvd.8, 17th floor, premises 11, 121099, Moscow, Russian Federation
Limited liability company Setra Lubricants[b]	2 Paveletskaya sq, Building1, 115054 Moscow, Russia
Lubricants UK Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Lytt Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom

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14. Related undertakings of the group – continued

Manormaker (Nominee No. 1) Limited (99.90%)	11 Black Horse Lane, Ipswich, Suffolk, IP1 2EF, United Kingdom
Manormaker (Nominee No. 2) Limited (99.90%)	11 Black Horse Lane, Ipswich, Suffolk, IP1 2EF, United Kingdom
Manormaker GP Limited (99.90%)	11 Black Horse Lane, Ipswich, Suffolk, IP1 2EF, United Kingdom
Mardi Gras Transportation System Company LLC (70.34%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Markoil, S.A. Unipersonal	Avenida de la Transición Española 30, Parque Empresarial Omega, Edificio D. 28108 Alcobendas, Madrid, Spain
Masana Petroleum Solutions (Pty) Ltd (37.88%)	199 Oxford Road, Oxford Parks, Dunkeld, Johannesburg, Gauteng, 2196, South Africa
Mayaro Initiative for Private Enterprise Development (70.00%)	5-5A Queen's Park West, Port-of-Spain, Trinidad and Tobago
Mehoopany Holdings LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Mes Tecnologia En Servicios Y Energia, S.A. De C.V.[c]	Av. Santa Fe No. 505 Piso 10, Col. Cruz Manca Santa Fe, Deleg. CuajimalpaC.P., 05349 México D.F., Mexico
Minza Pty. Ltd.	Level 17, 717 Bourke Street, Docklands VIC, Australia
Mountain City Remediation, LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
No. 1 Riverside Quay Proprietary Limited	Level 17, 717 Bourke Street, Docklands VIC, Australia
Nordic Lubricants A/S	Arne Jacobsens Allé 7, 5th Floor, 2300, Copenhagen, Denmark
Nordic Lubricants AB	Hemvärnsgatan , 171 54, Solna, Sweden
North America Funding Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
OMD87, Inc.	111 Eighth Avenue, New York, New York, 10011
Omega Oil Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
OnSight Analytics Solutions India Private Ltd. (74.50%)	Office No. 306, Regus Business Center , 3rd Floor, Abbusali St, Saligramam, Chennai, Tamil Nadu, 600093, India
OOO BP STL[b]	Novinskiy blvd.8, 18th floor, office 14, 121099, Moscow, Russian Federation
Orion Delaware Mountain Wind Farm LP[b]	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Orion Energy Holdings, LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Orion Energy L.L.C.[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Orion Post Land Investments, LLC[b]	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Oyambre 1, S.L.	Avenida de la Transición Espanola 30, Alcobendas, 28108, Madrid, Spain
Pacroy (Thailand) Co., Ltd. (39.50%)	23rd Fl. Rajanakarn Bldg, 3 South Sathon Road, Yannawa South Sathon, Bangkok 10120, Thailand
Peaks America Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Pearl River Delta Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Petrocorner Retail S.L.U.	Ronda de Poniente 3, 1ªPlanta, 28760 Tres Cantos, Madrid, Spain
Phoenix Petroleum Services, Limited Liability Company	Royal Tulip Al Rasheed Hotel, Baghdad Tower, PO Box 8070, Baghdad, Iraq
Pozuelo 4, S.L.	Avenida de la Transición Espanola 30, Alcobendas, 28108, Madrid, Spain
PRODUITS METALLURGIE DOITTAU	Campus Saint Christophe, Bâtiment Galilée 3, 10 Avenue de l'Entreprise, 95863, Cergy Saint Christophe, Cergy Pontoise, France
Prospect International, C.A. (In liquidation)	Avenida Eugenio Mendoza / San Felipe Edificio Centro Letonia, Torre Ing-Bank, Piso 12, Oficina 124-B, La Castellana, Caracas, 1060, Venezuela, Bolivarian Republic of
PT BP Petrochemicals Indonesia	20th Floor Summitmas II Jl., Jend. Sudirman Kav. 61- 62, Jakarta, Selatan, Indonesia
PT Castrol Indonesia (68.30%)	Perkantoran Hijau Arkadia, Tower B 9th Floor, Jl. Let. Jenderal TB. Simatupang Kav. 88, Jakarta12520, Indonesia
PT Castrol Manufacturing Indonesia (68.30%)	JL. Raya, Merak KM 117, DS Gerem, Gerem Grogol, Cilegon, Banten, Indonesia
PT Jasatama Petroindo[c]	Perkantoran Hijau Arkadia, Tower B 8th Floor, Jl. Let. Jenderal TB. Simatupang Kav. 88, Jakarta12520, Indonesia
Puente Arce 4, S.L.	Avenida de la Transición Espanola 30, Alcobendas, 28108, Madrid, Spain
Remediation Management Services Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Richfield Oil Corporation	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Rio Corvo 2, S.L.	Avenida de la Transición Espanola 30, Alcobendas, 28108, Madrid, Spain
Rolling Thunder I Power Partners, LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Romax Insight Korea Ltd. (74.50%)	504 Smart Building, 213-3 Cheomdan-ro, Jeju-si, Jeju-do, Korea, Republic of
Ropemaker Deansgate Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Ropemaker Properties Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Ruhr Oel GmbH (ROG)	Alexander-von-Humboldt-Straße 1, Gelsenkirchen, 45896, Germany
Rusdene GSS Limited[w]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Saturn Insurance Inc.	400 Cornerstone Drive, Suite 240, Williston VT 05495, United States
Sherbino I Holdings LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Sherbino Mesa I Land Investments LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Sociedade de Promocao Imobiliaria Quinta do Loureiro, SA	Lagoas Park, Edificio 3, Porto Salvo, Oeiras, Portugal
Société de Gestion de Dépots d'Hydrocarbures- GDH[b]	Campus Saint Christophe, Bâtiment Galilée 3, 10 Avenue de l'Entreprise, 95863, Cergy Saint Christophe, Cergy Pontoise, France
SOFAST Limited (63.09%)[x]	23rd Fl. Rajanakarn Bldg, 3 South Sathon Road, Yannawa South Sathon, Bangkok 10120, Thailand
South Texas Shale LLCb	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Southeast Texas Biofuels LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Southern Ridge Pipeline Holding Company	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Southern Ridge Pipeline LP LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Sp/f Decision3 (GreenSteam) Company (61.68%)[y]	Krosslíð 11, FO-100 Tórshavn , Faroe Islands

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

14. Related undertakings of the group – continued

SRHP (99.99%)[b]	Campus Saint Christophe, Bâtiment Galilée 3, 10 Avenue de l'Entreprise, 95863, Cergy Saint Christophe, Cergy Pontoise, France
Standard Oil Company, Inc.	251 East Ohio Street, Suite 500, Indianapolis IN 46204, United States
Stryde Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Sunrise Oil Sands Partnership (50.00%)[f]	c/o Husky Oil Operations Limited, 707- 8th Avenue SW, Calgary AB T2P 1H5, Canada
Taradadis Pty. Ltd.	Level 17, 717 Bourke Street, Docklands VIC, Australia
Telcom General Corporation (99.96%)[d]	818 West Seventh Street, 2nd Floor, Los Angeles, CA, 90017
Terre de Grace Partnership (75.00%)[f]	1100, 635- 8th Avenue SW, Calgary AB T2P 3M3, Canada
The Anaconda Company	814 Thayer Avenue, Bismarck, ND, 58501-4018
The BP Share Plans Trustees Limited[i]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
The Burmah Oil Company (Pakistan Trading) Limited	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
The Standard Oil Company	4400 Easton Commons Way , Suite 125, Columbus OH 43219, United States
TISA Education Complex LLC (65.88%)[b]	153 Neftchilar Avenue, Baku, AZ1010, Azerbaijan
TJKK	15th Fl. Roppongi Hills Mori Tower, 10-1 Roppongi 6-chome, Minato-ku, Tokyo106-6115, Japan
Toledo Refinery Holding Company LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Torrelavega 7, S.L.	Avenida de la Transición Espanola 30, Alcobendas, 28108, Madrid, Spain
Union Texas International Corporation	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Vastar Pipeline, LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Viceroy Investments Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Villacarriedo 8, S.L.	Avenida de la Transición Espanola 30, Alcobendas, 28108, Madrid, Spain
Warrenville Development Limited Partnership[b]	33 North LaSalle Street, Chicago, Illinois 60602, United States
Water Way Trading and Petroleum Services LLC (90.00%)	Khur Al-Zubair, pear No 1, Basra, Iraq
Welchem, Inc.	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
West Kimberley Fuels Pty Ltd	Level 17, 717 Bourke Street, Docklands VIC, Australia
Westlake Houston Development, LLC[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Whiting Clean Energy, Inc.	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Windpark Energy Nederland B.V.	d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands
Winwell Resources, L.L.C.[b]	5615 Corporate Blvd., Suite 400B, Baton Rouge LA 70808, United States
Wiriagar Overseas Ltd	Estera Corporate Services (BVI) Limited, Jayla Place, Wickhams Cay 1, PO Box 3190, Road Town, Tortola, VG1110, Virgin Islands, British

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Related undertakings other than subsidiaries

A Flygbranslehantering AB (AFAB) (25.00%)	Box 135, 190 46 Arlanda, Sweden
Aashman Power Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
ABG Autobahn-Betriebe GmbH (32.58%)[b]	Brucknerstraße 4, 1041 Wien, Austria
Abu Dhabi Marine Areas Limited (33.33%)[h]	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, United Kingdom
Advanced Biocatalytics Corporation (24.20%)[a]	18010 Skypark Circle , #130 , Irvine CA 92614, United States
AEP I HoldCo LLC (24.30%)[b]	Harvard Business Services, Inc., 16192 Coastal Hwy, Lewes, Delaware, 19958, United States
AGES International GmbH & Co. KG, Langenfeld (24.70%)[f]	Berghausener Straße 96, 40764 Langenfeld, Germany
AGES Maut System GmbH & Co. KG, Langenfeld (24.70%)[f]	Berghausener Straße 96, 40764 Langenfeld, Germany
Air BP Copec S.A. (51.00%)	Patricio Raby Benavente, Moneda N° 920 Of 205, Santiago, Chile
Air BP Italia Spa (50.00%)	Via Sardegna 38, 00187, Roma, Italy
Air BP PBF del Peru S.A.C. (50.00%)	Avenida Ricardo Rivera Navarrete n.501 / room 1602, Lima, Peru, Peru
Air BP Petrobahia Ltda. (50.00%)	Av. Anita Garibaldi, n.252, 2o floor, Ala Sul, Federação, Salvador, Bahia, 40210-750, Brazil
Aircraft Fuel Supply B.V. (28.57%)	Oude Vijfhuizerweg 6, 1118LV Luchthaven, Schiphol, Netherlands
Aircraft Refuelling Company GmbH (33.33%)[b]	Trabrennstraße 6-8 3, A-1020, Wien, Austria
Aker BP ASA (30.00%)	Oksenoyveien 10, , 1366 Lysaker, Norway
Alaska LNG Project LLC (33.33%)[b]	Corporation Service Company, 2711 Centerville Road,, Suite 400, Wilmington DE 19808, United States
Alaska Tanker Company, LLC (25.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Alyeska Pipeline Service Company (48.44%)	9360 Glacier Highway, Suite 202, Juneau AK 99801, United States
Alyssum Group Ltd (26.20%)[e]	522 Fulham Road, London, SW6 5NR, United Kingdom
Ambarli Depolama Hizmetleri Limited Sirketi (50.00%)	Yakuplu Mahallesi Genc, Osman Caddesi, No.7 Beylikdüzü, Istanbul, Turkey
Ammenn GmbH (75.00%)	Luisenstraße 5 a, 26382 Wilhelmshaven, Germany
Apollo Geração de Energia Ltda (49.97%)[b]	Sitio Canto, número S/N, bairro / distrito Zona Rural, município Russas- CE, CEP 62900-000
Aragonesa de Gestión de Energías Alternativas, SL (49.97%)	Calle Alcala numero 63, 28014, Madrid, Spain
ATAS Anadolu Tasfiyehanesi Anonim Sirketi (68.00%)[z]	Degirmen yolu cad. No:28 , Asia OfisPark K:3 İcerenkoy-Atasehir, Istanbul, 34752, Turkey
Atlantic 1 Holdings LLC (34.00%)[b]	RL&F Service Corp, 920 North King Street, 2nd Floor, Wilmington DE 19801, United States
Atlantic 2/3 Holdings LLC (42.50%)[b]	RL&F Service Corp, 920 North King Street, 2nd Floor, Wilmington DE 19801, United States
Atlantic 4 Holdings LLC (37.78%)[b]	RL&F Service Corp, 920 North King Street, 2nd Floor, Wilmington DE 19801, United States
Atlantic LNG 2/3 Company of Trinidad and Tobago Unlimited (42.50%)	Princes Court, Cor. Pembroke & Keate Street, Port-of-Spain, Trinidad and Tobago
Atlantic LNG 4 Company of Trinidad and Tobago Unlimited (37.78%)	Princes Court, Cor. Pembroke & Keate Street, Port-of-Spain, Trinidad and Tobago
Atlantic LNG Company of Trinidad and Tobago (34.00%)	Princes Court, Cor. Pembroke & Keate Street, Port-of-Spain, Trinidad and Tobago
Atlas Methanol Company Unlimited (36.90%)	Maracaibo Drive, Point Lisas Industrial Estate, Point Lisas, Trinidad and Tobago
Australasian Lubricants Manufacturing Company Pty Ltd (50.00%)[h]	Building 1, 747 Lytton Road, Murarrie QLD 4172, Australia
Australian Terminal Operations Management Pty Ltd (50.00%)	Level 3, Unit 3, 22 Albert Road, South Melbourne VIC 3205, Australia
Auwahi Holdings, LLC (50.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Auwahi Wind Energy LLC (50.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Aviation Fuel Services Limited (25.00%)	Calshot Way Central Area, Heathrow Airport, Hounslow, Middlesex, TW6 1PY, United Kingdom
Aviation Service (Iraq) Limited (40.00%)[α]	2 World Business Centre Heathrow, Newall Road, London Heathrow Airport, Hounslow, TW6 2SF, United Kingdom
Axion Comercializacion De Combustibles Y Lubricantes S.A. (50.00%)	Avenida Luis Alberto de Herrera 1248, Oficina 1901, Montevideo, Uruguay
Axion Energy Argentina S.A. (50.00%)	Carlos María Della Paolera 265, Piso 22, Ciudad Autónoma de Buenos Aires, Argentina
Axion Energy Holding S.L. (50.00%)[b]	Arbea Campus Empresarial, Edifico 1. Ctra de Fuencarral a Alcobendas, M603, KM 3,8 28108 Alcobendas, MADRID, SPAIN
Axion Energy Paraguay S.R.L. (50.00%)[b]	Av. España 1369 esquina San Rafael, Asunción, Paraguay
Axuy Energy Holdings S.R.L. (50.00%)[b]	Avenida Luis Alberto de Herrera 1248, Oficina 1901, Montevideo, Uruguay
Axuy Energy Investments S.R.L. (50.00%)[b]	Avenida Luis Alberto de Herrera 1248, Oficina 1901, Montevideo, Uruguay
Azerbaijan Gas Supply Company Limited (23.06%)[h]	Maples & Calder, P.O. Box 309, Ugland House, 113 South Church Street, George Town, Grand Cayman, Cayman Islands
Azerbaijan International Operating Company (30.37%)[β]	190 Elgin Avenue, George Town, Grand Cayman , KY1-9005, Cayman Islands
Baplor S.A. (50.00%)	Colonia 810, Oficina 403, Montevideo, Uruguay
Barranca Sur Minera S.A. (50.00%)	Calle 14, No 781, Piso 2, Oficina 3, Ciudad de La Plata, Provincia de Buenos Aires, Argentina
Beer GmbH (50.00%)	Saganer Straße 31, 90475 Nürnberg, Germany
Beer GmbH & Co. Mineralol-Vertriebs-KG (50.00%)[f]	Saganer Straße 31, 90475 Nürnberg, Germany
BGFH Betankungs-Gesellschaft Frankfurt-Hahn GbR (50.00%)[f]	Sportallee 6, 22335 Hamburg, Germany
Bighorn Solar 1, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Billund Refuelling I/S (50.00%)	GA Centervej 1, DK-7190, Billund, Denmark
Blackbear Alabama Solar 1, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Blackbear Alabama Solar Land Holdings, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Blendcor (Pty) Limited (37.50%)[α]	135 Honshu Road, Islandview, Durban, 4052, South Africa

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

14. Related undertakings of the group – continued

Blue Marble Holdings Limited (23.58%)[γ]	Northgate House, 2nd Floor, Upper Borough Walls, Bath, BA1 1RG, United Kingdom
Blue Ocean Seismic Services Limited (52.50%)[a]	12-14 Carlton Place, Southampton, SO15 2EA, United Kingdom
Bodmin Solar Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
BP AOC Pumpstation Maatschap (50.00%)[f]	Rijndwarsweg 3, 3198 LK Europoort, Rotterdam, Netherlands
BP Bunge Bioenergia S.A. (48.27%)	Avenida das Nações Unidas, nº 12.399, 4º andar, Brooklin Paulista, São Paulo, CEP 04578-000, Brazil
BP Dhofar LLC (49.00%)	P.O.Box 20302/211, 20302, Oman
BP Esso AOC Maatschap (22.80%)[f]	Rijndwarsweg 3, 3198 LK Europoort, Rotterdam, Netherlands
BP Esso Pipeline Maatschap (50.00%)[f]	Rijndwarsweg 3, 3198 LK Europoort, Rotterdam, Netherlands
BP Guangzhou Development Oil Product Co., Ltd (40.00%)[b]	Room X2072, 2/F, No.13 Longxue Road, Longxue Island, Nansha District, Guangzhou, Guangdong, 511450, China
BP Petro China Jiangmen Fuels Co., Ltd. (49.00%)[b]	Room A, building B , 5th floor, no. 22 gangang road, Jiangmen, China
BP PetroChina Petroleum Co., Ltd (49.00%)[b]	Room B1, 11th Floor, No.22 Gang Kou Yi Road, Peng Jiang District, Jiangmen, Guangdong Province, China
BP PETRONAS Acetyls Sdn. Bhd. (70.00%)	Level 8, Symphony House, Pusat Dagangan Dana 1, Jalan PJU 1A/46 47301 Petaling Jaya, Selangor Darul Ehsan, Malaysia
BP Sinopec (ZheJiang) Petroleum Co., Ltd (40.00%)[b]	F12, Hua Zhe Square Tower 1, Hang Zhou City, Zhe Jiang Province, China
BP Sinopec Marine Fuels Pte. Ltd. (50.00%)	112 Robinson Road, #05-01, Robinson 112, 068902, Singapore
BP West Africa Supply Limited (50.00%)	Number 1, Rehoboth Place, Dade Street, North Labone Estates, Accra, Accra Metropolitan, Greater Accra, P. O. BOX CT3278, Ghana
BP YPC Acetyls Company (Nanjing) Limited (50.00%)[b]	9# Huo Ju Road, Liu He District, Nanjing, Jiangsu Province, China
BP-Husky Refining LLC (50.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
BP-Japan Oil Development Company Limited (50.00%)[h]	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
Braendstoflageret Kobenhavns Lufthavn I/S (20.83%)[f]	Københavns, Lufthavn, 2770 Kastrup, Denmark
BTC International Investment Co. (30.10%)[δ]	Maples & Calder, P.O. Box 309, Ugland House, 113 South Church Street, George Town, Grand Cayman, Cayman Islands
Burnthouse Solar Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Butamax™ Advanced Biofuels LLC (50.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Caesar Oil Pipeline Company, LLC (39.39%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Cairns Airport Refuelling Service Pty Ltd (33.33%)	Company Matters Pty Ltd, Level 12, 680 George Street, Sydney NSW 2000, Australia
Cantera K-3 Limited Partnership (39.00%)[f]	6400 Shafer Ct., Suite 400, Rosemont IL 60018-4927, United States
Canton Renewables, LLC (50.00%)[b]	30600 Telegraph Road, Suite 2345, Bingham Farms MI 48025, United States
Castrol Cuba S.A. (50.00%)	Calle 6 No 319, esq 5ta. Ave., Miramar, Playa, La Habana, Cuba
Castrol DongFeng Lubricant Co., Ltd (50.00%)[b]	C1/C2-1, C1/C2-2, 1-6F, No. C1/C2 building, No.107 Huazhong Electronics Industry Park, Fangcao 2 Road, Wuhan Economic and Technological Development Zone, Wuhan, Hubei Province, China
Cedar Creek II Holdings LLC (50.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Cedar Creek II, LLC (50.00%)[b]	1560 Broadway, Suite 2090, Denver, Colorado, 80202
Cefari RNG OKC, LLC (50.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Cekisan Depolama Hizmetleri Limited Sirketi (35.00%)	Liman Mah. 60 Sk., Çekisan-İdari Bina sit. No:25 A/1, Konyaaltı, Antalya, Turkey
Central African Petroleum Refineries (Pvt) Ltd (20.75%)	Block 1 Tendeseka Office Park, Samora Machel Av/Renfrew Road, Harare, Zimbabwe
CERF Shelby, LLC (50.00%)[b]	800 S. Gay Street, Suite 2021, Knoxville TN 37929, United States
Chicap Pipe Line Company (56.17%)	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
China American Petrochemical Company, Ltd. (CAPCO) (61.36%)	6th Floor, No. 413 Section 2 Ti-Ding Blvd., Neihu, Taipei, 11493, Taiwan
China Aviation Oil (Singapore) Corporation Ltd (20.03%)	8 Temasek Boulevard #31-02, Suntec City Tower 3, Singapore 038988, Singapore
Chittering Solar Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Clean Eagle RNG, LLC (50.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Clean Vision Solar LLC (49.97%)[b]	400 Montgomery Street, Floor 8, San Francisco, CA 94104
Cleopatra Gas Gathering Company, LLC (37.28%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
CNAF Air BP General Aviation Fuel Company Limited (49.00%)	11/F, Building No.2, No. 32 Lingang Road Section One, Xihang Port Street, Shuangliu District, Chengdu, Sichuan Province, China
Coastal Oil Logistics Limited (25.00%)	10th Floor, The Bayleys Building, Cnr Brandon St and Lambton Quay, Wellington, 6011, New Zealand
Compatible Opportunity Lda (49.97%)	Rua Sousa Martins, no 10, 1050 218, Lisboa, Portugal
Compatibleglobe Lda (49.97%)	Rua Sousa Martins, no 10, 1050 218, Lisboa, Portugal
Concessionaria Stalvedro SA (50.00%)	San Gottardo Sud, 6780, Airolo, Switzerland
Continental Divide Solar I, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Continental Divide Solar II, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Continental Divide Solar Land Holdings, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
CSG Convenience Service GmbH (24.80%)	Wittener Straße 45, 44789 Bochum, Germany
Danish Refuelling Services I/S (50.00%)[f]	Kastrup Lufthavn, 2770 Kastrup, Denmark
Danish Tankage Services I/S (50.00%)[f]	Kastrup Lufthavn 1, 2770 Kastrup, Denmark
Dapsun- Investimentos e Consultoria, LDA. (24.99%)	Rua Júlio Dinis, n.º 247, 6.º, E-1, Edifício Mota Galiza, Parish of Lordelo do Ouro and Massarelos, 4050-027, Porto, Portugal
Dinarel S.A. (20.00%)	La Cumparsita 1373, piso 4°, Montevideo, Uruguay
Donoma Power Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
DOPARK GmbH (25.00%)	Westfalendamm 166, 44141 Dortmund, Germany
Dusseldorf Fuelling Services GbR (33.00%)[f]	Sportallee 6, 22335 Hamburg, Germany

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14. Related undertakings of the group – continued

Dusseldorf Tank Services GbR (33.00%)[f]	Sportallee 6, 22335 Hamburg, Germany
El Temsah Petroleum Company "PETROTEMSAH" (25.00%)	5 El Mokhayam El Daiem St, 6th Sector, Nasr City, Egypt
Elk Hill Solar 1, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Elk Hill Solar 2, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
EMDAD Aviation Fuel Storage FZCO (33.33%)	P.O.Box 261781, Dubai, United Arab Emirates
Emoil Storage Company FZCO (20.00%)	Plot No. B003R04, Box No. 9400, Dubai, United Arab Emirates, Dubai, United Arab Emirates
EMSEP S.A. de C.V. (50.00%)	Av. Paseo de la Reforma 505 piso 32, Colonia Cuauhtémoc, Delegación Cuauhtémoc (06500), CDMX, Mexico
Endymion Oil Pipeline Company, LLC (45.72%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Energías Renovables de Ixion, SL (49.97%)	Calle Alcala numero 63, 28014, Madrid, Spain
Energy Emerging Investments, LLC (50.00%)[b]	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Entrepot petrolier de Chambery (32.00%)	562 Avenue du Parc de l'Ile, 92000, NANTERRE, France
Entrepôt Pétrolier de Puget sur Argens- EPPA (58.25%)	Campus Saint Christophe, Bâtiment Galilée 3, 10 Avenue de l'Entreprise, 95863, Cergy Saint Christophe, Cergy Pontoise, France
Erdol-Lagergesellschaft m.b.H. (23.00%)[b]	Radlpaßstraße 6, 8502 Lannach, Austria
Etzel-Kavernenbetriebsgesellschaft mbH & Co. KG (33.33%)[f]	Bertrand-Russell-Straße 3, 22761 Hamburg, Germany
Etzel-Kavernenbetriebs-Verwaltungsgesellschaft mbH (33.33%)	Bertrand-Russell-Straße 3, 22761 Hamburg, Germany
EverSource Advisors Private Ltd (24.99%)	One Indiabulls Center, 16th Floor, Tower 2A, Senapati Bapat Marg, Mumbai City, Maharashtra, Mumbai, 400013, India
EverSource Management Holdings (24.99%)	3rd Floor, Standard Chartered Tower, Bank Street, 19 Cybercity, Ebene, 72201, Mauritius
Ffos Las Solar Developments Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
FFS Frankfurt Fuelling Services (GmbH & Co.) OHG (33.00%)[f]	Sportallee 6, 22335 Hamburg, Germany
Field Services Enterprise S.A. (50.00%)	Av. Leandro N. Alem 1180, piso 11°, Buenos Aires, Argentina
Finite Carbon Corporation (50.00%)	435 Devon Park Drive, Suite 700, Wayne, Pennsylvania, 19087, United States
Finite Resources, Inc. (50.00%)	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
Fip Verwaltungs GmbH (50.00%)	Rheinstraße 36, 49090 Osnabrück, Germany
Flat Ridge 2 Wind Energy LLC (50.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Flat Ridge 2 Wind Holdings LLC (50.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Flughafen Hannover Pipeline Verwaltungsgesellschaft mbH (50.00%)	Überseeallee 1, 20457, Hamburg, Hamburg, Germany
Flughafen Hannover Pipelinegesellschaft mbH & Co. KG (50.00%)[f]	Überseeallee 1, 20457, Hamburg, Hamburg, Germany
Fly Victor Ltd (26.20%)	60 Sloane Avenue, London, SW3 3XB, United Kingdom
Flytanking AS (50.00%)	Postboks 36, Stjordal, NO-7501, Norway
Foreseer Ltd (25.00%)	121A Thoday Street, Cambridge , Cambridgeshire, CB1 3AT , United Kingdom
Formosa BP Chemicals Corporation (50.00%)	No. 1-1Formosa Industrial Comples, Mailiao, Yunlin Hsien, Taiwan
Fotech Group Limited (22.40%)[a]	5th Floor, Condor House, 10 St Paul's Churchyard, London, EC4M 8AL , United Kingdom
Fowler I Holdings LLC (50.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Fowler II Holdings LLC (50.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Fowler Ridge II Wind Farm LLC (50.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Fowler Ridge Wind Farm LLC (50.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Free Power for Schools 13 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 14 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 15 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 17 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 19 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 4 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 5 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 6 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Free Power for Schools 7 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Freetricity Central June Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Freetricity Commercial June Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Fresh-Serve Bakeries LLC (37.04%)[b]	Corporation Service Company, 421 West Main Street, Frankfort KY 40601, United States
Fuelling Aviation Service- FAS (50.00%)[b]	3 Rue des Vignes, Aéroport Roissy Charles de Gaulle, 93290, TREMBLAY EN FRANCE, France
Fuerzas Energéticas del Sur de Europa IV, SL (49.97%)	Calle Alcala numero 63, 28014, Madrid, Spain
Fuerzas Energéticas del Sur de Europa XIX, SL (49.97%)	Calle Alcala numero 63, 28014, Madrid, Spain
Fundación para la Eficiencia Energética de la Comunidad Valenciana (33.33%)[b]	Calle Lituania nº 10, Castellón de la Plana, Spain
Gardermeon Fuelling Services AS (33.33%)	Postboks 133, Gardermoen, NO-2061, Norway
Gas Natural Acu Comercializadora de Energia Ltda. (50.00%)	Rua do Russel 804, 5th floor, Gloria, Rio de Janeiro, Brazil
Gas Natural Acu S.A. (30.00%)	Praia do Flamengo 66, 13th and 14th floors, Block A, Flamengo, Rio de Janeiro, Brazil
Gas Natural Infraestrutura S.A. (28.51%)	Rua do Russel 804, 5th floor, Gloria, Rio de Janeiro, Brazil
Gemalsur S.A. (50.00%)	Colonia 810, Oficina 403, Montevideo, Uruguay
Georgian Pipeline Company (30.37%)[β]	190 Elgin Avenue, George Town, Grand Cayman , KY1-9005, Cayman Islands

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14. Related undertakings of the group – continued

Gezamenlijke Tankdienst Schiphol B.V. (50.00%)	Anchoragelaan 6, 1118LD Luchthaven Schiphol, Netherlands
GISSCO S.A. (50.00%)	2,Vouliagmenis Ave & Papaflessa, 16777 Elliniko, Athens, Attika, Greece
Glade CD Solar Holdings, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Glade Solar Class B, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Glade Solar Construction Holdings, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Glade Solar Construction, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Glade Solar Holdings 1, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Glade Solar Holdings 2, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Glade Solar Holdings, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Glade Solar Land Holdings, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Gnowee Power Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Goshen Phase II LLC (50.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Gothenburgh Fuelling Company AB (GFC) (33.33%)	Box 2154, 438 14, LANDVETTER, Sweden
Gravcap, Inc. (25.00%)	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Great Ropemaker Partnership (G.P.) Limited (50.00%)[α]	33 Cavendish Square, London, W1G 0PW, United Kingdom
Great Ropemaker Property (Nominee 1) Limited (50.00%)	33 Cavendish Square, London, W1G 0PW, United Kingdom
Great Ropemaker Property (Nominee 2) Limited (50.00%)	33 Cavendish Square, London, W1G 0PW, United Kingdom
Great Ropemaker Property Ltd (50.00%)	33 Cavendish Square, London, W1G 0PW, United Kingdom
Green Growth Feeder Fund Pte. Ltd (24.99%)	163 Penang Road, #08-01, Winsland House II, Singapore, 238463, Singapore
Grid Edge Limited (60.00%)[a]	Mclaren Building Suite, 14a Mclaren Building, 46 Priory Queensway, Birmingham, B4 7LR, United Kingdom
Groupement Pétrolier de Saint Pierre des Corps-GPSPC (20.00%)[b]	150 Avenue Yves Farge, 37700, SAINT PIERRE DES CORPS, France
Guangdong Dapeng LNG Company Limited (30.00%)[b]	10-11/FTime Finance Center, No.4001 Shennan Dadao, Futian Street, Futian District, Shenzhen, Guangdong Province, China
GVÖ Gebinde-Verwertungsgesellschaft der Mineralölwirtschaft mbH (21.00%)	Steindamm 55, 20099 Hamburg, Germany
H7 Energy Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Hamburg Tank Service (HTS) GbR (33.00%)[f]	Sportallee 6, 22335 Hamburg, Germany
Hebei Dongming Yinglun Petroleum Co., Ltd. (49.00%)[b]	South Side, Floor 10, Insurance Industrial Park, No. 672, Chengjiao Street,, Qiaoxi District, Shijiazhuang City, Hebei Province, China
Heinrich Fip GmbH & Co. KG (50.00%)[f]	Rheinstraße 36, 49090 Osnabrück, Germany
Heliex Power Limited (32.40%)[a]	Kelvin Building , Bramah Avenue , East Kilbride, Glasgow , Scotland, G75 0RD, United Kingdom
Henan Dongming Yinglun Petroleum Co., Ltd. (49.00%)[b]	Room 124, Longhu Enterprise Service Center, Floor 1, Building No. 10, Courtyard No.1, Long Xing Jia Yuan, No. 66, Longhu Outer Ring Road, Zhengdong New District, Zhenzhou City
HFS Hamburg Fuelling Services GbR (25.00%)[f]	Sportallee 6, 22335 Hamburg, Germany
Hiergeist Heizolhandel GmbH & Co. KG (50.00%)[f]	Grubenweg 4, 83666 Waakirchen-Marienstein, Germany
Hokchi Energy S.A. de C.V. (50.00%)	Torre A, piso 4, oficina 402, Calzada Legaria 549, Colonia 10 de Abril, Delegación Miguel Hidalgo, Ciudad de Mexico, C. P. 11250, Mexico
Hokchi Iberica S.L. (50.00%)	Campus Empresarial Arbea- Edificio Nº 1, Carretera Fuencarral a Alcobendas (M-603), Km 3,8., Alcobendas, Madrid, Spain
Howbery Solar Park Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Impact Solar 1, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Impact Solar Class B, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Impact Solar Construction, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Impact Solar Holdings 1, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Impact Solar Holdings 2, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Impact Solar Holdings, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Implantación de Fuentes Energéticas de Origen Renovable, SL (49.97%)	Calle Alcala numero 63, 28014, Madrid, Spain
In Salah Gas Limited (25.50%)[α]	IFC 5, St Helier, Jersey, JE1 1ST, Jersey
In Salah Gas Services Limited (25.50%)[α]	IFC 5, St Helier, Jersey, JE1 1ST, Jersey
India Gas Solutions Private Limited (50.00%)	Unit Nos.71 & 737th Floor, Maker Maxity, 2nd North Avenue, Bandra- Kurla Complex, Bandra (East), Mumbai 400 051, Maharashtra, India
Jamaica Aircraft Refuelling Services Limited (51.00%)[h]	PCJ Building36 Trafalgar Road, Kingston 10, Jamaica
Johnson Corner Solar I, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808, United States
Kala Power Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Kingston Research Limited (50.00%)	C/O Banks Cooper Associates, 21 Marina Court, Hull, HU1 1TJ , United Kingdom
Klaus Köhn GmbH (50.00%)	An der Braker Bahn 22, 26122 Oldenburg, Germany
Köhn & Plambeck GmbH & Co. KG (50.00%)[f]	An der Braker Bahn 22, 26122 Oldenburg, Germany
Kurt Ammenn GmbH & Co. KG (50.00%)[f]	Luisenstraße 5 a, 26382 Wilhelmshaven, Germany
LCA Aviation Fuelling Systems Limited (35.00%)	90 Archiepiskopou str, Dromolaxia – Meneou, 7020 Larnaca , Cyprus
LFS Langenhagen Fuelling Services GbR (50.00%)[f]	Sportallee 6, 22335 Hamburg, Germany
Lightning Hybrids, LLC (31.60%)[d]	160 Greentree Drive, Suite 101, Dover, County of Kent DE 19904, United States
Lightsource Asset Holdings (Australia) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Asset Holdings (Europe) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom

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

14. Related undertakings of the group – continued

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

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

14. Related undertakings of the group – continued

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

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

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

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14. Related undertakings of the group – continued

Lightsource SPV 112 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 114 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 115 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 116 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 118 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 123 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 126 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 127 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 128 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 130 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 133 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 135 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 138 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 140 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 142 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 143 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 145 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 149 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 151 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 152 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 154 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 155 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 156 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 160 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 162 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 166 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 167 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 169 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 170 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 171 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 174 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 175 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 176 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 179 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 18 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 180 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 182 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 183 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 184 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 185 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 187 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 189 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 19 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 191 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 192 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 196 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 199 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 20 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 200 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 201 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 202 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 203 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 204 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 205 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 206 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 212 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 213 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 214 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 215 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 216 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 217 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 218 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 219 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 221 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 222 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 223 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 224 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 225 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom

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

14. Related undertakings of the group – continued

Lightsource SPV 226 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 227 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 230 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 232 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 233 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 234 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 235 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 236 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 237 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 238 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 239 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 241 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 242 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 243 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 244 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 245 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 246 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 247 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 248 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 249 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 25 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 250 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 251 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 252 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 253 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 254 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 255 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 258 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 259 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 26 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 261 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 262 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 263 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 264 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 265 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 266 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource SPV 267 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource SPV 268 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource SPV 269 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource SPV 270 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource SPV 271 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource SPV 272 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource SPV 273 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource SPV 274 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource SPV 275 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource SPV 276 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource SPV 277 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource SPV 278 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource SPV 279 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource SPV 280 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource SPV 281 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource SPV 282 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource SPV 283 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource SPV 284 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource SPV 285 (NI) Limited (49.97%)	Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA
Lightsource SPV 286 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 29 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 32 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 35 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 39 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 40 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 41 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 42 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 44 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 47 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 49 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 5 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 50 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom

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14. Related undertakings of the group – continued

Lightsource SPV 54 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 56 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 60 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 69 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 73 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 74 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 75 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 76 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 78 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 79 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 8 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource SPV 88 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 91 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 92 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource SPV 98 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Timon Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lightsource Trading Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Viking 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Lightsource Viking 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Limited Liability Company TYNGD (20.00%)[b]	Pervomayskaya street, 32A, 678144, Lensk, Sakha (Yakutiya) Republic, Russian Federation
Limited Liability Company Yermak Neftegaz (49.00%)[b]	Kosmodamianskaya nab, 52/3, 115035, Moscow, Russian Federation
LL Property Services 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
LL Property Services Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
LLC "Kharampurneftegaz" (49.00%)[b]	629830 Yamalo-Nenetskiy Anatomy Region, city of Gubkinskiy, Russian Federation
Lora Solar Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Lotos- Air BP Polska Spółka z ograniczoną odpowiedzialnością (50.00%)	Grunwaldzka 472B, 80-309, Gdansk, Poland
LOTTE BP Chemical Co., Ltd (50.94%)	2-2 Sangnam-ri, Chungryang-myun, Ulju-gun, Ulsan 689-863, Republic of Korea
LREHL Renewables India SPV 1 Private Limited (37.93%)	815-816 International Trade Tower, Nehru Place, New Delhi, New Delhi, 110019, India
LS Australia FinCo 1 Pty Limited (49.97%)	C/- Baker McKenzie, Level 19, 181 William Street, Melbourne VIC 3000, Australia
LS Australia HoldCo1 Pty Ltd (49.97%)	Level 19 'CBW', 181 William Street, Melbourne VIC 3000, Australia
LSBP NE Development LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Maasvlakte Europoort Pipeline Maatschap (50.00%)[f]	Rijndwarsweg 3, 3198 LK Europoort, Rotterdam, Netherlands
Maatschap Europoort Terminal (50.00%)[f]	Moezelweg 101, 3198LS Europoort, Rotterdam, Netherlands
Mach Monument Aviation Fuelling Co. Ltd. (70.00%)	Naz City, Building J, Suite 10 Erbil, Iraq
Malmo Fuelling Services AB (33.33%)	Box 22, SE 230 32 Malmö-Sturup, Sweden
Manchester Airport Storage and Hydrant Company Limited (25.00%)	Bircham Dyson Bell, 50 Broadway, London, SW1H 0BL , United Kingdom
Manor Farm (Solar Power) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Manpetrol S.A. (50.00%)	Francisco Behr 20, Barrio Pueyrredon, Comodoro Rivadavia, Provincia del Chubut, Argentina
Maputo International Airport Fuelling Services (MIAFS) Limitada (50.00%)[b]	Praca Dos Trabalhadores, Nr 09, Distrito Urbano 1, Maputo, Mozambique
Masana Employee Share Trust No. 1 (37.88%)[b]	199 Oxford Road, Oxford Parks, Dunkeld, Johannesburg, Gauteng, 2196, South Africa
Mavrix, LLC (50.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
McFall Fuel Limited (49.00%)	KPMG, 247 Cameron Road, Tauranga, 3110, New Zealand
Mediteranean Gas Co. "MEDGAS" (25.00%)	5 El Mokhayam El Daiem St, 6th Sector, Nasr City, Egypt
Mehoopany Wind Energy LLC (50.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Mehoopany Wind Holdings LLC (50.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Meri Power Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Middle East Lubricants Company LLC (29.33%)	6th Flr City Tower, 2- Sheikh Zayed Road, PO Box 1699, Dubai, United Arab Emirates
Milne Point Pipeline, LLC (50.00%)[b]	900 E. Benson Boulevard, Anchorage, Alaska, 99508, United States
Mobene Beteiligungs GmbH & Co. KG (50.00%)[f]	Spaldingstraße 64, 20097 Hamburg, Germany
Mobene Beteiligungs Verwaltungs GmbH (50.00%)	Spaldingstraße 64, 20097 Hamburg, Germany
Mobene GmbH & Co. KG (50.00%)[f]	Spaldingstraße 64, 20097 Hamburg, Germany
Mobene Verwaltungs-GmbH (50.00%)	Spaldingstraße 64, 20097 Hamburg, Germany
MTS Francis Court Solar Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
MTS Trefinnick Solar Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
N.V. Rotterdam-Rijn-Pijpleiding Maatschappij (RRP) (44.40%)	Butaanweg 215, NL-3196 KC Vondelingenplaat, Rotterdam, 3045, Havennummer , Netherlands
Natural Gas Vehicles Company "NGVC" (40.00%)	85 El Nasr Road, Cairo, Cairo, Egypt
New Zealand Oil Services Limited (50.00%)	Level 3, 139 The Terrace, Wellington, 6011, New Zealand
Nextpower Trevemper Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
NFX Combustíveis Marítimos Ltda. (50.00%)	Avenida Atlântica, no. 1.130, 2nd floor (part), Copacabana, Rio de Janeiro, RJ, 22021-000, Brazil
Nima Power Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Nord-West Oelleitung GmbH (59.33%)	Zum Ölhafen 207, 26384 Wilhelmshaven, Germany
Ocwen Energy Pty Ltd (49.50%)	GTH Accounting Group Pty Ltd '2', 1A Kitchener Street, Toowoomba QLD 4350, Australia
Olympic Pipe Line Company LLC (70.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States

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Oslo Lufthaven Tankanlegg AS (33.33%)	Postboks 134, Gardermoen, NO-2061, Norway
PAE E & P Bolivia Limited (50.00%)	Trinity Place Annex, Corner of Frederick & Shirley Streets, P.O. Box N-4805, Nassau, Bahamas
PAE Oil & Gas Bolivia Ltda. (50.00%)	Cuarto anillo, Avda. Ovidio Barbery N° 4200, Edificio Torre , e/ Jaime Román y Victor Pinto, Equipetrol Norte, Santa Cruz de la Sierra, Bolivia
Palk Power Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Pan American Energy Chile Limitada (50.00%)	Nueva de Lyon N° 145, piso 12, oficina 1203, Edificio Costa, Santiago de Chile, Chile
Pan American Energy do Brasil Ltda. (50.00%)[b]	Rua Manoel da Nóbrega n°1280, 10° andar, Sao Paulo, Sao Paulo, 04001-902, Brazil
Pan American Energy Group, S.L. (50.00%)[a]	Arbea Campus Empresarial, Edifico 1. Ctra de Fuencarral a Alcobendas, M603, KM 3,8 28108 Alcobendas, MADRID, SPAIN
Pan American Energy Holdings S.A. (50.00%)	Colonia 810, Oficina 403, Montevideo, Uruguay
Pan American Energy Iberica S.L. (50.00%)	Campus Empresarial Arbea- Edificio N° 1, Carretera Fuencarral a Alcobendas (M-603), Km 3,8., Alcobendas, Madrid, Spain
Pan American Energy Investments Ltd. (50.00%)	Trinity Place Annex, Corner of Frederick & Shirley Streets, P.O. Box N-4805, Nassau, Bahamas
Pan American Energy Uruguay S.A. (50.00%)	Colonia 810, Oficina 403, Montevideo, Uruguay
Pan American Energy US LLC (51.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
Pan American Energy, S.L. (50.00%)[b]	Arbea Campus Empresarial, Edifico 1. Ctra de Fuencarral a Alcobendas, M603, KM 3,8 28108 Alcobendas, MADRID, SPAIN
Pan American Fueguina S.A. (50.00%)	O´Higgins N° 194, Rio Grande, Argentina
Pan American Sur S.A. (50.00%)	O´Higgins N° 194, Rio Grande, Argentina
Parque Eolico Del Sur S.A. (27.50%)	0
Peninsular Aviation Services Company Limited (25.00%)[i]	P O Box 6369, Jeddah21442, Saudi Arabia
Pentland Aviation Fuelling Services Limited (50.00%)[c]	6th Floor (c/o Q8 Aviation), Dukes Court, Duke Street, Woking, GU21 5BH, Surrey
Petrostock SA (50.00%)	route de Pré-Bois 2, 1214, Vernier, Switzerland
Pharaonic Petroleum Company "PhPC" (25.00%)	70/72 Road 200, Maadi, Cairo, Egypt
Pont Andrew Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Porteiras Geração de Energia Ltda (49.97%)	Estrada BR 135, número S/N, KM 250, bairro / distrito Angico de Minas, município Japonvar- MG, CEP 39335-000
Prince William Sound Oil Spill Response Corporation (25.00%)	9360 Glacier Highway, Suite 202, Juneau AK 99801, United States
Proteus Oil Pipeline Company, LLC (45.72%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
PT Petro Storindo Energi (30.00%)	Bakrie Tower 17th Floor, Rasuna Epicentrum Complex Jl. H.R Rasuna Said, Jakarta, 12940, Indonesia
PT. Dirgantara Petroindo Raya (49.90%)	Wisma AKR, 25th floor, Jalan Panjang No.5, Kebon Jeruk, , Jakarta Barat, 11530, Indonesia
PTE Pipeline LLC (32.00%)[b]	2711 Centerville Road, Suite 400, Wilmington DE 19808, United States
R&B Technology Holding CO., LTD (59.02%)[a]	PO Box 472, 2nd Floor, Harbour Place, 103 South Church Street, George Town, Grand Cayman, KY1-1106, Cayman Islands
Rahamat Petroleum Company (PETRORAHAMAT) (50.00%)	70/72 Road 200, Maadi, Cairo, Egypt
RAPI SA (62.51%)	26 Kifissias Ave. and 2 Paradissou st., 15125 Maroussi, Athens, Greece
Raststaette Glarnerland AG, Niederurnen (20.00%)	Nideracher 1, 8867, Niederurnen, Switzerland
RD Petroleum Limited (49.00%)	399 Moray Place, Dunedin, 9016, New Zealand
Resolution Partners LLP (68.00%)[f]	1675 Broadway, Denver CO 80202, United States
Rhein-Main-Rohrleitungstransportgesellschaft mbH (35.00%)	Godorfer Hauptstraße 186, 50997 Köln, Germany
RMF Holdings Limited (49.00%)	KPMG, 247 Cameron Road, Tauranga, 3110, New Zealand
Romanian Fuelling Services S.R.L. (50.00%)	59 Aurel Vlaicu Street, Otopeni, Ilfov County, Romania
Rosneft Oil Company (19.75%)	26/1 Sofiyskaya Embankment, 115035, Moscow, Russian Federation, Russian Federation
Routex B.V. (25.00%)	Strawinskylaan 1725, 1077XX Amsterdam, Netherlands
S&JD Robertson North Air Limited (49.00%)	1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom
SABA- Sociedade Abastecedora de Aeronaves, Lda (25.00%)	Grupo Operacional de Combustiveis do Aeroporto de Lisboa, Edificio 19, 1.º Sala Saba, Lisboa, Portugal
SAFCO SA (33.33%)	International airport "El. Venizelos", Athens, Greece
Salzburg Fuelling GmbH (33.00%)[b]	Innsbrucker Bundesstraße 95, 5020 Salzburg, Austria
SAMCOL- Sociedade de Armazenamento e Manuseamento de Combustiveis Liquidos, Limitada (50.00%)[b]	Parcela 729, via onze mil cento e trinta, numero cento e qua, Matola Lingamo, Mozambique
Saraco SA (20.00%)	route de Pré-Bois 17, 1216, Cointrin, Switzerland
SeaPort Midstream Partners, LLC (49.00%)[b]	Cogency Global Inc., 850 New Burton Road, Suite 201, Dover, Delaware, 19904, United States
Sel PV 09 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Servicios Logísticos de Combustibles de Aviación, S.L (50.00%)	Paseo de la Castellana 278, Madrid, Spain, Spain
Shakti Power Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Shandong Dongming Yinglun Petroleum Co., Ltd. (49.00%)[b]	Room B-703, B-704, B-705, B-706, B-707, Floor 7, Block B, No.8, Luoyuan Avenue, Lixia District, Jinan City, China
Sharjah Aviation Services Co. LLC (49.00%)[a]	P O Box- 97, Sharjah, United Arab Emirates
Sharjah Pipeline Company LLC (49.00%)	Sharjah 42244, Sharjah, UAE, Sharjah, United Arab Emirates
Shell and BP South African Petroleum Refineries (Pty) Ltd (37.50%)[h]	1 Refinery Road, Prospecton, 4110, South Africa
Shell Mex and B.P. Limited (40.00%)[a]	Shell Centre, London, SE1 7NA, United Kingdom

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14. Related undertakings of the group – continued

Shenzhen Cheng Yuan Aviation Oil Company Limited (25.00%)[b]	Fu Yong Town, Bao An county, ShenZhen Airport, Guangdong Province, China
Shenzhen Dapeng LNG Marketing Company Limited (30.00%)[b]	Guangdong Dapeng Liquefied Natural Gas Filling Station, Cheng Tou Corner, Xia Sha Village, Dapeng Street, Dapeng New District, Shenzhen, China
Sherbino I Wind Farm LLC (50.00%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
SKA Energy Holdings Limited (50.00%)	LOB 16, Suite #309, Jebel Ali Free Zone, Dubai, PO BOX 262794, United Arab Emirates
SM Realisations Limited (In Liquidation) (40.00%)	Shell Centre, London, SE1 7NA, England
Société d'Avitaillement et de Stockage de Carburants Aviation "SASCA" (40.00%)[b]	1 Place Gustave Eiffel, 94150, RUNGIS, France
Société de Gestion de Produits Pétroliers- SOGEPP (37.00%)	27 Route du Bassin Numéro 6, 92230, GENNEVILLIERS, France
Solar Photovoltaic (SPV2) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Solar Photovoltaic (SPV3) Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Solar Strategic Energy LLC (49.97%)b	400 Montgomery Street, Floor 8, San Francisco, CA 94104
South Caucasus Pipeline Company Limited (28.83%)[α]	Maples & Calder, P.O. Box 309, Ugland House, 113 South Church Street, George Town, Grand Cayman, Cayman Islands
South Caucasus Pipeline Holding Company Limited (28.83%)	Maples & Calder, P.O. Box 309, Ugland House, 113 South Church Street, George Town, Grand Cayman, Cayman Islands
South Caucasus Pipeline Option Gas Company Limited (28.83%)	Maples & Calder, P.O. Box 309, Ugland House, 113 South Church Street, George Town, Grand Cayman, Cayman Islands
South China Bluesky Aviation Oil Company Limited (24.50%)[b]	2-5F, No. 571, Yuncheng Dong Road, Baiyun District, Guangzhou City, Guangdong Province, China
Stansted Intoplane Company Limited (20.00%)	Causeway House, 1 Dane Street, Bishop's Stortford, Hertfordshire, CM23 3BT, United Kingdom
STDG Strassentransport Dispositions Gesellschaft mbH (50.00%)	Holstenhofweg 47, 22043 Hamburg, Germany
Stockholm Fuelling Services Aktiebolag (25.00%)	Box 7, 190 45 Arlanda, Sweden
Stonewall Resources Ltd. (50.00%)	Palm Grove House, P.O. Box 438, Road Town, Tortola, Virgin Islands, British
Sula Power Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Sun and Soil Renewable 12 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Tankanlage AG Mellingen (33.33%)	Birmenstorferstrasse 2, 5507, Mellingen, Switzerland
TAR- Tankanlage Ruemlang AG (27.32%)	Zwüscheteich, 8153, Rümlang, Switzerland
TAU Tanklager Auhafen AG (50.00%)	Auhafenstrasse 10a, 4132, Muttenz, Switzerland
TCE Participações S.A. (50.00%)	Avenida Paulista, 287, 1st floor, room 10, São Paulo, São Paulo, 01311000, Brazil
Team Terminal B.V. (22.80%)	Rijndwarsweg 3, 3198 LK Europoort, Rotterdam, Netherlands
Tecklenburg GmbH (50.00%)	Wesermünder Straße 1, 27729 Hambergen, Germany
Tecklenburg GmbH & Co. Energiebedarf KG (50.00%)[f]	Wesermünder Straße 1, 27729 Hambergen, Germany
Terminal CP S.A.U. (50.00%)	Av. Leandro N. Alem 1180, piso 11°, Buenos Aires, Argentina
Terminales Canarios, S.L. (50.00%)	Carretera de San Andréss/n, La Jurada-María Jiménez, Santa Cruz de Tenerife, Spain
TFSS Turbo Fuel Services Sachsen GbR (20.00%)[f]	Sportallee 6, 22335 Hamburg, Germany
TGC Solar 106 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
TGC Solar 91 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
TGFH Tanklager-Gesellschaft Frankfurt-Hahn GbR (50.00%)[f]	Sportallee 6, 22335 Hamburg, Germany
TGH Tankdienst-Gesellschaft Hamburg GbR (33.33%)[f]	Sportallee 6, 22335 Hamburg, Germany
TGHL Tanklager-Gesellschaft Hannover-Langenhagen GbR (50.00%)[f]	Sportallee 6, 22335 Hamburg, Germany
TGK Tanklagergesellschaft Koln-Bonn (25.00%)[f]	Sportallee 6, 22335 Hamburg, Germany
Thames Electricity Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
The Baku-Tbilisi-Ceyhan Pipeline Company (30.10%)[δ]	Maples & Calder, P.O. Box 309, Ugland House, 113 South Church Street, George Town, Grand Cayman, Cayman Islands
The Consolidated Petroleum Company Limited (50.00%)[α]	Shell Centre, London, SE1 7NA, United Kingdom
The Consolidated Petroleum Supply Company Limited (50.00%)[ζ]	Shell Centre, London, SE1 7NA, United Kingdom
The Great Ropemaker Partnership (50.00%)[f]	33 Cavendish Square, London, W1G 0PW, United Kingdom
Thornton Transportation LLC (37.04%)[b]	Corporation Service Company, 421 West Main Street, Frankfort KY 40601, United States
Thorntons LLC (37.04%)[b]	CSC, 251 Little Falls Drive, Wilmington, County of New Castle DE 19808, United States
TLK Holding Company LLC (37.04%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
TLK Intermediate Holding Company LLC (37.04%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
TLK Operating Company LLC (37.04%)[b]	Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, United States
TLM Tanklager Management GmbH (49.00%)[b]	Am Tankhafen 4, 4020 Linz, Austria
TLS Tanklager Stuttgart GmbH (45.00%)	Zum Ölhafen 49, 70327 Stuttgart, Germany
Tonatiuh Trading 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
TRaBP GbR (75.00%)[f]	Huestraße 25, 44787, Bochum, Germany
Trafineo GmbH & Co. KG (75.00%)[f]	Wittener Straße 56, Bochum, Germany
Trafineo Service GmbH (75.00%)	Wittener Straße 45, 44789 Bochum, Germany
Trafineo Verwaltungs-GmbH (75.00%)	Wittener Straße 56, Bochum, Germany
TransTank GmbH (50.00%)	Am Stadthafen 60, 45881 Gelsenkirchen, Germany
Tricoya Ventures UK Limited (36.73%)	Brettenham House, 19 Lancaster Place, London, WC2E 7EN, United Kingdom
Tuwale Power Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom

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

14. Related undertakings of the group – continued

TWQE2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HU, United Kingdom
Ubiworx Systems Designated Activity Company (47.47%)	Trinity House, Charleston Road, Ranelagh, Dublin 6, D06C8X4, Ireland
United Gas Derivatives Company "UGDC" (33.33%)	Building No. 349 & 351, Third Sector of City Centre, Fifth Settlement, Cairo, Egypt
United Kingdom Oil Pipelines Limited (22.15%)	5-7 Alexandra Road, Hemel Hempstead, Hertfordshire, HP2 5BS, United Kingdom
Vale do Cochá Geração de Energia Ltda (49.97%)	Estrada BR 030, número S/N, CXPST 08, bairro / distrito Zona Rural, município Montalvania- MG, CEP 39495-000
Vendimia Grid, AIE (49.97%)	Calle Alcala numero 63, 28014, Madrid, Spain
Verde Grande Geração de Energia Ltda (49.97%)	Fazenda Contendas, localizada na Rodovia Joaquim de Freitas, sentido Mato Verde a Catuti, Km 2 à direita, Zona Rural, município de Mato Verde-MG, CEP 39527-000
VIC CBM Limited (50.00%)	Eni House, 10 Ebury Bridge Road, London, SW1W 8PZ, United Kingdom
Vientos Ombu III S.A. (25.00%)	Av. Leandro N. Alem 1180, piso 11°, Buenos Aires, Argentina
Vientos Patagonicos Chubut Norte III S.A. (24.50%)	Lavalle 190, piso 6 Depto L, Buenos Aires
Vientos Sudamericanos Chubut Norte IV S.A. (24.50%)	Lavalle 190, piso 6 Depto L, Buenos Aires
Virginia Indonesia Co. CBM Limited (50.00%)	Eni House, 10 Ebury Bridge Road, London, SW1W 8PZ, United Kingdom
Walton-Gatwick Pipeline Company Limited (42.33%)	5-7 Alexandra Road, Hemel Hempstead, Herts., HP2 5BS, United Kingdom
Wellington LandCo Pty Ltd (49.97%)	Level 19 'CBW', 181 William Street, Melbourne VIC 3000, Australia
West London Pipeline and Storage Limited (30.50%)	5-7 Alexandra Road, Hemel Hempstead, Herts., HP2 5BS, United Kingdom
Whitetail Solar 1, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Whitetail Solar 2, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Whitetail Solar 3, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Whitetail Solar 6, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Whitetail Solar Land Holdings, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Wick Farm Grid Limited (24.99%)	Woodwater House, Pynes Hill, Exeter, EX2 5WR, United Kingdom
Wildflower Solar I, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Wildflower Solar Land Holdings, LLC (49.97%)[b]	Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808
Wiri Oil Services Limited (27.78%)	Ross Pauling & Partners Limited, 106b Bush Road, Albany, Auckland, 0632, New Zealand
Yangtze River Acetyls Co., Ltd (51.00%)[b]	97 Weijiang Road (in the Petrochemical Park), Changshou District, Chongqing, China
Your Power No. 1 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Your Power No. 10 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Your Power No. 19 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Your Power No. 2 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Your Power No. 3 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Your Power No. 8 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Your Power No12 Limited (49.97%)	7th Floor, 33 Holborn, London, EC1N 2HT, United Kingdom
Zonneweide Westdorperveen B.V. (49.97%)	Prins Bernhardplein 200, 1097JB, Amsterdam, Netherlands
Zubie, Inc. (20.30%)	160 Greentree Drive, Suite 101, Dover, County of Kent DE 19904, United States

[a] Preference shares
[b] Member interest
[c] A and B shares
[d] Common stock and preference shares
[e] Ordinary shares and preference shares
[f] Partnership interest
[g] A, B and D shares
[h] A shares
[i] Interest held directly by BP p.l.c.
[j] 99% held directly by BP p.l.c.
[k] 1% held directly by BP p.l.c.
[l] Ordinary, A and B shares
[m] Common stock and redeemable preference shares
[n] Ordinary A, B and C shares
[o] 0.008% held directly by BP p.l.c.
[p] 80.01% ordinary shares and 99.07% preference shares
[q] Members interest, (49.99%) subordinated units and (4.37%) common units traded on the New York stock exchange
[r] 93.64% ordinary shares and 81.18% preference shares
[s] Subsidiary in which the group does not hold a majority of the voting rights but exercises control over it
[t] Ordinary shares and redeemable preference shares
[u] Ordinary and A shares
[v] Ordinary and deferred shares
[w] Subsidiary undertaking pursuant to sections 1162(2), 1162(3)(b) and Paragraph 6 of Schedule 7 of the Companies Act 2006
[x] 100% ordinary shares and 58.65% preference shares
[y] 92.31% B shares and 78.43% D shares
[z] 15% held directly by BP p.l.c
[α] B shares
[β] Unlimited redeemable shares
[γ] 96.52% C shares
[δ] 1.89% A shares and 40.80% B shares
[ε] 43.2% A shares, 43.2% C shares, 43.2% D shares, 43.2% E shares, 43.2% F shares and 43.2% G shares
[ζ] 5% held directly by BP p.l.c

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

Additional disclosures

Selected financial information

This information has been extracted or derived from the audited consolidated financial statements of the BP group. Note 1 to the financial statements includes details on the basis of preparation of these financial statements. The selected information should be read in conjunction with the audited financial statements and related notes. The audited consolidated financial statements and related notes as of 31 December 2019 and 2018 and for the three years ended 31 December 2019 are presented on page 132.

					$ million except per share amounts
	2019	2018	2017	2016	2015
Income statement data					
Sales and other operating revenues	**278,397**	298,756	240,208	183,008	222,894
Profit (loss) before interest and taxation	**11,706**	19,378	9,474	(430)	(7,918)
Finance costs and net finance expense relating to pensions and other post-retirement benefits	**(3,552)**	(2,655)	(2,294)	(1,865)	(1,653)
Taxation	**(3,964)**	(7,145)	(3,712)	2,467	3,171
Non-controlling interests	**(164)**	(195)	(79)	(57)	(82)
Profit (loss) for the year[a]	**4,026**	9,383	3,389	115	(6,482)
Inventory holding (gains) losses★, before tax	**(667)**	801	(853)	(1,597)	1,889
Taxation charge (credit) on inventory holding gains and losses	**156**	(198)	225	483	(569)
RC profit (loss)★ for the year	**3,515**	9,986	2,761	(999)	(5,162)
Net (favourable) adverse impact of non-operating items★ and fair value accounting effects★, before tax[b]	**8,263**	3,380	3,730	6,746	15,067
Taxation charge (credit) on non-operating items and fair value accounting effects	**(1,788)**	(643)	(325)	(3,162)	(4,000)
Underlying RC profit★ for the year	**9,990**	12,723	6,166	2,585	5,905
Earnings per share[c] – cents					
Profit (loss) for the year[a] per ordinary share					
Basic	**19.84**	46.98	17.20	0.61	(35.39)
Diluted	**19.73**	46.67	17.10	0.60	(35.39)
RC profit (loss) for the year per ordinary share★	**17.32**	50.00	14.02	(5.33)	(28.18)
Underlying RC profit for the year per ordinary share★	**49.24**	63.70	31.31	13.79	32.22
Dividends paid per share – cents	**41.00**	40.50	40.00	40.00	40.00
– pence	**31.977**	30.568	30.979	29.418	26.383
Capital expenditure★[d]					
Organic capital expenditure★	**15,238**	15,140	16,501	16,675	N/A
Inorganic capital expenditure★	**4,183**	9,948	1,339	777	N/A
	19,421	25,088	17,840	17,452	20,202
Balance sheet data (at 31 December)					
Total assets	**295,194**	282,176	276,515	263,316	261,832
Net assets	**100,708**	101,548	100,404	96,843	98,387
Share capital	**5,404**	5,402	5,343	5,284	5,049
BP shareholders' equity	**98,412**	99,444	98,491	95,286	97,216
Finance debt due after more than one year	**57,237**	55,803	54,873	51,073	45,567
Gearing★	**31.1%**	30.0%	27.0%	26.5%	21.2%
Ordinary share data[e]					Share million
Basic weighted average number of shares	**20,285**	19,970	19,693	18,745	18,324
Diluted weighted average number of shares	**20,400**	20,102	19,816	18,855	18,324

[a] Profit attributable to BP shareholders.

[b] See pages 300 and 344 for further analysis of these items.

[c] A reconciliation to GAAP information is provided on page 344.

[d] From 2017 onwards BP reports organic, inorganic and total capital expenditure on a cash basis which were previously reported on an accruals basis. This aligns with BP's financial framework and is consistent with other financial metrics used when comparing sources and uses of cash. An analysis of capital expenditure on a cash basis for 2015 is not available.

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

Additional information

Capital expenditure

	2019	2018	2017
			$ million
Capital expenditure			
Organic capital expenditure	**15,238**	15,140	16,501
Inorganic capital expenditure[a]	**4,183**	9,948	1,339
	19,421	25,088	17,840

	2019	2018	2017
			$ million
Organic capital expenditure by segment			
Upstream			
US	**4,019**	3,482	2,999
Non-US	**7,885**	8,545	10,764
	11,904	12,027	13,763
Downstream			
US	**913**	877	809
Non-US	**2,084**	1,904	1,590
	2,997	2,781	2,399
Other businesses and corporate			
US	**47**	54	64
Non-US	**290**	278	275
	337	332	339
	15,238	15,140	16,501
Organic capital expenditure by geographical area			
US	**4,979**	4,413	3,872
Non-US	**10,259**	10,727	12,629
	15,238	15,140	16,501

[a] On 31 October 2018, BP acquired from BHP Billiton Petroleum (North America) Inc. 100% of the issued share capital of Petrohawk Energy Corporation, a wholly owned subsidiary of BHP that holds a portfolio of unconventional onshore US oil and gas assets. The entire consideration payable of $10,268 million, after customary closing adjustments, was paid in instalments between July 2018 and April 2019. The amounts presented as inorganic capital expenditure include $3,480 million for 2019 and $6,788 million for 2018 relating to this transaction. 2018 includes $1,739 million relating to the purchase of an additional 16.5% interest in the Clair field west of Shetland in the North Sea, as part of the agreements with Conoco-Phillips in which Conoco-Philips simultaneously purchased BP's entire 39.2% interest in the Greater Kuparuk Area on the North Slope of Alaska. 2019 and 2018 also include amounts relating to the 25-year extension to our ACG production-sharing agreement* in Azerbaijan. 2017 includes amounts paid to acquire interests in Mauritania and Senegal and in the Zohr gas field in Egypt.

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Non-operating items

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

			$ million
	2019	2018	2017
Upstream			
Impairment and gain (loss) on sale of businesses and fixed assets[a b]	**(6,893)**	(90)	(563)
Environmental and other provisions	**(32)**	(35)	1
Restructuring, integration and rationalization costs[c]	**(89)**	(131)	(24)
Fair value gain (loss) on embedded derivatives	**—**	17	33
Other[d]	**67**	56	(118)
	(6,947)	(183)	(671)
Downstream			
Impairment and gain (loss) on sale of businesses and fixed assets[a e]	**(72)**	(54)	579
Environmental and other provisions	**(78)**	(83)	(19)
Restructuring, integration and rationalization costs[c]	**85**	(405)	(171)
Fair value gain (loss) on embedded derivatives	**—**	—	—
Other	**(12)**	(174)	—
	(77)	(716)	389
Rosneft			
Impairment and gain (loss) on sale of businesses and fixed assets	**(103)**	(95)	—
Environmental and other provisions	**—**	—	—
Restructuring, integration and rationalization costs	**—**	—	—
Fair value gain (loss) on embedded derivatives	**—**	—	—
Other	**—**	—	—
	(103)	(95)	—
Other businesses and corporate			
Impairment and gain (loss) on sale of businesses and fixed assets[a f]	**(917)**	(260)	(22)
Environmental and other provisions[g]	**(231)**	(640)	(156)
Restructuring, integration and rationalization costs[c]	**6**	(190)	(72)
Fair value gain (loss) on embedded derivatives	**—**	—	—
Gulf of Mexico oil spill response	**(319)**	(714)	(2,687)
Other	**(30)**	(159)	90
	(1,491)	(1,963)	(2,847)
Total before interest and taxation	**(8,618)**	(2,957)	(3,129)
Finance costs[h]	**(511)**	(479)	(493)
Total before taxation	**(9,129)**	(3,436)	(3,622)
Taxation credit (charge) on non-operating items[i]	**1,943**	510	1,172
Taxation - impact of US tax reform[j]	**—**	121	(859)
Total after taxation	**(7,186)**	(2,805)	(3,309)

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

[b] 2019 includes impairments charges principally resulting from the announcements to dispose of certain assets in the US and Egypt. 2018 includes an impairment reversal for assets in the North Sea and Angola. 2017 includes an impairment charge relating to BPX Energy (previously known as the US Lower 48 business), partially offset by gains associated with asset divestments. In addition, 2017 includes an impairment charge arising following the announcement of the agreement to sell the Forties Pipeline System business to INEOS.

[c] Restructuring charges are classified as non-operating items where they relate to an announced major group restructuring. A major group restructuring is a restructuring programme affecting more than one of the group's operating segments that is expected to result in charges of more than $1 billion over a defined period. Following the Gulf of Mexico oil spill in 2010 and since the fall in oil prices in late 2014, major group restructuring programmes were initiated.The group's restructuring programme, originally announced in 2014, was completed in 2018.

[d] 2018 and 2017 include exploration write-offs of $124 million and $145 million respectively in relation to the value ascribed to certain licences in the deepwater Gulf of Mexico as part of the accounting for the acquisition of upstream assets from Devon Energy in 2011. 2017 also includes BP's share of an impairment reversal recognized by the Angola LNG equity-accounted entity, partially offset by other items.

[e] 2017 primarily reflects the disposal of our shareholding in the SECCO joint venture.

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

[g] 2019 and 2018 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 Mexico oil spill related legal provisions.

[h] Relates to the unwinding of discounting effects relating to Gulf of Mexico oil spill payables.

[i] 2017 includes the tax effect of the increase in the provision in the fourth quarter for business economic loss and other claims associated with the Deepwater Horizon Court Supervised Settlement Program (DHCSSP) at the new US tax rate.

[j] In 2017 the US tax reform reduced the US federal corporate income tax rate from 35% to 21%, effective from 1 January 2018. The impact disclosed has been calculated as the change in deferred tax balances at 31 December 2017, excluding the increase in the provision in the fourth quarter for business economic loss and other claims associated with the DHCSSP, which arises following the reduction in the tax rate. 2018 reflects a further impact following a clarification of the tax reform. The impact of the US tax reform has been treated as a non-operating item because it is not considered to be part of underlying business operations, has a material impact upon the reported result and is substantially impacted by Gulf of Mexico oil spill charges, which are also treated as non-operating items. Separate disclosure is considered meaningful and relevant to investors.

Liquidity and capital resources

Financial framework

BP's financial framework sets a number of parameters in support of growing shareholder value, distributions and returns, while maintaining a strong balance sheet. BP's objective over time is to grow sustainable free cash flow★ through a combination of operating cash flow★ growth and capital discipline, in service of growing shareholder distributions over the long term.

We maintain our progressive dividend policy that reflects 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.

In a constant price environment, surplus organic free cash flow★ is expected to grow and be used to ensure the right balance between deleveraging the balance sheet, growing distributions and disciplined investment, depending on the context and outlook at the time. In a period of low prices, the group has the flexibility to reduce cash costs and to reduce or defer capital investment, as appropriate.

Gulf of Mexico oil spill payments were $2.4 billion on a post-tax basis in 2019 and are expected to step down to around $1 billion per annum thereafter. In 2020, we expect to meet our target of $10 billion divestment and other proceeds and plan a further $5 billion of agreed disposals by mid-2021. In 2020, divestment proceeds★ will be primarily focussed on reducing gearing★.

We continue to target a gearing band of 20-30%. In 2019, gearing moved to 31.1%, above the top end of the band, reflecting the impact of completing the acquisition of BHP's onshore US assets using available cash. Gearing may increase in the short-term with the impact of lower prices, but is expected to reduce again in line with the receipt of divestment proceeds.

In 2019, the return on average capital employed★ was 8.9%[a] at an average of $64 per barrel. At $55 per barrel 2017 real, return on average capital employed is targeted to improve to over 10% by 2021, as we continue to grow our underlying business.

[a] Nearest equivalent GAAP measures: Numerator – Profit attributable to BP shareholders $4.0 billion; Denominator – Average capital employed $167.6 billion.

Dividends and other distributions to shareholders

The dividend is determined in US dollars, the economic currency of BP, and the dividend level is reviewed by the board each quarter. The quarterly dividend was increased to 10.50 cents per share for the fourth quarter of 2019, having been increased to 10.25 cents from 10.00 cents per share in the third quarter of 2018.

The total dividend distributed to BP shareholders in 2019 was $8.3 billion (2018 $8.1 billion). Prior to its suspension in the fourth quarter of 2019, shareholders had the option to receive a scrip dividend in place of receiving cash and in 2019 the total dividend paid in cash was $6.9 billion (2018 $6.7 billion). The impact of the scrip dilution since the third quarter of 2017 was fully offset in January 2020.

Details of share repurchases to satisfy the requirements of certain employee share-based payment plans are set out on page 334. The share buyback programme, to offset the dilutive impact of the scrip dividend, purchased 235 million ordinary shares in 2019 at a cost of $1.5 billion (2018 $355 million), including fees and stamp duty.

Financing the group's activities

The group's principal commodities, oil and gas, are priced internationally in US dollars. Group policy has generally been to minimize economic exposure to currency movements by financing operations with US dollar debt. Where debt is issued in other currencies, including euros, it is 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 70 for further information on risks associated with prices and markets and Financial statements – Note 29.

The group's finance debt at 31 December 2019 amounted to $67.7 billion (2018 $65.1 billion[b]). Of the total finance debt, $10.5 billion is classified as short term at the end of 2019 (2018 $9.3 billion). See Financial statements – Note 26 for more information on the short-term balance. Net debt★ was $45.4 billion at the end of 2019, an increase of $1.9 billion from the 2018 year-end position of $43.5 billion[b].

The ratio of finance debt to finance debt plus total equity at 31 December 2019 was 40.2% (2018 39.1%[b]). The ratio of net debt to net debt plus total equity★ was 31.1% at the end of 2019 (2018 30.0%[b]). 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 $22.5 billion at 31 December 2019 (2018 $22.5 billion) are included in net debt. We manage our cash position so that the group has adequate cover to respond to potential short-term market illiquidity, short term price environment volatility and expect to maintain a robust cash position.

The group also has an undrawn committed $10 billion credit facility and undrawn committed bank facilities of $7.6 billion (see Financial statements – Note 29 for more information).

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

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

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

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.

[b] As a result of the adoption of IFRS 16 'Leases', leases that were previously classified as finance leases under IAS 17 are now presented as 'Lease liabilities' on the group balance sheet and therefore do not form part of finance debt. Comparative information for finance debt (previously termed 'gross debt'), net debt and gearing (previously termed 'net debt ratio') have been amended to be on a consistent basis with amounts presented for 2019.

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 324 and Risk factors on page 70, 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 2019, the group's share of third-party finance debt of equity-accounted entities was $17.3 billion (2018 $16.1 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 2019 were $692 million (2018 $696 million) in respect of liabilities of joint ventures★and associates★and $523 million (2018 $432 million) in respect of liabilities of other third parties. Of these amounts, $681 million (2018 $684 million) of the joint ventures and associates guarantees relate to borrowings and for other third-party guarantees, $494 million (2018 $423 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 2019 and the proportion of that expenditure for which contracts have been placed.

							$ million
							Payments due by period
Capital expenditure	Total	2020	2021	2022	2023	2024	2025 and thereafter
Committed	24,853	12,745	7,070	2,599	1,398	396	645
of which is contracted	11,382	7,497	3,388	347	52	27	71

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 2019, the group had committed to capital expenditure relating to investments in equity-accounted entities amounting to $1,156 million. Contracts were in place for $864 million of this total.

The following table summarizes the group's principal contractual obligations at 31 December 2019, distinguishing between those for which a liability is recognized on the balance sheet and those for which no liability is recognized. Further information on borrowings is given in Financial statements – Note 26 and more information on leases is given in Financial statements – Note 28.

							$ million
							Payments due by period
Expected payments by period under contractual obligations	Total	2020	2021	2022	2023	2024	2025 and thereafter
Balance sheet obligations							
Borrowings[a]	75,567	14,166	8,119	9,156	8,030	8,363	27,733
Lease liabilities[b]	11,299	2,514	1,839	1,364	1,105	876	3,601
Decommissioning liabilities[c]	25,964	395	218	80	196	146	24,929
Environmental liabilities[c]	1,867	278	276	224	206	170	713
Gulf of Mexico oil spill liabilities[d]	16,129	1,628	1,355	1,267	1,219	1,141	9,519
Pensions and other post-retirement benefits[e]	18,016	1,127	1,155	1,076	1,072	1,048	12,538
	148,842	20,108	12,962	13,167	11,828	11,744	79,033
Off-balance sheet obligations							
Unconditional purchase obligations[f]							
Crude oil and oil products	64,486	48,954	6,720	3,919	2,016	1,288	1,589
Natural gas and LNG	39,097	12,182	4,478	3,247	2,692	2,183	14,315
Chemicals and other refinery feedstocks	5,009	2,918	927	922	118	53	71
Power	5,001	2,673	1,164	394	204	121	445
Utilities	964	144	123	103	67	64	463
Transportation	20,526	1,650	1,637	1,428	1,361	1,332	13,118
Use of facilities and services	20,855	2,565	2,132	1,767	1,460	1,252	11,679
	155,938	71,086	17,181	11,780	7,918	6,293	41,680
Total	304,780	91,194	30,143	24,947	19,746	18,037	120,713

[a] Expected payments include interest totalling $7,843 million ($1,730 million in 2020, $1,393 million in 2021, $1,207 million in 2022, $1,008 million in 2023, $809 million in 2024 and $1,696 million thereafter).

[b] Expected payments include interest totalling $1,577 million ($307 million in 2020, $248 million in 2021, $202 million in 2022, $164 million in 2023, $133 million in 2024 and $523 million thereafter).

[c] The amounts presented are undiscounted.

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

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

[f] Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms (such as fixed or minimum purchase volumes, timing of purchase and pricing provisions). Agreements that do not specify all significant terms, or that are not enforceable, are excluded. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas, feedstocks and pipeline systems. In addition, the amounts shown for 2020 include purchase commitments existing at 31 December 2019 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 2020 to 2022 worldwide, we are contractually committed to deliver approximately 292 million barrels of oil, 8,600 billion cubic feet of natural gas, and 36 million tonnes of liquefied natural gas. The commitments principally relate to group subsidiaries based in Canada, Egypt, Singapore, United Kingdom and United States. We expect to fulfil these delivery commitments with production from our proved developed reserves and supplies from existing contracts, supplemented by market purchases as necessary.

Upstream analysis by region

Our upstream operations are set out below by geographical area, with associated significant events for 2019. 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 and production.

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

Our LNG supply activities are located in Abu Dhabi, Angola, Australia, Indonesia and Trinidad. In 2019 we marketed around 4.6 million tonnes of our LNG production to IST, which uses contractual rights to access import terminal capacity in the liquid markets of Italy (Rovigo), the Netherlands (Gate), Spain (Bilbao), the UK (the Isle of Grain) and the US (Cove Point), with the remainder marketed directly to customers or trading entities. LNG is supplied to customers into markets including Argentina, China, the Dominican Republic, European Union, India, Japan, Kuwait, Singapore, South Korea, Taiwan, Thailand and Turkey.

Europe

BP is active in the North Sea and the Norwegian Sea. In 2019 BP's production came from three key areas: the Shetland area comprising the Clair, Foinaven, and Schiehallion fields; the central area comprising the Andrew area, Culzean, ETAP, Kinnoull and Shearwater fields; and Norway, through our equity accounted 30% interest in Aker BP.

- In March 2019 a final investment decision was made on Seagull (BP 50%), a development tieback to ETAP in the central UK North Sea.
- In June BP confirmed the start-up of gas production from the Total operated Culzean field (BP 32%) in the central UK North Sea.
- Also in June, BP was awarded a new exploration licence in the 31st Offshore Licensing Round in the West of Shetland Area in the UK North Sea for one licence covering 10 blocks (BP 50% and operator).
- In October production started at the Equinor operated Johan Sverdrup field (Aker BP 11.57%).
- The Alligin field commenced production through the Glen Lyon facility in December 2019.
- Development of the Vorlich field continued with two wells successfully drilled during the year. Production is expected to commence in 2020.
- In January 2020 BP announced that it had agreed terms to sell its interests in the Andrew Area and non-operated interest in Shearwater to Premier Oil. The deal covers the Andrew, Arundel, Cyrus, Farragon and Kinnoull fields plus our interest in Shearwater. BP currently owns 62.75% of Andrew, 100% of Arundel, 100% of Cyrus, 50% of Farragon and 77.06% of Kinnoull. We have a 27.50% share in Shearwater. Under the terms of the agreement, Premier Oil will pay BP $625m. The transaction is expected to complete in 2020.

North America

Our upstream activities in North America are located in five areas: deepwater Gulf of Mexico, the Lower 48 states, Alaska, Canada and Mexico.

BP has around 290 lease blocks in the Gulf of Mexico and operates four production hubs.

- In February 2019 we announced the start-up of the Constellation project (BP 66.67%), operated by Anadarko.
- On 6 May BP announced the final investment decision for the Thunder Horse South Expansion Phase 2 in the US Gulf of Mexico (BP operator 75%, ExxonMobil 25%). This project will add two new subsea production units approximately two miles to the south of the existing Thunder Horse platform with two new production wells in the near term. Eventually eight wells will be drilled as part of the overall development, with first oil expected in 2021.
- In June BP confirmed the discovery of King Embayment in the Mars corridor, in the US Gulf of Mexico (BP 28.5%).
- BP participated in two lease sales in 2019. In March we were awarded 23 leases in lease sale 252, and in August we were awarded 21 leases in lease sale 253.
- We have interests in three Paleogene fields: Tiber, Guadalupe, and Kaskida. Over the next few years we will be running subsurface work to better understand and define the concept development for these fields. BP has history with the development of technology required to develop such high pressure, deepwater fields and will continue to connect with the market to understand the options we will have available for the development of these fields.

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

BPX Energy, BP's onshore oil and gas business in the Lower 48 states, has significant operated and non-operated activities across Colorado, Louisiana, New Mexico, Oklahoma, Texas and Wyoming producing natural gas, oil, NGLs and condensate, with primary focus on developing unconventional resources in Texas. It had a 1.5 billion boe proved reserve base at 31 December 2019, predominantly in unconventional reservoirs (tight gas, shale gas and coalbed methane, and newly acquired shale oil). This resource spans 3.4 million net developed acres and has approximately 10,000 operated gross wells, with daily net production around 500mboe/d.

BPX Energy operates as a separate business while remaining part of our Upstream segment. With its own governance, systems and processes, it is structured to increase competitive performance through swift decision making and innovation, while maintaining BP's commitment to safe, reliable and compliant operations.

- On 1 March BPX Energy assumed physical control of all Petrohawk Energy Corporation operations from BHP following acquisition of these assets in 2018. BPX is making progress towards its goal of achieving $400 million of annual synergies by 2021, when integration is completed. BPX surpassed the 2019 savings estimate of $90m, delivering $240m in the first year after the acquisition.
- In November 2019 BPX Energy confirmed agreements to sell its oil and gas interests in the San Juan basin in Colorado and New Mexico and the Arkoma basin in Oklahoma. These disposals completed in March 2020. Additionally, in December 2019 BPX Energy completed divestments in certain fields within the Anadarko basin in Oklahoma and Texas and the Haynesville basin in Texas. Primarily as a result of the divestment program of heritage assets, BPX Energy incurred $4.7 billion in impairment charges. Proceeds of $642 million were received in 2019, including performance deposits for the disposals that closed in 2020.

BP's onshore US crude oil and product pipelines and related transportation assets are included in the Downstream segment.

In Alaska, BP Exploration (Alaska) Inc. (BPXA) operated nine North Slope oilfields in the Greater Prudhoe Bay area at the end of the year. BP owns significant interests in three producing fields operated by others, as well as a non-operating interest in the Liberty development project.

BP Pipelines (Alaska) Inc. (BPPA) owns a 49% interest in the Trans-Alaska Pipeline System (TAPS). TAPS transports crude oil from Prudhoe Bay on the Alaska North Slope to the port of Valdez in southcentral Alaska. In April 2012 Unocal (1.37%) gave notice to the other TAPS owners of their intention to withdraw as an owner of TAPS. The remaining Owners and Unocal reached agreement in mid-2019 to settle ongoing litigation and transfer Unocal's interest in TAPS to the other owners. The Parties are seeking regulatory approval at the state and federal level.

- On 27 August BP announced an agreement to sell the entirety of interests in its Alaska operations to Hilcorp Energy, including upstream and midstream businesses, for a headline price of $5.6

billion. BP will retain decommissioning liabilities associated with TAPS as part of the transaction. Subject to regulatory approval, the transaction is expected to complete in 2020. As part of this transaction BP recognized impairments of circa $1 billion in 2019.

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

- In July the government of Canada issued an order prohibiting any work or activity authorized under the Canada Oil and Gas Operations Act on frontier lands that are situated in Canadian Arctic offshore waters. This includes the Beaufort Sea. The order will remain in effect until 31 December 2021. BP currently holds an intangible balance of $64 million related to two blocks operated by others in this area.

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

- Following approval from Comisión Nacional de Hidrocarburos (CNH), the Mexican regulator, of the exploration plans for both Salina Basin operations in March 2018, seismic interpretation and well planning activities continued in 2019. These activities are expected to ramp up in 2020 with tentative plans to commence drilling in the first half of 2021.
- The Sureste Basin operation received exploration plan approval in July 2019 from CNH. Seismic licensing and reprocessing activities were initiated in 2019 and are expected to continue in 2020 with plans for drilling to commence in 2022.
- In November we signed a swap agreement with Equinor covering our interests in Blocks 1 and 3 in the Salina Basin. Subject to receipt of Government approvals expected in the second half of 2020, BP's interests are expected to be 56.67% in Block 1 and 10% in Block 3.

South America

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

In Brazil BP has interests in 26 exploration concessions across five basins.

- In the North Campos basin BP is now formally the operator of BM-C-30 and BM-C-32 blocks following Anadarko's withdrawal from both blocks and the transfer of their interest. The Brazilian National Petroleum Agency (ANP) approved the joint venture's request for a postponement of declaration of commerciality.
- In the Foz de Amazonas basin Total as operator of blocks FZA-M-57, 86, 88, 125 and 127 is analysing the next steps following IBAMA's license denial. The Foz do Amazonas blocks are eligible for a 2-year license extension according to Resolution 708, the deadline to request such extension is May 2020 for the Total-operated blocks. In the BP-operated block FZA-M-59, the extension deadline is March 2020, environmental licensing process is ongoing and the extension has been requested. All blocks may also be subject to further extensions should ANP agree.
- In the South Campos basin ANP approved a revised plan of appraisal for the BM-C-35 block. The agreement includes a commitment to drill an exploratory well in 2021 with a deadline to declare commerciality or end the appraisal period by 1 March 2022.
- In the Pau Brasil block the consortium group is undertaking seismic reprocessing to aid in subsurface description.
- In the Potiguar basin blocks ANP approved the consortium's request to modify the appraisal plan timelines.
- In October, in the 16th bid round, BP was awarded exploration and production rights to block C-M-477 offshore Brazil in the Campos Basin (BP 30%) and to block S-M-1500 (BP 100%) in the Santos Basin.

PAEG, a joint venture that is owned by BP (50%) and Bridas Corporation (50%), has activities mainly in Argentina and Mexico, but is also present in Uruguay and Bolivia.

During the second quarter, BP achieved new access in Argentina's first offshore licensing round blocks, obtaining the CAN-111 and CAN-113 blocks (BP 50%).

In Trinidad & Tobago BP holds interests in exploration and production licences and production-sharing contracts★(PSCs) covering 1.6 million acres offshore of the east and north-east coast. Facilities include 15 offshore platforms and two onshore processing facilities. Production comprises gas and associated liquids.

BP also holds interests in the Atlantic LNG facility. BP's shareholding averages 39% across four LNG trains★ with a combined capacity of approximately 15 million tonnes per annum. We sell gas to trains 1, 2 and 3 and process gas in train 4. Most of the LNG produced from BP gas supplied to trains 2, 3 and 4 is sold to third parties under long-term contracts. BP sells approximately one third of its gas production to the National Gas Company who supply the volumes into the petrochemical, power and other industrial markets. The remainder BP sells to third parties under long-term contracts.

- Production started at the Angelin project (BP 100% and operator) in February 2019.
- BP confirmed the following hydrocarbon discoveries during the year: Bélé-1 in April, Tuk-1 in May, Hi-Hat-1 in June, Boom-1 in September, and Ginger in November, all located offshore Trinidad and Tobago (BP 30%).
- The initial gas sales and LNG offtake arrangements for Atlantic LNG Train 1 ended in September 2018 and gas is currently sold into Train 1 on a short-term basis with BP lifting the majority of the LNG produced. The Train 1 gas supply arrangements are under discussion for the period April 2020 onwards.
- BP is operator of the Manakin Block which was discovered in 1998 and is a cross border reservoir field with the Venezuelan reservoir, Cocuina. Manakin declared commerciality in January 2018 however cross border commercial agreements have not progressed due to the impact of US sanctions.

Africa

BP's upstream activities in Africa are located in Algeria, Angola, Côte d'Ivoire, Egypt, The Gambia, Libya, Madagascar, Mauritania, São Tomé & Príncipe and Senegal.

In Algeria BP, Sonatrach and Equinor are partners in the In Salah (BP 33.15%) and In Amenas (BP 45.89%) non-operated joint ventures that supply gas to the domestic and European markets.

In Angola, BP owns an interest in five major deepwater offshore licences and is operator in two of these, Blocks 18 and 31, that are producing. We also have an equity interest in the Angola LNG plant (BP 13.6%).

- On 6 June BP announced an agreement to extend the production-sharing agreement★(PSA) for Block 15 to 2032 and to provide for Sonangol to take a 10% equity interest in the Block. The transaction completed on 27 January 2020.
- Development progressed at the Total-operated Zinia 2 deep offshore development project in Block 17 (BP 16.67%). At the end of 2019 construction activities were underway, with first production expected in 2021.
- Development progressed at the Platina project in Block 18, with construction activities expected to commence in 2020 and first production expected in 2021.
- In November BP agreed to join the New Gas Consortium (NGC), subject to completion of certain conditions precedent. This will be the first upstream natural gas partnership in Angola and will be operated by ENI (BP 11.8%).

- In December the Total-operated Block 17 contractor group signed an agreement with the national agency ANPG (Agência Nacional de Petróleo, Gás e Biocombustíveis) and Sonangol, to extend all Block 17 production licenses up to 2045, subject to Government approval. As part of the extension agreement, Sonangol will become a 5% holder in Block 17 from 2020 with an additional 5% interest from 2036.

In Côte d'Ivoire, BP has interests in five offshore oil blocks with Kosmos Energy (KE) under agreements with the government of Côte d'Ivoire and the state oil company Société Nationale d'Operations Pétrolières de la Côte d'Ivoire (PETROCI) (BP 45%). Seismic reprocessing and interpretation are ongoing and are expected to be completed by the end of 2020.

In Egypt, BP and its partners currently produce 60% of Egypt's gas production.

- In February 2019 production started at the Giza and Fayoum fields in the West Nile Delta development (BP 82.75%).
- In March 2019 BP confirmed a gas discovery, in the ENI operated Nour North Sinai offshore prospect (BP 25%) in the Egyptian Eastern Mediterranean. Technical studies are currently being progressed by the operator.
- In June BP announced an agreement to sell its interests in Gulf of Suez oil concessions in Egypt, including BP's interest in the Gulf of Suez Production Company (GUPCO), to Dragon Oil. The agreement, completed in October 2019.
- In September BP confirmed the start-up of the offshore Baltim South West gas field in Egypt (BP 50%).
- Work continues at the West Nile Delta Raven project, which is mechanically complete and currently addressing issues identified during commissioning. Start up is now expected in the second half of 2020.

In the Gambia, BP has a 90% interest in offshore block A1 with the state oil company, Gambia National Petroleum Corporation. An exploration well is expected to be drilled during the first two years of the licence.

In Libya, BP partners with the Libyan Investment Authority (LIA) in an exploration and production-sharing agreement (EPSA) to explore acreage in the onshore Ghadames and offshore Sirt basins (BP 85%). BP wrote off all balances associated with the Libya EPSA in 2015.

- BP, LIA and Eni continue to work with the NOC towards Eni acquiring a 42.5% interest in the BP-operated EPSA in Libya. On completion, Eni would become operator of the EPSA. The companies are continuing to work together to finalize and complete all agreements.

In Mauritania and Senegal, BP has a 62% participating interest in the C6, C8, C12 and C13 exploration blocks in Mauritania and a 60% participating interest in the Cayar Profond Offshore and St Louis Profond Ofshore exploration blocks in Senegal. Together these blocks cover approximately 24,300 square kilometres. BP also had a 15% interest in the Total operated C18 exploration block until exit in May 2019. For the Greater Tortue Ahmeyin (GTA) Unit across the border of Mauritania and Senegal, BP has 56% participating interest. The Phase 1 Execute activity has continued to ramp up following the exploitation license grant on 20th February 2019.

- In July BP confirmed that the GTA-1 (BP 56% and operator) appraisal well, located offshore Senegal, encountered approximately 30 metres of net gas pay in high-quality Albian reservoir confirming gas resource expectations.
- In September BP confirmed the Yakaar-2 appraisal well in the Cayar Profond block (BP 60% and Operator), located offshore Senegal, encountered approximately 22 metres of net gas pay in the reservoir confirming gas resource.
- In December BP confirmed the successful result of the Orca-1 appraisal well located in block C8 (BP 62% and operator) in the Bir Allah appraisal area offshore Mauritania. The well successfully encountered all five of the gas sands originally targeted. The well was then further deepened to reach an additional target, which also encountered gas.

In Madagascar, BP has interest in four PSCs for exploration licences situated offshore northwest Madagascar, under agreements with the government of Madagascar represented by Office des Mines Nationales et des Industries Stratégiques (OMNIS) (BP 100%). A baseline monitoring survey is underway as part of Phase 1 of the exploration period.

In São Tomé & Príncipe, BP is operator in two offshore blocks under PSAs with KE and the state oil company Agencia Nacional do Petroleo (BP 50%). Following the acquisition and analysis of baseline environmental data, seismic acquisition is ongoing and expected to be completed by mid-2020.

Asia

BP has activities in Abu Dhabi, Azerbaijan, China, India, Iraq, Kuwait, Oman and Russia.

In China we have a 30% equity stake in the Guangdong LNG regasification terminal and trunkline project with a total storage capacity of 640,000 cubic metres. The project is supplied under a long-term contract with Australia's North West Shelf venture (BP 16.67%).

- In the first quarter of 2019 BP relinquished its interest in its two PSCs for shale gas exploration, development and production in the Neijiang-Dazu block and Rong Chang Bei block in the Sichuan basin, resulting in a $141m exploration write-off. Exit was fully completed in the fourth quarter of 2019 when a termination agreement was formally executed with CNPC.

In Azerbaijan, BP operates two PSAs, Azeri-Chirag-Gunashli (ACG) (BP 30.37%) and Shah Deniz (BP 28.83%) and also holds a number of other exploration leases.

- Naftiran Intertrade Co Ltd (NICO), a subsidiary of the National Iranian Oil Company, holds a 10% interest in the Shah Deniz joint venture. For information on the exclusion of this project from EU and US trade sanctions, or exemptions from such trade sanctions in relation to this project, see International trade sanctions on page 320.
- In April a final investment decision was made on the Azeri Central East (ACE) project, the next stage of the Azeri-Chirag-Deepwater Gunashli (ACG) field. The $6 billion development includes a new offshore platform and facilities designed to process up to 100,000 barrels of oil per day. The project is expected to achieve first production in 2023.

BP holds a 30.1% interest in and operates the Baku-Tbilisi-Ceyhan oil pipeline. The 1,768-kilometre pipeline transports oil from the BP-operated ACG oilfield and gas condensate from the Shah Deniz gas field in the Caspian Sea, along with other third-party oil, to the eastern Mediterranean port of Ceyhan. The pipeline has a capacity of 1mmboe/d, with an average throughput in 2019 of 643mboe/d.

BP (as operator of Azerbaijan International Operating Company) also operates the Western Route Export Pipeline that transports ACG oil to Supsa on the Black Sea coast of Georgia, with an average throughput of 76mboe/d in 2019.

BP is technical operator of, and currently holds a 28.83% interest in, the 693 kilometre South Caucasus Pipeline. The pipeline takes gas from Azerbaijan through Georgia to the Turkish border and has a capacity of 440mboe/d (including expansion), with average throughput in 2019 of 177mboe/d.

BP also holds a 12% interest in the Trans Anatolian Natural Gas Pipeline. In the first phase, which commenced in 2018, gas from Shah Deniz is transported from Georgia to Eskishehir in Turkey. The capacity of the pipeline during the first phase is 100mboe/d and the average throughput in 2019 was 47mboe/d. The second phase will take gas from Eskishehir to the connection with the Trans Adriatic Pipeline (TAP) in Greece. BP has a 20% interest in TAP, that will take gas through Greece and Albania into Italy.

In Oman BP operates the Khazzan field in Block 61 (BP 60%).

- Progress on the Ghazeer project, phase two of the Khazzan development, is on track for first gas in 2021.

- In July BP and Eni signed an EPSA for Block 77 (BP 50%) in central Oman with the Ministry of Oil and Gas of the Sultanate of Oman. Approval by Royal Decree is still pending.

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 6 million tonnes of LNG (0.786bcfed regasified) in 2019. Our interest in the ADNOC Onshore concession expires at the end of 2054.

- In March 2019 ADNOC and ADNOC LNG agreed to extend the gas supply agreement to 2040. The new agreement took effect from 1 April 2019, and replaced an existing agreement which expired on 31 March 2019.
- Also in March 2019 ADNOC LNG and NGSCO agreed to extend the transportation agreements and the shipping services agreement to 2022. The new agreements took effect from 1 April 2019, and replaced an existing agreement which expired on 31 March 2019.

In 2016 BP signed an enhanced technical service agreement for south and east Kuwait conventional oilfields, which includes the Burgan field, with Kuwait Oil Company. Target performance for the 2018-19 plan was delivered and implementation of the 2019-20 plan is underway.

In India we have a participating interest in two oil and gas PSAs (KG D6 33.33% and NEC25 33.33%), one oil and gas block under a Revenue Sharing Contract (KG-UDWHP-2018/1), all operated by Reliance Industries Limited (RIL). We also have a stake in a 50:50 joint venture (India Gas Solutions Private Limited) with RIL for the sourcing and marketing of gas in India.

- In June BP and RIL announced the sanction of the MJ gas development project (also known as D55) in Block KG D6, offshore the east coast of India. MJ is the third of three new projects in the Block KG D6 integrated development plan.
- All three KG D6 Projects (R-Series, Satellites Cluster and MJ) are under development with first gas production phased over 2020-2022. R-Series, the first of the three projects, is expected to begin production in 2020.
- BP and its partner RIL have been awarded the ultra deep-water Block KG-UDWHP-2018/1 (RIL operator 60%, BP 40%) adjacent to Block KG D6 in India's Open Acreage Licensing Policy round 2 and both RIL and BP have entered into a Revenue Sharing Contract with the Government of India (GoI).
- Pursuant to government approval, Niko (NECO) Limited's 10% participating interest in Block KG D6 has been assigned to BP and RIL proportionately in the ratio of their existing interests (RIL 6.67%, BP 3.33%), in compliance with the PSC and JOA requirements.

In Iraq BP holds a 47.6% working interest and is the lead contractor in the Rumaila technical service contract in southern Iraq. The technical services contract runs to December 2034. Rumaila is one of the world's largest oil fields, comprising five producing reservoirs. BP's activities have not been materially impacted by the continued political instability and public protests which have occurred in 2019.

In Russia in addition to its 19.75% equity interest in Rosneft, BP holds a 20% interest in Taas-Yuryakh Neftegazodobycha (Taas) together with Rosneft (50.1%) and a consortium comprising Oil India Limited, Indian Oil Corporation Limited and Bharat PetroResources Limited (29.9%). Taas is developing the Srednebotuobinskoye oil and gas condensate field in East Siberia. Also with Rosneft, we hold a 49% interest in Kharampurneftegaz LLC (Kharampur) to develop subsoil resources within the Kharampurskoe and Festivalnoye licence areas in Yamalo-Nenets. Rosneft (51%) and BP (49%) jointly own Yermak Neftegaz LLC (Yermak), which conducts onshore exploration in the West Siberian and Yenisei-Khatanga basins and currently holds five exploration and production licences. See Rosneft on page 61 for further details.

- In April the right to explore two additional oil and gas licence areas located in Sakha (Yakutia) was transferred to a Yermak wholly owned subsidiary.

Australasia

BP has activities in Australia and Eastern Indonesia.

In Australia BP is one of seven participants in the North West Shelf (NWS) venture, which has been producing LNG, pipeline gas, condensate, LPG and oil since the 1980s. Six partners (including BP) hold an equal 16.67% interest in the gas infrastructure and an equal 15.78% interest in the gas and condensate reserves, with a seventh partner owning the remaining 5.32%. BP also has a 16.67% interest in some of the NWS oil reserves and related infrastructure. The NWS venture is currently the largest single source supplier to the domestic market in Western Australia and one of the largest LNG export projects in the region, with five LNG trains in operation. BP's net share of the capacity of NWS LNG trains 1-5 is 2.7 million tonnes of LNG per year.

BP is also one of five participants in the Browse LNG venture (operated by Woodside) and holds a 17.33% interest.

- The Browse joint venture participants are progressing the development of Browse by connecting it via a 900km pipeline to the NWS Venture's Karratha Gas Plant. A final investment decision is expected in late 2021.
- During the second quarter BP achieved new access with a farm-in to an exploration permit WA-359-P offshore Western Australia (BP 42.5% and operator).
- In September BP confirmed the award of the WA-541 acreage permit in Western Australia's offshore Northern Carnarvon basin (BP 50%).

In Papua Barat, Eastern Indonesia, BP operates the Tangguh LNG plant (BP 40.22%). The asset currently comprises 16 producing wells, two offshore platforms, two pipelines and an LNG plant with two production trains. It has a total capacity of 7.6 million tonnes of LNG per annum. Tangguh supplies LNG to customers in Indonesia, Mexico, China, South Korea, and Japan through a combination of long, medium and short-term contracts.

The Tangguh expansion project comprises a third LNG processing train, two offshore platforms, 13 new production wells, an expanded LNG loading facility, and supporting infrastructure. The project will add 3.8 million tonnes per annum (mtpa) of production capacity to the existing facility, bringing total plant capacity to 11.4mtpa. The installation of offshore platforms and pipelines has completed while the multi-year drilling campaign continues after the completion of the first production well. The construction of the LNG processing train is in progress with expected start-up in 2021.

Downstream plant capacity

The following table[a] summarizes BP group's interests in refineries and average daily crude distillation capacities as at 31 December 2019.

Fuels value chain	Country	Refinery	Crude distillation capacities[bc] Group interest[d] (%)	BP share thousand barrels per day
US				
US North West	US	Cherry Point	100	251
US East of Rockies		Whiting	100	440
		Toledo	50	80
				771
Europe				
Rhine	Germany	Gelsenkirchen	100	265
		Lingen	100	97
	Netherlands	Rotterdam	100	387
Iberia	Spain	Castellón	100	110
				859
Rest of world				
Australia	Australia	Kwinana	100	152
New Zealand	New Zealand	Whangarei[ef]	10.1	34
Southern Africa	South Africa	Durban[e]	50	90
				276
Total BP share of capacity at 31 December 2019				1,906

[a] This does not include BP's interest in Pan American Energy Group.
[b] Crude distillation capacity is gross rated capacity, which is defined as the highest average sustained unit rate for a consecutive 30-day period under normal operational conditions.
[c] On 31 December 2019 we completed the sale of our interest in the German Bayernoil refinery.
[d] BP share of equity, which is not necessarily the same as BP share of processing entitlements.
[e] Indicates refineries not operated by BP.
[f] Reflects BP share of processing entitlement, which is not the same as BP share of equity.

Petrochemicals production capacity[a]

The following table summarizes BP group's share of petrochemicals production capacities as at 31 December 2019.

			BP share of capacity thousand tonnes per annum[b]				
							Product
Geographical area	Site	Group interest[c] (%)	PTA	PX	Acetic acid	Olefins and derivatives	Others
US							
	Cooper River	100	1,400	—	—	—	—
	Texas City[d]	100	—	900	600	—	100
			1,400	900	600	—	100
Europe							
UK	Hull	100	—	—	500	—	200
Belgium	Geel	100	1,400	700	—	—	—
Germany	Gelsenkirchen[e]	100	—	—	—	3,300	—
	Mülheim[e]	100	—	—	—	—	200
			1,400	700	500	3,300	400
Rest of world							
Trinidad & Tobago	Point Lisas	36.9	—	—	—	—	700
China	Chongqing	51	—	—	200	—	100
	Nanjing	50	—	—	300	—	—
	Zhuhai[f]	91.9	2,500	—	—	—	—
Indonesia	Merak	100	500	—	—	—	—
South Korea	Ulsan[g]	34-51	—	—	300	—	100
Malaysia	Kertih	70	—	—	400	—	—
Taiwan	Mai Liao	50	—	—	200	—	—
	Taichung	61.4	500	—	—	—	—
			3,500	—	1,400	—	900
			6,300	1,600	2,500	3,300	1,400
Total BP share of capacity at 31 December 2019							15,100

[a] Petrochemicals production capacity is the proven maximum sustainable daily rate (MSDR) multiplied by the number of days in the respective period, where MSDR is the highest average daily rate ever achieved over a sustained period.
[b] Capacities are shown to the nearest hundred thousand tonnes per annum.
[c] Includes BP share of non-operated equity-accounted entities, as indicated.
[d] For acetic acid, group interest is quoted at 100%, reflecting the capacity entitlement which is marketed by BP.
[e] Due to the integrated nature of these plants with our Gelsenkirchen refinery, the income and expenditure of these plants is managed and reported through the fuels business.
[f] BP Zhuhai Chemical Company Ltd is a subsidiary★of BP, the capacity of which is shown above at 100%.
[g] Group interest varies by product.

Oil and gas disclosures for the group

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 2019 BP had material volumes of proved undeveloped reserves held for more than five years in Russia, Trinidad, Gulf of Mexico and the North Sea. These are part of ongoing infrastructure-led development activities for which BP has a historical track record of completing comparable projects in these countries. We have no proved undeveloped reserves held for more than five years in our onshore US developments.

In each case the volumes are being progressed as part of an adopted development plan where there are physical limits to the development timing such as infrastructure limitations, contractual limits including gas delivery commitments, late life compression and the complex nature of working in remote locations, or where there are significant commitments on delivery to the relevant authority.

Over the past five years, BP has annually progressed a weighted average 19% (19% for 2018 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 less than five and a half years. We expect the turnover time to remain near this level and anticipate the volume of proved undeveloped reserves held for more than five years to remain about the same.

Proved reserves as estimated at the end of 2019 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 2019 we progressed 1,328mmboe of proved undeveloped reserves (561mmboe for our subsidiaries★ alone) to proved developed reserves through ongoing investment in our subsidiaries' and equity-accounted entities' upstream development activities. Total development expenditure, excluding midstream activities, was $15,206 million in 2019 ($10,815 million for subsidiaries and $4,391 million for equity-accounted entities). The major areas with progressed volumes in 2019 were Russia, US, Trinidad, Egypt, Azerbaijan, Argentina, Oman and UAE. Revisions of previous estimates for proved undeveloped reserves are due to changes relating to field performance, well results or changes in commercial conditions including price impacts. There were material net negative revisions in the US Lower 48 due to reducing price impacts and changes in our development plan to incorporate activity associated with the purchase of new assets partially offset by material net positive revisions to our proved undeveloped resources in Russia as a result of development drilling results. The following tables describe the changes to our proved undeveloped reserves position through the year for our subsidiaries and equity-accounted entities and for our subsidiaries alone.

Subsidiaries and equity-accounted entities	volumes in mmboe[a]
Proved undeveloped reserves at 1 January 2019	8,908
Revisions of previous estimates	(320)
Improved recovery	316
Discoveries and extensions	563
Purchases	17
Sales	(35)
Total in year proved undeveloped reserves changes	541
Proved developed reserves reclassified as undeveloped	31
Progressed to proved developed reserves by development activities (e.g. drilling/completion)	(1,328)
Proved undeveloped reserves at 31 December 2019	8,152

Subsidiaries only	volumes in mmboe[a]
Proved undeveloped reserves at 1 January 2019	4,447
Revisions of previous estimates	(545)
Improved recovery	309
Discoveries and extensions	130
Purchases	10
Sales	(29)
Total in year proved undeveloped reserves changes	(127)
Proved developed reserves reclassified as undeveloped	13
Progressed to proved developed reserves by development activities (e.g. drilling/completion)	(561)
Proved undeveloped reserves at 31 December 2019	3,771

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

BP bases its proved reserves estimates on the requirement of reasonable certainty with rigorous technical and commercial assessments based on conventional industry practice and regulatory requirements. BP only applies technologies that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. BP applies high-resolution seismic data for the identification of reservoir extent and fluid contacts only where there is an overwhelming track record of success in its local application. In certain cases BP uses numerical simulation as part of a holistic assessment of recovery factor for its fields, where these simulations have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. In certain deepwater fields BP has booked proved reserves before production flow tests are conducted, in part because of the significant safety, cost and environmental implications of conducting these tests. The industry has made substantial technological improvements in understanding, measuring and delineating reservoir properties without the need for flow tests. To determine reasonable certainty of commercial recovery, BP employs a general method of reserves assessment that relies on the integration of three types of data:

- well data used to assess the local characteristics and conditions of reservoirs and fluids
- field scale seismic data to allow the interpolation and extrapolation of these characteristics outside the immediate area of the local well control
- data from relevant analogous fields.

Well data includes appraisal wells or sidetrack holes, full logging suites, core data and fluid samples. BP considers the integration of this data in certain cases to be superior to a flow test in providing understanding of overall reservoir performance. The collection of data from logs, cores, wireline formation testers, pressures and fluid samples calibrated to each other and to the seismic data can allow reservoir properties to be determined over a greater volume than the localized volume of investigation associated with a short-term flow test. There is a strong track record of proved reserves recorded using these methods, validated by actual production levels.

Governance

BP's centrally controlled process for proved reserves estimation approval forms part of a holistic and integrated system of internal control. It consists of the following elements:

- Accountabilities of certain officers of the group to ensure that there is review and approval of proved reserves bookings independent of the operating business and that there are effective controls in the approval process and verification that the proved reserves estimates and the related financial impacts are reported in a timely manner.
- Capital allocation processes, whereby delegated authority is exercised to commit to capital projects that are consistent with the delivery of the group's business plan. A formal review process exists to ensure that both technical and commercial criteria are met prior to the commitment of capital to projects.
- Group audit, whose role is to consider whether the group's system of internal control is adequately designed and operating effectively to respond appropriately to the risks that are significant to BP.
- Approval hierarchy, whereby proved reserves changes above certain threshold volumes require immediate review and all proved reserves require annual central authorization and have scheduled periodic reviews. The frequency of periodic review ensures that 100% of the BP proved reserves base undergoes central review every three years.

BP's vice president of segment reserves is the petroleum engineer primarily responsible for overseeing the preparation of the reserves estimate. He has more than 35 years of diversified industry experience, with 14 years spent managing the governance and compliance of BP's reserves estimation. He is a past member of the Society of Petroleum Engineers Oil and Gas Reserves Committee and of the American Association of Petroleum Geologists Committee on Resource Evaluation and is the current chair of the bureau of the United Nations Economic Commission for Europe Expert Group on Resource Management.

No specific portion of compensation bonuses for senior management is directly related to proved reserves targets. Additions to proved reserves is one of several indicators by which the performance of the Upstream segment is assessed by the remuneration committee for the purposes of determining compensation bonuses for the executive directors. Other indicators include a number of financial and operational measures.

BP's variable pay programme for the other senior managers in the Upstream segment is based on individual performance contracts. Individual performance contracts are based on agreed items from the business performance plan, one of which, if chosen, could relate to proved reserves.

Compliance

International Financial Reporting Standards (IFRS) do not provide specific guidance on reserves disclosures. BP estimates proved reserves in accordance with SEC Rule 4-10 (a) of Regulation S-X and relevant Compliance and Disclosure Interpretations (C&DI) and Staff Accounting Bulletins as issued by the SEC staff.

By their nature, there is always some risk involved in the ultimate development and production of proved reserves including, but not limited to: final regulatory approval; the installation of new or additional infrastructure, as well as changes in oil and gas prices; changes in operating and development costs; and the continued availability of additional development capital. All the group's proved reserves held in subsidiaries and equity-accounted entities are estimated by the group's petroleum engineers or by independent petroleum engineering consulting firms and then assured by the group's petroleum engineers.

DeGolyer & MacNaughton (D&M), an independent petroleum engineering consulting firm, has estimated the net proved crude oil, condensate, natural gas liquids (NGLs) and natural gas reserves, as of 31 December 2019, of certain properties owned by Rosneft as part of our equity-accounted proved reserves. The properties evaluated by D&M account for 100% of Rosneft's net proved reserves as of 31 December 2019. The net proved reserves estimates prepared by D&M were prepared in accordance with the reserves definitions of Rule 4-10(a)(1)-(32) of Regulation S-X. All reserves estimates involve some degree of uncertainty. BP has filed D&M's independent report on its reserves estimates as an exhibit to this Annual Report on Form 20-F filed with the SEC.

Netherland, Sewell & Associates (NSAI), an independent petroleum engineering consulting firm, has estimated the net proved crude oil, condensate, natural gas liquids (NGLs) and natural gas reserves, as of 31 December 2019, 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 2019. The net proved reserves estimates prepared by NSAI were prepared in accordance with the reserves definitions of Rule 4-10(a)(1)-(32) of Regulation S-X. All reserves estimates involve some degree of uncertainty. BP has filed NSAI's independent report on its reserves estimates as an exhibit to this Annual Report on Form 20-F filed with the SEC.

Our proved reserves are associated with both concessions (tax and royalty arrangements) and agreements where the group is exposed to the upstream risks and rewards of ownership, but where our entitlement to the hydrocarbons★ is calculated using a more complex formula, such as with PSAs. In a concession, the consortium of which we are a part is entitled to the proved reserves that can be produced over the licence period, which may be the life of the field. In a PSA, we are entitled to recover volumes that equate to costs incurred to develop and produce the proved reserves and an agreed share of the remaining volumes or the economic equivalent. As part of our entitlement is driven by the monetary amount of costs to be recovered, price fluctuations will have an impact on both production volumes and reserves.

We disclose our share of proved reserves held in equity-accounted entities (joint ventures★ and associates★), although we do not control these entities or the assets held by such entities.

BP's estimated net proved reserves and proved reserves replacement

91% of our total proved reserves of subsidiaries at 31 December 2019 were held through joint operations★(89% in 2018), and 28% of the proved reserves were held through such joint operations where we were not the operator (34% in 2018).

Estimated net proved reserves of crude oil at 31 December 2019[a b c]

	Developed	Undeveloped	Total
			million barrels
UK	206	200	406
US[d]	1,063	842	1,905
Rest of North America[e]	40	179	218
South America[f]	7	5	12
Africa	156	40	196
Rest of Asia	1,074	525	1,599
Australasia	26	4	30
Subsidiaries	2,572	1,794	4,367
Equity-accounted entities	3,567	2,847	6,415
Total	6,140	4,642	10,781

Estimated net proved reserves of natural gas liquids at 31 December 2019[a b]

	Developed	Undeveloped	Total
			million barrels
UK	8	5	13
US	229	250	479
Rest of North America	—	—	—
South America	2	21	23
Africa	12	4	16
Rest of Asia	—	—	—
Australasia	4	—	4
Subsidiaries	255	280	535
Equity-accounted entities	107	55	162
Total	363	334	697

Estimated net proved reserves of liquids★

	Developed	Undeveloped	Total
			million barrels
Subsidiaries[f]	2,828	2,074	4,902
Equity-accounted entities[g]	3,675	2,902	6,576
Total	6,502	4,976	11,478

Estimated net proved reserves of natural gas at 31 December 2019[a b]

	Developed	Undeveloped	Total
			billion cubic feet
UK	493	207	700
US	6,330	2,127	8,458
Rest of North America	—	—	—
South America[h]	2,192	2,235	4,427
Africa	1,163	742	1,905
Rest of Asia	3,667	3,401	7,068
Australasia	2,256	1,132	3,389
Subsidiaries	16,101	9,844	25,946
Equity-accounted entities[i]	11,079	8,576	19,656
Total	27,181	18,421	45,601

Estimated net proved reserves on an oil equivalent basis[j]

	Developed	Undeveloped	Total
			million barrels of oil equivalent
Subsidiaries	5,604	3,771	9,375
Equity-accounted entities	5,585	4,381	9,965
Total	11,189	8,152	19,341

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently, 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 2019 marker prices used were Brent★ $62.74/bbl (2018 $71.43/bbl and 2017 $54.36/bbl) and Henry Hub★ $2.58/mmBtu (2018 $3.10/mmBtu and 2017 $2.96/mmBtu).

[c] Includes condensate.

[d] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 4.5 million barrels on which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

[e] All of the reserves in Canada are bitumen.

[f] Includes 11 million barrels of liquids in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[g] Includes 357 million barrels of liquids in respect of the non-controlling interest in Rosneft held assets in Russia including 26 million barrels held through BP's interests in Russia other than Rosneft.

[h] Includes 1,330 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[i] Includes 1,430 billion cubic feet of natural gas in respect of the non-controlling interest in Rosneft held assets in Russia including 569 billion cubic feet held through BP's interests in Russia other than Rosneft.

[j] Includes 982 million barrels of oil equivalent associated with Assets held for sale in the US.

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 2019, on an oil equivalent basis including equity-accounted entities, decreased by 3% (decrease of 8% for subsidiaries and increase of 2% for equity-accounted entities) compared with 31 December 2018. Natural gas represented about 41% (48% for subsidiaries and 34% for equity-accounted entities) of these reserves. The change includes a net decrease from acquisitions and disposals of 133mmboe (decrease of 134mmboe within our subsidiaries and increase of 1mmboe within our equity-accounted entities). Acquisition activity in our subsidiaries occurred in India, and divestment activity in our subsidiaries in the US and Egypt. There were no material acquisitions or divestments in our equity-accounted entities.

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 2019, the proved reserves replacement ratio excluding acquisitions and disposals was 67% (100% in 2018 and 143% in 2017) for subsidiaries and equity-accounted entities, 25% for subsidiaries alone and 141% for equity-accounted entities alone. There was a net decrease (221mmboe) of reserves due to lower gas and oil prices mainly within the US Lower 48 (-206mmboe). The total loss was partly offset by increases in reserves in our PSAs, principally in Azerbaijan, Iraq and Angola.

In 2019 net additions to the group's proved reserves (excluding production and sales and purchases of reserves-in-place) amounted to 939mmboe (230mmboe for subsidiaries and 709mmboe for equity-accounted entities), through revisions to previous estimates, improved recovery from, and extensions to, existing fields and discoveries of new fields. The subsidiary additions were through improved recovery from, and extensions to, existing fields and discoveries of new fields where they represented a mixture of proved developed and proved undeveloped reserves. Volumes added in 2019 principally resulted from the application of conventional technologies and extensions of field size by development drilling. The principal proved reserves additions in our subsidiaries by region were in the US, Oman, UAE, Azerbaijan and India. We had material reductions in our proved reserves in US Lower 48 principally due to lower oil and gas prices. The principal reserves additions in our equity-accounted entities were in Pan American Energy Group, Rosneft and Kharampurneftegaz LLC.

15% of our proved reserves are associated with PSAs. The countries in which we produced under PSAs in 2019 were Algeria, Angola, Azerbaijan, Egypt, India, Indonesia and Oman. In addition, the technical service contract (TSC) governing our investment in the Rumaila field in Iraq functions as a PSA.

The group holds no licences due to expire within the next three years that would have a significant impact on BP's reserves or production. BP holds reserves classified as Assets held for sale within the US associated with our announced divestment of our Alaska and San Juan fields.

For further information on our reserves see page 239.

BP's net production by country – crude oil[a] and natural gas liquids

thousand barrels per day

BP net share of production[b]

	Crude oil			Natural gas liquids		
	2019	2018	2017	**2019**	2018	2017
Subsidiaries						
UK[c d]	**100**	101	80	**3**	5	6
Total Europe	**100**	101	80	**3**	5	6
Alaska[c]	**71**	106	109	**—**	—	—
Lower 48 onshore[c]	**66**	18	10	**58**	37	34
Gulf of Mexico deepwater	**263**	261	251	**24**	23	21
Total US	**400**	385	370	**81**	60	56
Canada[e]	**24**	24	20	**—**	—	—
Total Rest of North America	**24**	24	20	**—**	—	—
Total North America	**424**	408	390	**81**	60	56
Trinidad & Tobago[c]	**7**	7	12	**9**	9	10
Total South America	**7**	7	12	**9**	9	10
Angola	**115**	147	192	**—**	—	—
Egypt[c]	**34**	49	40	**—**	—	—
Algeria	**7**	9	9	**8**	11	10
Total Africa	**156**	204	241	**8**	11	10
Abu Dhabi[c]	**180**	169	158	**—**	—	—
Azerbaijan	**79**	72	90	**—**	—	—
Iraq	**64**	54	73	**—**	—	—
India	**—**	—	1	**—**	—	—
Oman	**20**	17	2	**—**	—	—
Total Rest of Asia	**343**	313	325	**—**	—	—
Total Asia	**343**	313	325	**—**	—	—
Australia[c]	**15**	16	15	**2**	2	2
Eastern Indonesia[c]	**2**	2	1	**—**	—	—
Total Australasia	**17**	17	17	**2**	2	2
Total subsidiaries	**1,046**	1,051	1,064	**104**	88	85
Equity-accounted entities (BP share)						
Rosneft (Russia, Canada, Venezuela, Vietnam)	**920**	919	900	**3**	4	4
Abu Dhabi	**—**	16	99	**—**	—	—
Argentina[c]	**54**	52	60	**1**	—	—
Bolivia[c]	**2**	3	3	**—**	—	—
Egypt	**—**	—	—	**3**	3	2
Norway[c]	**35**	34	31	**2**	2	2
Russia[c]	**35**	14	5	**—**	—	—
Angola	**1**	1	1	**5**	3	4
Other	**—**	—	—	**—**	—	—
Total equity-accounted entities	**1,047**	1,040	1,099	**14**	12	12
Total subsidiaries and equity-accounted entities[f]	**2,093**	2,091	2,163	**118**	100	97

[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 2019, BP completed the sale of its interest in the Gulf of Suez Petroleum Company (GUPCO) in Egypt and certain US assets in Lower 48 onshore and disposed of its interests in the Gulf of Mexico Santiago and Santa Cruz wells. In 2018, BP acquired various interests in the Permian Basin, Eagle Ford and Haynesville Shales in Lower 48 onshore as a result of the acquisition of BHP's US unconventional assets, increased its interest in the Clair asset in the UK North Sea, and acquired an interest in LLC Kharampurneftegaz in Russia, and in certain US offshore assets. It also disposed of its interests in the Greater Kuparuk Area in Alaska, the Magnus field in the UK North Sea, and in certain other assets in the UK North Sea and US onshore assets. In 2017, BP renewed its onshore concession of the United Arab Emirates that grants BP 10% interest in ADCO onshore concession. It also decreased its interest in Magnus field in North Sea and completed the formation of Pan American Energy Group (PAEG) (BP 50%, Bridas Corporation 50%), which is a combination of Pan American Energy and Axion Energy with an effective decrease in interest.

[d] Volumes relate to six BP-operated fields within ETAP. BP has no interests in the remaining three ETAP fields, which are operated by Shell.

[e] All of the production from Canada in Subsidiaries is bitumen.

[f] Includes 3 net mboe/d of NGLs from processing plants in which BP has an interest (2018 3mboe/d and 2017 3mboe/d).

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

BP's net production by country – natural gas

			million cubic feet per day
			BP net share of production[a]
	2019	2018	2017
Subsidiaries			
UK[b]	**129**	152	182
Total Europe	**129**	152	182
Lower 48 onshore[b]	**2,175**	1,705	1,467
Gulf of Mexico deepwater	**179**	190	186
Alaska	**4**	5	5
Total US	**2,358**	1,900	1,659
Canada	**2**	7	9
Total Rest of North America	**2**	7	9
Total North America	**2,361**	1,907	1,667
Trinidad & Tobago[b]	**1,977**	2,136	1,936
Total South America	**1,977**	2,136	1,936
Egypt[b]	**952**	878	745
Algeria	**186**	183	205
Total Africa	**1,138**	1,061	949
Azerbaijan	**367**	256	232
India	**15**	32	60
Oman	**594**	538	79
Total Rest of Asia	**976**	826	371
Total Asia	**976**	826	371
Australia[b]	**411**	437	426
Eastern Indonesia[b]	**375**	382	357
Total Australasia	**786**	819	783
Total subsidiaries[c]	**7,366**	6,900	5,889
Equity-accounted entities (BP share)			
Rosneft (Russia, Canada, Egypt, Venezuela, Vietnam)	**1,279**	1,286	1,308
Argentina	**250**	264	329
Bolivia	**64**	71	89
Norway[b]	**56**	59	53
Angola	**87**	80	77
Western Indonesia	**—**	—	—
Total equity-accounted entities[c]	**1,736**	1,760	1,855
Total subsidiaries and equity-accounted entities	**9,102**	8,659	7,744

[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 2019, BP completed the sale of its interest in the Gulf of Suez Petroleum Company (GUPCO) in Egypt and certain US assets in Lower 48 onshore and disposed of its interests in the Gulf of Mexico Santiago and Santa Cruz wells. In 2018, BP acquired various interests in the Permian Basin, Eagle Ford and Haynesville Shales in Lower 48 onshore as a result of the acquisition of BHP's US unconventional assets, increased its interest in the Clair asset in the UK North Sea, and acquired an interest in LLC Kharampurneftegaz in Russia, and in certain US offshore assets. It also disposed of its interests in the Greater Kuparuk Area in Alaska, the Magnus field in the UK North Sea, and in certain other assets in the UK North Sea and US onshore assets. In 2017, BP decreased its interest in Magnus field in North Sea and completed the formation of Pan American Energy Group (PAEG) (BP 50%, Bridas Corporation 50%), which is a combination of Pan American Energy and Axion Energy with an effective decrease in interest.

[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.

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

The following tables provide additional data and disclosures in relation to our oil and gas operations.

Average sales price per unit of production (realizations★)[a]

$ per unit of production

	Europe		North America		South America	Africa	Asia		Australasia	Total group average
	UK	Rest of Europe	US	Rest of North America[b]			Russia	Rest of Asia		
Subsidiaries										
2019										
Crude oil[c]	**65.44**	**—**	**59.19**	**40.92**	**63.30**	**63.75**	**—**	**64.39**	**59.65**	**61.56**
Natural gas liquids	**29.58**	**—**	**14.67**	**—**	**25.86**	**31.89**	**—**	**—**	**38.11**	**18.23**
Gas	**4.01**	**—**	**1.93**	**—**	**2.78**	**4.59**	**—**	**3.99**	**6.86**	**3.39**
2018										
Crude oil[c]	71.28	—	67.11	33.57	69.17	68.81	—	70.80	67.54	67.81
Natural gas liquids	31.63	—	25.81	—	35.74	39.14	—	92.47	52.14	29.42
Gas	7.71	—	2.43	—	3.08	4.82	—	3.85	7.97	3.92
2017										
Crude oil[c]	53.67	—	49.98	36.80	55.44	53.61	—	52.88	53.26	51.71
Natural gas liquids	32.77	—	22.42	—	26.79	36.48	—	—	39.39	26.00
Gas	5.09	—	2.36	—	2.25	3.82	—	3.44	6.14	3.19
Equity-accounted entities[d]										
2019										
Crude oil[c]	**—**	**64.75**	**—**	**—**	**56.85**	**—**	**57.00**	**—**	**—**	**57.36**
Natural gas liquids[e]	**—**	**—**	**—**	**—**	**18.14**	**—**	**N/A**	**—**	**—**	**20.40**
Gas	**—**	**5.01**	**—**	**—**	**3.98**	**—**	**1.83**	**—**	**—**	**3.39**
2018										
Crude oil[c]	—	70.24	—	—	62.35	—	62.46	39.49	—	62.24
Natural gas liquids[e]	—	—	—	—	—	—	N/A	—	—	—
Gas	—	7.93	—	—	4.36	—	1.70	—	—	2.50
2017										
Crude oil[c]	—	55.08	—	—	49.97	—	45.66	15.61	—	42.33
Natural gas liquids[e]	—	—	—	—	—	—	N/A	—	—	—
Gas	—	5.78	—	—	4.49	—	1.63	—	—	2.47

Average production cost per unit of production[f]

$ per unit of production

	Europe		North America		South America	Africa	Asia		Australasia	Total group average
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
2019	**13.22**	**—**	**8.46**	**13.36**	**3.36**	**7.95**	**—**	**5.15**	**2.33**	**6.84**
2018	13.76	—	9.63	13.10	3.08	7.31	—	5.72	2.35	7.15
2017	14.58	—	8.68	15.02	4.41	6.47	—	6.37	2.79	7.11
Equity-accounted entities										
2019	**—**	**12.51**	**—**	**—**	**11.50**	**10.40**	**3.07**	**—**	**—**	**5.13**
2018	—	12.15	—	—	10.61	—	3.09	5.92	—	4.16
2017	—	10.33	—	—	11.92	—	3.19	3.27	—	4.32

[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] All of the production from Canada in Subsidiaries is bitumen.

[c] Includes condensate.

[d] In certain countries it is common for equity-accounted entities' agreements to include pricing clauses that require selling a significant portion of the entitled production to local governments or markets at discounted prices.

[e] Natural gas liquids for Russia are included in crude oil.

[f] Units of production are barrels for liquids and thousands of cubic feet for gas. Amounts do not include ad valorem and severance taxes.

Environmental expenditure

	2019	2018	2017
			$ million
Operating expenditure	**511**	501	441
Capital expenditure	**468**	449	487
Clean-ups	**23**	31	22
Additions to environmental remediation provision	**272**	428	249
Increase (decrease) in decommissioning provision	**1,045**	137	(228)

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 $511 million in 2019 (2018 $501 million) showed an overall increase of 2%, with increases in Upstream costs (due in large part to increases in expenditure associated with the acquisitions of BHP assets into BPX Energy) largely balanced out by slight reductions in costs for Downstream and Shipping.

Environmental capital expenditure in 2019 was slightly higher overall than in 2018 largely due to increased costs in Upstream, due in large part to increases in expenditure associated with the acquisitions of BHP assets into BPX Energy.

Clean-up costs were $23 million in 2019 (2018 $31 million) representing oil spill clean-up costs and other associated remediation and disposal costs. The reduction compared to 2018 results largely from the downstream business where clean-up costs in BP Pipelines (North America) were significantly lower than in 2018.

In addition to operating and capital expenditure, we also establish provisions for future environmental remediation work. Expenditure against such provisions normally occurs in subsequent periods and is not included in environmental operating expenditure reported for such periods.

Provisions for environmental remediation are made when a clean-up is probable and the amount of the obligation can be reliably estimated. Generally, this coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The extent and cost of future environmental restoration, remediation and abatement programmes are inherently difficult to estimate. They often depend on the extent of contamination, and the associated impact and timing of the corrective actions required, technological feasibility and BP's share of liability. Though the costs of future programmes could be significant and may be material to the results of operations in the period in which they are recognized, it is not expected that such costs will be material to the group's overall results of operations or financial position.

Additions to our environmental remediation provision was similar to prior years and also reflects scope reassessments of the remediation plans of a number of our sites in the US and Canada. The charge for environmental remediation provisions in 2019 included $9 million in respect of provisions for new sites (2018 $8 million and 2017 $8 million).

In addition, we make provisions on installation of our oil and gas producing assets and related pipelines to meet the cost of eventual decommissioning. On installation of an oil or natural gas production facility, a provision is established that represents the discounted value of the expected future cost of decommissioning the asset.

In 2019, the net increase in the decommissioning provision was due to a change in the discount rate and a detailed reviews of expected future costs.

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

BP's activities are subject to a broad range of EU, US, international, national, regional, and local legislation and regulations, including legislation that implements international conventions and protocols. These cover virtually all aspects of BP's activities and include matters such as licence acquisition, production rates, royalties, environmental, health and safety protection, fuel specifications and transportation, trading, pricing, anti-trust, export, taxes, and foreign exchange.

Following the UK's exit from the European Union on 31 January 2020, the UK has now entered a transition period which, unless extended, is due to run until 31 December 2020. During the transition period, most EU law will continue to apply to the UK and therefore to BP's UK business during that period. The vast majority of environment-related statutory instruments passed by the UK Government in anticipation of Brexit have included no substantive changes to the current EU underlying regime, but rather seek to make the amendments required to allow their continued operation after the transition period. The UK Government's Environment Bill and 25 Year Plan will be central to the UK's environmental regime going forward but further changes are as yet uncertain. The following section describes EU laws and regulations relevant to our business both in the UK and the EU.

Upstream 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 US government entities are usually by lease. Arrangements with private property owners are also usually in the form of leases.

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. Both exploration and production licences are generally for a specified period of time. In the US, leases from the US government typically remain in effect for a specified term, but may be extended beyond that term as long as there is production in paying quantities. The term of BP's licences and the extent to which these licences may be renewed vary from country to country.

PSAs entered into with a government entity or state-owned or controlled company generally require BP (alone or with other contracting companies) to provide all the financing and bear the risk of exploration and production activities in exchange for a share of the production remaining after royalties, if any. Less typically, BP may explore for, develop and produce hydrocarbons under a service agreement with the host entity in exchange for reimbursement of costs and/or a fee paid in cash rather than production.

BP frequently conducts its exploration and production activities in joint arrangements or co-ownership arrangements with other international oil companies, state-owned or controlled companies and/or private companies. These joint arrangements may be incorporated or unincorporated arrangements, while the co-ownerships are typically unincorporated. Whether incorporated or unincorporated, relevant agreements set out each party's level of participation or ownership interest in the joint arrangement or co-ownership. 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 these agreed ownership interests. Ownership of joint arrangement or co-owned property and hydrocarbons to which the joint arrangement or co-ownership is entitled is also shared in these proportions. To the extent that any liabilities arise, whether to governments or third parties, or as between the joint arrangement parties or co-owners themselves, each joint arrangement party or co-owner will generally be liable to meet these in proportion to its ownership interest. In many upstream operations, a party (known as the operator) will be appointed (pursuant to a joint operating agreement) to carry out day-to-day operations on behalf of the joint arrangement or co-ownership. The operator is typically one of the joint arrangement parties or a co-owner and will carry out its duties either through its own staff, or by contracting out various elements to third-party contractors or service providers. BP acts as operator on behalf of joint arrangements and co-ownerships in a number of countries.

Frequently, work (including drilling and related activities) will be contracted out to third-party service providers. The relevant contract will specify the work, the remuneration, and typically the risk allocation between the parties. Depending on the service to be provided, the contract may also contain provisions allocating risks and liabilities associated with pollution and environmental damage, damage to a well or hydrocarbon reservoirs and for claims from third parties or other losses. The allocation of those risks vary among contracts and are determined through negotiation between the parties.

In general, BP incurs income tax on income generated from production activities (whether under a licence or PSA). In addition, depending on the area, BP's production activities may be subject to a range of other taxes, levies and assessments, including special petroleum taxes and revenue taxes. The taxes imposed on oil and gas production profits and activities may be substantially higher than those imposed on other activities, for example in Abu Dhabi, Angola, Egypt, Norway, the UK, the US, Russia and Trinidad & Tobago.

Greenhouse gas regulation

In December 2015, nearly 200 nations at the United Nations climate change conference in Paris (COP21) agreed the Paris Agreement, for implementation post-2020. The Paris Agreement 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. There is no quantitative long-term emissions goal. However, countries 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 by sources and removals by sinks of GHGs in the second half of this century. The Paris Agreement commits all parties 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. Developed country NDCs should include absolute emission reduction targets, and developing countries are encouraged to move towards absolute emission reduction targets over time. The Paris Agreement places binding commitments on countries to report on their emissions and progress made on their NDCs and to undergo international review of collective progress. It also requires countries to submit revised NDCs every five years, which are expected to be more ambitious with each revision. Global assessments of progress will occur every five years, starting in 2023. On 1 June 2017, the US announced that it will withdraw from the Paris Agreement. The process for withdrawal can be completed no earlier than 4 November 2020.

Recent annual United Nations climate change conferences have established a 'Paris Rulebook' defining how some elements of the Paris Agreement will be implemented. Rules for implementing Article 6, which could enable international carbon trading to assist in meeting NDCs, have not been agreed. This has now been deferred to COP26 to take place in Glasgow, Scotland in November 2020.

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. Current and announced measures and developments potentially affecting BP's businesses include the following:

United States

In the US, BP's operations are affected by GHG regulation in a number of ways. The federal Clean Air Act (CAA), for example, regulates air emissions, permitting, fuel specifications and other aspects of our production, refining, distribution and marketing activities.

Environmental Protection Agency (EPA) regulations aimed at limiting methane emissions from new and modified sources in the oil and natural gas sector in the US by 40-45% from 2012 levels by 2025 were introduced by the Obama administration. In August 2019, however, the EPA issued a new proposed rule to that would both rescind certain methane regulations and potentially remove storage and transmission facilities from the regulatory scheme. In addition, the Bureau of Land Management (BLM) in 2018 issued a new waste prevention rule which rescinded the prior 2017 rule regarding methane regulation on federal lands. The EPA rule and the new BLM rule are being challenged by states and NGOs. The final outcome of the rule revisions and legal challenges with respect to these EPA and BLM rules is uncertain.

In 2019, the EPA issued the final Affordable Clean Energy (ACE) Rule, which is intended to address GHG emissions from certain existing sources in the electricity sector, and which is intended to replace the Obama-administration's Clean Power Plan (CPP). A number of lawsuits have been filed regarding the legality of the ACE Rule and the repeal of the CPP regulations. The outcome with respect to these rules may affect electricity generation practices and prices, reliability of electricity supply, and regulatory requirements affecting other GHG emission sources in other sectors and have potential impacts on combined heat and power installations.

The Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007 impose the Renewable Fuel Standard (RFS), requiring transportation fuel sold in the United States to contain a minimum volume of renewable fuels. Certain state initiatives impose lower GHG emissions thresholds for transportation fuels (e.g., in California and Oregon). In 2019, EPA promulgated regulations easing volatility requirements for certain categories of gasoline and revising certain elements of the RFS credit-trading programme, which is the open market for renewables credit trading.

The GHG mandatory reporting rule (GHGMRR), requires annual GHG emissions reports to be filed with the EPA. In addition to direct emissions from affected facilities, producers and importers/exporters of petroleum products, certain natural gas liquids and GHG products are required to report product volumes and notional GHG emissions as if these products were fully combusted.

A number of states, municipalities and regional organizations have responded to current and proposed federal changes easing environmental regulation with separate initiatives that affect our US operations. For example, the California cap and trade programme started in January 2012 and expanded to cover emissions from transportation fuels in 2015. The State of Washington has adopted a carbon cap rule although the state's supreme court has modified the rule to exclude coverage of sales and distribution of petroleum fuels.

Our US businesses are subject to increased GHG and other environmental requirements and regulatory uncertainty, including that future US administrations could revise or revoke current administration programs, as well as increased expenditures in having to comply with numerous diverse and non-uniform regulatory initiatives at the state and local level.

European Union

- The EU has adopted various measures seeking to reduce GHG emissions and encourage renewables. A set of regulatory measures were adopted which included: a collective national reduction target for emissions not covered by the EU Emissions Trading System (EU ETS) Directive; binding national renewable energy targets (including targets in the transport sector) under the Renewable Energy Directive; and a legal framework to promote carbon capture and storage (CCS).

- In 2014 EU leaders adopted a climate and energy framework setting targets for the year 2030 including at least 40% cuts in GHG emissions from 1990 levels. The GHG reduction target is to be achieved by a 43% reduction of emissions from sectors covered by the EU ETS, and a 30% GHG reduction by Member States for all other GHG emissions. Measures to achieve the 2030 targets include a significant revision of the EU ETS for Phase 4 addressing surplus allowances and the amount of free allocation for sectors prone to international competition. In November 2018 a 32% share of renewable energy and a 32.5% increase in energy efficiency was agreed which must be met by EU Member States by 2030. It also sets a renewable energy target of 14% for the transportation sector.
- In December 2019 the European Commission proposed an ambitious 'European Green Deal'. These proposals will require formal approval by European Member States and include:
  - a climate neutrality commitment for 2050 and raising the 2030 ambition to at least 50% GHG reductions by 2030 from 1990 levels, up from the 40% currently agreed;
  - a proposal to enshrine the 2050 climate-neutrality target into legislation;
  - a plan to extend the Emissions Trading System to include the maritime sector and reduce the allowances allocated for free to airlines;
  - a proposal to implement a carbon border tax adjustment to protect European industry from carbon leakage; and
  - a review of the Energy Taxation Directive, with the aim of harmonising and directing energy taxation across the member states.
- The Medium Combustion Plants Directive 2015 (MCPD) regulates sulphur dioxide (SO2), nitrogen oxides (NOx) and particulates emissions and monitoring of carbon monoxide (CO) emissions from certain mid-size plants. It applies to new plants and by 2025 or 2030 to existing plants, depending on their size.
- The National Emission Ceilings Directive 2016 (NECD) introduces stricter emissions limits from 2020 and 2030, with new indicative national targets applying from 2025. NECD has been implemented in the UK by the National Emission Ceilings Regulations 2018. Each EU Member State was also required to produce a National Air Pollution Control Programme setting out the measures it will take to ensure compliance with the 2020 and 2030 reduction commitments.
- The EU Fuel Quality Directive affects our production and marketing of transport fuels. Revisions adopted in 2009 mandate reductions in the life cycle GHG emissions per unit of energy and tighter environmental fuel quality standards for petrol and diesel.
- In December 2019 the Dutch Supreme Court (De Hoge Raad) ruled that the Dutch Government must reduce gross GHG Emissions in the Netherlands by 25% based on 1990 levels. The Dutch Government is expected to publish its policy proposals to achieve the 25% target in early 2020.
- The German Government has passed a national emissions trading law that will in a first phase include limits on emissions from transport and heating fuels. Impacted fuel suppliers in Germany will pay a fixed price for emissions certificates of EUR 25 per tonne CO_2 in 2021 rising to EUR 55 per tonne by 2025. From 2026 emissions certificates will be auctioned but with prices limited between EUR 55 and EUR 65 per tonne CO_2 emitted.

Other

- Alberta Province has adopted large facility carbon emission regulations requiring reductions in carbon intensity year-on-year which can be met by improving emissions intensity, the purchase of offsets or payments into a provincial emissions technology fund. Emissions not covered under these regulations are subject to escalating Federal carbon emissions backstop pricing. Additional requirements are in place relating to electricity generation sources and limits on overall oil sands emissions.
- The Canadian federal climate change regulations include a national backstop carbon price starting at C$20/tonne in 2019 and escalating to C$50/tonne by 2022 (or equivalent system for provinces with cap-and-trade systems), with provincial implementation of the price and associated large emitters pricing system, use of any funds generated, and outcome reporting. Newfoundland & Labrador and Nova Scotia have implemented regulations that meet equivalency requirements of the Federal regulations via economy wide carbon taxes on fuels and large emitter programs (intensity based for Newfoundland & Labrador and cap and trade for Nova Scotia).
- China is operating emission trading pilot programmes in five cities and three provinces. One of BP's subsidiaries and one of BP's joint venture companies in China are participating in these schemes. China launched its national emissions trading market (initially covering the power sector only) politically in 2017 with a three-step roadmap ("National ETS"). The National ETS will not supersede the above eight pilot programmes immediately but allow those pilot schemes to be incorporated into the national scheme gradually. In the short term, the existing pilot schemes are expected to operate in parallel covering the non-power sectors. In March 2018, the new Ministry of Ecology and Environment was established as part of the overall ministerial restructuring which absorbs the climate change responsibilities previously under the National Development and Reform Commission and takes charge of the development of the National ETS. As of December 2019, the National ETS is still at the first phase (infrastructure development phase) and preparing for the second phase (simulation trading phase).
- China has also adopted more stringent vehicle tailpipe emission standards and vehicle efficiency standards to address air pollution and GHG emissions. These standards will have an impact on transportation fuel product mix and overall demand. In addition, China has also introduced a mandate for sales of new energy vehicles (NEVs) commencing in 2020. This has been accelerating NEV penetration into the light vehicle sector and impact light fuel demand.

For information on the steps that BP is taking in relation to climate change issues and for details of BP's GHG reporting, see Sustainability – Environment on page 40.

Other environmental regulation

Current and proposed fuel and product specifications, emission controls (including control of vehicle emissions), 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 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 314 and for a discussion of legal proceedings, see page 319.

A significant proportion of our fixed assets are located in the US and the EU. US and EU environmental, health and safety regulations significantly affect BP's operations. Significant legislation and regulation in the US and the EU affecting our businesses and profitability include the following:

United States

- The Trump administration has issued a number of Executive Orders affecting federal permitting and rulemaking processes that seek to reduce regulatory burdens placed on manufacturing generally and the energy industry specifically. It is not clear how much or how quickly these regulatory requirements will be reduced given statutory and rulemaking constraints and the likely legal challenges to some of these initiatives which can result in regulatory uncertainty and compliance challenges for our operations.
- The National Environmental Policy Act (NEPA) requires an environmental analysis prior to undertaking any major federal action that significantly affects the environment, which includes the issuance of federal permits. The environmental reviews required by NEPA can delay, modify or block projects. State law analogues to NEPA could also limit or delay our projects. The Trump administration has taken steps to significantly modify and streamline the NEPA review process for major infrastructure projects including energy production, pipeline and transmission systems. The timing and effect on our operations remain uncertain and any final rule is likely to face legal challenges.
- As discussed above under 'Greenhouse gas regulation', US fuel markets are affected by EPA regulation of light, medium and heavy duty vehicle emissions (both fuel economy and tailpipe standards) as well as for non-road engines and vehicles and certain large GHG stationary emission sources. California also imposes Low Emission Vehicle (LEV) and Zero Emission Vehicle (ZEV) standards on vehicle manufacturers and a number of other states, as allowed by CAA authority, have adopted standards identical to California's standards. These regulations may impact fuel demand and product mix in California and those states adopting LEV and ZEV standards and may impact BP's product mix and demand for particular products. The Trump administration has challenged California's authority to impose stricter vehicle emission standards, which are followed by numerous other states, and the outcome of this challenge remains uncertain.
- In 2018 the Trump administration proposed rolling back the Obama administration's fuel economy and tailpipe carbon dioxide emissions standards for passenger cars and light trucks covering model years (MY) 2021 through 2026 by locking in the 2020 standards until 2026. It has also proposed eliminating the waiver allowing California to set its own LEV and ZEV standards and for other states to adopt standards identical to California. In September 2019, NHTSA and EPA issued part one of One National Program for fuel economy regulation by announcing EPA's decision to withdraw California's waiver of pre-emption for its LEV and ZEV standards and finalizing the Department of Transportation's regulatory text relating to pre-emption of state fuel economy standards. California and twenty-five states and cities filed a lawsuit challenging those regulations. The outcome of that litigation is uncertain.
- In January 2020, EPA issued an Advance Notice of Proposed Rule (ANPR) soliciting pre-proposal comments on a rulemaking known as the Cleaner Trucks Initiative. The rule would establish new emission standards for oxides of nitrogen (NOx) and other pollutants for highway heavy-duty engines. It would seek to streamline and improve certification procedures to reduce costs for engine manufacturers. California is also working on tighter heavy-duty engine NOx standards. EPA has not notified fuels suppliers of any expected fuel specification changes that would be included with these new engine standards and BP continues to monitor this rule for implications for fuels.
- The Clean Water Act regulates wastewater and other effluent discharges from BP's facilities, and BP is required to obtain discharge permits, install control equipment and implement operational controls and preventative measures.
- The Resource Conservation and Recovery Act regulates the generation, storage, transportation and disposal of wastes associated with our operations and can require corrective action at locations where such wastes have been disposed of or released.
- 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 other federal and state laws which also require notification of spills to designated government agencies.
- The Emergency Planning and Community Right-to-Know Act requires reporting on the storage, use and releases of certain quantities of listed hazardous substances to designated government agencies.
- The Toxic Substances Control Act (TSCA) regulates BP's manufacture, import, export, sale and use of chemical substances and products. In addition, EPA has revised processes and procedures for 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. Thus far, two substances have been identified for specific ongoing monitoring of developments and impacts.
- The Occupational Safety and Health Act imposes workplace safety and health requirements on BP operations along with significant process safety management obligations (PSM), requiring continuous evaluation and improvement of operational practices to enhance safety and reduce workplace emissions at gas processing, refining and other regulated facilities. The US Occupational Safety and Health Administration (OSHA) conducts inspections under the National Emphasis Program to ensure compliance with PSM requirements in both refineries and chemical plants.
- The Oil Pollution Act 1990 (OPA) imposes operational requirements, liability standards and other obligations governing the transportation of petroleum products in US waters. States may impose additional obligations. Alaska and the West Coast states currently have the most demanding state requirements.
- The Outer Continental Shelf Land Act, the MLA and other statutes give the Department of Interior (DOI) and the BLM authority to regulate operations and air emissions, including equipment and testing, on offshore and onshore operations on federal lands subject to DOI authority.
- The Endangered Species Act 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. With an increasing number of species being protected, we have experienced increasing restrictions on our activities.

European Union

- The Industrial Emissions Directive (IED) 2010 provides the framework for granting permits for major industrial sites. It lays down rules on integrated prevention and control of air, water and soil pollution arising from industrial activities. As part of the IED framework, additional emission limit values are informed by sector specific and cross-sector Best Available Technology (BAT) Conclusions. These include the BAT Conclusions for the refining sector, for large combustion plants as well as common wastewater and waste gas treatment and management systems in the chemical sector these may require BP to further reduce its emissions, particularly its air and water emissions.
- The EU regulation on ozone depleting substances 2009 (ODS Regulation) requires companies to reduce the use of ozone depleting substances (ODSs) and phase out use of certain ODSs.

BP continues to replace ODSs in refrigerants and/or equipment in the EU and elsewhere, in accordance with the Montreal Protocol and related legislation. The Kigali Amendment to the Montreal Protocol (which aims to reduce hydrofluorocarbons) came into force on 1 January 2019. In addition, the EU regulation on fluorinated GHGs with high global warming potential (the F-gas Regulations) require a phase-out of certain hydrofluorocarbons, based on global warming potential.

- European regulations also establish passenger car performance standards for CO2 tailpipe emissions (European Regulation (EC) No 443/2009). By 2021, the European passenger fleet emissions target for new vehicles will be 95 grams of CO2 per kilometre. This target will be achieved by manufacturing fuel efficient vehicles and vehicles using alternative, low carbon fuels such as hydrogen and electricity. In addition, vehicle emission test cycles and vehicle type approval procedures are being updated to improve accuracy of emission and efficiency measurements. European vehicle CO2 emission regulations also impact the fuel efficiency of vans. By 2020, the EU fleet of newly registered vans must meet a target of 147 grams of CO2 per kilometre, which is 19% below the 2012 fleet average.
- In 2019, the European Parliament and the Council adopted Regulation (EU) 2019/631 setting CO2 emission performance standards for new passenger cars and for new light commercial vehicles (vans) in the EU for the period after 2020. From a 2021 baseline, it requires EU fleet-wide reductions of 15% by 2025 and 37.5% by 2030 for passenger cars, and 15% by 2025 and 31% by 2030 for new light commercial vehicles.
- The EU Registration, Evaluation Authorization and Restriction of Chemicals (REACH) Regulation 2006 requires registration of chemical substances manufactured in or imported into the EU, together with the submission of relevant hazard and risk data. REACH affects our manufacturing or trading/import operations in the EU. BP maintains compliance by checking whether imports are covered by the registrations of non-EU suppliers' representatives, preparing and submitting registration dossiers to cover new manufactured and imported substances, and updating previously submitted registrations as required. Some substances registered previously, including substances supplied to us by third parties for our use, are now subject to evaluation and review for potential authorization or restriction procedures, and possible banning, by the European Chemicals Agency and EU member state authorities. In addition, BP's facilities and operations in several EU countries continue to undergo REACH compliance inspections by the competent authority for the respective EU member state. An amendment to the Annex of the Regulation on classification, labelling and packaging of substances and mixture (CLP Regulation) requires harmonized notification of information on hazardous materials (certain lubricant and fuel formations) to EU member state poison centres. The uniform notification rules will apply as of January 2020 for consumer products, from 2021 for professional and 2024 for industrial uses.
- The EU Offshore Safety Directive was adopted in 2013. Its purpose is to introduce a harmonized regime aimed at reducing the potential environmental, health and safety impacts of the offshore oil and gas industry throughout EU waters. The Directive has been implemented in the UK primarily through the Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015.
- The Water Framework Directive (WFD) published in 2000 aims to protect the quantity and quality of ground and surface waters of the EU member states. The implementation in the EU member states is still ongoing, planned to be finalised by 2027. At the moment a Fitness Check (comprehensive policy evaluation) of the EU Water Legislation is ongoing, also covering the WFD and its daughter directives (Groundwater Directive and Environmental Quality Standards Directive). The outcome of the policy evaluation, expected to be published in 2020, may require additional compliance efforts and increased costs for managing freshwater withdrawals and discharges from BP's EU operations.

Other countries and regions

Turkey has published REACH-like regulations, known as KKDIK, as well as related implementation schedules and substance registrations.

Regulations governing the discharge of treated water have also been developed in countries outside of the US and EU. This includes regulations in Trinidad and Angola. In Trinidad, BP is upgrading its water treatment facilities to meet consent levels agreed with the regulators to apply water discharge rules arising from the Certificate of Environmental Clearance (CEC) Regulations 2001 and associated Water Pollution Rules 2007. In Angola, BP has upgraded produced water treatment systems to meet revised oil in water limits for produced water discharge under Executive Decree ED 97-14.

The Abidjan Convention, along with the Additional Protocol published in 2012, sets environmental quality standards for the discharge of chemicals to the marine environment. The convention and associated protocols has been ratified by 19 African nations including Senegal and Mauritania. BP is currently designing produced water management systems to meet the environmental quality standards for our future gas operations in Mauritania and Senegal.

Environmental maritime regulations

BP's shipping operations are subject to extensive national and international regulations governing liability, operations, training, spill prevention 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 liability, spill response and preparedness regulations under 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 2019, the HNS Convention had not entered into force.
- A global sulphur cap of 0.5% applies to marine fuel under MARPOL. In order to comply, ships will 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 new global cap will not alter the lower limits that apply in the sulphur oxides Emissions Control Areas established by the IMO.
- In December 2019 EPA finalized measures to facilitate smooth implementation of IMO 2020. EPA finalized technical corrections that will allow fuel suppliers to distribute distillate diesel fuel that complies with the 5,000 ppm international sulphur standard for ships instead of the fuel standards that otherwise apply to distillate diesel fuel in the United States. The EPA clarified that fuel meeting the 5,000 ppm global sulphur cap may not be used inside of Emission Control Area (ECA) boundaries.
- 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. OSPAR Recommendation 2001/1 regulates the management of produced water from offshore installations in the North Sea including reductions in the total quantity of oil in produced water and a performance standard for dispersed oil in produced water discharged into the sea. Guidelines for the implementation of a risk-based approach to the management of produced water discharges from offshore installations supports a key goal of achieving a reduction of oil in produced water discharged into the sea by 2020 to a level which

will adequately ensure that each of those discharges will present no harm to the marine environment.

To meet its financial responsibility requirements, BP Shipping maintains marine 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 will necessarily be adequately covered by insurance or that liabilities will not exceed insurance recoveries.

Legal proceedings

Proceedings relating to the Deepwater Horizon oil spill

Introduction

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

Many of the lawsuits in federal court relating to the Incident were consolidated into two multi-district litigation proceedings, one in federal district court in Houston for the securities cases (MDL 2185) and another in federal district court in New Orleans for the remaining cases (MDL 2179). A Plaintiffs' Steering Committee (PSC) was established to act on behalf of individual and business plaintiffs in MDL 2179. All federal and state governmental claims in relation to the Incident have now been settled or dismissed and the 2014 administrative agreement with the US Environmental Protection Agency and BP's obligations thereunder ended in March 2019. The remaining proceedings arising from the Incident are discussed below.

PSC settlements

PSC settlements – Economic and Property Damages Settlement Agreement

In 2012 the Economic and Property Damages Settlement was entered into with the PSC to resolve certain economic and property damage claims.

The economic and property damages claims process, which is under court supervision through the settlement claims process established by the Economic and Property Damages Settlement, continued in 2019. Only a very small number of business economic loss claims remain to be determined, although certain business economic loss claims continue to be appealed by BP and/or the claimants.

PSC settlements – Medical Benefits Class Action Settlement

In 2012 the Medical Benefits Class Action Settlement (Medical Settlement) was entered into with the PSC. It involves payments to qualifying class members based on a matrix for certain Specified Physical Conditions (SPCs), as well as a 21-year Periodic Medical Consultation Program (PMCP) for qualifying class members, and also includes provisions regarding class members pursuing claims for later-manifested physical conditions (LMPCs).

The deadline for submitting SPC and PMCP claims was 12 February 2015. A total of 37,226 claims have been submitted. As of 31 December 2019, 27,604 claims (comprising 22,831 SPC claims and 4,773 PMCP claims) have been approved for compensation totalling approximately $67 million; 9,621 claims have been denied; and 1 claim is pending determination.

In order to seek compensation from BP for an LMPC, class members must file a notice with the Medical Claims Administrator within 4 years after the date of first diagnosis of the LMPC. As of 31 December 2019, there were 2,701 pending lawsuits brought by class members claiming LMPCs.

Other civil complaints – economic loss

The vast majority of economic loss and property damage claims from individuals and businesses that either opted out of the 2012 PSC settlement and/or were excluded from that settlement have been settled or dismissed. On 19 July 2017 the district court held that maritime claims by 215 plaintiffs would be subject to further proceedings in MDL 2179 under OPA 90 and under general maritime law. Most of these have now been either settled or dismissed. On 5 February 2019, the district court issued a case management order addressing the 184 remaining plaintiffs in MDL 2179 with claims for economic loss or property damage. The district court ordered BP and 69 of those plaintiffs to undertake mandatory mediation and so far this has resulted in settlement of more than 40 plaintiffs' claims. The district court ordered that BP file any dispositive motions as to the other 115 plaintiffs (principally Mexican-resident plaintiffs who are fishermen or fishing cooperatives) by 7 March 2019. BP moved to dismiss those 115 claims on 7 March 2019, and its motion remains pending.

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 2012 PSC settlement and/or were excluded from that settlement have been dismissed.

In 2019, the district court in MDL 2179 determined in a series of proceedings that 923 plaintiffs had post-explosion clean-up, medical monitoring and personal injury claims that complied with the court's prior order to show cause why their claims should not be dismissed. Five plaintiffs have appealed their dismissal to the Fifth Circuit. Briefing is ongoing and oral argument and a decision are expected in 2020.

Individual securities litigation

Following court approval of the settlement of a securities class action brought on behalf of a class of post-explosion American depository share (ADS) holders in 2017, there remained individual cases filed in state and federal courts by pension funds, investment funds and advisers. These were against BP entities and several current and former officers and directors seeking damages for alleged losses those funds suffered because of their purchases and/or holdings of BP ordinary shares and, in certain cases, ADSs. The funds assert claims under English law and, for plaintiffs purchasing ADSs, federal securities law. All of the cases, with the exception of one case that has been stayed, were transferred to MDL 2185. As at 31 December 2019, 28 actions on behalf of 115 plaintiffs remained pending in MDL 2185. Pursuant to a scheduling order issued by the district court, fact and expert discovery with respect to 16 representative plaintiffs is scheduled to proceed through to August 2020 and dispositive motions are scheduled to be filed by 27 October 2020.

Canadian class actions

Following various legal proceedings, on 26 February 2016, a plaintiff seeking to assert claims under Canadian law against BP on behalf of a class of Canadian residents who allegedly suffered losses because of their purchase of BP ordinary shares and ADSs filed a motion in the Court of Appeal for Ontario to lift a stay on the action. The plaintiff's motion was granted on 29 July 2016. On 1 September 2017 the court granted in part and denied in part BP's motion for summary judgment, limiting the case to three alleged misstatements and narrowing the class period. On 3 April 2018, the Court of Appeal for Ontario affirmed that decision. On 24 June 2019, the plaintiff filed an amended complaint adding fraud claims. On 8 November 2019, the court granted BP's motion to dismiss the case in its entirety. On 6 December 2019, the plaintiff appealed that decision.

Non-US government lawsuits

On 18 October 2012, before a Mexican Federal District Court located in Mexico City, a class action complaint was filed against BP America Production Company (BPAPC) and other BP subsidiaries. The plaintiffs, who allegedly are fishermen, are seeking, among other things, compensatory damages for the class members who allegedly suffered economic losses, as well as an order requiring BP to remediate environmental damage resulting from the Incident, to provide funding for the preservation of the environment and to conduct environmental impact studies in the Gulf of Mexico for the next 10 years. On 27 June 2018, BP answered the complaint by seeking dismissal on various grounds including that no oil reached Mexican waters or land and there was no economic or environmental harm in Mexico.

On 3 December 2015 and 29 March 2016, Acciones Colectivas de Sinaloa (ACS) filed two class actions (which have since been consolidated) in a Mexican Federal District Court on behalf of several Mexican states against BPXP, BPAPC, and other purported BP subsidiaries. In these class actions, plaintiffs seek an order requiring the BP defendants to repair the damage to the Gulf of Mexico, to pay penalties, and to compensate plaintiffs for damage to property, to health and for economic loss. BPXP and BPAPC opposed class certification and sought dismissal, principally on the basis that no oil reached Mexican waters or land and there was no economic or environmental harm in Mexico. On 25 September 2019, the court certified the class. On 15 October 2019, BP appealed that decision.

Other legal proceedings

FERC and CFTC matters

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

Lead paint matters

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

Scharfstein v. BP West Coast Products, LLC

A class action lawsuit was filed against BP West Coast Products, LLC (BPWCP) in Oregon State Court under the Oregon Unlawful Trade Practices Act on behalf of customers who used a debit card at ARCO gasoline stations in Oregon during the period 1 January 2011 to 30 August 2013, alleging that ARCO sites in Oregon failed to provide sufficient notice of the 35 cents per transaction debit card fee. In January 2014, the jury rendered a verdict against BPWCP and awarded statutory damages of $200 per class member. On 25 August 2015, the trial court determined the size of the class to be slightly in excess of two million members. On 31 May 2016 the trial court entered a judgment against BPWCP for the amount of $417.3 million. On 31 May 2018 the Oregon Court of Appeals affirmed the trial court's ruling. In March 2019, BP and the Plaintiffs agreed to a settlement of the class action lawsuit, subject to final court approval. On 4 June 2019 the court granted final approval of the settlement agreement. The judgment dismissing the case was entered on 13 June 2019. No appeal was taken from the judgment on or before the 14 July 2019 deadline. On 15 July 2019, BP made its first payment under the terms of the settlement agreement. The second and final payment is due in July 2020.

Climate change

BP p.l.c., BP America Inc. and BP Products North America Inc. are co-defendants with other oil and gas companies in multiple lawsuits brought in various state courts on behalf of several US cities and counties, one state, and a crab fishing industry association. In the lawsuits, the plaintiffs generally plead a variety of legal theories seeking to hold the defendant companies responsible for impacts allegedly caused by and/or relating to climate change and claim damages. All of the cases remain at relatively early stages.

Louisiana Coastal restoration

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

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 three of these private landowner cases.

International trade sanctions

During the period covered by this report, non-US subsidiaries, or other non-US entities of BP, conducted limited activities in, or with persons from, certain countries identified by the US Department of State as State Sponsors of Terrorism or otherwise subject to US and EU sanctions (Sanctioned Countries). Sanctions restrictions continue to be insignificant to the group's financial condition and results of operations. BP monitors its activities with Sanctioned Countries, persons from Sanctioned Countries and individuals and companies subject to US and EU sanctions and seeks to comply with applicable sanctions laws and regulations.

BP has a 28.8% interest in and operates the Azerbaijan Shah Deniz field (Shah Deniz) and a related gas pipeline entity, South Caucasus Pipeline Company Limited (SCPC), and has a 23% non-operating interest in a related gas marketing entity, Azerbaijan Gas Supply Company Limited (AGSC). Naftiran Intertrade Co. Limited and NICO SPV Limited (collectively, NICO) have a 10% non-operating interest in each of Shah Deniz and SCPC and an 8% non-operating interest in AGSC. Shah Deniz, SCPC and AGSC continue in operation as they were excluded from the main operative provisions of the EU regulations as well as from the application of the 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 shall pay to BP Exploration Shah Deniz Limited (BPXSD), as the Shah Deniz Operator, an amount in respect of compensation for NICO's waiver of its right to lift its share of Shah Deniz condensate. Such amounts shall be used to cover cash calls to NICO in respect of operating costs due from NICO to BPXSD. On 27 November 2019, OFAC issued a new licence in relation to these arrangements.

Following the imposition in 2011 of further US and EU sanctions against Syria, BP terminated all sales of crude oil and petroleum products into Syria, though BP continues to supply aviation fuel to non-governmental Syrian resellers outside of Syria.

BP has a joint arrangement in Cuba which imports, manufactures, markets and sells lubricants.

During 2014 the US and the EU imposed sanctions on certain Russian activities, individuals and entities, including Rosneft. Certain sectoral sanctions also apply to entities in which entities on the relevant sectoral sanctions list own a certain percentage interest. In August 2017, Russia related sanctions were passed in the US which target among other things: (i) Russian energy export pipelines; (ii) privatisation of state owned assets in Russia; and (iii) certain international offshore Arctic, deepwater and/or shale exploration and production oil projects. We are not aware of any material adverse effect on our current income and investment in Russia or elsewhere as a consequence of those sanctions.

BP maintains bank accounts and has registered and paid required fees to maintain registrations of patents and trademarks in certain Sanctioned Countries.

BP has equity interests in non-operated joint arrangements with air fuel sellers, resellers, and fuel delivery services around the world. From time to time, the joint arrangement operator or other partners may sell or deliver fuel to airlines from Sanctioned Countries or flights to Sanctioned Countries, without BP's involvement.

BP has no control over the activities non-controlled associates may undertake in Sanctioned Countries or with persons from Sanctioned Countries.

Disclosure pursuant to ITRA Section 219

To our knowledge, none of BP's activities, transactions or dealings are required to be disclosed pursuant to ITRA Section 219.

Material contracts

On 4 April 2016 the district court approved the Consent Decree among BP Exploration & Production Inc., BP Corporation North America Inc., BP p.l.c., the United States and the states of Alabama, Florida, Louisiana, Mississippi and Texas (the Gulf states) which fully and finally resolved any and all natural resource damages (NRD) claims of the United States, the Gulf states, and their respective natural resource trustees and all Clean Water Act (CWA) penalty claims, and certain other claims of the United States and the Gulf states.

Concurrently, the definitive Settlement Agreement that BP entered into with the Gulf states (Settlement Agreement) with respect to State claims for economic, property and other losses became effective.

BP has filed the Consent Decree and the Settlement Agreement as exhibits to its Annual Report on Form 20-F 2019 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 2019 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 2019 to 3 March 2020.

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

BP has adopted a robust set of board governance principles, which reflect the UK Corporate Governance Code approach to corporate governance. As such, the way in which BP makes determinations of directors' independence differs from the NYSE rules.

BP's board governance principles require that all non-executive directors be determined by the board to be 'independent in character and judgement and free from any business or other relationship which could materially interfere with the exercise of their judgement'. The BP board has determined that, in its judgement, all of the non-executive directors are independent. In doing so, however, the board did not explicitly take into consideration the independence requirements outlined in the NYSE's listing standards.

Committees

BP has a number of board committees that are broadly comparable in purpose and composition to those required by NYSE rules for domestic US companies. For instance, BP has a chairman's (rather than executive) committee and remuneration (rather than compensation) committee. BP also has an audit committee, which NYSE rules require for both US companies and foreign private issuers. These committees are composed solely of non-executive directors whom the board has determined to be independent, in the manner described above.

The BP board governance principles prescribe the composition, main tasks and requirements of each of the committees (see the board committee reports on pages 90-99). BP has not, therefore, adopted separate charters for each committee but the board will focus on developing a new corporate governance framework as the successor to the BP governance principles. This framework will reinforce the effectiveness of the internal control framework and be more closely aligned with BP's new purpose and ambition.

Under US securities law and the listing standards of the NYSE, BP is required to have an audit committee that satisfies the requirements of Rule 10A-3 under the Exchange Act and Section 303A.06 of the NYSE Listed Company Manual. BP's audit committee complies with these requirements. The BP audit committee does not have direct responsibility for the appointment, reappointment or removal of the independent auditors. Instead, it follows the UK Companies Act 2006 and the UK Corporate Governance code 2018 by making recommendations to the board on these matters for it to put forward for shareholder approval at the AGM.

One of the NYSE's additional requirements for the audit committee states that at least one member of the audit committee is to have 'accounting or related financial management expertise'. The board determined that Brendan Nelson possesses such expertise and also possesses the financial and audit committee experiences set forth in both the UK Corporate Governance Code and SEC rules (see Audit committee report on page 91). Mr Nelson is the audit committee financial expert as defined in Item 16A of Form 20-F.

Shareholder approval of equity compensation plans

The NYSE rules for US companies require that shareholders must be given the opportunity to vote on all equity-compensation plans and material revisions to those plans. BP complies with UK requirements that are similar to the NYSE rules. The board, however, does not explicitly take into consideration the NYSE's detailed definition of what are considered 'material revisions'.

Code of ethics

The NYSE rules require that US companies adopt and disclose a code of business conduct and ethics for directors, officers and employees. BP has adopted a code of conduct, which applies to all employees and members of the board, and has board governance principles that address the conduct of directors. In addition BP has adopted a code of ethics for senior financial officers as required by the SEC. BP considers that these codes and policies address the matters specified in the NYSE rules for US companies.

Code of ethics

The company has adopted a code of ethics for its group chief executive, chief financial officer, group controller, group head of audit and chief accounting officer as required by the provisions of Section 406 of the Sarbanes-Oxley Act of 2002 and the rules issued by the SEC. There have been no waivers from the code of ethics relating to any officers.

BP also has a code of conduct, which is applicable to all employees, officers and members of the board. This was updated (and published) in July 2014.

Controls and procedures

Evaluation of disclosure controls and procedures

The company maintains 'disclosure controls and procedures', as such term is defined in Exchange Act Rule 13a-15(e), that are designed to ensure that information required to be disclosed in reports the company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including the company's group chief executive and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating our disclosure controls and procedures, our management, including the group chief executive and chief financial officer, recognize that any controls and procedures, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud within the company, if any, have been detected. Further, in the design and evaluation of our disclosure controls and procedures our management necessarily was required to apply its judgement in evaluating the costs and benefits of possible control and procedure design options. Also, we have investments in unconsolidated entities. As we do not control these entities, our disclosure controls and procedures with respect to such entities are necessarily substantially more limited than those we maintain with respect to our consolidated subsidiaries. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. The company's disclosure controls and procedures have been designed to meet, and management believes that they meet, reasonable assurance standards.

The company's management, with the participation of the company's group chief executive and chief financial officer, has evaluated the effectiveness of the company's disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b) as of the end of the period covered by this annual report. Based on that evaluation, the group chief executive and chief financial officer have concluded that the company's disclosure controls and procedures were effective at a reasonable assurance level.

Management's report on internal control over financial reporting

Management of BP is responsible for establishing and maintaining adequate internal control over financial reporting. BP's internal control over financial reporting is a process designed under the supervision of the principal executive and financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of BP's financial statements for external reporting purposes in accordance with IFRS.

As of the end of the 2019 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 2019 was effective.

The company's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with IFRS and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of BP; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of BP's assets that could have a material effect on our financial statements. BP's internal control over financial reporting as of 31 December 2019 has been audited by Deloitte LLP, an independent registered public accounting firm, as stated in their report appearing on page 151 of *BP Annual Report and Form 20-F 2019*.

Changes in internal control over financial reporting

There were no changes in the group's internal control over financial reporting that occurred during the period covered by the Form 20-F that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Principal accountant's fees and services

The audit committee has established policies and procedures for the engagement of the independent registered public accounting firm, Deloitte LLP, to render audit and certain assurance services. The policies provide for pre-approval by the audit committee of specifically defined audit, audit-related, non-audit and other services that are not prohibited by regulatory or other professional requirements. Deloitte is engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit nature. The committee regularly reviews the policy, including in 2019, to assesses whether the policy remains fit for purpose against the latest ethical standards and guidance. The committee will review the policy again in 2020 and the policy will be updated in line with the revised FRC 2019 Ethical Standards.

Under the policy, pre-approval is given for specific services within the following categories: advice on accounting, auditing and financial reporting matters; internal accounting and risk management control reviews (excluding any services relating to information systems design and implementation); non-statutory audit; project assurance and advice on business and accounting process improvement (excluding any services relating to information systems design and implementation relating to BP's financial statements or accounting records); due diligence in connection with acquisitions, disposals and joint arrangements★ (excluding valuation or involvement in prospective financial information); provision of, or access to, Deloitte publications, workshops, seminars and other training materials; provision of reports from data gathered on non-financial policies and information; provision of the independent third party audit in accordance with US Generally Accepted Government Auditing Standards, over the company's Conflict Minerals Report – where such a report is required under the SEC rule 'Conflict Minerals', issued in accordance with Section 1502 of the Dodd Frank Act; and assistance with understanding non-financial regulatory requirements. BP operates a two-tier system for audit and non-audit services. For audit related services, the audit committee has a pre-approved aggregate level, within which specific work may be approved by management. Non-audit services are pre-approved for management to authorize per individual engagement, but above a defined level must be approved by the chairman of the audit committee or the full committee. In response to the revised regulatory guidelines of the UK Financial Reporting Council, the audit committee reviewed and updated its policies with effect from 1 January 2017 and in 2018 further updated its policies to clarify the engagement of the incoming auditor, Deloitte, and the outgoing auditor (and auditor of Rosneft) Ernst & Young to ensure independence. The defined maximum level for pre-approval has been reduced in line with FRC guidance on 'non-trivial' engagements. The audit committee has delegated to the chairman of the audit committee authority to approve permitted services provided that the chairman reports any decisions to the committee at its next scheduled meeting. Any proposed service not included in the approved service list must be approved in advance by the audit committee chairman and reported to the committee, or approved by the full audit committee in advance of commencement of the engagement.

The audit committee evaluates the performance of the auditor each year. The audit fees payable to Deloitte are reviewed by the committee in the context of other global companies for cost effectiveness. The committee keeps under review the scope and results of audit work and the independence and objectivity of the auditor. External regulation and BP policy requires the auditor to rotate its lead audit partner every five years. See Financial statements – Note 36 and Audit committee report on page 93 for details of fees for services provided by the auditor.

Directors' report information

This section of *BP Annual Report and Form 20-F 2019* forms part of, and includes certain disclosures which are required by law to be included in, the Directors' report.

Indemnity provisions

In accordance with BP's Articles of Association, on appointment each director is granted an indemnity from the company in respect of liabilities incurred as a result of their office, to the extent permitted by law. These indemnities were in force throughout the financial year and at the date of this report. In respect of those liabilities for which directors may not be indemnified, the company maintained a directors' and officers' liability insurance policy throughout 2019. During the year, a review of the terms and scope of the policy was undertaken. The policy was renewed during 2018 and continued into 2019. Although their defence costs may be met, neither the company's indemnity nor insurance provides cover in the event that the director is proved to have acted fraudulently or dishonestly. Certain subsidiaries are trustees of the group's pension schemes. Each director of these subsidiaries★ is granted an indemnity from the company in respect of liabilities incurred as a result of such a subsidiary's activities as a trustee of the pension scheme, to the extent permitted by law. These indemnities were in force throughout the financial year and at the date of this report.

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 68, Liquidity and capital resources on page 301 and Financial statements – Notes 29 and 30.

Exposure to price risk, credit risk, liquidity risk and cash flow risk

The disclosures in relation to exposure to price risk, credit risk, liquidity risk and cash flow risk are included in Financial statements – Note 29.

Important events since the end of the financial year

Disclosures of the particulars of the important events affecting BP which have occurred since the end of the financial year are included in the Strategic report as well as in other places in the Directors' report.

Likely future developments in the business

An indication of the likely future developments in the business of the company is included in the Strategic report.

Research and development

Indications of our activities in the field of research and development are provided throughout the Strategic report and the Directors' report including examples on pages 15 (technology and innovation), 16 (creating low carbon businesses), 28 and 65 (venturing), 31 (modernizing the group) and 57 (*BP Infinia*). See also page 180 for our expenditure on research and development.

Branches

As a global group our interests and activities are held or operated through subsidiaries, branches, joint arrangements★ or associates★ established in – and subject to the laws and regulations of – many different jurisdictions.

Employees

Disclosures in respect of how the directors have engaged with employees and had regard to their interests are included in How the board has engaged with shareholders, the workforce and other stakeholders on page 88 and section 172 statement on page 66.

The disclosures concerning policies in relation to the employment of disabled persons and employee involvement are included in Sustainability – Our people on page 47.

Employee share schemes

Certain shares held as a result of participation in some employee share plans carry voting rights. Voting rights in respect of such shares are exercisable via a nominee. Dividend waivers are in place in respect of unallocated shares held in employee share plan trusts.

Suppliers, customers and others

Disclosures in respect of how the directors have engaged with suppliers, customers and others in business relationships with the company are included in How the board has engaged with shareholders, the workforce and other stakeholders on page 88 and section 172 statement on page 66.

Change of control provisions

On 5 October 2015, the United States lodged with the district court in MDL 2179 a proposed Consent Decree between the United States, the Gulf states, BP Exploration & Production Inc., BP Corporation North America Inc. and BP p.l.c., to fully and finally resolve any and all natural resource damages claims of the United States, the Gulf states and their respective natural resource trustees and all Clean Water Act penalty claims, and certain other claims of the United States and the Gulf states. Concurrently, BP entered into a definitive Settlement Agreement with the five Gulf states (Settlement Agreement) with respect to state claims for economic, property and other losses. On 4 April 2016, the district court approved the Consent Decree, at which time the Consent Decree and Settlement Agreement became effective. The federal government and the Gulf states may jointly elect to accelerate the payments under the Consent Decree in the event of a change of control or insolvency of BP p.l.c., and the Gulf states individually have similar acceleration rights under the Settlement Agreement. For further details of the Consent Decree and the Settlement Agreement, see Legal proceedings in *BP Annual Report and Form 20-F 2015*.

Greenhouse gas emissions

The disclosures in relation to greenhouse gas emissions are included in Sustainability – Climate change on page 40.

Disclosures required under Listing Rule 9.8.4R

The information required to be disclosed by Listing Rule 9.8.4R can be located as set out below:

Information required	Page
(1) Amount of interest capitalized	180
(2) – (11)	Not applicable
(12), (13) Dividend waivers	323
(14)	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 Chairman's letter (pages 2-3), the Chief executive officer's letter (pages 4-5), the Strategic report (inside cover and pages 1-71), Additional disclosures (pages 297-325) and Shareholder information (pages 327-336), including but not limited to statements under the headings 'Our ambition for the energy transition', 'Our business model', 'Our strategy' and 'Measuring our progress' and including but not limited to statements regarding: the coronavirus pandemic (COVID19), its impact, consequences and challenges and how BP is prepared for and responding to this; plans and expectations relating to organic capital expenditure, maintaining a strong financial frame, deleveraging our balance sheet, working capital and operating cash flows, capital discipline, growth in sustainable free cash flow and shareholder distributions and future dividend payments; BP's new ambition to be a net zero company by 2050 or sooner and help the world get to net zero, including its aims regarding emissions across operations, the carbon content of its oil and gas production; a 50% cut in the carbon intensity of products BP sells, methane measurement at major oil and gas processing sites by 2023 and subsequent reduction of methane intensity of operations, and aims to increase the proportion of investment into non-oil and gas businesses over time; aims to help the world get to net zero; plans for incentivising BP's global workforce; plans for a wide-ranging restructuring of the business; the aim to build a more agile, innovative and efficient BP; continuing commitment to safe and reliable operations; commitment to continuing to perform as BP transforms; continuing commitment to the investor proposition and commitment to transparency and advocacy for a low carbon world; plans and expectations regarding the new leadership structure, including timing of its implementation and areas of focus; plans to focus on developing a new corporate governance framework; plans and expectations regarding our relationships with trade associations; plans to advance a low-carbon future through the reduce, improve, create framework; plans and expectations regarding BP's level of investment in energy sources and technologies other than oil and gas resources and reserves; expectations regarding world energy demand, including the growth in relative demand for renewables, oil and gas, and the proportional growth of renewables; expectations regarding scenarios that are consistent with the Paris goals; expectations with respect to the world energy mix, production, consumption and emissions to 2040; plans and expectations regarding BP's portfolio, including to maintain a focused portfolio, to manage the portfolio through disciplined investment to support growing returns and to focus on highest-quality barrels; plans and expectations to deliver 2021 financial targets; expectations with respect to reserves bookings from new discoveries; plans and expectations regarding BP's quality of execution, including to get more from a unit of capital compared to peers; plans and expectations with regard to the supply and trading function, the fuels, lubricants and the petrochemicals businesses; plans and expectations with regard to new technologies, including their efficiency and impact on production; plans and expectations regarding the retail business, including BP Chargemaster, and to roll-out electric vehicle charging networks in China, Germany and the UK; plans to develop a number of digital platforms to connect consumers with local, low carbon electricity and to enhance productivity through digital solutions; plans and expectations regarding BP's role in OGCI's Net Zero Teesside project; plans and expectations regarding BP's advancing low carbon accreditation programme; plans and expectations with respect to the commercial optimization programme; plans and expectations regarding BPX Energy, including for it to achieve $400 million of annual synergies by 2021; plans and expectations with respect to the Alternative Energy portfolio, including for Lightsource BP to have 10GW of developed assets by the end of 2023, Grid Edge's impact on energy use and carbon emissions of buildings and expectations for Brazil's ethanol demand to increase up to 55% by 2030; plans and expectations regarding BP Launchpad, including to quickly create multiple businesses valued over $1 billion; plans and expectations regarding BP Ventures, including to grow advanced mobility, power and storage, carbon management, bio and low carbon products and its investment in Finite Resources; plans and expectations regarding the Other business and corporate annual charge and underlying quarterly charge in 2020; plans and expectations relating to divestments and disposals, including expectations that BP will meet its target of $10 billion of divestment proceeds by the end of 2020 and a further $5 billion of agreed disposals by mid-2021; expectations with respect to completion and the timing of receipt of proceeds of agreed divestments and disposals including the sale of BP's Alaska operations to Hilcorp Energy and the sale of BP's interests in the Andrew Area and Shearwater to Premier Oil; expectations regarding the determination of business economic loss claims in respect of the 2012 PSC settlement and expectations with respect to the timing and amount of future payments relating to the Gulf of Mexico oil spill including 2012 PSC settlement payments; plans and expectations regarding sales commitments of BP and its equity-accounted entities; expectations regarding underlying production and capital investment; plans and expectations with respect to gearing including to target gearing within a 20-30% band, for divestment proceeds to be primarily focused on reducing gearing and for gearing to increase in the short-term and subsequently reduce in line with divestment proceeds; expectations regarding oil prices, including for prices to be challenging in 2020; expectations for return on average capital employed to improve to over 10% by 2021; plans with regard to BP's exploration budget; expectations regarding depreciation, depletion and amortization charges; expectations regarding the effective tax rate in 2020; plans to produce 900,000boe/d from new projects by 2021 and expectations regarding operating cash margins of this production; plans to start up four projects in 2020; plans and expectations for the Raven project to come onstream at the end of 2020; plans and expectations with respect to a joint venture with ZPCC to build an acetic acid plant; plans and expectations regarding investment, development, and production levels and the timing thereof with respect to projects and partnerships in Angola, Australia, Azerbaijan, Brazil, Egypt, the Gambia, India, Indonesia, Mexico, Russia, São Tomé and Príncipe, Turkey, Oman, the UK North Sea, the Gulf of Mexico, and the continental United States; expectations regarding the Trans Anatolian Natural Gas Pipeline; plans and expectations regarding relationships with governments, customers, partners, suppliers, communities and key stakeholders, including working with the Washington state legislature to advance a new carbon bill; plans and expectations with respect to BP's public reporting of ambitions, plans, progress and reporting structure; plans and expectations regarding the effectiveness of the group's foreign currency exchange risk management; plans and expectations regarding plant reliability and base decline, including for base decline to remain between 3-5%; plans and expectations regarding business models in sustainable chemicals and plastics, including with respect to *BP Infinia* technology and to build a $25-million pilot plant to prove the technology; plans and expectations regarding the Tangguh gas facility; expectations regarding refining margins, North American heavy crude oil discounts and refining turnarounds; plans to undertake joint exploration and development with Rosneft, including to create a joint venture investment fund; expectations regarding pensions and other post-retirement benefits, including contributions; expectations regarding payments under contractual obligations and sales commitments; plans and expectations regarding BP's workforce, including the aim to attract, develop and retain the best talent, to create a diverse inclusive working environment and an open culture and to ensure equal opportunity in recruitment; policies and goals related to risk management plans; aim to help countries around the world grow their domestic energy supplies and boost energy security; plans and projections regarding oil and gas reserves, including the turnover time of proved undeveloped reserves to proved developed reserves and volume of turnover; expectations regarding the costs of environmental restoration programmes; expectations regarding contingent liabilities and their impact on BP; expectations regarding the future value of assets; expectations regarding future regulations and policy, their impact on BP's business and plans regarding compliance with such regulations; and expectations regarding legal and trial proceedings, court decisions, potential investigations and civil actions by regulators, government entities and/or other entities or parties, and the timing and potential impact of such proceedings and BP's intentions in respect thereof; and (ii) certain statements in Corporate governance (pages 72-99) and the Directors' remuneration report (pages 100-127) with regard to the anticipated future composition of the board of directors and the effects thereof; the board's goals and areas of focus, including changes to KPIs and those goals stemming from the board's annual evaluation; plans and expectations regarding directors' share ownership and remuneration; plans regarding the governance and remuneration processes; and goals, activities and areas of focus of board committees, are all forward looking in nature.

By their nature, forward-looking statements involve risk and uncertainty because they relate to events and depend on circumstances that will or may occur in the future and are outside the control of BP. Actual results may differ materially from those expressed in such statements, depending on a variety of factors, including: the specific factors identified in the discussions accompanying such forward looking statements; the receipt of relevant third party and/or regulatory approvals; the timing and level of maintenance and/or turnaround activity; the timing and volume of refinery additions and outages; the timing of bringing new projects onstream; the timing, quantum and nature of certain acquisitions and divestments; future levels of industry product supply, demand and pricing, including supply growth in North America; OPEC quota restrictions; production-sharing agreements effects; operational and safety problems; potential lapses in product quality; economic and financial market conditions generally or in various countries and regions; political stability and economic growth in relevant areas of the world; changes in laws and governmental regulations and policies, including related to climate change; changes in social attitudes and customer preferences; regulatory or legal actions including the types of enforcement action pursued and the nature of remedies sought or imposed; the actions of prosecutors, regulatory authorities and courts; delays in the processes for resolving claims; amounts ultimately determined to be payable and the timing of payments relating to the Gulf of Mexico oil spill; exchange rate fluctuations; development and use of new technology; recruitment and retention of a skilled workforce; the success or otherwise of partnering; the actions of competitors, trading partners, contractors, subcontractors, creditors, rating agencies and others; our access to future credit resources; business disruption and crisis management; the impact on our reputation of ethical misconduct and non-compliance with regulatory obligations; trading losses; major uninsured losses; decisions by Rosneft's management and board of directors; the actions of contractors; natural disasters and adverse weather conditions; changes in public expectations and other changes to business conditions; public health situations (including an outbreak of an epidemic or pandemic); wars and acts of terrorism; cyberattacks or sabotage; and other factors discussed elsewhere in this report including under Risk factors (pages 70-71). In addition to factors set forth elsewhere in this report, those set out above are important factors, although not exhaustive, that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements.

Statements regarding competitive position

Statements referring to BP's competitive position are based on the company's belief and, in some cases, rely on a range of sources, including investment analysts' reports, independent market studies and BP's internal assessments of market share based on publicly available information about the financial results and performance of market participants.

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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, Hamburg and Dusseldorf Stock Exchanges.

On 27 February 2020, 916,049,377 ADSs (equivalent to approximately 5,496,296,262 ordinary shares or some 27.15% of the total issued share capital, excluding shares held in treasury) were outstanding and were held by approximately 77,424 ADS holders. Of these, about 76,535 had registered addresses in the US at that date. One of the registered holders of ADSs represents some 1,237,693 underlying holders.

On 27 February 2020 there were approximately 229,193 ordinary shareholders. Of these shareholders, around 1,535 had registered addresses in the US and held a total of some 4,094,154 ordinary shares.

Since a number of the ordinary shares and ADSs were held by brokers and other nominees, the number of holders in the US may not be representative of the number of beneficial holders or their respective country of residence.

Dividends

The company's current policy is to pay interim dividends on a quarterly basis on its ordinary shares.

Its policy is also to announce dividends for ordinary shares in US dollars and state an equivalent sterling dividend. Dividends on the company's ordinary shares will be paid in sterling and on the company's ADSs in US dollars. The rate of exchange used to determine the sterling amount equivalent is the average of the market exchange rates in London over the four business days prior to the sterling equivalent announcement date. The directors may choose to declare dividends in any currency provided that a sterling equivalent is announced. It is not the company's intention to change its current policy of announcing dividends on ordinary shares in US dollars.

Information regarding dividends announced and paid by the company on ordinary shares and preference shares is provided in Financial statements – Note 10.

A Scrip Dividend Programme (Scrip Programme) was approved by shareholders in 2010 and was renewed for a further three years at the 2018 AGM. It 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 4 February 2020 that the board had suspended the Scrip Programme in respect of the third quarter 2019 and fourth quarter 2019 dividends. Ordinary shareholders and ADS holders (subject to certain exceptions) may be able to participate in dividend reinvestment plans. Any decisions with respect to future dividends will be made by the board of BP p.l.c. following the end of each quarter.

Future dividends will be dependent on future earnings, the financial condition of the group, the Risk factors set out on page 70 and other matters that may affect the business of the group set out in Our strategy on page 16 and in Liquidity and capital resources on page 301.

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
2015	UK pence	40.00	39.18	39.29	39.81	158.28
	US cents	60	60	60	60	240
2016	UK pence	42.08	41.50	45.35	47.59	176.52
	US cents	60	60	60	60	240
2017	UK pence	48.95	46.54	45.73	44.66	185.88
	US cents	60	60	60	60	240
2018	UK pence	43.01	44.66	47.58	48.15	183.40
	US cents	60	60	61.50	61.50	243
2019	**UK pence**	**46.43**	**48.39**	**50.09**	**46.95**	**191.86**
	US cents	**61.50**	**61.50**	**61.50**	**61.50**	**246**

[a] Dividends announced and paid by the company on ordinary and preference shares are provided in Financial statements – Note 10.

There are currently no UK foreign exchange controls or restrictions on remittances of dividends on the ordinary shares or on the conduct of the company's operations, other than restrictions applicable to certain countries and persons subject to EU economic sanctions or those sanctions adopted by the UK government which implement resolutions of the Security Council of the United Nations.

Shareholder taxation information

This section describes the material US federal income tax and UK taxation consequences of owning ordinary shares or ADSs to a US holder who holds the ordinary shares or ADSs as capital assets for tax purposes. It does not apply, however, inter alia to members of special classes of holders some of which may be subject to other rules, including: tax-exempt entities, life insurance companies, dealers in securities, traders in securities that elect a mark-to-market method of accounting for securities holdings, investors liable for alternative minimum tax, holders that, directly or indirectly, hold 10% or more of the company's voting stock, holders that hold the shares or ADSs as part of a straddle or a hedging or conversion transaction, holders that purchase or sell the shares or ADSs as part of a wash sale for US federal income tax purposes, or holders whose functional currency is not the US dollar. In addition, if a partnership holds the shares or ADSs, the US federal income tax treatment of a partner will generally depend on the status of the partner and the tax treatment of the partnership and may not be described fully below.

A US holder is any beneficial owner of ordinary shares or ADSs that is for US federal income tax purposes (1) a citizen or resident of the US, (2) a US domestic corporation, (3) an estate whose income is subject to US federal income taxation regardless of its source, or (4) a trust if a US court can exercise primary supervision over the trust's administration and one or more US persons are authorized to control all substantial decisions of the trust.

This section is based on the tax laws of the United States, including the Internal Revenue Code of 1986, as amended, its legislative history, existing and proposed US Treasury regulations thereunder, published rulings and court decisions, and the taxation laws of the UK, all as currently in effect, as well as the income tax convention between the US and the UK that entered into force on 31 March 2003 (the 'Treaty'). These laws are subject to change, possibly on a retroactive basis. This section further assumes that each obligation under the terms of the deposit agreement relating to BP ADSs and any related agreement will be performed in accordance with its terms.

For purposes of the Treaty and the estate and gift tax Convention (the 'Estate Tax Convention') and for US federal income tax and UK taxation purposes, a holder of ADRs evidencing ADSs will be treated as the owner of the company's ordinary shares represented by those ADRs. Exchanges of ordinary shares for ADRs and ADRs for ordinary shares generally will not be subject to US federal income tax or to UK taxation other than stamp duty or stamp duty reserve tax, as described below.

Investors should consult their own tax adviser regarding the US federal, state and local, UK and other tax consequences of owning and disposing of ordinary shares and ADSs in their particular circumstances, and in particular whether they are eligible for the benefits of the Treaty in respect of their investment in the shares or ADSs.

Taxation of dividends

UK taxation

Under current UK taxation law, no withholding tax will be deducted from dividends paid by the company, including dividends paid to US holders. A shareholder that is a company resident for tax purposes in the UK or trading in the UK through a permanent establishment generally will not be taxable in the UK on a dividend it receives from the company. A shareholder who is an individual resident for tax purposes in the UK is subject to UK tax but until 5 April 2016, was entitled to a tax credit on cash dividends paid on ordinary shares or ADSs of the company equal to one-ninth of the cash dividend.

From 6 April 2016 the dividend tax credit was replaced by a new tax-free dividend allowance and dividends paid by the company on or after 6 April 2016 do not carry a UK tax credit. The dividend allowance was £5,000 but this has been reduced to £2,000 as of 6 April 2018.

The dividend allowance of £2,000 means there is no UK tax due on the first £2,000 of dividends received. Dividends above this level are subject to tax at 7.5% for basic tax payers, 32.5% for higher rate tax payers and 38.1% for additional rate tax payers.

Although the first £2,000 of dividend income is not subject to UK income tax, it does not reduce the total income for tax purposes. Dividends within the dividend allowance still count towards basic or higher rate bands, and may therefore affect the rate of tax paid on dividends received in excess of the £2,000 allowance. For instance, if an individual has an annual gross salary of £50,000 and also receives a dividend of £12,000 they will be subject to the following scenario. The individual's personal allowance and the basic rate tax band will be used up by the gross salary. The remaining part of the salary and the whole of the dividend will be subject to tax at the higher rate, although the dividend allowance will reduce the amount of dividend subject to tax. The dividend of £12,000 will be reduced by the dividend allowance of £2,000 leaving taxable dividend income of £10,000. The dividend will be taxed at 32.5% so that the total tax payable on the dividends is £3,250.

How the shareholder pays the tax arising on the dividend income depends on the amount of dividend income and salary they receive in the tax year. If less than £2,000 they will not need to report anything or pay any tax. If between £2,000 and £10,000, the shareholder can pay what they owe by: contacting the helpline; asking HMRC to change their tax code – the tax will be taken from their wages or pension or through completion of the 'Dividends' section of their tax return, where one is being filed. If over £10,000 they will be required to file a self-assessment tax return and should complete the 'Dividends' section with details of the amounts received.

US federal income taxation

A US holder is subject to US federal income taxation on the gross amount of any dividend paid by the company out of its current or accumulated earnings and profits (as determined for US federal income tax purposes). Dividends paid to a non-corporate US holder that constitute qualified dividend income will be taxable to the holder at a preferential rate, provided that the holder has a holding period in the ordinary shares or ADSs of more than 60 days during the 121-day period beginning 60 days before the ex-dividend date and meets other holding period requirements. Dividends paid by the company with respect to the ordinary shares or ADSs will generally be qualified dividend income.

For US federal income tax purposes, a dividend must be included in income when the US holder, in the case of ordinary shares, or the Depositary, in the case of ADSs, actually or constructively receives the dividend and will not be eligible for the dividends-received deduction generally allowed to US corporations in respect of dividends received from other US corporations. US ADS holders should consult their own tax adviser regarding the US tax treatment of the dividend fee in respect of dividends. Dividends will be income from sources outside the US and generally will be 'passive category income' or, in the case of certain US holders, 'general category income', each of which is treated separately for purposes of computing a US holder's foreign tax credit limitation.

As noted above in UK taxation, a US holder will not be subject to UK withholding tax. Accordingly, the receipt of a dividend will not entitle the US holder to a foreign tax credit.

The amount of the dividend distribution on the ordinary shares that is paid in pounds sterling will be the US dollar value of the pounds sterling payments made, determined at the spot pounds sterling/US dollar rate on the date the dividend distribution is includible in income, regardless of whether the payment is, in fact, converted into US dollars. Generally, any gain or loss resulting from currency exchange fluctuations during the period from the date the pounds sterling dividend payment is includible in income to the date the payment is converted into US dollars will be treated as ordinary income or loss and will not be eligible for the preferential tax rate on qualified dividend income. The gain or loss generally will be income or loss from sources within the US for foreign tax credit limitation purposes.

Distributions in excess of the company's earnings and profits, as determined for US federal income tax purposes, will be treated as a return of capital to the extent of the US holder's basis in the ordinary shares or ADSs and thereafter as capital gain, subject to taxation as described in Taxation of capital gains – US federal income taxation section below.

In addition, the taxation of dividends may be subject to the rules for passive foreign investment companies (PFIC), described below under 'Taxation of capital gains – US federal income taxation'. Distributions made by a PFIC do not constitute qualified dividend income and are not eligible for the preferential tax rate applicable to such income.

Taxation of capital gains

UK taxation

A US holder may be liable for both UK and US tax in respect of a gain on the disposal of ordinary shares or ADSs if the US holder is (1) resident for tax purposes in the United Kingdom at the date of disposal, (2) if he or she has left the UK for a period not exceeding five complete tax years between the year of departure from and the year of return to the UK and acquired the shares before leaving the UK and was resident in the UK in the previous four out of seven tax years before the year of departure, (3) a US domestic corporation resident in the UK by reason of its business being managed or controlled in the UK or (4) a citizen of the US that carries on a trade or profession or vocation in the UK through a branch or agency or a corporation that carries on a trade, profession or vocation in the UK, through a permanent establishment, and that has used, held, or acquired the ordinary shares or ADSs for the purposes of such trade, profession or vocation of such branch, agency or permanent establishment. However, such persons may be entitled to a tax credit against their US federal income tax liability for the amount of UK capital gains tax or UK corporation tax on chargeable gains (as the case may be) that is paid in respect of such gain.

Under the Treaty, capital gains on dispositions of ordinary shares or ADSs generally will be subject to tax only in the jurisdiction of residence of the relevant holder as determined under both the laws of the UK and the US and as required by the terms of the Treaty.

Under the Treaty, individuals who are residents of either the UK or the US and who have been residents of the other jurisdiction (the US or the UK, as the case may be) at any time during the six years immediately preceding the relevant disposal of ordinary shares or ADSs may be subject to tax with respect to capital gains arising from a disposition of ordinary shares or ADSs of the company not only in the jurisdiction of which the holder is resident at the time of the disposition but also in the other jurisdiction.

For gains on or after 23 June 2010, the UK Capital Gains Tax rate will be dependent on the level of an individual's taxable income. Where total taxable income and gains after all allowable deductions are less than the upper limit of the basic rate income tax band of £37,500 (for

2019/20), the rate of Capital Gains Tax will be 10%. For gains (and any parts of gains) above that limit the rate will be 20%.

From 6 April 2008, entitlement to the annual exemption is based on an individual's circumstances (taking into account Domicile status, remittance basis of taxation and number of years in the UK). For individuals who are entitled to the exemption for 2019/20, this has been set at £12,000. Corporation tax on chargeable gains is levied at 19 per cent for companies from 1 April 2017.

US federal income taxation
A US holder who sells or otherwise disposes of ordinary shares or ADSs will recognize a capital gain or loss for US federal income tax purposes equal to the difference between the US dollar value of the amount realized on the disposition and the US holder's tax basis, determined in US dollars, in the ordinary shares or ADSs. Any such capital gain or loss generally will be long-term gain or loss, subject to tax at a preferential rate for a non-corporate US holder, if the US holder's holding period for such ordinary shares or ADSs exceeds one year.

Gain or loss from the sale or other disposition of ordinary shares or ADSs will generally be income or loss from sources within the US for foreign tax credit limitation purposes. The deductibility of capital losses is subject to limitations.

We do not believe that ordinary shares or ADSs will be treated as stock of a passive foreign investment company (PFIC) for US federal income tax purposes, but this conclusion is a factual determination that is made annually and thus is subject to change. If we are treated as a PFIC, unless a US holder elects to be taxed annually on a mark-to-market basis with respect to ordinary shares or ADSs, any gain realized on the sale or other disposition of ordinary shares or ADSs would in general not be treated as capital gain. Instead, a US holder would be treated as if he or she had realized such gain rateably over the holding period for ordinary shares or ADSs and would be taxed at the highest tax rate in effect for each such year to which the gain was allocated, in addition to which an interest charge in respect of the tax attributable to each such year would apply. Certain 'excess distributions' would be similarly treated if we were treated as a PFIC.

Additional tax considerations

Scrip Programme
Until the publication of the 2019 third quarter results, the company had an optional Scrip Programme, wherein holders of BP ordinary shares or ADSs could elect to receive any dividends in the form of new fully paid ordinary shares or ADSs of the company instead of cash. Please consult your tax adviser for the consequences to you.

UK inheritance tax
The Estate Tax Convention applies to inheritance tax. ADSs held by an individual who is domiciled for the purposes of the Estate Tax Convention in the US and is not for the purposes of the Estate Tax Convention a national of the UK will not be subject to UK inheritance tax on the individual's death or on transfer during the individual's lifetime unless, among other things, the ADSs are part of the business property of a permanent establishment situated in the UK used for the performance of independent personal services. In the exceptional case where ADSs are subject to both inheritance tax and US federal gift or estate tax, the Estate Tax Convention generally provides for tax payable in the US to be credited against tax payable in the UK or for tax paid in the UK to be credited against tax payable in the US, based on priority rules set forth in the Estate Tax Convention.

UK stamp duty and stamp duty reserve tax
The statements below relate to what is understood to be the current practice of HM Revenue & Customs in the UK under existing law.

Provided that any instrument of transfer is not executed in the UK and remains at all times outside the UK and the transfer does not relate to any matter or thing done or to be done in the UK, no UK stamp duty is payable on the acquisition or transfer of ADSs. Neither will an agreement to transfer ADSs in the form of ADRs give rise to a liability to stamp duty reserve tax.

Purchases of ordinary shares, as opposed to ADSs, through the CREST system of paperless share transfers will be subject to stamp duty reserve tax at 0.5%. The charge will arise as soon as there is an agreement for the transfer of the shares (or, in the case of a conditional agreement, when the condition is fulfilled). The stamp duty reserve tax will apply to agreements to transfer ordinary shares even if the agreement is made outside the UK between two non-residents. Purchases of ordinary shares outside the CREST system are subject either to stamp duty at a rate of £5 per £1,000 (or part, unless the stamp duty is less than £5, when no stamp duty is charged), or stamp duty reserve tax at 0.5%. Stamp duty and stamp duty reserve tax are generally the liability of the purchaser.

A subsequent transfer of ordinary shares to the Depositary's nominee will give rise to further stamp duty at the rate of £1.50 per £100 (or part) or stamp duty reserve tax at the rate of 1.5% of the value of the ordinary shares at the time of the transfer. For ADR holders electing to receive ADSs instead of cash, after the 2012 first quarter dividend payment, HM Revenue & Customs no longer seeks to impose 1.5% stamp duty reserve tax on issues of UK shares and securities to non-EU clearance services and depositary receipt systems.

US Medicare Tax
A US holder that is an individual or estate, or a trust that does not fall into a special class of trusts that is exempt from such tax, is subject to a 3.8% tax on the lesser of (1) the US holder's 'net investment income' (or 'undistributed net investment income' in the case of an estate or trust) for the relevant taxable year and (2) the excess of the US holder's modified adjusted gross income for the taxable year over a certain threshold (which in the case of individuals is between $125,000 and $250,000, depending on the individual's circumstances). A holder's net investment income generally includes its dividend income and its net gains from the disposition of shares or ADSs, unless such dividend income or net gains are derived in the ordinary course of the conduct of a trade or business (other than a trade or business that consists of certain passive or trading activities). If you are a US holder that is an individual, estate or trust, you are urged to consult your tax advisers regarding the applicability of the Medicare tax to your income and gains in respect of your investment in the shares or ADSs.

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 2019

Range of holdings	Number of ordinary shareholders	Percentage of total ordinary shareholders	Percentage of total ordinary share capital excluding shares held in treasury
1-200	52,926	22.96	0.01
201-1,000	77,165	33.47	0.21
1,001-10,000	88,204	38.26	1.37
10,001-100,000	10,640	4.61	1.10
100,001-1,000,000	928	0.40	1.68
Over 1,000,000[a]	693	0.30	95.63
Totals	230,556	100.00	100.00

[a] Includes JPMorgan Chase Bank, N.A. holding 27.04% 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 2019[a]

Range of holdings	Number of ADS holders	Percentage of total ADS holders	Percentage of total ADSs
1-200	46,802	59.80	0.27
201-1,000	20,337	25.98	1.05
1,001-10,000	10,654	13.61	3.00
10,001-100,000	466	0.60	0.84
100,001-1,000,000	7	0.01	0.14
Over 1,000,000[b]	1	0.00	94.70
Totals	78,267	100.00	100.00

[a] One ADS represents six 25 cent ordinary shares.

[b] One holder of ADSs represents 1,231,543 underlying shareholders.

As at 31 December 2019 there were also 1,236 preference shareholders. Preference shareholders represented 0.41% and ordinary shareholders represented 99.59% of the total issued nominal share capital of the company (excluding shares held in treasury) as at that date.

As at 31 December 2019, we had been notified pursuant to DTR5 that BlackRock, Inc. held 7.37% of the voting rights attached to the issued share capital of the company.

The company did not receive any notifications pursuant to DTR5 between 1 January 2020 and 27 February 2020.

Under the US Securities Exchange Act of 1934 BP is aware of the following interests as at 27 February 2020:

Holder	Holding of ordinary shares	Percentage of ordinary share capital excluding shares held in treasury
JPMorgan Chase Bank N.A., depositary for ADSs, through its nominee Guaranty Nominees Limited	5,496,296,263	27.13
BlackRock, Inc.	1,531,724,983	7.60
The Vanguard Group, Inc	813,197,253	4.00

The company's major shareholders do not have different voting rights.

The company has also been notified of the following interests in preference shares as at 27 February 2020:

Holder	Holding of 8% cumulative first preference shares	Percentage of class
The National Farmers Union Mutual Insurance Society Limited	945,000	13.10
Hargreaves Lansdown Asset Management Limited	644,225	8.90
Canaccord Genuity Group Inc.	544,163	7.50
M&G Investment Management Ltd.	528,150	7.30
Interactive Investor Share Dealing Services	513,068	7.10
A J Bell Securities Limited	390,807	5.40

Holder	Holding of 9% cumulative second preference shares	Percentage of class
The National Farmers Union Mutual Insurance Society Limited	987,000	18.00
M&G Investment Management Ltd.	644,450	11.80
Safra Group	385,000	7.00
Canaccord Genuity Group Inc.	273,135	5.00
Barclays PLC	271,080	5.00

As at 27 February 2020, the total preference shares in issue comprised only 0.42% of the company's total issued nominal share capital (excluding shares held in treasury), the rest being ordinary shares.

Annual general meeting

The 2020 AGM will be held on Wednesday 27 May 2020 at 11.00am. A separate notice convening the meeting is distributed to shareholders, which includes an explanation of the items of business to be considered at the meeting.

All resolutions for which notice has been given will be decided on a poll. Deloitte LLP have expressed their willingness to continue in office as auditors and a resolution for their reappointment is included in the *Notice of BP Annual General Meeting 2020*.

Memorandum and Articles of Association

The following summarizes certain provisions of the company's Memorandum and Articles of Association and applicable English law. This summary is qualified in its entirety by reference to the UK Companies Act 2006 (the Act) and the company's Memorandum and Articles of Association. The Memorandum and Articles of Association are available online at *bp.com/usefuldocs*.

The company's Articles of Association may be amended by a special resolution at a general meeting of the shareholders. At the annual general meeting (AGM) held on 21 May 2018 shareholders voted to adopt new Articles of Association to reflect developments in market practice and to provide clarification and additional flexibility where necessary or appropriate.

Objects and purposes

BP is a public company limited by shares, incorporated under the name BP p.l.c. and is registered in England and Wales with the registered number 102498. The provisions regulating the operations of the company, known as its 'objects', were historically stated in a company's memorandum. The Act abolished the need to have object provisions and so at the AGM held on 15 April 2010 shareholders approved the removal of its objects clause together with all other provisions of its Memorandum that, by virtue of the Act, are treated as forming part of the company's Articles of Association.

Directors and secretary

The business and affairs of BP shall be managed by the directors. The company's Articles of Association provide that directors may be appointed by the existing directors or by the shareholders in a general meeting. Any person appointed by the directors will hold office only until the next general meeting, notice of which is first given after their appointment and will then be eligible for re-election by the shareholders. A director may be removed by BP as provided for by applicable law and shall vacate office in certain circumstances as set out in the Articles of Association. In addition the company may, by special resolution, remove a director before the expiration of his/her period of office and, subject to the Articles of Association, may by ordinary resolution appoint another person to be a director instead. There is no requirement for a director to retire on reaching any age.

The Articles of Association place a general prohibition on a director voting in respect of any contract or arrangement in which the director has a material interest other than by virtue of such director's interest in shares in the company. However, in the absence of some other material interest not indicated below, a director is entitled to vote and to be counted in a quorum for the purpose of any vote relating to a resolution concerning the following matters:

- The giving of security or indemnity with respect to any money lent or obligation taken by the director at the request or benefit of the company or any of its subsidiary undertakings.
- Any proposal in which the director is interested, concerning the underwriting of company securities or debentures or the giving of any security to a third party for a debt or obligation of the company or any of its subsidiary undertakings.
- Any proposal concerning any other company in which the director is interested, directly or indirectly (whether as an officer or shareholder or otherwise) provided that the director and persons connected with such director are not the holder or holders of 1% or more of the voting interest in the shares of such company.

- Any proposal concerning the purchase or maintenance of any insurance policy under which the director may benefit.
- Any proposal concerning the giving to the director of any other indemnity which is on substantially the same terms as indemnities given or to be given to all of the other directors or to the funding by the company of his expenditure on defending proceedings or the doing by the company of anything to enable the director to avoid incurring such expenditure where all other directors have been given or are to be given substantially the same arrangements.
- Any proposal concerning an arrangement for the benefit of the employees and directors or former employees and former directors of the company or any of its subsidiary undertakings, including but without being limited to a retirement benefits scheme and an employees' share scheme, which does not accord to any director any privilege or advantage not generally accorded to the employees or former employees to whom the arrangement relates.

The Act requires a director of a company who is in any way interested in a contract or proposed contract with the company to declare the nature of the director's interest at a meeting of the directors of the company. The definition of 'interest' includes the interests of spouses, children, companies and trusts. The Act also requires that a director must avoid a situation where a director has, or could have, a direct or indirect interest that conflicts, or possibly may conflict, with the company's interests. The Act allows directors of public companies to authorize such conflicts where appropriate, if a company's Articles of Association so permit. BP's Articles of Association permit the authorization of such conflicts. The directors may exercise all the powers of the company to borrow money, except that the amount remaining undischarged of all moneys borrowed by the company shall not, without approval of the shareholders, exceed two times the amount paid up on the share capital plus the aggregate of the amount of the capital and revenue reserves of the company. Variation of the borrowing power of the board may only be affected by amending the Articles of Association.

Remuneration of non-executive directors shall be determined in the aggregate by resolution of the shareholders. Remuneration of executive directors is determined by the remuneration committee. This committee is made up of non-executive directors only. There is no requirement of share ownership for a director's qualification.

The Articles of Association provide entitlement to the directors' pensions and death and disability benefits to the directors' relations and dependants respectively.

The circumstances in which a director's office will automatically terminate include: when a director ceases to hold an executive office of the company and the directors resolve that he should cease to be a director; if a medical practitioner provides an opinion that a director has become incapable of acting as a director and may remain so incapable for a further three months and the directors resolve that he should cease to be a director; and if all of the other directors vote in favour of a resolution stating that the person should cease to be a director.

The company secretary has express powers to delegate any of the powers or discretions conferred on him or her.

Dividend rights; other rights to share in company profits; capital calls

If recommended by the directors of BP, shareholders of BP may, by resolution, declare dividends but no such dividend may be declared in excess of the amount recommended by the directors. The directors may also pay interim dividends without obtaining shareholder approval. No dividend may be paid other than out of profits available for distribution, as determined under IFRS and the Act. Dividends on ordinary shares are payable only after payment of dividends on BP preference shares. Any dividend unclaimed after a period of 10 years from the date of declaration of such dividend shall be forfeited and reverts to BP. If the company exercises its right to forfeit shares and sells shares belonging to an untraced shareholder then any entitlement to claim dividends or other monies unclaimed in respect of those shares will be for a period of twelve months after the sale. The company may take such steps as the directors decide are appropriate in the circumstances to trace the member entitled and the sale may be made at such time and on such terms as the directors may decide.

The directors have the power to declare and pay dividends in any currency provided that a sterling equivalent is announced. It is not the company's intention to change its current policy of paying dividends in US dollars. At the company's AGM held on 15 April 2010, shareholders approved the introduction of a Scrip Dividend Programme (Scrip Programme) and to include provisions in the Articles of Association to enable the company to operate the Scrip Programme. The Scrip Programme was renewed at the company's AGM held on 21 May 2018 for a further three years. The Scrip Programme enables ordinary shareholders and BP ADS holders to elect to receive new fully paid ordinary shares (or BP ADSs in the case of BP ADS holders) instead of cash. The operation of the Scrip Programme is always subject to the directors' decision to make the scrip offer available in respect of any particular dividend. Should the directors decide not to offer the scrip in respect of any particular dividend, cash will automatically be paid instead. The directors may determine in relation to any scrip dividend plan or programme how the costs of the programme will be met, the minimum number of ordinary shares required in order to be able to participate in the programme and any arrangements to deal with legal and practical difficulties in any particular territory.

Apart from shareholders' rights to share in BP's profits by dividend (if any is declared or announced), the Articles of Association provide that the directors may set aside:

- A special reserve fund out of the balance of profits each year to make up any deficit of cumulative dividend on the BP preference shares.
- A general reserve out of the balance of profits each year, which shall be applicable for any purpose to which the profits of the company may properly be applied. This may include capitalization of such sum, pursuant to an ordinary shareholders' resolution, and distribution to shareholders as if it were distributed by way of a dividend on the ordinary shares or in paying up in full unissued ordinary shares for allotment and distribution as bonus shares.

Any such sums so deposited may be distributed in accordance with the manner of distribution of dividends as described above.

Holders of shares are not subject to calls on capital by the company, provided that the amounts required to be paid on issue have been paid off. All shares are fully paid.

Share transfers and share certificates

The directors may permit transfers to be effected other than by an instrument in writing and that share certificates will not be required to be issued by the company if they are not required by law.

The company may charge an administrative fee in the event that a shareholder wishes to replace two or more certificates representing shares with a single certificate or wishes to surrender a single certificate and replace it with two or more certificates. All certificates are sent at the member's risk.

Voting rights

The Articles of Association of the company provide that voting on resolutions at a shareholders' meeting will be decided on a poll other than resolutions of a procedural nature, which may be decided on a show of hands. If voting is on a poll, every shareholder who is present in person or by proxy has one vote for every ordinary share held and two votes for every £5 in nominal amount of BP preference shares held. If voting is on a show of hands, each shareholder who is present at the meeting in person or whose duly appointed proxy is present in person will have one vote, regardless of the number of shares held, unless a poll is requested.

Shareholders do not have cumulative voting rights.

For the purposes of determining which persons are entitled to attend or vote at a shareholders' meeting and how many votes such persons may cast, the company may specify in the notice of the meeting a time, not more than 48 hours before the time of the meeting, by which a person who holds shares in registered form must be entered on the company's register of members in order to have the right to attend or vote at the meeting or to appoint a proxy to do so.

Holders on record of ordinary shares may appoint a proxy, including a beneficial owner of those shares, to attend, speak and vote on their behalf at any shareholders' meeting, provided that a duly completed proxy form is received not less than 48 hours (or such shorter time as the directors may determine) before the time of the meeting or adjourned meeting or, where the poll is to be taken after the date of the meeting, not less than 24 hours (or such shorter time as the directors may determine) before the time of the poll.

Record holders of BP ADSs are also entitled to attend, speak and vote at any shareholders' meeting of BP by the appointment by the approved depositary, JPMorgan Chase Bank N.A., of them as proxies in respect of the ordinary shares represented by their ADSs. Each such proxy may also appoint a proxy. Alternatively, holders of BP ADSs are entitled to vote by supplying their voting instructions to the depositary, who will vote the ordinary shares represented by their ADSs in accordance with their instructions.

Proxies may be delivered electronically.

Corporations who are members of the company may appoint one or more persons to act as their representative or representatives at any shareholders' meeting provided that the company may require a corporate representative to produce a certified copy of the resolution appointing them before they are permitted to exercise their powers.

Matters are transacted at shareholders' meetings by the proposing and passing of resolutions, of which there are two types: ordinary or special.

An ordinary resolution requires the affirmative vote of a majority of the votes of those persons voting at a meeting at which there is a quorum. A special resolution requires the affirmative vote of not less than three quarters of the persons voting at a meeting at which there is a quorum. Any AGM requires 21 clear days' notice. The notice period for any other general meeting is 14 clear days subject to the company obtaining annual shareholder approval, failing which, a 21 clear day notice period will apply.

Liquidation rights; redemption provisions

In the event of a liquidation of BP, after payment of all liabilities and applicable deductions under UK laws and subject to the payment of secured creditors, the holders of BP preference shares would be entitled to the sum of (1) the capital paid up on such shares plus, (2) accrued and unpaid dividends and (3) a premium equal to the higher of (a) 10% of the capital paid up on the BP preference shares and (b) the excess of the average market price over par value of such shares on the LSE during the previous six months. The remaining assets (if any) would be divided pro rata among the holders of ordinary shares.

Without prejudice to any special rights previously conferred on the holders of any class of shares, BP may issue any share with such preferred, deferred or other special rights, or subject to such restrictions as the shareholders by resolution determine (or, in the absence of any such resolutions, by determination of the directors), and may issue shares that are to be or may be redeemed.

Variation of rights

The rights attached to any class of shares may be varied with the consent in writing of holders of 75% of the shares of that class or on the adoption of a special resolution passed at a separate meeting of the holders of the shares of that class. At every such separate meeting, all of the provisions of the Articles of Association relating to proceedings at a general meeting apply, except that the quorum with respect to a meeting to change the rights attached to the preference shares is 10% or more of the shares of that class, and the quorum to change the rights attached to the ordinary shares is one third or more of the shares of that class.

Shareholders' meetings and notices

Shareholders must provide BP with a postal or electronic address in the UK to be entitled to receive notice of shareholders' meetings. Holders of BP ADSs are entitled to receive notices under the terms of the deposit agreement relating to BP ADSs. The substance and timing of notices are described above under the heading Voting rights.

Under the Act, the AGM of shareholders must be held once every year, within each six month period beginning with the day following the company's accounting reference date. All general meetings shall be held at a time and place determined by the directors. If any shareholders' meeting is adjourned for lack of quorum, notice of the time and place of the adjourned meeting may be given in any lawful manner, including electronically. Powers exist for action to be taken either before or at the meeting by authorized officers to ensure its orderly conduct and safety of those attending.

The directors have power to convene a general meeting which is a hybrid meeting, that is to provide facilities for shareholders to attend a meeting which is being held at a physical place by electronic means as well (but not to convene a purely electronic meeting).

The provisions of the Articles of Association in relation to satellite meetings permit facilities being provided by electronic means to allow those persons at each place to participate in the meeting.

Limitations on voting and shareholding

There are no limitations, either under the laws of the UK or under the company's Articles of Association, restricting the right of non-resident or foreign owners to hold or vote BP ordinary or preference shares in the company other than limitations that would generally apply to all of the shareholders and limitations applicable to certain countries and persons subject to EU economic sanctions or those sanctions adopted by the UK government which implement resolutions of the Security Council of the United Nations.

Disclosure of interests in shares

The Act permits a public company to give notice to any person whom the company believes to be or, at any time during the three years prior to the issue of the notice, to have been interested in its voting shares requiring them to disclose certain information with respect to those interests. Failure to supply the information required may lead to disenfranchisement of the relevant shares and a prohibition on their transfer and receipt of dividends and other payments in respect of those shares and any new shares in the company issued in respect of those shares. In this context the term 'interest' is widely defined and will generally include an interest of any kind whatsoever in voting shares, including any interest of a holder of BP ADSs.

Called-up share capital

Details of the allotted, called-up and fully-paid share capital at 31 December 2019 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 21 May 2019, authorization was given to the directors to allot shares in the company and to grant rights to subscribe for, or to convert any security into, shares in the company up to an aggregate nominal amount as set out in the Notice of Meeting 2019. These authorities were given for the period until the next AGM in 2020 or 21 August 2020, whichever is the earlier. These authorities are renewed annually at the AGM.

Company records and service of notice

In relation to notices not covered by the Act, the reference to notice by advertisement in a national newspaper also includes advertisements via other means such as a public announcement.

Purchases of equity securities by the issuer and affiliated purchasers

In November 2017 BP began a share repurchase or buyback programme (the programme). The sole purpose of the programme is to reduce the issued share capital of the company to offset the ongoing dilutive effect of scrip dividends over time, as announced by the company on 31 October 2017. 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 2019 AGM covering the period until the date of the company's 2020 AGM or 21 August 2020, whichever is earlier. The maximum number of ordinary shares to be purchased under this authority will not exceed 2,025,988,313 ordinary shares. The shares purchased will be cancelled.

The following table provides details of ordinary share purchases made (1) under the programme and (2) by the Employee Share Ownership Plans (ESOPs) and other purchases of ordinary shares and ADSs made to satisfy the requirements of certain employee share-based payment plans.

	Total number of shares purchased[a]	**Average price paid per share $**	Number of shares purchased by ESOPs or for certain employee share-based plans[b]	Number of shares purchased as part of the buyback programme[c]	Maximun approximate dollar value of shares yet to be purchased under the programme $ million
2019					
January	**Nil**				N/A
February 5 – February 21	**2,753,983**	**7.10**	120,000	2,633,983	N/A
March 11 – March 29	**4,260,056**	**7.29**	Nil	4,260,056	N/A
April 30	**120,000**	**7.32**	120,000	Nil	N/A
May 8 – May 31	**5,012,700**	**6.97**	Nil	5,012,700	N/A
June 3 – June 25	**5,763,677**	**6.96**	Nil	5,763,677	N/A
July	**Nil**				N/A
August 5 – August 29	**18,852,607**	**6.11**	Nil	18,852,607	N/A
September 2 – September 24	**16,867,892**	**6.24**	878,000	15,989,892	N/A
October 7- October 31	**103,926,413**	**6.33**	Nil	103,926,413	N/A
November 1 – November 29	**55,589,904**	**6.53**	Nil	55,589,904	N/A
December 2- December 19	**23,921,618**	**6.25**	Nil	23,921,618	N/A
2020					
January 7- January 28	**120,057,464**	**6.47**	Nil	120,057,464	N/A
February (to February 26)	**Nil**				N/A

[a] All share purchases were of ordinary shares of 25 cents each and/or ADSs (each representing six ordinary shares) and were on/open market transactions.

[b] Transactions represent the purchase of ordinary shares by ESOPs and other purchases of ordinary shares and ADSs made to satisfy requirements of certain employee share-based payment plans.

[c] The company announced its intent to commence the programme on 31 October 2017 and announced further details and commencement of the programme on 15 November 2017. At the AGM on 21 May 2019, authorization was given to the company to repurchase up to 2,025,988,313 ordinary shares, for the period ending on the date of the AGM in 2020 or 21 August 2020, whichever is the earlier. This authorization is renewed annually at the AGM. The total number of ordinary shares repurchased during 2019 under the programme was 235,950,850 at a cost of $1,511 million (including fees and stamp duty) representing 1.16% of the company's issued share capital excluding shares held in treasury on 31 December 2019. All ordinary shares repurchased in 2019 under the programme were cancelled in order to reduce the company's issued share capital.

Fees and charges payable by ADS holders

The Depositary collects fees for delivery and surrender of ADSs directly from investors depositing shares or surrendering ADSs for the purpose of withdrawal or from intermediaries acting for them. The Depositary collects fees for making distributions to investors by deducting those fees from the amounts distributed or by selling a portion of the distributable property to pay the fees.

The charges of the Depositary payable by investors are as follows:

Type of service	Depositary actions	Fee
Depositing or substituting the underlying shares	Issuance of ADSs against the deposit of shares, including deposits and issuances in respect of: • Share distributions, stock splits, rights, merger. • Exchange of securities or other transactions or event or other distribution affecting the ADSs or deposited securities.	$5.00 per 100 ADSs (or portion thereof) evidenced by the new ADSs delivered.
Selling or exercising rights	Distribution or sale of securities, the fee being an amount equal to the fee for the execution and delivery of ADSs that would have been charged as a result of the deposit of such securities.	$5.00 per 100 ADSs (or portion thereof).
Withdrawing an underlying share	Acceptance of ADSs surrendered for withdrawal of deposited securities.	$5.00 for each 100 ADSs (or portion thereof) evidenced by the ADSs surrendered.
Expenses of the Depositary	Expenses incurred on behalf of holders in connection with: • Stock transfer or other taxes and governmental charges. • Delivery by cable, telex, electronic and facsimile transmission. • Transfer or registration fees, if applicable, for the registration of transfers of underlying shares. • Expenses of the Depositary in connection with the conversion of foreign currency into US dollars (which are paid out of such foreign currency).	Expenses payable are subject to agreement between the company and the Depositary by billing holders or by deducting charges from one or more cash dividends or other cash distributions.
Dividend fees	ADS holders who receive a cash dividend are charged a fee which BP uses to offset the costs associated with administering the ADS programme.	The Deposit Agreement provides that a fee of $0.05 or less per ADS can be charged. The current fee is $0.02 per BP ADS per calendar year (equivalent to $0.005 per BP ADS per quarter per cash distribution).
Global Invest Direct (GID) Plan	New investors and existing ADS holders can buy, sell or reinvest dividends into further BP ADSs by enrolling in BP's GID Plan, sponsored and administered by the Depositary.	Cost per transaction is $2.00 for recurring, $2.00 for one-time automatic investments, and $5.00 for investment made by check. Dividend reinvestment is 5% of the dividend amount up to a maximum of $5.00. Purchase trading commission is $0.12 per share.

Fees and payments made by the Depositary to the issuer

The Depositary has agreed to reimburse certain company expenses related to the company's ADS programme and incurred by the company in connection with the ADS programme arising during the year ended 31 December 2019. The Depositary reimbursed to the company, or paid amounts on the company's behalf to third parties, or waived its fees and expenses, of $15,923,592.90 for the year ended 31 December 2019.

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 2019.

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 2019 $
Fees for delivery and surrender of BP ADSs	169,235.12
Dividend fees[a]	15,754,357.78
Total	15,923,592.90

[a] Dividend fees are charged to ADS holders who receive a cash distribution, which BP uses to offset the costs associated with administering the ADS programme.

Under certain circumstances, including removal of the Depositary or termination of the ADR programme by the company, the company is required to repay the Depositary certain amounts reimbursed and/or expenses paid to or on behalf of the company during the 12-month period prior to notice of removal or termination.

Documents on display

BP Annual Report and Form 20-F 2019 is available online at *bp.com/annualreport*. To obtain a hard copy of BP's complete audited financial statements, free of charge, UK based shareholders should contact BP Distribution Services by calling +44 (0) 800 037 2172 or by emailing *bpdistributionservices@bp.com*. If based in the US or Canada shareholders should contact Issuer Direct by calling +1 888 301 2505 or by emailing *bpreports@issuerdirect.com*.

The company is subject to the information requirements of the US Securities Exchange Act of 1934 applicable to foreign private issuers. In accordance with these requirements, the company files its Annual Report and Form 20-F and other related documents with the SEC. The SEC maintains an internet site at *www.sec.gov* that contains reports and other information regarding issuers, including BP, that file electronically with the SEC. BP's SEC filings are also available at *bp.com/sec*. BP discloses in this report (see Corporate governance practices (Form 20-F Item 16G) on page 321) significant ways (if any) in which its corporate governance practices differ from those mandated for US companies under NYSE listing standards.

Shareholding administration

If you have any queries about the administration of shareholdings, such as change of address, change of ownership, dividend payment options or to change the way you receive your company documents (such as the *BP Annual Report and Form 20-F* and *Notice of BP Annual General Meeting*) please contact the BP Registrar or the BP ADS Depositary.

Ordinary and preference shareholders

The BP Registrar, Link Asset Services
The Registry, 34 Beckenham Road, Beckenham, Kent BR3 4TU, UK
Freephone in UK 0800 701107
From outside the UK +44 (0)371 277 1014

ADS holders

BP Shareowner Services
PO Box 64504, St Paul, MN 55164-0504, US
Toll-free in US and Canada +1 877 638 5672
From outside the US and Canada +1 651 306 4383

2020 shareholder calendar[a]

27 Mar 2020	Fourth quarter interim dividend payment for 2019
28 April 2020	First quarter results announced
11 May 2020	Record date (to be eligible for the first quarter interim dividend)
27 May 2020	Annual general meeting
19 Jun 2020	First quarter interim dividend payment for 2020
3 Jul 2020	8% and 9% preference shares record date
28 Jul 2020	Second quarter results announced
31 Jul 2020	8% and 9% preference shares dividend payment
7 Aug 2020	Record date (to be eligible for the second quarter interim dividend)
18 Sep 2020	Second quarter interim dividend payment for 2020
27 Oct 2020	Third quarter results announced
6 Nov 2020	Record date (to be eligible for the third quarter interim dividend)
18 Dec 2020	Third quarter interim dividend payment for 2020

[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/d
Billion cubic feet per day.

bcfe
Billion cubic feet equivalent.

b/d
Barrels per day.

boe/d
Barrels of oil equivalent per day.

FPSO
Floating production, storage and offloading.

GAAP
Generally accepted accounting practice.

Gas
Natural gas.

gCO_2e/MJ
Grams of carbon dioxide equivalent per megajoule of energy.

GHG
Greenhouse gas.

GRI
Global Reporting Initiative.

$GtCO_2$
Gigatonnes of carbon dioxide.

GWh
Gigawatt hour.

HSSE
Health, safety, security and environment.

IFRS
International Financial Reporting Standards.

KPIs
Key performance indicators.

LNG
Liquefied natural gas.

LPG
Liquefied petroleum gas.

mb/d
Thousand barrels per day.

mboe/d
Thousand barrels of oil equivalent per day.

mmb/d or Mb/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.

mmte or Mte
Million tonnes.

$MteCO_2$
Million tonnes of CO_2 equivalent.

MW
Megawatt.

NGLs
Natural gas liquids.

PSA
Production-sharing agreement.

PTA
Purified terephthalic acid.

RC
Replacement cost.

SEC
The United States Securities and Exchange Commission.

Definitions

Unless the context indicates otherwise, the definitions for the following glossary terms are given below.

Non-GAAP measures are sometimes referred to as alternative performance measures.

CA100+ resolution glossary

CA100+ resolution
The CA100+ resolution means the special resolution requisitioned by Climate Action 100+ and passed at BP's 2019 Annual General Meeting, the text of which is set out below.

Special resolution: Climate Action 100+ shareholder resolution on climate change disclosures.
That in order to promote the long term success of the company, given the recognised risks and opportunities associated with climate change, we as shareholders direct the company to include in its strategic report and/or other corporate reports, as appropriate, for the year ending 2019 onwards, a description of its strategy which the board considers, in good faith, to be consistent with the goals of Articles 2.1(a)(1) and 4.1(2) of the Paris Agreement(3) (the 'Paris goals'), as well as:

(1) Capital expenditure: how the company evaluates the consistency of each new material capex investment, including in the exploration, acquisition or development of oil and gas resources and reserves and other energy sources and technologies, with (a) the Paris goals and separately (b) a range of other outcomes relevant to its strategy.

(2) Metrics and targets: the company's principal metrics and relevant targets or goals over the short, medium and/or long-term, consistent with the Paris goals, together with disclosure of:

   a. The anticipated levels of investment in (i) oil and gas resources and reserves; and (ii) other energy sources and technologies.

   b. The company's targets to promote reductions in its operational greenhouse gas emissions, to be reviewed in line with changing protocols and other relevant factors

   c. The estimated carbon intensity of the company's energy products and progress on carbon intensity over time.

   d. Any linkage between the above targets and executive remuneration.

(3) Progress reporting: an annual review of progress against (1) and (2) above.

Such disclosure and reporting to include the criteria and summaries of the methodology and core assumptions used, and to omit commercially confidential or competitively sensitive information and be prepared at reasonable cost; and provided that nothing in this resolution shall limit the company's powers to set and vary its strategy, or associated targets or metrics, or to take any action which it believes in good faith, would best promote the long-term success of the company.

The Paris goals

(1) Article 2.1(a) of the Paris Agreement states the goal of 'Holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels, recognizing that this would significantly reduce the risks and impacts of climate change'.

(2) Article 4.1 of the Paris Agreement: In order to achieve the long-term temperature goal set out in Article 2, parties aim to reach global peaking of greenhouse gas emissions as soon as possible, recognizing that peaking will take longer for developing country parties, and to undertake rapid reductions thereafter in accordance with best available science, so as to achieve a balance between anthropogenic emissions by sources and removals by sinks of greenhouse gases in the second half of this century, on the basis of equity, and in the context of sustainable development and efforts to eradicate poverty.

(3) U.N. Framework Convention on Climate Change Conference of Parties, Twenty-First Session, Adoption of the Paris Agreement, U.N. Doc. FCCC/CP/2015/L.9/Rev.1 (Dec. 12, 2015).

New material capex investment

For the purposes of the 2019 evaluation discussed on pages 19-22, 'new material capex investment' means a decision taken by the resource commitment meeting (RCM) in 2019 to incur inorganic or organic investments greater than $250 million that relate to a new project or asset, extending an existing project or asset, or acquiring or increasing a share in a project, asset or entity.

There were eight investments that met the above criteria in 2019.

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.

1. Operational carbon intensity (CI)

   The annual average operational GHG emissions ($TeCO_2e$/unit), divided by the relevant unit of output:

   - per thousand barrels of oil equivalent in Upstream
   - per utilized equivalent distillation capacity in refining
   - per thousand tonnes in petrochemicals.

2. Profitability index (PI)

   Operating cash flow divided by investment required (both on a present value basis).

   'Investment required' means economic resources including capital investment, decommissioning expenditure and the value of any credit support to third parties (e.g. partner carry).

Average emissions intensity of marketed energy products

The weighted average GHG emissions per unit of energy delivered grams CO_2e/MJ, estimated in respect of marketing sales of energy products. GHG emissions are estimated on a lifecycle basis covering production, distribution and use of the relevant products, assuming full stoichiometric combustion to CO_2.

Net zero aims and ambition glossary

Net zero

References to global net zero in the phrase, 'to help the world get to net zero', means achieving '...a balance between anthropogenic emissions by sources and removals by sinks of greenhouse gases...on the basis of equity, and in the context of sustainable development and efforts to eradicate poverty', as set out in Article 4 (1) of the Paris Agreement.

References to net zero for BP in the context of our ambition and Aims 1 and 2 as set out on page 7 (such as 'be a net zero company by 2050 or sooner'), means achieving a balance between (a) the relevant Scope 1 and 2 emissions (for our Aim 1), or Scope 3 emissions (for our Aim 2), and (b) the aggregate of applicable deductions from qualifying activities such as sinks under our methodology at the applicable time.

Emissions from the carbon in our Upstream oil and gas production

Estimated CO_2 emissions from the combustion of upstream production of crude oil, natural gas and natural gas liquids (NGLs) on a BP equity-share basis based on BP's net share of production, excluding BP's share of Rosneft production and assuming that all produced volumes undergo full stoichiometric combustion to CO_2.

Adjusted 2015 baseline

In accordance with our zero net growth methodology, the starting direct and indirect GHG emissions baseline (end of 2015) is adjusted at the end of each reporting year for any qualifying changes (being changes due to (a) acquisitions, divestments, outsourcing or insourcing where the total for the year is greater than 5% the total direct and indirect GHG emissions in the previous year or (b) methodology or protocol changes).

Adjusted effective tax rate (ETR)
Non-GAAP measure. The adjusted ETR is calculated by dividing taxation on an underlying replacement cost (RC) basis excluding the impact of reductions in the rate of the UK North Sea supplementary charge (in 2016 and 2015) by underlying RC profit or loss before tax. Taxation on an underlying RC basis is taxation on a RC basis for the period adjusted for taxation on non-operating items and fair value accounting effects. Information on underlying RC profit or loss is provided below. BP believes it is helpful to disclose the adjusted ETR because this measure may help investors to understand and evaluate, in the same manner as management, the underlying trends in BP's operational performance on a comparable basis, period on period. The nearest equivalent measure on an IFRS basis is the ETR on profit or loss for the period. A reconciliation to GAAP information is provided on page 344.

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.

Brent
A trading classification for North Sea crude oil that serves as a major benchmark price for purchases of oil worldwide.

Capital expenditure
Total cash capital expenditure as stated in the group cash flow statement.

Consolidation adjustment – UPII
Unrealized profit in inventory arising on inter-segment transactions.

Commodity trading contracts
BP's Upstream and Downstream segments both participate 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. These physical trading activities, together with associated incremental trading opportunities, are discussed in Upstream on page 50 and in Downstream on page 56. 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 arbitrage between markets.

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 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 over-the-counter (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, products 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. Because the physically settled transactions are delivered by cargo, the BFOE contract additionally specifies 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 achieved by transacting offsetting sale or purchase contracts for the same location and delivery period that are offset during the scheduling of delivery or dispatch. 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 often 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. 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.

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 on the respective exchange.

Effective tax rate (ETR) on replacement cost (RC) profit or loss

Non-GAAP measure. The ETR on RC profit or loss is calculated by dividing taxation on a RC basis by RC profit or loss before tax. Information on RC profit or loss is provided below. BP believes it is helpful to disclose the ETR on RC profit or loss because this measure excludes the impact of price changes on the replacement of inventories and allows for more meaningful comparisons between reporting periods. The nearest equivalent measure on an IFRS basis is the ETR on profit or loss for the period. A reconciliation to GAAP information is provided on page 344.

Fair value accounting effects

Non-GAAP adjustments to IFRS profit or loss. We use derivative instruments to manage the economic exposure relating to inventories above normal operating requirements of crude oil, natural gas and petroleum products. Under IFRS, these inventories are recorded at historical cost. The related derivative instruments, however, are required to be recorded at fair value with gains and losses recognized in the income statement. This is because hedge accounting is either not permitted or not followed, principally due to the impracticality of effectiveness-testing requirements. Therefore, measurement differences in relation to recognition of gains and losses occur. Gains and losses on these inventories are not recognized until the commodity is sold in a subsequent accounting period. Gains and losses on the related derivative commodity contracts are recognized in the income statement, from the time the derivative commodity contract is entered into, on a fair value basis using forward prices consistent with the contract maturity.

BP enters into physical commodity contracts to meet certain business requirements, such as the purchase of crude for a refinery or the sale of BP's gas production. Under IFRS these physical contracts are treated as derivatives and are required to be fair valued when they are managed as part of a larger portfolio of similar transactions. Gains and losses arising are recognized in the income statement from the time the derivative commodity contract is entered into.

IFRS require that inventory held for trading is recorded at its fair value using period-end spot prices, whereas any related derivative commodity instruments are required to be recorded at values based on forward prices consistent with the contract maturity. Depending on market conditions, these forward prices can be either higher or lower than spot prices, resulting in measurement differences.

BP enters into contracts for pipelines and other transportation, storage capacity, oil and gas processing and liquefied natural gas (LNG) that, under IFRS, are recorded on an accruals basis. These contracts are risk-managed using a variety of derivative instruments that are fair valued under IFRS. This results in measurement differences in relation to recognition of gains and losses.

The way that BP manages the economic exposures described above, and measures performance internally, differs from the way these activities are measured under IFRS. BP calculates this difference for consolidated entities by comparing the IFRS result with management's internal measure of performance. Under management's internal measure of performance the inventory, transportation and capacity contracts in question are valued based on fair value using relevant forward prices prevailing at the end of the period. The fair values of derivative instruments used to risk manage certain oil, gas and other contracts, are deferred to match with the underlying exposure and the commodity contracts for business requirements are accounted for on an accruals basis. We believe that disclosing management's estimate of this difference provides useful information for investors because it enables investors to see the economic effect of these activities as a whole.

In addition, from 2018 fair value accounting effects include changes in the fair value of the near-term portions of LNG contracts that fall within BP's risk management framework. LNG contracts are not considered derivatives, because there is insufficient market liquidity, and they are therefore accrual accounted under IFRS. However, oil and natural gas derivative financial instruments (used to risk manage the near-term portions of the LNG contracts) are fair valued under IFRS. The fair value accounting effect reduces timing differences between recognition of the derivative financial instruments used to risk manage the LNG contracts and the recognition of the LNG contracts themselves, which therefore gives a better representation of performance in each period. Comparative information has not been restated on the basis that the effect was not material.

Finance debt ratio
Finance debt ratio is defined as the ratio of finance debt to the total of finance debt plus total equity.

Free cash flow
Operating cash flow less net cash used in investing activities and lease liability payments included in financing activities, as presented in the group cash flow statement.

Gearing and net debt
Non-GAAP measures. Net debt is calculated as finance debt, as shown in the balance sheet, plus the fair value of associated derivative financial instruments that are used to hedge foreign currency exchange and interest rate risks relating to finance debt, for which hedge accounting is applied, less cash and cash equivalents. Gearing is defined as the ratio of net debt to the total of net debt plus total equity. BP believes these measures provide useful information to investors. Net debt enables investors to see the economic effect of finance debt, related hedges and cash and cash equivalents in total. Gearing enables investors to see how significant net debt is relative to total equity. The derivatives are reported on the balance sheet within the headings 'Derivative financial instruments'. See Financial statements – Note 27 for information on finance debt, which is the nearest equivalent measure to net debt on an IFRS basis.

We are unable to present reconciliations of forward-looking information for gearing to finance debt ratio, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to present a meaningful comparable GAAP forward-looking financial measure. These items include fair value asset (liability) of hedges related to finance debt and cash and cash equivalents, that are difficult to predict in advance in order to include in a GAAP estimate.

Henry Hub
A distribution hub on the natural gas pipeline system in Erath, Louisiana, that lends its name to the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange and the over-the-counter swaps traded on Intercontinental Exchange.

Hydrocarbons
Liquids and natural gas. Natural gas is converted to oil equivalent at 5.8 billion cubic feet = 1 million barrels.

Inorganic capital expenditure
A subset of capital expenditure and is a non-GAAP measure. Inorganic capital expenditure comprises consideration in business combinations and certain other significant investments made by the group. It is reported on a cash basis. BP believes that this measure provides useful information as it allows investors to understand how BP's management invests funds in projects which expand the group's activities through acquisition. Further information and a reconciliation to GAAP information is provided on page 299.

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

Joint arrangement
An arrangement in which two or more parties have joint control.

Joint control
Contractually agreed sharing of control over an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control.

Joint operation
A joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement.

Joint venture
A joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement.

Liquids
Comprises crude oil, condensate and natural gas liquids. For the Upstream segment, it also includes bitumen.

LNG train
An LNG train is a processing facility used to liquefy and purify natural gas in the formation of LNG.

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.

Net debt including leases
Non-GAAP measure. Net debt including leases is calculated as net debt plus lease liabilities, less the net amount of partner receivables and payables relating to leases entered into on behalf of joint operations. BP believes this measure provides useful information to investors as it enables investors to understand the impact of the group's lease portfolio on net debt. See Financial statements – Note 27 for information on finance debt, which is the nearest equivalent measure to net debt on an IFRS basis.

Net generating capacity
The sum of the rated capacities of the assets/turbines that have entered into commercial operation, including BP's share of equity-accounted entities. The gross data is the equivalent capacity on a gross-joint venture basis, which includes 100% of the capacity of equity-accounted entities where BP has partial ownership.

Non-operating items
Charges and credits are included in the financial statements that BP discloses separately because it considers such disclosures to be meaningful and relevant to investors. They are items that management considers not to be part of underlying business operations and are disclosed in order to enable investors better to understand and evaluate the group's reported financial performance. Non-operating items within equity-accounted earnings are reported net of incremental income tax reported by the equity-accounted entity. An analysis of non-operating items by segment and type is shown on page 300.

Operating cash flow
Net cash provided by (used in) operating activities as stated in the group cash flow statement. When used in the context of a segment rather than the group, the terms refer to the segment's share thereof.

Operating cash flow excluding Gulf of Mexico oil spill payments
Non-GAAP measure. It is calculated by excluding post-tax operating cash flows relating to the Gulf of Mexico oil spill from net cash provided by operating activities as reported in the group cash flow statement. BP believes net cash provided by operating activities excluding amounts related to the Gulf of Mexico oil spill is a useful measure as it allows for more meaningful comparisons between reporting periods. The nearest equivalent measure on an IFRS basis is net cash provided by operating activities.

Organic free cash flow is operating cash flow excluding Gulf of Mexico oil spill payments less organic capital expenditure.

Operating cash margin
Operating cash margin is operating cash flow divided by the applicable number of barrels of oil equivalent produced, at $52/bbl flat oil prices. Expected operating cash margins are calculated over the period 2016-2025.

Operating management system (OMS)
BP's OMS helps us manage risks in our operating activities by setting out BP's principles for good operating practice. It brings together BP requirements on health, safety, security, the environment, social responsibility and operational reliability, as well as related issues, such as maintenance, contractor relations and organizational learning, into a common management system.

Organic capital expenditure
A subset of capital expenditure and is a non-GAAP measure. Organic capital expenditure comprises capital expenditure less inorganic capital expenditure. BP believes that this measure provides useful information as it allows investors to understand how BP's management invests funds in developing and maintaining the group's assets. An analysis of organic capital expenditure by segment and region, and a reconciliation to GAAP information is provided on page 299.

We are unable to present reconciliations of forward-looking information for organic capital expenditure to total cash capital expenditure, because without unreasonable efforts, we are unable to forecast accurately the adjusting item, inorganic capital expenditure, that is difficult to predict in advance in order to derive the nearest GAAP estimate.

Organic sources of cash and organic uses of cash
Non-GAAP measure. Organic sources of cash is the sum of operating cash flow, excluding Gulf of Mexico oil spill payments, and proceeds of loan repayments. Organic uses of cash is the sum of organic capital expenditure, dividends and share buybacks. The nearest equivalent measure on an IFRS basis for organic sources of cash is net cash provided by operating activities and the nearest equivalent measures on an IFRS basis for organic uses of cash are total cash capital expenditure, dividends paid to BP shareholders and net issue (repurchase) of shares.

Production-sharing agreement / contract (PSA / PSC)
An arrangement through which an oil and gas company bears the risks and costs of exploration, development and production. In return, if exploration is successful, the oil company receives entitlement to variable physical volumes of hydrocarbons, representing recovery of the costs incurred and a stipulated share of the production remaining after such cost recovery.

Readily marketable inventory (RMI)
RMI is inventory held and price risk-managed by our integrated supply and trading function (IST) which could be sold to generate funds if required. It comprises oil and oil products for which liquid markets are available and excludes inventory which is required to meet operational requirements and other inventory which is not price risk-managed. RMI is reported at fair value. Inventory held by the Downstream fuels business for the purpose of sales and marketing, and all inventories relating to the lubricants and petrochemicals businesses, are not included in RMI. BP believes that disclosing the amounts of RMI and paid-up RMI is useful to investors as it enables them to better understand and evaluate the group's inventories and liquidity position by enabling them to see the level of discretionary inventory held by IST and to see builds or releases of liquid trading inventory.

Paid-up RMI excludes RMI which has not yet been paid for. For inventory that is held in storage, a first-in first-out (FIFO) approach is used to determine whether inventory has been paid for or not. Unpaid RMI is RMI which has not yet been paid for by BP. RMI at fair value, Paid-up RMI and Unpaid RMI are non-GAAP measures. A reconciliation of total inventory as reported on the group balance sheet to paid-up RMI is provided on page 346.

Realizations
Realizations are the result of dividing revenue generated from hydrocarbon sales, excluding revenue generated from purchases made for resale and royalty volumes, by revenue generating hydrocarbon production volumes. Revenue generating hydrocarbon production reflects the BP share of production as adjusted for any production which does not generate revenue. Adjustments may include losses due to shrinkage, amounts consumed during processing, and contractual or regulatory host committed volumes such as royalties. For the Upstream segment, realizations include transfers between businesses.

Refining availability
Represents Solomon Associates' operational availability for BP-operated refineries, which is defined as the percentage of the year that a unit is available for processing after subtracting the annualized time lost due to turnaround activity and all planned mechanical, process and regulatory downtime.

Refining marker margin (RMM)
The average of regional indicator margins weighted for BP's crude refining capacity in each region. Each regional marker margin is based on product yields and a marker crude oil deemed appropriate for the region. The regional indicator margins may not be representative of the margins achieved by BP in any period because of BP's particular refinery configurations and crude and product slate.

Refining net cash margin per barrel
Refining net cash margin is defined by Solomon Associates as the net margin achieved after subtracting cash operating expenses and adding any refinery revenue from other sources. Net cash margin is expressed in US dollars per barrel of net refinery input.

Refinery utilization
Refinery utilization is calculated as annual throughput (thousands of barrels per day) divided by crude distillation capacity.

Replacement cost (RC) profit or loss
Reflects the replacement cost of inventories sold in the period and is arrived at by excluding inventory holding gains and losses from profit or loss. RC profit or loss is the measure of profit or loss that is required to be disclosed for each operating segment under IFRS. RC profit or loss for the group is a non-GAAP measure. Management believes this measure is useful to illustrate to investors the fact that crude oil and product prices can vary significantly from period to period and that the impact on our reported result under IFRS can be significant. Inventory holding gains and losses vary from period to period due to changes in prices as well as changes in underlying inventory levels. In order for investors to understand the operating performance of the group excluding the impact of price changes on the replacement of inventories, and to make comparisons of operating performance between reporting periods, BP's management

believes it is helpful to disclose this measure. The nearest equivalent measure on an IFRS basis is profit or loss attributable to BP shareholders. See Financial statements – Note 5. A reconciliation to GAAP information is provided on page 298.

RC profit or loss per share
Non-GAAP measure. Earnings per share is defined in Financial statements – Note 11. RC profit or loss per share is calculated using the same denominator. The numerator used is RC profit or loss attributable to BP shareholders rather than profit or loss attributable to BP shareholders. BP believes it is helpful to disclose the RC profit or loss per share because this measure excludes the impact of price changes on the replacement of inventories and allows for more meaningful comparisons between reporting periods. The nearest equivalent measure on an IFRS basis is basic earnings per share based on profit or loss for the period attributable to BP shareholders. A reconciliation to GAAP information is provided on page 344.

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.

Return on average capital employed
Non-GAAP measure. Return on average capital employed (ROACE) is underlying replacement cost profit, after adding back non-controlling interest and interest expense net of tax (for 2015, 2016 and 2017 interest expense was net of notional tax at an assumed 35%), divided by average capital employed (total equity plus finance debt), excluding cash and cash equivalents and goodwill. Interest expense is finance costs excluding lease interest and the unwinding of the discount on provisions and other payables before tax. BP believes it is helpful to disclose the ROACE because this measure gives an indication of the company's capital efficiency. The nearest GAAP measures of the numerator and denominator are profit or loss for the period attributable to BP shareholders and average capital employed respectively. The reconciliation of the numerator and denominator is provided on page 345.

We are unable to present forward-looking information of the nearest GAAP measures of the numerator and denominator for ROACE, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to calculate a meaningful comparable GAAP forward-looking financial measure. These items include inventory holding gains or losses and interest net of tax, that are difficult to predict in advance in order to include in a GAAP estimate.

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.

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.

UK National Balancing Point
A virtual trading location for sale, purchase and exchange of UK natural gas. It is the pricing and delivery point for the Intercontinental Exchange natural gas futures contract.

Unconventionals
Resources found in geographic accumulations over a large area, that usually present additional challenges to development such as low permeability or high viscosity. Examples include shale gas and oil, coalbed methane, gas hydrates and natural bitumen deposits. These typically require specialized extraction technology such as hydraulic fracturing or steam injection.

Underlying effective tax rate (ETR)
Non-GAAP measure. The underlying ETR is calculated by dividing taxation on an underlying replacement cost (RC) basis by underlying RC profit or loss before tax. Taxation on an underlying RC basis is taxation on a RC basis for the period adjusted for taxation on non-operating items and fair value accounting effects. Information on underlying RC profit or loss is provided below. BP believes it is helpful to disclose the underlying ETR because this measure may help investors to understand and evaluate, in the same manner as management, the underlying trends in BP's operational performance on a comparable basis, period on period. The nearest equivalent measure on an IFRS basis is the ETR on profit or loss for the period. A reconciliation to GAAP information is provided on page 344.

We are unable to present reconciliations of forward-looking information for underlying ETR to ETR on profit or loss for the period, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to present a meaningful comparable GAAP forward-looking financial measure. These items include the taxation on inventory holding gains and losses, non-operating items and fair value accounting effects, that are difficult to predict in advance in order to include in a GAAP estimate.

Underlying production
Production after adjusting for acquisitions and divestments and entitlement impacts in our production-sharing agreements (PSAs). 2019 underlying production, when compared with 2018, is production after adjusting for BPX Energy, other acquisitions and divestments, and entitlement impacts in our PSAs.

Underlying RC profit or loss
Non-GAAP measure. RC profit or loss after adjusting for non-operating items and fair value accounting effects. See page 300 and 344 for additional information on the non-operating items and fair value accounting effects that are used to arrive at underlying RC profit or loss in order to enable a full understanding of the events and their financial impact. BP believes that underlying RC profit or loss is a useful measure for investors because it is a measure closely tracked by management to evaluate BP's operating performance and to make financial, strategic and operating decisions and because it may help investors to understand and evaluate, in the same manner as management, the underlying trends in BP's operational performance on a comparable basis, year on year, by adjusting for the effects of these non-operating items and fair value accounting effects.

The nearest equivalent measure on an IFRS basis for the group is profit or loss for the year attributable to BP shareholders. The nearest equivalent measure on an IFRS basis for segments is RC profit or loss before interest and taxation. Underlying profit in the chief executive officer's letter on page 4 refers to full year underlying RC profit for the group. A reconciliation to GAAP information is provided on page 298.

Underlying replacement cost (RC) profit or loss per share
Non-GAAP measure. Earnings per share is defined Financial statements – Note 11. Underlying RC profit or loss per share is calculated using the same denominator. The numerator used is underlying RC profit or loss attributable to BP shareholders rather than profit or loss attributable to BP shareholders. BP believes it is helpful to disclose the underlying RC profit or loss per share because this measure may help investors to understand and evaluate, in the same manner as management, the underlying trends in BP's operational performance on a comparable basis, period on period. The nearest equivalent measure on an IFRS basis is basic earnings per share based on profit or loss for the period attributable to BP shareholders. A reconciliation to GAAP information is provided on page 344.

Upstream plant reliability
BP-operated Upstream plant reliability is calculated taking 100% less the ratio of total unplanned plant deferrals divided by installed production capacity. Unplanned plant deferrals are associated with the topside plant and where applicable the subsea equipment (excluding wells and reservoir). Unplanned plant deferrals include breakdowns, which does not include Gulf of Mexico weather related downtime.

Upstream unit production cost
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.

Wellwork
Activities undertaken on previously completed wells with the primary objective to restore or increase production.

West Texas Intermediate (WTI)
A light sweet crude oil, priced at Cushing, Oklahoma, which serves as a benchmark price for purchases of oil in the US.

Working capital
Movements in inventories and other current and non-current assets and liabilities as stated in the group cash flow statement.

Trade marks

Trade marks of the BP group appear throughout this report. They include: *Aral, ARCO, BP, BP Infinia, BPme, BPme Rewards, Castrol*

Trade marks:

Butamax – a registered trade mark of Butamax Advance Biofuels LLC.

Fulcrum BioEnergy – registered trade marks of Fulcrum BioEnergy, Inc.

M&S Simply Food – a registered trade mark of Marks & Spencer plc.

REWE to Go – a registered trade mark of REWE.

Non-GAAP measures reconciliations

Non-GAAP information on fair value accounting effects

The impacts of fair value accounting effects, relative to management's internal measure of performance, and a reconciliation to GAAP information is set out below. Further information on fair value accounting effects is provided on page 339.

			$ million
	2019	2018	2017
Upstream			
Unrecognized (gains) losses brought forward from previous period[a]	**(455)**	(419)	(393)
Favourable (adverse) impact relative to management's measure of performance	**706**	(39)	27
Exchange translation gains (losses) on fair value accounting effects	**2**	3	2
Unrecognized (gains) losses carried forward	**253**	(455)	(364)
Downstream[b]			
Unrecognized (gains) losses brought forward from previous period[a]	**(56)**	(151)	(71)
Favourable (adverse) impact relative to management's measure of performance	**160**	95	(135)
Unrecognized (gains) losses carried forward	**104**	(56)	(206)
Favourable (adverse) impact relative to management's measure of performance – by region			
Upstream			
US	**(179)**	(35)	192
Non-US	**885**	(4)	(165)
	706	(39)	27
Downstream[b]			
US	**148**	(155)	(29)
Non-US	**12**	250	(106)
	160	95	(135)
	866	56	(108)
Taxation credit (charge)	**(155)**	12	12
	711	68	(96)

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

[b] Fair value accounting effects arise solely in the fuels business.

Reconciliation of basic earnings per ordinary share to RC profit (loss) per share and to underlying RC profit per share

					Per ordinary share – cents
	2019	2018	2017	2016	2015
Profit (loss) for the year[a]	**19.84**	46.98	17.20	0.61	(35.39)
Inventory holding (gains) losses, before tax	**(3.29)**	4.01	(4.32)	(8.52)	10.31
Taxation charge (credit) on inventory holding gains and losses	**0.77**	(0.99)	1.14	2.58	(3.10)
RC profit (loss) for the year	**17.32**	50.00	14.02	(5.33)	(28.18)
Net (favourable) adverse impact of non-operating items and fair value accounting effects, before tax	**40.73**	16.93	18.94	35.99	82.23
Taxation charge (credit) on non-operating items and fair value accounting effects	**(8.81)**	(3.23)	(1.65)	(16.87)	(21.83)
Underlying RC profit for the year	**49.24**	63.70	31.31	13.79	32.22

[a] Profit attributable to BP shareholders.

Reconciliation of effective tax rate (ETR) to ETR on RC profit or loss and adjusted ETR

Taxation (charge) credit

					$ million
	2019	2018	2017	2016	2015
Taxation on profit or loss for the year	**(3,964)**	(7,145)	(3,712)	2,467	3,171
Adjusted for taxation on inventory holding gains and losses	**(156)**	198	(225)	(483)	569
Taxation on a RC profit or loss basis	**(3,808)**	(7,343)	(3,487)	2,950	2,602
Adjusted for taxation on non-operating items and fair value accounting effects	**1,788**	522	1,184	3,162	4,000
Adjusted for the impact of US tax reform	**—**	121	(859)	—	—
Adjusted for the impact of the reduction in the rate of the UK North Sea supplementary charge	**—**	—	—	434	915
Adjusted taxation	**(5,596)**	(7,986)	(3,812)	(646)	(2,313)

Effective tax rate

					%
	2019	2018	2017	2016	2015
ETR on profit or loss for the year	**49**	43	52	107	33
Adjusted for inventory holding gains and losses	**2**	(1)	3	(31)	1
ETR on RC profit or loss	**51**	42	55	76	34
Adjusted for non-operating items and fair value accounting effects	**(15)**	(5)	(9)	(69)	(15)
Adjusted for the impact of US tax reform	**—**	1	(8)	—	—
Adjusted for the impact of the reduction in the rate of the UK North Sea supplementary charge	**—**	—	—	16	12
Adjusted ETR	**36**	38	38	23	31

Return on average capital employed (ROACE)

					$ million
	2019	2018	2017	2016	2015
Profit (loss) for the year attributable to BP shareholders	**4,026**	9,383	3,389	115	(6,482)
Inventory holding (gains) losses, net of tax	**(511)**	603	(628)	(1,114)	1,320
Non-operating items and fair value accounting effects, net of tax	**6,475**	2,737	3,405	3,584	11,067
Underlying RC profit	**9,990**	12,723	6,166	2,585	5,905
Interest expense, net of tax[a]	**1,744**	1,583	924	635	576
Non-controlling interests	**164**	195	79	57	82
Adjusted underlying RC profit	**11,898**	14,501	7,169	3,277	6,563
Total equity	**100,708**	101,548	100,404	96,843	98,387
Finance debt	**67,724**	65,132	62,574	57,665	52,465
Capital employed (2019 average $167,556 million)	**168,432**	166,680	162,978	154,508	150,852
Less: Goodwill	**11,868**	12,204	11,551	11,194	11,627
Cash and cash equivalents	**22,472**	22,468	25,586	23,484	26,389
	134,092	132,008	125,841	119,830	112,836
Average capital employed excluding goodwill and cash and cash equivalents	**133,050**	128,925	123,481	117,002	118,702
ROACE	**8.9%**	11.2 %	5.8%	2.8%	5.5%

[a] Calculated on a post-tax basis (for 2017 and earlier interest expense was net of notional tax at an assumed 35%).

Readily marketable inventory (RMI)

Readily marketable inventory (RMI) is oil and oil products inventory held and price risk-managed by BP`s integrated supply and trading function (IST) which could be sold to generate funds if required. Details of RMI balances and a reconciliation to GAAP information is set out below. Further information on RMI, RMI at fair value, paid-up RMI and unpaid RMI is provided on page 341.

At 31 December		$ million
	2019	2018
RMI at fair value	**6,837**	4,202
Paid-up RMI	**3,217**	1,641

Reconciliation of non-GAAP information

At 31 December		$ million
	2019	2018
Reconciliation of total inventory to paid-up RMI		
Inventories as reported on the group balance sheet	**20,880**	17,988
Less: (a) inventories which are not oil and oil products and (b) oil and oil product inventories which are not risk-managed by IST	**(14,280)**	(14,066)
RMI on IFRS basis	**6,600**	3,922
Plus: difference between RMI at fair value and RMI on an IFRS basis	**237**	280
RMI at fair value	**6,837**	4,202
Less: unpaid RMI at fair value	**(3,620)**	(2,561)
Paid-up RMI	**3,217**	1,641

The Directors' report on pages 72-99, 101 (in respect of the remuneration committee report shown in green only), 128-130, 232-259 and 297-346 was approved by the board and signed on its behalf by Ben J. S. Mathews, company secretary on 18 March 2020.

BP p.l.c.
Registered in England and Wales No. 102498

Signatures

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

BP p.l.c.
(Registrant)

/s/ Ben J. S. Mathews
Company secretary
18 March 2020

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 2019. A cross reference to Form 20-F requirements is included on page 348.

This document contains the Strategic report on the inside front cover and pages 1-71 and the Directors' report on pages 72-99, 101 (in part only), 128-130, 232-259 and 297-346. 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 100-127. The consolidated financial statements of the group are on pages 131-231 and the corresponding reports of the auditor are on pages 132-151. The parent company financial statements of BP p.l.c. are on pages 260-296.

The Directors' statements (comprising the Statement of directors' responsibilities; Risk management and internal control; Longer-term viability; Going concern; and Fair, balanced and understandable), the independent auditor's report on the annual report and accounts to the members of BP p.l.c., the parent company financial statements of BP p.l.c. and corresponding auditor's report and a non-GAAP measure of operating cash flow excluding Gulf of Mexico oil spill payments★ in the tables on pages 35, 36 and 37 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 2019 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 2019*, forms any part of this document. References in this document to other documents on the BP website, such as *BP Energy Outlook*, *BP Sustainability Report*, *BP Statistical Review* of *World Energy* and *BP Technology Outlook* are included as an aid to their location and are not incorporated by reference into this document.

BP p.l.c. is the parent company of the BP group of companies. The company was incorporated in 1909 in England and Wales and changed its name to BP p.l.c. in 2001. Where we refer to the company, we mean BP p.l.c. The company and each of its subsidiaries★ are separate legal entities. Unless otherwise stated or the context otherwise requires, the term "BP" 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 328 for more details) and in Germany in the form of a global depositary certificate representing BP ordinary shares traded on the Frankfurt, Hamburg and Dusseldorf Stock Exchanges.

The term 'shareholder' in this report means, unless the context otherwise requires, investors in the equity capital of BP p.l.c., both direct and indirect. As the company's shares, in the form of ADSs, are listed on the NYSE, an Annual Report on Form 20-F is filed with the SEC. Ordinary shares are ordinary fully paid shares in BP p.l.c. of 25 cents each. Preference shares are cumulative first preference shares and cumulative second preference shares in BP p.l.c. of £1 each.

Registered office and our worldwide headquarters:
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Our agent in the US:
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Registered in England and Wales No. 102498.
London Stock Exchange symbol 'BP'.

Exhibits

The following documents are filed in the Securities and Exchange Commission (SEC) EDGAR system, as part of this Annual Report on Form 20-F, and can be viewed on the SEC's website.

Exhibit 1	Memorandum and Articles of Association of BP p.l.c.*******†
Exhibit 2	Description of rights of each class of securities registered under Section 12 of the Securities Exchange Act of 1934†
Exhibit 4.1	The BP Executive Directors' Incentive Plan******†
Exhibit 4.4	Director's Service Agreement for B Looney†
Exhibit 4.7	Director's Service Contract for Dr B Gilvary***†
Exhibit 4.10	The BP Share Award Plan 2015*******†
Exhibit 8	Subsidiaries (included as Note 37 to the Financial Statements)
Exhibit 11	Code of Ethics*†
Exhibit 12	Rule 13a – 14(a) Certifications†
Exhibit 13	Rule 13a – 14(b) Certifications#†
Exhibit 15.1	Consent of DeGolyer and MacNaughton†
Exhibit 15.2	Report of DeGolyer and MacNaughton†
Exhibit 15.3	Consent of Netherland, Sewell & Associates†
Exhibit 15.4	Report of Netherland, Sewell & Associates†
Exhibit 15.5	Consent Decree*******†
Exhibit 15.6	Gulf states Settlement Agreement*******†
Exhibit 15.7	Consent of Ernst & Young LLP†
Exhibit 15.8	Consent of Deloitte LLP†
Exhibit 101	Interactive data files

* 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 2010.

*** Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2011.

***** Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2013.

****** Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2014.

******* Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2015.

\# Furnished only.

† Included only in the annual report filed in the Securities and Exchange Commission EDGAR system.

The total amount of long-term securities of BP p.l.c. and its subsidiaries under any one instrument does not exceed 10% of their total assets on a consolidated basis.

The company agrees to furnish copies of any or all such instruments to the SEC on request.

Paper: Nautilus SuperWhite is a premium ecological paper. It is made from 100% post-consumer waste recycled paper and is FSC® (Forest Stewardship Council®) certified. The paper also holds the EU Ecolabel certification. The manufacturing mill also holds ISO 14001 environmental certification. Printed in the UK by Pureprint Group.

FSC www.fsc.org RECYCLED Paper made from recycled material FSC® C022913

BP's corporate reporting suite includes information about our financial and operating performance, sustainability performance and also on global energy trends and projections.

Annual Report and Form 20-F 2019
Details of our financial and operating performance in print and online.

bp.com/annualreport

BP Energy Outlook
Provides our projections of future energy trends and factors that could affect them out to 2040.

bp.com/energyoutlook

Sustainability Report 2019
Details of our sustainability performance with additional information online.

bp.com/sustainability

Statistical Review of World Energy 2020
An objective review of key global energy trends.

bp.com/statisticalreview

Financial and Operating Information 2015-2019
How technology could influence the way we meet the energy challenge into the future.

bp.com/financialandoperating

Copies
You can order BP's printed publications free of charge from *bp.com/annualreport.*

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