BP PLC
Form 20-F
March 29, 2018

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 20-F

(Mark One)
REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) or (g) OF THE SECURITIES EXCHANGE ACT OF 1934

OR

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended 31 December 2017
OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

OR

SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number: 1-6262

BP p.l.c.
(Exact name of Registrant as specified in its charter)

England and Wales
(Jurisdiction of incorporation or organization)

1 St James's Square, London SW1Y 4PD
United Kingdom
(Address of principal executive offices)

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Securities registered or to be registered pursuant to Section 12(b) of the Act

Title of each class	Name of each exchange on which registered
Ordinary Shares of 25c each	New York Stock Exchange*
Floating Rate Guaranteed Notes due May 2018	New York Stock Exchange
Floating Rate Guaranteed Notes due August 2018	New York Stock Exchange
Floating Rate Guaranteed Notes due September 2018	New York Stock Exchange
Floating Rate Guaranteed Notes due 2019	New York Stock Exchange
Floating Rate Guaranteed Notes due 2021	New York Stock Exchange
Floating Rate Guaranteed Notes due 2022	New York Stock Exchange
1.375% Guaranteed Notes due 2018	New York Stock Exchange
2.241% Guaranteed Notes due 2018	New York Stock Exchange
4.750% Guaranteed Notes due 2019	New York Stock Exchange
2.237% Guaranteed Notes due 2019	New York Stock Exchange
1.676% Guaranteed Notes due 2019	New York Stock Exchange
1.768% Guaranteed Notes due 2019	New York Stock Exchange
2.315% Guaranteed Notes due 2020	New York Stock Exchange
2.521% Guaranteed Notes due 2020	New York Stock Exchange
4.500% Guaranteed Notes due 2020	New York Stock Exchange
4.742% Guaranteed Notes due 2021	New York Stock Exchange
3.561% Guaranteed Notes due 2021	New York Stock Exchange
2.112% Guaranteed Notes due 2021	New York Stock Exchange
2.500% Guaranteed Notes due 2022	New York Stock Exchange
2.520% Guaranteed Notes due 2022	New York Stock Exchange
3.245% Guaranteed Notes due 2022	New York Stock Exchange
3.062% Guaranteed Notes due 2022	New York Stock Exchange
2.750% Guaranteed Notes due 2023	New York Stock Exchange
3.216% Guaranteed Notes due 2023	New York Stock Exchange
3.994% Guaranteed Notes due 2023	New York Stock Exchange
3.535% Guaranteed Notes due 2024	New York Stock Exchange
3.814% Guaranteed Notes due 2024	New York Stock Exchange
3.224% Guaranteed Notes due 2024	New York Stock Exchange
3.506% Guaranteed Notes due 2025	New York Stock Exchange
3.119% Guaranteed Notes due 2026	New York Stock Exchange
3.017% Guaranteed Notes due 2027	New York Stock Exchange
3.279% Guaranteed Notes due 2027	New York Stock Exchange
3.588% Guaranteed Notes due 2027	New York Stock Exchange
3.723% Guaranteed Notes due 2028	New York Stock Exchange

* Not for trading, but only in connection with the registration of American Depositary Shares, pursuant to the requirements of the Securities and Exchange Commission

Securities registered or to be registered pursuant to Section 12(g) of the Act.
None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act.
None

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.

Ordinary Shares of 25c each	21,288,193,071
Cumulative First Preference Shares of £1 each	7,232,838
Cumulative Second Preference Shares of £1 each	5,473,414

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. Yes No

Note—Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 from their obligations under those Sections.

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or an emerging growth company. See definition of "large accelerated filer," "accelerated filer," and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer Accelerated filer Non-accelerated filer Emerging growth company

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange Act.

† The term "new or revised financial accounting standard" refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.

Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing:

U.S. GAAP International Financial Reporting Standards as issued by the International Accounting Standards Board Other

If "Other" has been checked in response to the previous question, indicate by check mark which financial statement item the registrant has elected to follow.

Item 17 Item 18

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No

4 B P A nnual R eport and Form 20-F 2017 A year of strong delivery and growth BP Annual Report and Form 20-F 2017

Strategic report Overview 2 BP at a glance 4 How we run our business 6 Chairman's letter 8 Group chief executive's letter 10 The changing world of energy Strategy 12 Our strategy 14 A year of delivery 18 Measuring our progress Performance 20 Global energy markets 21 Group performance 26 Upstream 32 Downstream 38 Rosneft 41 Other businesses and corporate 41 Gulf of Mexico oil spill 42 Alternative Energy 44 Innovation in BP 47 Sustainability 47 Safety and security 50 Climate change 51 Managing our impacts 51 Value to society 52 Human rights 52 Environment 52 Ethical conduct 53 Our people 55 How we manage risk 57 Risk factors Corporate governance 60 Board of directors 66 Executive team 70 Introduction from the chairman 72 Board activity in 2017 76 Shareholder engagement 76 International advisory board 77 Audit committee 84 Safety, ethics and environment assurance committee 86 Remuneration committee 87 Geopolitical committee 88 Chairman's committee 89 Nomination committee 90 Directors' remuneration report Financial statements 123 Consolidated financial statements of the BP group 130 Notes on financial statements 191 Supplementary information on oil and natural gas (unaudited) Additional disclosures 247 Contents Including information on liquidity and capital resources, oil and gas disclosures, upstream regional analysis and legal proceedings. Shareholder information 279 Contents Including information on dividends, our annual general meeting and share prices. 289 Glossary 294 Non-GAAP measures reconciliations 297 Signatures 298 Cross-reference to Form 20-F 299 Information about this report Glossary Words with this symbol are defined in the glossary on page 289. Cautionary statement This document should be read in conjunction with the cautionary statement on page 277. Contents

The energy we produce serves to power economic growth and lift people out of poverty. The way heat, light and mobility are delivered is changing. We aim to anchor our business in these changing patterns of demand, rather than in the quest for supply. We have a real contribution to make to the world's ambition of a low carbon future. BP Annual Report and Form 20-F 2017 1

BP at a glance See Glossary ScaleWe are a global energy business with wide reach across the world's energy system. We have operations in Europe, North and South America, Australasia, Asia and Africa. 74,000 70 18,441 employees countries million barrels of oil equivalent – proved hydrocarbon reservesa 18,300 1.5bn retail sites barrels of oil equivalent transported by BP shipping a On a combined basis of subsidiaries and equity-accounted entities. Senegal Made a major gas discovery offshore Senegal with joint venture partner Kosmos Energy. US Achieved record crude throughput levels at Whiting refinery, and listed BP Midstream Partners as a separate company. Azerbaijan Signed a contract that will help maximize recovery from the Azeri-Chirag-Deepwater Gunashli fields over the next 32 years. Europe Established Lightsource BP – Europe's biggest developer of large-scale solar projects, and achieved record production at our Geel petrochemicals plant in Belgium. Trinidad Made two significant gas discoveries with the Savannah and Macadamia exploration wells. BP in action Highlights of some of our activities in 2017. Argentina Formed a new integrated energy company with Bridas, to create the country's largest privately owned energy company. Egypt Made a gas discovery in the North Damietta Offshore Concession in the East Nile Delta. Mexico Opened more than 120 retail sites, and became one of the first private companies to supply natural gas to its domestic market. Gulf of Mexico Found significant additional oil resources at our Atlantis field using new seismic imaging technology. BP Annual Report and Form 20-F 20172

See Glossary Performance Data as at or for the year ended 31 December 2017 unless otherwise stated. More information Group performance Page 21 Upstream Page 26 Downstream Page 32 Rosneft Page 38 Alternative Energy Page 42 $3.4bn 3.6 18 profit attributable to BP shareholders (2016 $115 million) KPI million barrels of oil equivalent per day – hydrocarbon production (2016 3.3mmboe/d) KPI tier 1 process safety events (2016 16) KPI $6.2bn 143% underlying replacement cost profit (2016 $2.6 billion) KPI group proved reserves replacement ratio a (2016 109%) KPI We delivered seven major projects in 2017 1 Taurus and Libra 2 Trinidad onshore compression 3 Quad 204 4 Persephone 5 Juniper 6 Khazzan Phase 1 7 Zohr See A year of delivery on page 14. a On a combined basis of subsidiaries and equity-accounted entities. KPI See key performance indicators on page 18. Russia Agreed to develop resources in the Kharampurskoe and Festivalnoye licence areas jointly with Rosneft. China Sold our interest in SECCO petrochemical company to Sinopec. Indonesia Established a retail joint venture with AKR. India Agreed to work with Reliance Industries in areas such as differentiated fuels and lower carbon energy solutions. Strategic report – overview 3BP Annual Report and Form 20-F 2017

How we run our business From the deep sea to the desert, from rigs to retail, we deliver energy products and services to people around the world. We provide customers with fuel for transport, energy for heat and light, lubricants to keep engines moving and the petrochemicals products used to make everyday items such as paints, clothes and packaging. We have a diverse portfolio across businesses, resource types and geographies. Having upstream and downstream businesses, along with well-established trading capabilities, helps to mitigate the impact of commodity pricing cycles. Our geographic reach gives us access to growing markets and new resources, as well as diversifying exposure to geopolitical events. We believe that our long history, well-recognized brands and customer offers, combined with our unique partnership with Rosneft, help differentiate us from our peers. Our role in society The energy we produce helps to support economic growth and improve quality of life for millions of people. We strive to be a world-class operator, a responsible corporate citizen and a good employer. We believe that the societies and communities we work in should benefit from our presence. In supplying energy we contribute to economies around the world by employing local staff, helping to develop national and local suppliers, and through the taxes we pay to governments. Additionally, we aim to create meaningful, sustainable and positive impacts in those communities through our social investments. bp.com/society Business model foundations We also seek to grow or extend the life of existing fields – such as our Quad 204 major project which aims to unlock additional resources from the Schiehallion area of the UK North Sea. Transporting and trading We move oil and gas through pipelines and by ship, truck and rail. We also trade a variety of products including oil, natural gas, liquefied natural gas, power, carbon products and currencies. BP's traders complete around U50,000 transactions and serve more than 12,000 customers across some Q40 countries in a year. Our customers range from independent power producers to utilities and municipalities. In addition we are helping to meet LNG demand in Asia including developments in China and Vietnam. Finding oil and gas New access allows us to renew our portfolio, discover additional resources and replenish our development options. We focus our exploration activities in the areas that are competitive in the portfolio, and develop and use technology to reduce costs and risks. Developing and extracting oil and gas We create value by seeking to progress hydrocarbon resources and turn them into proved reserves or divest them if they do not fit with our strategic priorities. We develop the resources that meet our return threshold, and produce hydrocarbons that we then sell to the market or distribute to our downstream facilities. Our upstream pipeline of future projects gives us choice about which we pursue – see page 30. Creating shareholder value Safe and reliable operations We strive to create and maintain a safe operating culture where safety is front and centre. This is not only safer for people and the environment – it also improves the reliability of our assets. See Safety and security on page 47. Talented people We work to attract, motivate, develop 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 depends on it. See Our people on page 53. Finding oil and gas Developing and extracting oil and gas 4 BP Annual Report and Form 20-F 2017

Generating renewable energy We have been investing in renewables for many years – and our focus today is on biofuels, biopower, wind energy and solar energy. We operate a biofuels business in Brazil, using one of the world's most sustainable and advantaged feedstocks to produce both low carbon ethanol and low carbon power. We provide renewable power through our significant interests in onshore wind energy in the US, and develop and deploy technology in our wind business to drive efficiency. Through our acquisition of Clean Energy's renewable natural gas business, we are helping to power vehicle fleets from organic waste. And in solar energy we will target the growing demand for large-scale solar projects worldwide, including with our partner Lightsource. Our lubricants business has premium brands and access to growth markets. It also leverages technology and customer relationships, all of which we believe gives us competitive advantage. We serve automotive, industrial, marine and energy markets across the world. And in petrochemicals our proprietary technology solutions deliver leading cost positions compared to our competitors. In addition to our own petrochemicals plants, we work with partners and license our technology to third parties. We use our market intelligence to analyse supply and demand for commodities across our global network. This helps us deliver what the market needs, when it needs it, identify the best markets for BP's crude oil, source optimal raw materials for our refineries and provide competitive supply for our marketing businesses. Manufacturing and marketing fuels and products We produce refined petroleum products at our refineries and supply distinctive fuel and convenience retail services to consumers. Our advantaged infrastructure, logistics network and key partnerships help us to have differentiated fuels businesses and deliver compelling customer offers. Technology, innovation and venturing New technologies are enabling us to produce energy safely and more efficiently. We selectively research and invest in areas with the potential to add greatest value to our business now and in the future. See Innovation in BP on page 44. Partnerships and collaboration We aim to build enduring relationships with governments, customers, partners, suppliers and communities in the countries where we operate. See Rosneft on page 38. Governance and oversight Our risk management systems and policy provide a consistent and clear framework for managing and reporting risks. The board regularly reviews how we identify, evaluate and manage risks. See How we manage risk on page 55. Manufacturing Transporting and trading Marketing fuels and products Generating renewable energy

Chairman's letter Above: Meeting with investors at the 2017 annual general meeting. Dear fellow shareholder, In 2017, the global economy continued to be strong and to grow while concerns around the geopolitical environment increased. For BP, as a global business, this was the backdrop to our operations. Against this background we have had a strong year. A year in which there was delivery and growth across all our businesses as Bob describes later in his letter. This was achieved with continued strong focus on safety. It's an impressive performance from a great team. They are now fully into their stride and are performing very well. All of this gave us confidence to continue the dividend at 10 cents per ordinary share through 2017 and shareholders can still take dividends in shares rather than cash. In the fourth quarter we restarted share buybacks to offset the dilutive effects of the scrip shares. It remains the board's policy to grow sustainable free cash flow and distributions to shareholders. So, a strong year and an important first year in the delivery of the commitment we made in 2016 to shareholders. So, I'd like to take stock and reflect on where BP is now and the progress that we've made over the past eight years. BP's path We were faced with a crisis in 2010 that could have threatened the very being of the company. A crisis that should never have happened. It required resolute action on many fronts to see us through and it is a great tribute to everyone in BP that the foundations were laid for our recovery. This involved doing things differently and thinking differently. We had to act simultaneously on many fronts. We had to address the issues in the US while restructuring our investments in Russia – and all the while ensuring that we had a clear strategy for delivering value for our shareholders. All of this in a world that is looking towards a transition to lower carbon. In addressing these challenges, BP showed a deep resilience. With the leadership of Bob and his team the whole organization was engaged with the board playing a full role. It is from this resilience that we have been able to set a clear strategy with goals out to 2021. A strategy which will grow BP and be responsive to the many changes that are happening in the world around us. Our challenge for the future Our goals aim to balance society's need for more energy with our clear ambition of playing our part in the transition to a lower carbon world. We are investing for the future in both hydrocarbons and in technologies which will be important in that transition. The world is changing quickly, quicker than we have seen before. There is no one solution and no one right way ahead. Our approach is clearly aimed at being flexible and responsive. Our goals aim to balance society's need for more energy with our clear ambition of playing our part in the transition to a lower carbon world. We are investing for the future in both hydrocarbons and in technologies which will be important in that transition. BP Annual Report and Form 20-F 20176

Above: Visiting Aker's Tranby technology centre near Oslo. More information Corporate governance Page 59 Whatever scenario we look at, whether from BP or the IEA, there will need to be investment to ensure that sufficient hydrocarbons are available during the transition for the years to come. The world will continue to need supplies of hydrocarbons. We need the understanding and trust of society to make these investments to meet this global demand. Renewables cannot be developed quickly enough to meet the increasing need for energy. This is not a choice between two investment approaches, both are needed for the world to be able to grow. Our strategic priorities address this. We are committed and we demonstrate that commitment in reports that we will soon publish. Remuneration Executive remuneration remains a clear issue of focus for shareholders and society. I would like to thank our shareholders for the support which you gave to our new remuneration report at the 2017 AGM. This was an important step forward in regaining your confidence. As is clear from Dame Ann Dowling's letter later in this report, we are implementing this policy in a considered way. As is the case with the way remuneration works, there are awards maturing which are governed by our previous policy. We have carefully considered the impact of these. Working with the executives, the committee has exercised appropriate discretion to reflect your experience as shareholders over the past three years. Ann will be standing down from this committee at the AGM after three years in the chair. I would like to thank her for all the work that she has done in leading the committee through some very difficult times. Paula Reynolds will take the chair of this committee. The board The board has continued to work with Bob and his team on many issues relating to our strategy, our oversight of the risks that BP faces and our understanding of the evolving challenges of the lower carbon transition. Our oversight of these risks is principally carried out through the work of our committees. However there are certain risks, such as cyber security, where it is important that it is considered by the board. As a board we know that we can only bring long-term value to our shareholders if we understand the needs of and serve the communities in which we work. We need to listen to and be responsive to the voices of those communities and of our own employees. Membership of the board continues to evolve. Paul Anderson will be retiring at the AGM in May. Paul joined the board two months before the Deepwater Horizon accident. He has very deep experience of the energy industry and has been a major source of advice and counsel to me and to the board over these years. Paul has made a great contribution to the board and its committees over some difficult times. I thank him on my own behalf and on behalf of the board. Melody Meyer was elected to the board at the 2017 AGM. Melody has an extensive career in global oil and gas at Chevron. The board is proposing that Dame Alison Carnwath be elected as a director at the 2018 AGM. Alison has extensive financial experience both as an executive and non-executive. She has worked with global organizations and will bring a broad range of skills to the BP board and to the audit committee which she will join upon appointment. Both these appointments emphasize the board's commitment to diversity. This will continue to enhance independent thinking and healthy challenge. Our purpose BP has a clear purpose. Our role is to produce energy which can power economic growth and lift people out of poverty. We need to do this in a way that responds to the ambition of a world for a low carbon future. We have made considerable progress in 2017. It has been a great year, but we must not be complacent. We are in a competitive environment in a quickly changing world and our business needs to be ready to meet those demands. Bob and his team have once again done an excellent job in steering BP through this year and setting a course for the future. Thank you to Bob and the team, to my colleagues on the board and to all our employees for all their work during the year. My thanks also go to you our shareholders for your support of BP. I will be standing down during 2018 at some time after the May AGM and as I look back I feel good about the company. It's in a great position to grow. I am sure that I will have the opportunity to thank you for the support you have given me in due course. Carl-Henric Svanberg Chairman R9 March 2018 $7.9 bn total dividends distributed to BP shareholders 5.7% ordinary shareholders annual dividend yield 5.7% ADS shareholders annual dividend yield See GlossaryBP Annual Report and Form 20-F 2017 7 Strategic report – ????

Group chief executive’s letter Dear fellow shareholder, In this report last year, BP set out a five-year strategy and promised a story of growth. One year into that five-year plan I am pleased to report that your company has just delivered a significant year of both disciplined execution and exciting growth. In many ways it was an extraordinary year for BP. Here are some of the headlines: • Underlying profit $6.2 billion. • Upstream production up 12%. • Record earnings in Downstream. • Our most successful year for exploration since 2004. • Group reserves replacement ratio the highest in Q0 years. Of course, we were helped by an improving oil price. But that only tells part of the story. 2017 was a year where we again maintained our improved trend in safety performance for most of our main personal and process safety metrics, although we have seen a slight increase in our tier 1 events. Better safety and improved operational reliability, combined with strong discipline in our cash and capital costs, fed through into our financial performance. In a complex and uncertain world this may seem like a simple equation – safe and reliable operations plus cost discipline is good for the bottom line. But it works and the numbers prove this. We plan for the long term and we also measure our progress year on year and quarter by quarter. We were disappointed that we had to increase the provision relating to claims associated with the Gulf of Mexico spill, although we made real progress during the year in our efforts to close out the remaining claims. The claims facility is now winding down although a number of claims remain to be resolved. Our five-year plan As I said, last year we set out our strategic priorities. Simply put, these are designed to meet the dual challenge: to produce more of the affordable energy that the world needs while producing and delivering it in new ways, with fewer emissions, that society wants. The key to this dual challenge is to recognize that this is not just a race to renewables, it’s a race to lower greenhouse gas emissions. So, while we are fully committed to the energy transition that is underway, we also see a lot of uncertainty around the pace and path of how this will unfold. Our aim is to build a strong and flexible strategy with a high-quality portfolio and the ability to adapt quickly as the pace and path become clearer. That means in the Upstream we are focused on growing oil and gas in a way that offers us advantages in terms of margin and value, with the reduced emissions in mind. In the Downstream we continue to develop advantaged manufacturing and marketing businesses that can create value from existing, new and emerging markets. Above: Chairing the panel of the Oil and Gas Climate Initiative meeting in London. We said that 2017 would be a very important year for BP. We set out ambitious plans for the year and we delivered on them. $3.4bn profit attributable to BP shareholders BP Annual Report and Form 20-F 20178

We are preparing for a low carbon future by investing in new companies and technologies across BP while also leveraging knowledge from the development of our existing Alternative Energy businesses. And we are modernizing how BP works, using technology and data to work more efficiently and digitizing our processes. Disciplined execution in 2017 We said that 2017 would be a very important year for BP. We set out ambitious plans for the year and we delivered on them. We promised to start up seven major projects in the Upstream. We brought these online and under budget for the portfolio as a whole. These projects, along with the six we brought online in 2016, have contributed to a 12% increase in our production. That helps to put us on track to deliver 900,000 barrels of new production per day by R021. We also strengthened our portfolio with our most successful year of exploration since 2004, sanctioned three exciting new projects in Trinidad, India and the Gulf of Mexico and added 143% reserves replacement for the group. In the Downstream we promised to grow earnings. In fact, we had our best ever year, with a replacement cost profit of $7.2 billion, driven by strong earnings growth in our marketing and manufacturing businesses. This came from volume growth in our premium fuels and lubricants, the growth of our successful convenience retail partnerships around the world and strong performance in manufacturing. Exciting growth opportunities This is a time of transformational change for our industry. An era of abundant resources and a changing fuel mix mean that we must be competitive today and adapt fast to change for tomorrow. So, we must modernize how we work, embrace new advanced technologies and maintain our downward pressure on costs. We are already in action across BP. In the Upstream we are growing gas and advantaged oil on many fronts: signing a 25-year extension to our ACG production-sharing agreement in Azerbaijan; strengthening our relationship with Petrobras and accessing the prolific Santos basin in Brazil; extending our innovative alliance with Kosmos in West Africa; growing in Norway though our Aker BP joint venture; and adding production from onshore Abu Dhabi following the deepening of our long-term strategic relationship with the Abu Dhabi National Oil Company (ADNOC) at the end of 2016. In the Downstream we are building competitively advantaged businesses; extending our differentiated retail fuels offer in material new markets such as Mexico, India, Indonesia and China; entering into a new joint venture with DongMing Petrochemical as part of a focused growth strategy in China; renewing and creating new partnerships in lubricants with Renault Nissan, Ford, VW and Volvo. At the same time, we must look to produce and deliver energy in new ways, with fewer emissions, to help meet the world's climate goals. At BP we have been working on this challenge for over two decades and that has informed our approach today: working to reduce emissions in our operations; improving the products our customers use to help them reduce their emissions; creating new low carbon businesses and offers that complement our existing portfolio. In the low carbon space, we entered into a new partnership with Lightsource, a global leader in the development, acquisition and long-term management of large-scale solar projects. In new ventures, we have a pipeline of more than 40 active investments with more than 200 partners looking to exploit opportunities in advanced mobility, bio products, carbon management and low carbon power and storage. These are a few examples that I believe show we are in great shape to act where we see opportunity to make a real difference to this transition and, at the same time, create value for our shareholders. Strength in relationships The world is changing fast and there is a lot of uncertainty of what the future will actually look like. To stay competitive a company needs to be in tune with society. While we are making progress with issues such as gender and ethnicity representation, we recognize we still have more to do. Beyond having the right strategy, to succeed and thrive in uncertainty requires strong and trusting relationships. I am grateful to our partners, host governments and other stakeholders who have stood by us in hard times and continue to work with us to help shape our future and the future energy landscape. I am also grateful to you, our shareholders who have shown great patience while we stabilized BP and built up our resilience. I hope you see our recent performance as signs that this patience is being rewarded. And last, but not least, I want to thank the global BP team. I don't believe there is another company of our size and scale that can adapt and manage change better than we can. This spirit of invention and purpose has been alive across BP for over a century and will carry us forward into what, I believe, is a very bright future. Bob Dudley Group chief executive R9 March 2018 Above: At the inauguration of the first phase of development of Oman's giant Khazzan gas field. More information Strategy Page 12 Group performance Page 21 95.3% refining availability 94.7% Upstream plant reliability See Glossary

Above: Our Ituiutaba sugar cane processing unit in Brazil. P 3 6 9 12 15 18 2020 2000 2040 Energy consumption by region (billion tonnes of oil equivalent) OECD Other Asia Rest of World China Africa India a a Evolving transition scenario. The changing world of energy The world of energy is changing every day. With rising concerns about climate, technological advances and geopolitical shifts, the energy mix is moving towards lower carbon sources. Growing demand for energy People rely on energy for heat, light and mobility. Growing economies need energy to support their industry and infrastructure. How that energy is delivered is changing rapidly and the energy mix of the future will become increasingly lower carbon. The demand for energy continues to grow – largely driven by rising incomes in emerging economies and a global population heading towards nine billion by R040. But this growth is much slower than in the previous 20 years. The extent of the increase is being curbed by gains in energy efficiency, as there is greater attention around the world on using energy more sustainably. Energy mix is shifting Today, oil and gas account for almost 60% of all energy used. Even in a scenario that is consistent with the Paris goals of limiting warming to less than 2ºC, oil and gas could provide around 40% of all energy used by 2040. So it’s essential that action is taken to reduce emissions from their production and use. In a low carbon world, gas offers a much cleaner alternative to coal for power generation and a valuable back-up for renewables, for example when the sun and wind aren’t available. Gas also provides heat for industry and homes and fuel for trucks and ships. • To meet the rising demand for cleaner energy, we are increasing our gas production. Renewables are the fastest-growing energy source and could account for at least 14% of all energy in 2040. • We are building up our renewable portfolio – focusing on biofuels, biopower, wind energy and solar energy. Oil is the primary fuel for transport today. We expect its share of the total energy mix will gradually decline as we see more energy efficiency in traditional engines, greater use of biofuels and gas, and growth in fully electric and hybrid vehicles, as well as ride sharing, in the years ahead. • We are developing new efficient fuels and lubricants that can help our customers and consumers to lower their emissions. Advances in technology Insights from our Energy Outlook and Technology Outlook help shape our strategic thinking. We consider how policy, consumer behaviour and advances in technology could affect the pace of the energy transition and how we produce and use energy in the coming decades. • We prioritize certain new technologies for in-depth analysis – based on their fit with our strategy and how soon and likely we think they are to break through technological and commercial barriers. We also invest in start-up companies to understand and participate in these potentially transformational technologies. See Innovation in BP on page 44. R040 outlook

Emerging greenhouse gas policy and regulation Governments are putting in place taxes, carbon trading schemes and other measures to limit greenhouse gas (GHG) emissions. A fifth of the world's GHG emissions are now covered by carbon pricing systems, double the coverage from just five years ago. We expect around two thirds of BP's direct emissions will be in countries subject to emissions and carbon policies by 2020. And we have been active as a trader in the world's current emissions trading systems since their inception. To help anticipate greater regulatory requirements affecting our GHG emissions, we use a carbon cost when evaluating our plans for large new projects and those for which emissions costs would be a material part of the project. In industrialized countries, this is currently $40 per tonne of carbon dioxide equivalent. • We also stress test at a carbon price of $80 per tonne. Our carbon cost, along with energy efficiency considerations, encourages projects to be set up in a way that will have lower GHG emissions. Around 80-90% of carbon dioxide emissions from oil and gas products are from their use by consumers in transportation, power plants, industries and buildings. So one of the biggest contributions we can make to advance the energy transition is by providing products and services that help consumers lower their carbon footprint. More information BP Energy Outlook Provides our projections of future energy trends and factors that could affect them out to 2040. See bp.com/energyoutlook Technology Outlook Describes how technology could influence the way we meet the energy challenge into the future. See bp.com/technologyoutlook P 3 6 9 12 15 18 22 % Q9 % Q0 % 8% 8% S3 % R5 % R2 % Q3 % W% 8% R5 % R7 % R6 % 21 % U% W% Q4 % S3 % 24 % R8 % T% W% 4% R040 Faster transition 2040 Even faster transition 2016 Actual energy mix R040 Evolving transition Oil Billion tonnes of oil equivalent. The sum of the fuel shares may not equal 100% due to rounding. Gas Coal Nuclear Hydro Renewables Energy consumption – 2040 projections Evolving transition In this scenario, government policies, technology and social preferences evolve in a manner and speed seen in the recent past. The growing world economy requires more energy but consumption increases less quickly than in the past. Faster transition This scenario sees carbon prices rising faster than in the evolving transition scenario with other policy interventions encouraging more rapid energy efficiency gains and fuel switching. Even faster transition This scenario matches carbon emissions similar to the International Energy Agency's sustainable development scenario which aims to limit the global temperature rise to well below 2°C. 80-90% CO_2 emissions

More information Financial framework How this underpins our commitment to sustain the dividend for our shareholders. See page 25 Growing gas and advantaged oil in the upstream Our strategy Seismic success Found significant additional oil resources at our Atlantis field in the Gulf of Mexico using a new seismic imaging technique. Enduring relationships Extended our contract in the Azeri-Chirag- Gunashi field in Azerbaijan for a further 25 years, continuing our long-term advantaged oil production. Invest in more gas and oil, producing both with increasing efficiency. Key highlights See page 27 Our industry is changing at a pace not seen in decades. Oil, gas and renewables are becoming more abundant and less costly. Through new technologies, energy will be produced more efficiently and in new ways, helping to meet the expected rise in demand. And the world is working towards a lower carbon future. Our strategy allows us to be competitive at a time when prices, policy, technology and customer preferences are evolving. We believe having a balanced portfolio with advantaged oil and gas, competitive downstream and low carbon activities, as well as a dynamic investment strategy give us resilience. With the experience we have, the portfolio we have created and the flexibility of our strategy, we can embrace the energy transition in a way that enhances our investor proposition, while meeting the need for energy today. Major project start-ups Started up seven major projects , making a significant contribution to the 900,000 barrels per day of expected new production by 2021. Exploration successes Made six potentially commercial discoveries – two in the UK, two in Trinidad, one in Egypt and one in Senegal with our partner Kosmos Energy. See Glossary

Modernizing the whole group Market-led growth in the downstream Venturing and low carbon across multiple fronts Automating well construction Launched DrillPlan® – a new technology to automate the entire well construction process – at our Khazzan field in Oman, in partnership with Schlumberger. Serving customers digitally Launched a range of digital apps to enhance our customers' experiences, such as BPMe and in partnership with TomTom Telematics, BP FleetMove. Speedier solutions Began a multi-year project to move our electronic information from physical data centres to the cloud. Carbon trading Used our powerful market insights and innovative platforms to help generate over Q2 million tonnes of CO2 reductions through carbon offsetting projects to help customers meet their emissions commitments. Renewable gas Acquired Clean Energy's renewable natural gas business – giving BP access to its network of gas transport customers and helping to make biogas, made from organic waste, more accessible to natural gas powered vehicle fleets. Generating solar energy Partnered with Lightsource – Europe's largest solar development company – to help propel its continuing and rapid expansion worldwide. Advancing biofuel technology Acquired the Nesika ethanol plant in Kansas, with joint venture partner DuPont, to commercialize Butamax® bio-isobutanol technology. Investing in artificial intelligence Invested in AI software for the oil and gas industry with venture partner Beyond Limits. Convenience partnerships Continued the rollout of our convenience partnership model across our retail network – adding more than 220 sites in 2017, bringing the total to 1,100. Retail sites in Mexico Became the first global brand to enter the Mexican retail fuels market since deregulation – opening more than 120 BP-branded retail sites during the year. Pursue new opportunities to meet evolving technology, consumer and policy trends. Simplify our processes and enhance our productivity through digital solutions. Innovate with advanced products and strategic retail partnerships. See page 46 See page 23 Strategic report – strategy Lower carbon products Expanded our lower carbon products portfolio with Castrol EDGE BIO-SYNTHETIC now available in the US, the supply of jet biofuel in Sweden and Norway, and our PTAir brand – now available globally. High-quality lubricants Announced plans to build a high-quality lubricants blend plant in China. See page 33 See Glossary

Fast facts Operator BP Partners BP (82.75%) RWE Dea (17.25%) Project type Conventional gas Peak annual average production ~105mboe/d (gross) ~80mboe/d (net) Fast facts Operator Atlantic LNG Partners 100% owned by BP Trinidad and Tobago which is owned by BP (70%) and Repsol (30%) Project type Liquefied natural gas Peak annual average production ~35mboe/d (gross) ~35mboe/d (net) 2 Trinidad: TROC • Increased production from low-pressure wells in our existing acreage in the Columbus Basin. • This onshore facility has the capacity to deliver nearly R00 million standard cubic feet of gas per day when fully operational. A year of delivery This was a big year for BP with seven major projects coming onstream, making it one of the most significant years for commissioning new projects in our history. This puts us well on the way to achieving our aim of 900,000 barrels of oil equivalent per day of new production from our new major projects by 2021. 1 Egypt: Taurus and Libra • Production around 20% above plan. • Added significant gas production to the Egyptian market. 1 Taurus and Libra 2 Trinidad onshore compression (TROC) 3 Quad 204 4 Persephone 5 Juniper 6 Khazzan Phase 1 7 Zohr See Glossary 100% of the gas from the project will be used for the national grid BP and its partners operate across U5,000km2 in Egypt – about the size of Croatia +50 years as largest contributor to natural gas production in Trinidad 14 BP Annual Report and Form 20-F 2017

Fast facts Operator Woodside Partners BP (16.67%) BHP, Chevron, Shell, Woodside and Mitsubishi-Mitsui (16.67% each) Project type Liquefied natural gas Peak annual average production ~50mboe/d (gross) ~8mboe/d (net) 4 Australia: Persephone • Increased gas production from the North West Shelf project – Australia's largest oil and gas resource development. • The North West Shelf project contributes around a third of Australia's oil and gas production. Fast facts Operator BP Partners BP (36%) Shell (54%) Siccar Point Energy (10%) Project type Conventional oil Peak annual average production ~125mboe/d (gross) ~45mboe/d (net) 3 UK North Sea: Quad 204 • Extended the lives of the Schiehallion and Loyal fields out to 2035 and beyond. • Constructed and installed Glen Lyon, the world's largest harsh-water floating production, storage and offloading vessel. • Progressed BP's aim to double UK North Sea production by 2020. Quad 204 is expected to return the fields to their historical peak production £2bn+ contracts awarded to UK companies

Fast facts Operator BP Partners 100% owned by BP Trinidad and Tobago, which is owned by BP (70%) and Repsol (30%) Project type Liquefied natural gas Peak annual average production ~95mboe/d (gross) ~95mboe/d (net) 5 Trinidad: Juniper • Our first subsea field development in Trinidad. • We expect Juniper will make a significant contribution to Trinidad & Tobago's national gas production. Fast facts Operator BP Partners BP (60%) Oman Oil (40%) Project type Tight gas Peak annual average production ~172mboe/d (gross) ~103mboe/d (net) 6 Oman: Khazzan Phase 1 • Accessed gas in extremely hard rock at depths of up to 5km using expertise from our US Lower 48 business. • Conducted the world's largest onshore seismic survey and SD modelling of the subsurface. • Designed to be inherently efficient and lower in greenhouse gas emissions. It weighs about Q0,000 tons – equivalent to 20 Boeing 747s fully loaded for take off One of the biggest tight gas projects in the Middle East 16 BP Annual Report and Form 20-F 2017

BP's net share from our seven major projects at peak production (in thousand barrels of oil equivalent per day) 8 Taurus and Libra TROC Quad 204 Persephone Juniper Khazzan Phase 1 Zohr 80 35 95 103 3645 Fast facts Operator ENI Partners BP (10%) Eni (60%) Rosneft (30%) Project type Dry gas Peak annual average production ~364mboe/d (gross) ~36mboe/d (net) 7 Egypt: Zohr • Started up in less than two and a half years from discovery – a record time for a field of this size in deepwater. • Thought to be the largest gas discovery in the Mediterranean. More information Go to youtube.com/bp to watch the stories behind our seven major projects. Looking ahead We plan to start-up six projects in 2018. 1 2 Egypt 3 UK North Sea 4 Azerbaijan 5 US 6 Russia More information Upstream project pipeline See page 30 ~1.3 billion barrels of proved reserves

2016 2017 2015 2014 2013 Profit (loss) for the year Underlying RC profit for the year 3.8 12.1 13.4 5.9 (6.5) 2.6 3.4 6.2 0.1 0 Underlying replacement cost profit ($ billion) 23.5 REM 3,230 3,141 3,239 3,268 3 , 5 9 5 2016 2017 2015 2013 2014 Production (mboe/d) 21.1 32.8 19.1 10.7 18.9 2016 2017 2015 2013 2014 Operating cash flow ($ billion) REM 4 7 7 4 62016 2017 2015 2013 2014 Major project delivery REM 20 28 20 16 18 REM Tier 1 process safety events a 2016 2017 2015 2013 2014 REM Reported recordable injury frequencya REM REM 2016 2017 2015 2013 2014 0.31 0.31 0.24 0.21 0.22 Measuring our progress 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. 2017 performance We started up seven major projects in Australia, Egypt, the UK North Sea, Oman and Trinidad. 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. R017 performance Operating cash flow was higher due to improved business results, including a more favourable price environment and higher production as well as lower Gulf of Mexico oil spill payments which amounted to $5.2 billion in 2017. 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 . R017 performance Profit for the year and underlying RC profit reflect higher oil and gas prices, and a stronger refining environment compared with 2016, as well as the benefit of major project start-ups, and stronger refining operational performance. Production is a useful measure for tracking how our major projects are helping to grow our business. We report production of crude oil, condensate, natural gas liquids (NGLs), natural bitumen and natural gas on a volume per day basis for our subsidiaries and equity-accounted entities. Natural gas is converted to barrels of oil equivalent at 5,800 standard cubic feet of natural gas = 1 boe. 2017 performance BP's total reported production including Upstream and Rosneft segments was 10% higher than in 2016 due to the Abu Dhabi onshore concession renewal and major project start-ups. We report tier 1 process safety events which are losses of primary containment of greatest consequence – causing harm to a member of the workforce, costly damage to equipment or exceeding defined quantities. R017 performance We have seen a slight increase in tier 1 process safety events, and we remain focused on our systematic approach to safety management and assurance. We assess our performance across a wide range of measures and indicators. 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, with non-financial metrics playing a useful role as leading indicators of future performance. BP management uses these measures to evaluate operating performance and make financial, strategic and operating decisions. Changes to KPIs We have added Upstream plant reliability to our KPIs this year to reflect our strategy and align the measures used for Upstream and Downstream. It will also be used to assess performance for the annual bonus in our 2018 remuneration outcomes assessment. We no longer report loss of primary containment as we are focusing on more comparable industry metrics. And in light of our refreshed strategy, announced in February 2017, we've updated the employee survey questions to reflect our new priorities and retired the group priorities index, which was based on priorities set in 2012. 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. 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. 2017 performance We have seen a small increase in our RIF compared with 2016. Improving safety in our operations is a high priority and we are working on it right across the business. 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. REM Measures used for the remuneration policy approved by shareholders at the 2017 AGM. REM These measures were used for executive remuneration under the terms of our discontinued 2014-16 policy. Measures for the annual bonus are focused on safety, reliable operations and financial performance. Measures for performance shares are focused on shareholder value, capital discipline and future growth. More information Directors' remuneration Page 90 BP Annual Report and Form 20-F 201718 See Glossary

2016 2017 2015 2014 2013 REM 0 29.0 20.0 9.5 (11.6) (16.5) 14.0 14.7 (8.3) (12.8) ADS basis Ordinary share basis Total shareholder return (%) U5.5 REM 71 73 73 73 73 2016 2017 2015 2014 2013 Employee engagement (%) R016 2015 2013 2014 95.3 94.9 94.7 95.3 95.32017 Refining availability (%) REM 129 63 61 109 143 2016 2017 2015 2013 2014 Reserves replacement ratio (%) REM 2016 2017 2015 2014 2013 Women Non UK/US c 21 21 18 18 23 21 19 22 21 24 Diversity and inclusion b (%) Return on average capital employed (%) 12 2016 2015 2013 2014 10.2 9.6 5.5 2.8 5.82017 REM 2016 2015 2013 2014 50.3 48.7 49.0 50.1 49.42017 Greenhouse gas emissions (million tonnes of CO 2 equivalent) 2016 2015 2013 2014 13.16 12.75 10.46 8.46 7.112017 Upstream unit production costs ($/boe) REM 95.0 91.7 93.4 95.3 94.7 2016 2015 2013 2014 2017 Upstream plant reliability (%) 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. 2017 performance The ratio was higher due to development activity in Abu Dhabi and Rosneft, expansion of the Khazzan development in Oman and extension of the ACG licence. Each year we report the percentage of women and individuals from countries other than the UK and the US among BP's group leaders. 2017 performance While the percentage of our group leaders who are women decreased slightly, the number of non-UK/US people rose. We are developing mentoring, sponsorship and coaching programmes to help more women advance. 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. 2017 performance Reduced TSR reflects lower share price growth in 2017 compared with 2016, while the dividend per share was maintained at the same level. We conduct an annual employee survey to understand and monitor levels of employee engagement and identify areas for improvement. 2017 performance The overall employee engagement score was up from two years ago, when we saw a decline that coincided with the uncertainties of a low oil price environment. Return on average capital employed (ROACE) 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 295 for more information including the nearest GAAP equivalent data. In recent years, ROACE has been lower in the oil and gas sector, due to the impact of lower oil prices on earnings and the capital investment made during the preceding period of $100 per barrel oil prices. 2017 performance The 2017 increase in ROACE is due to a stronger environment and improved business performance. Refining availability represents Solomon Associates' operational availability. 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. 2017 performance Refining availability was similar to 2016, reflecting continued strong operational performance in our portfolio. This performance is underpinned by our global reliability improvement programme which provides our refineries with a more structured and systematic approach to improving availability. The upstream unit production cost indicator shows how supply chain, headcount and scope optimization impact cost efficiency. R017 performance The lower unit production costs in 2017 reflect further efficiency increases and the benefit of new production start-ups. BP-operated Upstream plant reliability is calculated as 100% less the ratio of total unplanned plant deferrals divided by installed production capacity. 2017 performance The slight decrease in 2017 plant reliability was due in part to our new major projects ramping up, however this was partly offset by solid performance across existing assets. We provide data on greenhouse gas (GHG) emissions material to our business on a carbon dioxide-equivalent basis. This includes carbon dioxide (CO_2) and methane for direct emissions. Our GHG KPI encompasses all BP's consolidated entities as well as our share of equity-accounted entities other than BP's share of Rosneft. 2017 performance The primary reasons for the overall decrease include operational changes such as planned shutdowns at several of our refineries for maintenance, and actions taken by our businesses to reduce emissions in areas such as flaring, methane and energy efficiency. b Relates to BP employees. c Figures for 2013-16 have been amended. See Glossary

BP Annual Report and Form 20-F-201720 Global energy markets Oil prices recovered in 2017, but averaged only half the prices seen in 2011-13. While the market continues to rebalance in the face of ongoing co-ordinated OPEC and non-OPEC production restraint, inventories remain above their recent historical average. The world economy grew at 3.1% in 2017, its fastest rate of growth since 2011. This was significantly faster than the 2.4% seen in 2016 and slightly more than the average of nearly 3% over the past 20 years. Growth in the OECD picked up to 2.4%, from just 1.7% in 2016, benefiting from improvements in both consumption and investment across all major regions, and a pick-up in global trade. The non-OECD showed a similar broad-based improvement, growing by 4.3% in 2017, compared with 3.8% in 2016. Oil Crude oil prices ($/bbl – quarterly average) Q50 120 90 60 08 09 10 11 12 13 14 15 16 2017 Brent dated Prices Dated Brent crude oil prices averaged $54.19 per barrel in 2017 – the first annual increase since 2012 but roughly half the average of over $110 seen in 2011-13. Prices drifted lower over the first half of the year before rebounding, ending the year at their monthly high point, averaging $64 in December. Consumptiona Global consumption increased by 1.6 million barrels per day (mmb/d) to 97.8mmb/d for the year (1.6%) – due to continued low oil prices and a recovering world economy. Demand once again grew most rapidly in Asia's emerging economies (+1mmb/d), but OECD demand also increased for a third consecutive year. Productiona Global oil production saw weak growth for a second consecutive year, rising by just 0.4mmb/d. However, the source of global weakness was different in 2017. After falling in 2016, non-OPEC production recovered (+0.8mmb/d), led by the US. In contrast OPEC production declined by 0.4mmb/d – the first decline since 2013 – as the group engaged with certain non-OPEC producers to restrain output. Inventoriesa These changes resulted in global demand exceeding supply in 2017. As a result, oil inventories in the OECD began to decline, although they remained well above the recent historical range. At the end of November OECD commercial inventories were roughly 100 million barrels less than R016, but remained 90 million barrels above the five-year average. The surplus relative to the five-year average was well below the peak of S66 million barrels seen in July 2016. Natural gas 08 09 10 11 12 13 14 15 16 12 10 6 8 4 2 Henry HubNatural gas prices ($/mmBtu – quarterly average) R017 Prices Gas prices rebounded in all key markets in 2017, as global markets tightened. Liquefied natural gas (LNG) supply increased more slowly than expected, while LNG demand from China was unexpectedly strong, and high coal prices supported gas prices in the power generation sector. Gas prices in the US averaged $3.11 per million British thermal units (mmBtu), up by $0.65 compared with 2016 ($2.46). The Japanese spot price rebounded to $7.13/mmBtu in 2017 from $5.72/mmBtu in 2016, driven by stronger Asian LNG demand, notably from China but also Japan, Korea and Pakistan. The UK National Balancing Point hub price was 44.95 pence per therm, 30% higher than in 2016 (34.63), supported by increasing coal prices. Meanwhile pipeline outages and cold weather put pressure on UK prices towards the end of 2017. Broad differentials between regional gas prices have increased, even though they remain at much lower levels than the peaks observed in 2012 and 2013. Consumptionb Global consumption is estimated to have grown more rapidly in 2017 than in 2016. Strong growth in Asia, the Middle East and Africa offset a decline in North American consumption, where higher gas prices caused gas to lose market share to coal in the US power sector. Meanwhile demand in core European markets was broadly stable. And higher weather-related demand towards the end of the year boosted global annual demand. Productionb Total gas production is estimated to have increased substantially in 2017, in contrast to 2016, which had similar production to 2015. Significant production increases were achieved in Australia – supported by the start of new LNG trains , and in Russia. Global LNG supply capacity expanded strongly in 2017, adding almost three times as much new capacity as in 2016. Several trains came online in the US, Australia, Russia and Malaysia. See Glossary More information Prices and margins Pages 26 and 32 a From IEA Oil Market Report, 13 February 2018 ©, OECD/IEA 2018. b Based on BP estimates from the BP Energy Outlook.

BP Annual Report and Form 20-F 2017 21 Group performance We had strong delivery and growth across BP in 2017, enabling the company to get back into balance. The full-year underlying result was more than double a year earlier and our financial frame remains resilient. We recommenced share buybacks during the fourth quarter with the intention to offset any ongoing dilution from scrip dividends over time. Brian Gilvary, group chief financial officer In summary (20) (10)(15) (5) 0 105 15 20 2016 2015 2017 Segment RC profit (loss) before interest and tax ($ billion) Downstream Rosneft Upstream Other businesses and corporate – other Other businesses and corporate – Gulf of Mexico oil spill Consolidation adjustment – UPII Group RC profit (loss) before interest and tax Financial and operating performance $ million except per share amounts R017 2016 2015 Profit (loss) before interest and taxation 9,474 (430) (7,918) Finance costs and net finance expense relating to pensions and other post-retirement benefits (2,294) (1,865) (1,653) Taxation (3,712) 2,467 3,171 Non-controlling interests (79) (57) (82) Profit (loss) for the yeara 3,389 115 (6,482) Inventory holding (gains) losses , before tax (853) (1,597) 1,889 Taxation charge (credit) on inventory holding gains and losses 225 483 (569) Replacement cost profit (loss) 2,761 (999) (5,162) Net (favourable) adverse impact of non-operating items and fair value accounting effects , before tax 3,730 6,746 15,067 Taxation charge (credit) on non-operating items and fair value accounting effects (325) (3,162) (4,000) Underlying replacement cost profit 6,166 2,585 5,905 Dividends paid per share – cents 40.0 40.0 40.0 – pence 30.979 29.418 26.383 a Profit (loss) attributable to BP shareholders. More information Upstream Page 26 Downstream Page 32 Rosneft Page 38 Other businesses and corporate Page 41 Oil and gas disclosures for the group Page 259 See Glossary $6.2bn underlying replacement cost (RC) profit (2016 $2.6 billion) $3.4bn $18.9bn profit attributable to BP shareholders (2016 $115 million) operating cash flow (2016 $10.7 billion) Strategic report – perform ance

BP Annual Report and Form 20-F-201722 Results Profit for the year ended 31 December 2017 was $3.4 billion, compared with $115 million in 2016. Excluding inventory holding gains, replacement cost (RC) profit was $2.8 billion, compared with a loss of $1.0 billion in 2016. After adjusting for non-operating items of $3.3 billion and net adverse fair value accounting effects of $96 million (both on a post-tax basis), underlying RC profit for the year ended 31 December R017 was $6.2 billion, an increase of $3.6 billion compared with 2016. The increase was predominantly due to higher results in both Upstream and Downstream segments. The Upstream result reflected higher oil and gas prices and increased production. The Downstream result reflected strong refining performance, including an improved margin environment and growth in fuels marketing. The profit for the year ended 31 December 2016 was $115 million, compared with a loss of $6.5 billion in 2015. Excluding inventory holding gains, RC loss was $1.0 billion, compared with a loss of $5.2 billion in R015. After adjusting for non-operating items of $2.8 billion and net adverse fair value accounting effects of $0.8 billion (both on a post-tax basis), underlying RC profit for the year ended 31 December 2016 was $2.6 billion, a decrease of $3.3 billion compared with 2015. The reduction was predominantly due to lower results in both the Upstream and Downstream segments reflecting lower oil and gas prices and the weaker refining environment. Non-operating items The net charge for non-operating items was $3.6 billion pre-tax and $3.3 billion post tax in 2017. The post-tax non-operating charge includes a charge of $1.7 billion recognized in the fourth quarter relating to business economic loss and other claims associated with the Gulf of Mexico oil spill and a $0.9 billion deferred tax charge following the change in the US tax rate enacted in December 2017. In addition, the net charge also reflects an impairment charge in relation to upstream assets. The net charge for non-operating items of $5.7 billion pre-tax and $2.8 billion post tax in 2016 mainly related to additional charges for the Gulf of Mexico oil spill which were partially offset by net impairment reversals. Non-operating items in 2016 also included a restructuring charge of $0.8 billion (2015 $1.1 billion). More information on non-operating items and fair value accounting effects can be found on pages 250 and 294. See Financial statements – Note 2 for further information on the impact of the Gulf of Mexico oil spill on BP's financial results. Taxation The charge for corporate income taxes in 2017 includes a one-off deferred tax charge of $0.9 billion in respect of the revaluation of deferred tax assets and liabilities following the reduction in the US federal corporate income tax rate from 35% to 21% enacted in December 2017. The effective tax rate (ETR) on the profit or loss for the year was 52% in 2017, 107% in 2016 and 33% in 2015. The ETR for all three years was impacted by various one-off items. Adjusting for inventory holding impacts, non-operating items which include the impact of the US tax rate change, fair value accounting effects and the deferred tax adjustments as a result of the reductions in the UK North Sea supplementary charge in 2016 and 2015, the adjusted ETR on RC profit was 38% in 2017 (2016 23%, 2015 31%). The adjusted ETR for 2017 is higher than 2016 predominantly due to changes in the geographical mix of profits, notably the impact of the renewal of our interest in the Abu Dhabi onshore oil concession. The adjusted ETR for 2016 was lower than 2015 predominantly due to changes in the geographical mix of profits as a result of the lower oil price and the absence of foreign exchange impacts from the strengthening of the US dollar in 2015. In the current environment, the adjusted ETR in 2018 is expected to be above 40%. Cash flow and net debt information $ million 2017 2016 2015 Operating cash flow 18,931 10,691 19,133 Net cash used in investing activities (14,077) (14,753) (17,300) Net cash provided by (used in) financing activities (3,296) 1,977 (4,535) Cash and cash equivalents at end of year 25,586 23,484 26,389 Capital expenditure a Organic capital expenditure (16,501) (16,675) N/A Inorganic capital expenditure (1,339) (777) N/A (17,840) (17,452) (20,202) Gross debt 63,230 58,300 53,168 Net debt 37,819 35,513 27,158 Gross debt ratio (%) 38.6% 37.6% 35.1% Net debt ratio (%) 27.4% 26.8% 21.6% a From 2017 onwards we are reporting 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 now 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. Operating cash flow Net cash provided by operating activities for the year ended S1 December 2017 was $18.9 billion, $8.2 billion higher than the $10.7 billion reported in 2016. Operating cash flow in 2017 reflects $5.3 billion of pre-tax cash outflows related to the Gulf of Mexico oil spill (2016 $7.1 billion). Compared with 2016, operating cash flows in 2017 were impacted by improved business results, including a more favourable price environment and higher production, working capital effects, and a $2.5 billion increase in income taxes paid. Movements in inventories and other current and non-current assets and liabilities adversely impacted cash flow in the year by $3.4 billion. There was an adverse impact on working capital from the Gulf of Mexico oil spill of $5.2 billion. Other working capital effects, arising from a variety of different factors had a favourable effect of $1.8 billion. Receivables and inventories increased during the year principally due to higher oil prices. The effect of this on operating cash flow was more than offset by a corresponding increase in payables. BP actively manages its working capital balances to optimize cash flow. There was a decrease in net cash provided by operating activities of $8.4 billion in 2016 compared with 2015, of which $6.0 billion related to higher pre-tax cash outflows associated with the Gulf of Mexico oil spill. Cash flows were impacted by the continuing low oil price environment, with a lower average oil price in 2016 compared with 2015, working capital effects, and a reduction of $0.7 billion in income taxes paid. Movements in inventories and other current and non-current assets and liabilities adversely impacted cash flow in 2016 by $3.2 billion. There was an adverse impact from the Gulf of Mexico oil spill of $4.8 billion. Other working capital effects, arising from a variety of different factors, had a favourable impact of $1.6 billion. Inventories increased during 2016 because volumes were increased in our trading business to benefit from market opportunities, and due to higher prices towards the end of the year. The increase in inventory was largely offset by a corresponding increase in payables, limiting the increase in working capital.

See Glossary

From our headquarters in London to the underwater facilities in Western Australia – our modernization programme is transforming how we work across BP. We are simplifying how we operate to create a more agile organization and working to change mindsets so that they fit the increasingly competitive and margin-dependent industry. At the same time, we're digitizing and automating more of our work. We are in the process of systematically migrating our vast amounts of data from physical centres to the cloud, embracing the agility and power of cloud technologies, while maintaining necessary levels of data security. We have already moved our corporate website to Amazon Web Services®, and we now plan to close all our physical datacentres over several years, fully embracing the agility and power of cloud technologies. Microsoft Azure® is intended to become a group-wide platform for collaboration and data analytics, with services such as visualization and predictive tools to help us analyse data, gain insights and make decisions faster. We are also piloting the use of blockchain database technology in our oil and gas trading business to help increase efficiency in terms of speed and verification of transactions. Blockchain is a digital ledger system that records online transactions and helps to streamline financial processes and cut back office costs. Modernizing the whole group Speedier solutions Activity on W,000 servers in four datacentres moving to the cloud Strategic report – perform ance BP Annual Report and Form 20-F 2017 23 Strategic report – perform ance

BP Annual Report and Form 20-F 201724 Net cash used in investing activities Net cash used in investing activities for the year ended 31 December R017 decreased by $0.7 billion compared with 2016. The decrease mainly reflected an increase of $0.8 billion in disposal proceeds. The decrease of $2.5 billion in 2016 compared with 2015 reflected a reduction in cash outflow in respect of capital expenditure, including investment in joint ventures and associates , of $2.8 billion. The reduction in cash capital expenditure in 2016 reflected the group's response to the lower oil price environment. There were no significant cash flows in respect of acquisitions in 2017, R016 and 2015. The group has had significant levels of capital investment for many years. Total capital expenditure for 2017 was $17.8 billion (2016 $17.5 billion), of which organic capital expenditure was $16.5 billion (2016 $16.7 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 organic capital expenditure to be in the range of $15-16 billion in 2018. Disposal proceeds for 2017 were $3.4 billion (2016 $2.6 billion, 2015 $2.8 billion), including amounts received for the disposal of our interest in the SECCO joint venture. In addition, we received $0.8 billion in relation to the initial public offering of BP Midstream Partners LP's common units, shown within financing activities in the cash flow statement, and total proceeds for the year were $4.3 billion. In 2016 disposal proceeds included amounts received for the sale of certain midstream assets in the Downstream fuels business and our Decatur petrochemicals complex. In addition, we received $0.6 billion in relation to the sale of 20% from our shareholding in Castrol India Limited, shown within financing activities in the cash flow statement, giving total proceeds of $3.2 billion for the year. We expect disposal proceeds to be in the range of $2-3 billion in 2018. Net cash used in financing activities Net cash used in financing activities for the year ended 31 December R017 was $3.3 billion, compared with $2.0 billion provided by financing activities in 2016. This was mainly the result of a reduction of $3.5 billion in net proceeds from financing. The total dividend paid in cash in 2017 was $1.5 billion higher than in 2016, see below for further information. In 2016 the net cash provided by financing activities reflected higher net proceeds from financing of $3.6 billion ($4.0 billion higher net proceeds from long-term debt offset by a decrease of $0.4 billion in short-term debt). In addition, there was a cash inflow of $0.9 billion relating to increases in non-controlling interests, including the sale of 20% from our shareholding in Castrol India Limited described above. The total dividend paid in cash in 2016 was $2.1 billion lower than in 2015 – see below for further information. Total dividends distributed to shareholders in 2017 were 40.00 cents per share, the same as 2016. This amounted to a total distribution to shareholders of $7.9 billion (2016 $7.5 billion, 2015 $7.3 billion), of which shareholders elected to receive $1.7 billion (2016 $2.9 billion, R015 $0.6 billion) in shares under the scrip dividend programme. The total amount distributed in cash amounted to $6.2 billion during the year (2016 $4.6 billion, 2015 $6.7 billion). Debt Gross debt at the end of 2017 increased by $4.9 billion from the end of R016. The gross debt ratio at the end of 2017 increased by 1%. Net debt at the end of 2017 increased by $2.3 billion from the 2016 year-end position. The net debt ratio at the end of 2017 increased by 0.6%. We continue to target a net debt ratio in the range of 20-30%. Net debt and the net debt ratio are non-GAAP measures. See Financial statements – Note 25 for gross debt, which is the nearest equivalent measure on an IFRS basis, and for further information on net debt. Cash and cash equivalents at the end of 2017 were $2.1 billion higher than 2016. For information on financing the group's activities, see Financial statements – Note 27 and Liquidity and capital resources on page 251. Group reserves and production (including Rosneft segment)a 2017 2016 2015 Estimated net proved reserves (net of royalties) Liquids (mmb) 10,672 10,333 9,560 Natural gas (bcf) 45,060 43,368 44,197 Total hydrocarbons (mmboe) 18,441 17,810 17,180 Of which: Equity-accounted entitiesb 8,949 8,679 7,928 Production (net of royalties) Liquids (mb/d) 2,260 2,048 2,007 Natural gas (mmcf/d) 7,744 7,075 7,146 Total hydrocarbons (mboe/d) 3,595 3,268 3,239 Of which: Subsidiaries 2,164 1,939 1,969 Equity-accounted entitiesc 1,431 1,329 1,270 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 38 and Supplementary information on oil and natural gas on page 191 for further information. c Includes BP's share of Rosneft. See Rosneft on page 38 and Oil and gas disclosures for the group on page 259 for further information. Total hydrocarbon proved reserves at 31 December 2017, on an oil-equivalent basis including equity-accounted entities, increased by T% compared with 31 December 2016. The change includes a net increase from acquisitions and disposals of 47mmboe (increase of 90mmboe within our subsidiaries, decrease of 43mmboe within our equity-accounted entities). Acquisition activity in our subsidiaries occurred in Egypt, the US and the UK, and divestment activity in our subsidiaries was in the UK. In our equity-accounted entities, acquisitions occurred in Aker BP and Rosneft and divestments occurred in Aker BP and in Pan American Energy. Our total hydrocarbon production for the group was 10% higher compared with 2016. The increase comprised a 12% increase (12% increase for liquids and 11% increase for gas) for subsidiaries and an 8% increase (9% increase for liquids and 5% increase for gas) for equity-accounted entities. Above: On board Glen Lyon, our floating production storage and offloading vessel in the UK North Sea. See Glossary

BP Annual Report and Form 20-F 2017 25 See Glossary Principle 2017 achievement 2018 guidance Looking ahead – 2019 to 2021 Nearest GAAP equivalent measures * Capital expenditure : $17.8 billion. ** Gross debt ratio: 38.6%. *** Numerator: Profit attributable to BP shareholders $3.4 billion; Denominator: Average capital employed $159.4 billion. BP's financial framework underpins our commitment to sustain the dividend for our shareholders. We have been meeting those expectations each year. We expect our strong balance sheet to be able to deal with any near-term volatility. Beyond that, we aim to increase operating cash flow – from our planned upstream start-ups and growth in the downstream. With a constant capital frame, we intend to grow sustainable free cash flow and distributions to shareholders in the long term. Our financial framework Focused on delivering competitive returns Optimize capital expenditure Organic capital expenditure a was $16.5 billion*. This was within our original guidance of $15-17 billion. We expect organic capital expenditure of $15-16 billion. We expect organic capital expenditure of $15-17 billion per year. Make selective divestments Total divestment and other proceeds of $4.3 billionb achieved. This was just under our expected guidance of $4.5-5.5 billion for the year. We expect divestments of $2-3 billion. We expect $2-3 billion of divestments per year. Payments related to the Gulf of Mexico oil spill 2017 payments totalled $5.2 billion. We expect just over $3 billion of cash payments. We expect around $2 billion in R019, then stepping down to around $1 billion per year. Maintain flexibility around gearing Gearing at the end of 2017 was 27.4%** within our target range. Within the 20-30% band. Within the 20-30% band. Group return on average capital employed (ROACE) ROACE was 5.8%***. Further improvement. We are aiming to exceed Q0% by 2021 at real oil prices around $55/barrel. a From 2017 onwards we are reporting 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 now consistent with other financial metrics used when comparing sources and uses of cash. b This includes proceeds of $0.8 billion received in relation to the initial public offering of BP Midstream Partners LP's common units. Divestment proceeds for 2017 were $3.4 billion. Strategic report – perform ance

BP Annual Report and Form 20-F 201726 2017 was a strong year of delivery, demonstrated by the start-up of seven major projects. This shows we are creating real value and tangible growth – with opportunities out to 2021 and beyond. Bernard Looney, chief executive, Upstream 28,000km2 94.7% 6 new exploration access (2016 71,000km2) BP-operated upstream plant reliability (2016 95.3%) successful completion of turnarounds (2016 11) 3 80.5% 2.5 final investment decisions (2016 5) BP-operated upstream operating efficiency million barrels of oil equivalent per day – hydrocarbon production (2016 2.2mmboe/d) Upstream See Glossary 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 . 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. The global operations organization is responsible for safe, reliable and compliant operations, including upstream production assets and midstream transportation and processing activities. 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 the low-cost developer and producer in each basin, and as a business, get more from a unit of capital than our competitors. Growing gas and advantaged oil We will manage our portfolio through disciplined investment in the world's best oil and gas basins. We plan to grow both oil and gas production. Natural gas is a big lever for reducing greenhouse gas emissions. This means taking a leadership role in tackling the challenge of methane. Around half of our portfolio is currently gas and we expect this to grow as we bring our major projects on line. Our gas portfolio will be complemented by advantaged oil assets – oil we can produce at a higher margin or at a lower cost, creating a portfolio that is resilient whatever the price environment. Returns-led growth We want to grow – but not at any cost. We always look to grow returns and value. We believe this growth will come from many sources – production growth, expanding and managing our margins, operational efficiency, unit cost reduction, and capital efficiency with disciplined levels of capital reinvestment. Strategy Our strategy has three parts and is enabled by: Exploration Global wells organization Global operations organization Business model The Upstream segment is responsible for our activities in oil and natural gas exploration, field development and production. We do this through five global technical and operating functions: 2017 2016 2015 2014 2013 Replacement cost (RC) profit (loss) before interest and tax Underlying RC profit (loss) before interest and tax Upstream profitability ($ billion) -0.9 0.6 5.2 5.9 -0.5 1.2 15.2 18.3 8.9 16.7 In summary

BP Annual Report and Form 20-F 2017 27 Expanding gas projects in Trinidad Growing gas and advantaged oil Trinidad & Tobago is a key contributor to BP's growing gas portfolio and 2017 was a pivotal year for our business in the country. We started up two major gas projects in 2017: Juniper – our first subsea field development in Trinidad and the area's largest project for several years, and Trinidad onshore compression – the first project of its kind in the region and for BP. And we completed the Sercan 2 field development – a joint venture with EOG Resources. But these are just the start. We also made two significant gas discoveries with our Savannah and Macadamia exploration wells in offshore Trinidad. This demonstrates the benefit of our investment in seismic technology, which is helping us access the full potential of the Columbus Basin. Our next planned major project in Trinidad is the development of the Angelin natural gas field, which will include construction of our fifteenth offshore production facility in Trinidad. We expect first gas in early 2019. Largest contributor to natural gas production in Trinidad U0+ years In addition to our core Upstream exploration, development and production activities, the segment is responsible for midstream transportation, storage and processing. We also market and trade natural gas, including liquefied natural gas (LNG), power and natural gas liquids (NGL). In 2017 our activities took place in 29 countries. With the exception of our US Lower 48 onshore business, we deliver our exploration, development and production activities through five global technical and operating functions. We optimize and integrate the delivery of these activities across 13 regions, with support provided by global functions in specialist areas of expertise: technology, finance, procurement and supply chain, human resources, information technology and legal. The US Lower 48 continues to operate as a separate, asset-focused, onshore business. In 2016 we identified a future growth target of 900,000 barrels of oil equivalent per day of production from new projects by 2021 and we remain on track to deliver that. We expect this production to deliver 35% higher operating cash margins on average than our 2015 upstream assets, which supports our value over volume strategy. 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 are resilient and balanced – 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. We are also investing to modernize and transform the Upstream – embracing innovation, digitization and the adoption of big data, which we believe can drive a real step change in performance and efficiency. Extending the life of our Galeota terminal for 20+ years 15 million tonnes per annum capacity at our Atlantic liquefaction plant BP Annual Form 20-F 2017 See Glossary Strategic report – perform ance

BP Annual Report and Form 20-F 201728 Financial performance $ million 2017 2016 2015 Sales and other operating revenuesa 45,440 33,188 43,235 RC profit (loss) before interest and tax 5,221 574 (937) Net (favourable) adverse impact of non-operating items and fair value accounting effects 644 (1,116) 2,130 Underlying RC profit (loss) before interest and tax 5,865 (542) 1,193 Organic capital expenditure b 13,763 14,344 N/A BP average realizationsc $ per barrel Crude oild 51.71 39.99 49.72 Natural gas liquids 26.00 17.31 20.75 Liquids 49.92 38.27 47.32 $ per thousand cubic feet Natural gas 3.19 2.84 3.80 US natural gas 2.36 1.90 2.10 $ per barrel of oil equivalent Total hydrocarbons 35.38 28.24 35.46 Average oil marker pricese $ per barrel Brent 54.19 43.73 52.39 West Texas Intermediate 50.79 43.34 48.71 Average natural gas marker prices $ per million British thermal units Average Henry Hub gas pricef 3.11 2.46 2.67 pence per therm Average UK National Balancing Point gas price e 44.95 34.63 42.61 a Includes sales to other segments. b A reconciliation to GAAP information at the group level is provided on page 249. Organic capital expenditure on a cash basis in 2015 is not available. c Realizations are based on sales by consolidated subsidiaries only, which excludes equity-accounted entities. d Includes condensate and bitumen. 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. Certain regions use other local markers that are derived using differentials or a lagged impact from the Brent crude oil price. 90 60 30 120 150 Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec Brent ($/bbl) 2016 2017 2015 Five-year range The dated Brent price in 2017 averaged $54.19 per barrel. Prices drifted lower over the first half of the year before rebounding, ending the year at their monthly high point, averaging $64 in December. After falling in R016, non-OPEC production recovered (+0.8mmb/d), led by the US. In contrast OPEC production declined by 0.4mmb/d – the first decline since 2013 – as the group engaged with certain non-OPEC producers to restrain output. V 3 9 Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec Henry Hub ($/mmBtu) 2016 2017 2015 Five-year range The 2017 Henry Hub First of Month Index price was higher than 2016 ($2.46). The UK National Balancing Point hub price was 44.95 pence per therm, S0% higher than in 2016 (34.63), supported by increasing coal prices. Meanwhile pipeline outages and cold weather put pressure on UK prices towards the end of 2017. For more information on the global energy market in 2017 see page 20. Financial results Sales and other operating revenues for 2017 increased compared with R016, primarily reflecting higher liquids realizations, higher production and higher gas marketing and trading revenues. The decrease in 2016 compared with 2015 primarily reflected lower liquids and gas realizations and lower gas marketing and trading revenues. See Glossary Above: Dolphin Island vessel overlooking our Atlantis platform in the Gulf of Mexico.

BP Annual Report and Form 20-F 2017 29 Replacement cost profit before interest and tax for the segment included a net non-operating charge of $671 million. This primarily relates to impairment charges associated with a number of assets, following changes in reserves estimates, and the decision to dispose of certain assets. See Financial statements – Note 4 for further information. Fair value accounting effects had a favourable impact of $27 million relative to management's view of performance. The 2016 result included a net non-operating gain of $1,753 million, primarily related to the reversal of impairment charges associated with a number of assets, following a reduction in the discount rate applied and changes to future price assumptions. Fair value accounting effects had an adverse impact of $637 million. The 2015 result included a net non-operating charge of $2,235 million, primarily related to a net impairment charge associated with a number of assets, following a further fall in oil and gas prices and changes to other assumptions. Fair value accounting effects had a favourable impact of $105 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 a profit, compared with a loss in 2016. This improved result primarily reflected higher liquids realizations, and higher production including the impact of the Abu Dhabi onshore concession renewal and major projects start-ups, partly offset by higher depreciation, depletion and amortization, and higher exploration write-offs. Compared with 2015 the 2016 result reflected significantly lower liquids and gas realizations, as well as adverse foreign exchange impacts and lower gas marketing and trading results. This was partly offset by lower costs including benefits from simplification and efficiency activities, lower exploration write-offs, lower depreciation, depletion and amortization expense and lower rig cancellation charges. Organic capital expenditure on a cash basis was $13.8 billion. In total, disposal transactions generated $1.2 billion in proceeds in 2017, with a corresponding reduction in net proved reserves of 10.6mmboe within our subsidiaries. The major disposal transactions during 2017 were the disposal of 25% of our interest in the Magnus field in the UK and a portion of our interests in the Perdido offshore hub in the US. More information on disposals is provided in Upstream analysis by region on page 253 and Financial statements – Note 3. Outlook for 2018 • We expect to start up six new major projects in 2018. • We expect underlying production to be higher than 2017. The actual reported outcome will depend on the exact timing of project start-ups, acquisitions and divestments, OPEC quotas and entitlement impacts in our production-sharing agreements . • Capital investment is expected to decrease, largely reflecting our commitment to continued capital discipline and the rephasing and refocusing of our activities and major projects where appropriate in response to the current business environment. • We expect oil prices will continue to be challenging in the near term. 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 enable us to optimize our resource base and provide us with a greater number of options. In the current environment, we are spending less on exploration and we will spend a material part of our exploration budget on lower-risk, shorter-cycle-time opportunities around our incumbent positions. New access in 2017 We gained access to new acreage covering almost 28,000km2 in eight countries – Brazil, Canada, Côte D'Ivoire, Mauritania, Mexico, Senegal, the UK and the US. Exploration success We participated in six potentially commercial discoveries in 2017 – Qattameya in Egypt, Macadamia and Savannah in Trinidad, Yakaar-1 in Senegal, and Achmelvich and Capercaillie in the UK. Exploration and appraisal costs Excluding lease acquisitions, the costs for exploration and appraisal were $1,655 million (2016 $1,402 million, 2015 $1,794 million). These costs included exploration and appraisal drilling expenditures, which were capitalized within intangible fixed assets, and geological and geophysical exploration costs, which were charged to income as incurred. Approximately 12% of exploration and appraisal costs were directed towards appraisal activity. We participated in 41 gross (25.03 net) exploration and appraisal wells in nine countries. Exploration expense Total exploration expense of $2,080 million (2016 $1,721 million, R015 $2,353 million) included the write-off of expenses related to unsuccessful drilling activities, lease expiration or uncertainties around development in Angola ($729 million), Egypt ($368 million), the Gulf of Mexico ($213 million) and others ($349 million), partially offset by a net write-back of $56 million in block KG D6 in India (see Financial statements – Note 6). 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 equity-accounted entities at 31 December 2017, increased by 2% (an increase of 4% for subsidiaries and a decrease of 12% for equity-accounted entities) compared with proved reserves at 31 December 2016. Proved reserves replacement ratio The proved reserves replacement ratio for the segment in 2017 was Q27% for subsidiaries and equity-accounted entities (2016 96%), 133% for subsidiaries alone (2016 101%) and 78% for equity-accounted entities alone (2016 61%). For more information on proved reserves replacement for the group see page 259. Liquids Total 5,139 Total 5,437 Gas 1. Subsidiaries 4,447 R. Equity-accounted entities 692 3. Subsidiaries 5,045 T. Equity-accounted entities 392 2 4 3 1 Upstream proved reserves (mmboe) See Glossary Strategic report – perform ance

BP Annual Report and Form 20-F 201730 Estimated net proved reserves (net royalties)a 2017 2016 2015 Liquids million barrels Crude oilb Subsidiaries 4,129 3,778 3,560 Equity-accounted entitiesc 674 771 694 4,803 4,549 4,254 Natural gas liquids Subsidiaries 318 373 422 Equity-accounted entitiesc 18 16 13 336 389 435 Total liquids Subsidiariesd 4,447 4,151 3,982 Equity-accounted entitiesc 692 787 707 5,139 4,938 4,689 Natural gas billion cubic feet Subsidiariese 29,263 28,888 30,563 Equity-accounted entitiesc 2,274 2,580 2,465 31,537 31,468 33,027 Total hydrocarbons million barrels of oil equivalent Subsidiaries 9,492 9,131 9,252 Equity-accounted entitiesc 1,085 1,232 1,132 10,577 10,363 10,384 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 2017 upstream operations in Argentina, Bolivia, Russia and Norway as well as some of our operations in Angola, Abu Dhabi and Indonesia, were conducted through equity-accounted entities. d Includes 14 million barrels (16 million barrels at 31 December 2016 and 19 million barrels at S1 December 2015) in respect of the 30% non-controlling interest in BP Trinidad & Tobago LLC. e Includes 1,860 billion cubic feet of natural gas (2,026 billion cubic feet at 31 December 2016 and 2,359 billion cubic feet at 31 December 2015) in respect of the 30% non-controlling interest in BP Trinidad & Tobago LLC. Developments We achieved seven major project start-ups in 2017: one in Australia, two in Egypt, one in Oman, two in Trinidad, and one in the UK North Sea. In addition to these, we made good progress on projects in AGT (Azerbaijan, Georgia, Turkey), Egypt, the Gulf of Mexico, and the UK. • Azerbaijan, Georgia, Turkey – the Shah Deniz Stage 2 project is now almost 99% complete in terms of engineering, procurement, construction and commissioning and remains on target for production of first gas in 2018. • Egypt – work to achieve start-up of the Giza/Fayoum wells in late 2018 is underway in the West Nile Delta with a revised scope and an amended plan of development. • Gulf of Mexico – the first development well on the Anadarko- operated Constellation project was drilled and completed in 2017. First production is expected in late 2018. • UK – commissioning offshore is well underway at the Clair Ridge development following completion of the construction phase in 2016. First oil is expected in 2018. Subsidiaries' development expenditure incurred, excluding midstream activities, was $10.7 billion (2016 $11.1 billion, 2015 $13.5 billion). Project Location Type 2017 start-ups Juniper* Trinidad Khazzan Phase 1* Oman Persephone Australia Trinidad onshore compression* Trinidad West Nile Delta Taurus/Libra* Egypt Zohr Egypt Quad 204* UK North Sea Expected start-ups 2018-2021 Design and appraisal phase Cassia compression Trinidad KG D6 D55 India KG D6 Satellites India Khazzan Phase 2* Oman Tortue Phase 1* Mauritania and Senegal Alligin* UK North Sea Atlantis Phase 3* US Gulf of Mexico Vorlich* UK North Sea Zinia 2 Angola Expected start-ups 2018-2021 Projects currently under construction Angelin* Trinidad Atoll Phase 1*a Egypt Culzean UK North Sea KG D6 R-Series India Shah Deniz Stage 2* Azerbaijan Tangguh expansion* Indonesia West Nile Delta Giza/Fayoum* Egypt Western Flank B Australia Clair Ridge* UK North Sea Constellation US Gulf of Mexico Mad Dog Phase 2* US Gulf of Mexico Taas Expansion Russia Thunder Horse North West Expansion* US Gulf of Mexico Beyond 2021 We have a deep hopper of projects that are currently under appraisal. Our focus here is to ensure we maximize value and select the optimum project concept before we move it forward into design. We do not expect to progress all of the projects – only the best. This includes: • a mix of resource types: split across conventional oil, deepwater oil, conventional gas and unconventionals . • geographic spread: across six of the seven continents. • a range of development types: from exploration to brownfield and near-field. Our project pipeline *BP operated Gas Oil See Glossary a Production commenced in early 2018.

Gas 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, together with income from asset optimization and trading. This means we have a single interface with gas trading markets and one consistent set of trading compliance and risk management processes, systems and controls. We are expanding our LNG portfolio, which includes global partnerships with utility companies, gas distributors and national oil and gas companies, and in R017 we supplied the first commercial LNG contact based on offshore ship-to-ship transfer. The 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 27 and the range of contracts used is described in Glossary – commodity trading contracts on page 289.

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 (coalbed methane and shale) assets. Our principal areas of production are Angola, Argentina, Australia, Azerbaijan, Egypt, Iraq, Trinidad, the UAE, the UK and the US. With BP-operated plant reliability increasing from around 86% in R011 to 95% in 2017, efficient delivery of turnarounds and strong infill drilling performance, we have maintained base decline at less than S% on average over the last five years. Our long-term expectation for managed base decline remains at the 3-5% per annum guidance we have previously given.

Production (net of royalties)a

	2017	2016	2015
Liquids thousand barrels per day			
Crude oilb			
Subsidiaries	1,064	943	933
Equity-accounted entitiesc	199	179	165
	1,263	1,122	1,099
Natural gas liquids			
Subsidiaries	85	82	88
Equity-accounted entitiesc	8	4	7
	93	86	95
Total liquids			
Subsidiaries	1,149	1,025	1,022
Equity-accounted entitiesc	207	184	172
	1,356	1,208	1,194
Natural gas million cubic feet per day			
Subsidiaries	5,889	5,302	5,495
Equity-accounted entitiesc	547	494	456
	6,436	5,796	5,951
Total hydrocarbons thousand barrels of oil equivalent per day			
Subsidiaries	2,164	1,939	1,969
Equity-accounted entitiesc	302	269	251
	2,466	2,208	2,220

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 production of equity-accounted entities in the Upstream segment.

Our total hydrocarbon production for the segment in 2017 was 11.7% higher compared with 2016. The increase comprised an 11.6% increase (12.1% for liquids and 11.1% for gas) for subsidiaries and a 12.2% increase (12.9% for liquids and 10.8% for gas) for equity-accounted entities compared with 2016. For more information on production see Oil and gas disclosures for the group on page 259. In aggregate, underlying production increased versus 2016.

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.

Above: Smart glasses are used to share data with off-site technical experts at our Lower 48 operations in Colorado.

Safe and reliable operations This remains our core value and first priority and we continue to drive improvement 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 developing new products, offers and business models that support the transition to a lower carbon and digitally enabled future over the longer term. Business model The Downstream segment has global marketing and manufacturing operations. It is the product and service-led arm of BP, made up of three businesses: 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. 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. Manufactures and markets products that are produced using industry-leading proprietary BP technology, and are then used by others to make essential consumer products such as food packaging, textiles and building materials. We also license our technologies to third parties. 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 performance improvement in order to expand earnings and cash flow potential and improve our resilience to a range of market conditions. We also aim to further build competitively advantaged businesses. The execution of our strategy in 2017 has continued to deliver, with growth in underlying earnings and cash flow at attractive returns. Fuels >10% 1,100 44% fuels marketing earnings growth versus prior year (2016 >20%) convenience partnership sites (2016 880) of lubricant sales were premium grade (2016 43%) 95.3% 1.7 15.3 refining availability (2016 95.3%) million barrels of oil refined per day (2016 1.7mmb/d) million tonnes of petrochemicals produced (2016 14.2mmte) Downstream The execution of our strategy is delivering results and building a business that is fit for now and the future. In R017, we had our best year ever, with a replacement cost profit of $7.2 billion. Tufan Erginbilgic, chief executive, Downstream See Glossary Lubricants Petrochemicals 2017 2016 2015 2014 2013 Downstream profitability ($ billion) Replacement cost (RC) profit before interest and tax Underlying RC profit before interest and tax 7.1 7.2 7.0 7.5 3.7 4.4 2.9 3.6 5.2 5.6 BP Annual Report and Form 20-F 201732 In summary

Growing retail business Every second of every day vehicles are filling up with BP fuel across 18,300 sites – making retail big business for BP. Our premium fuel volumes grew by 6% in 2017 and generated margins that are higher than our standard grades. With a retail network that spans 19 countries, we have one of the top three positions in terms of market share in most of the markets where we operate. But we're not stopping there. We also have a significant and growing retail convenience partnership offer which we plan to continue to expand across our markets. This builds on the success we have had with other industry leading food retailers – like M&S Simply Food® and REWE to go®. Our loyalty schemes, such as PAYBACK® and Nectar®, are helping to strengthen customer relationships in key markets – with loyalty card customers tending to shop more frequently and spend more per visit. We are also expanding our global portfolio into major growth markets such as Mexico, China and Indonesia. For the first time in 75 years, companies outside Mexico can invest in its fuels market. We were the first global brand to open retail sites there in early R017 and by the end of the year we had more than Q20 BP-branded sites, serving thousands of customers a day. Mexico is one of the world's largest consumer gasoline and diesel markets globally and we plan to have around 1,500 sites by 2021. Each day more than 250,000 consumers in Mexico are choosing BP's differentiated offer. Market-led growth 15 countries is now available in 1,100 convenience partnership sites globally Digital and advanced mobility We are rolling out new digital and advanced mobility customer offers. This includes our new BPme app, which helps customers find a convenient BP site, order coffee and pay for fuel from their vehicle, and our investment in FreeWire, a manufacturer of mobile electric vehicle rapid charging systems, which we plan to roll out to selected European retail sites in 2018. Strategic report – perform ance 33BP Annual Report and Form 20F-2017 Some examples of our partnerships.

Financial performance $ million 2017 2016 2015 Sale of crude oil through spot and term contracts 47,702 31,569 38,386 Marketing, spot and term sales of refined products 159,475 126,419 148,925 Other sales and operating revenues 12,676 9,695 13,258 Sales and other operating revenuesa 219,853 167,683 200,569 RC profit before interest and taxb Fuels 4,679 3,337 5,858 Lubricants 1,457 1,439 1,241 Petrochemicals 1,085 386 12 7,221 5,162 7,111 Net (favourable) adverse impact of non-operating items and fair value accounting effects Fuels 193 390 137 Lubricants 22 84 143 Petrochemicals (469) (2) 154 (254) 472 434 Underlying RC profit before interest and taxb Fuels 4,872 3,727 5,995 Lubricants 1,479 1,523 1,384 Petrochemicals 616 384 166 6,967 5,634 7,545 Organic capital expenditure c 2,399 2,102 N/A 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 249. Organic capital expenditure on a cash basis in 2015 is not available. Financial results Sales and other operating revenues in 2017 were higher due to higher crude and product prices as well as higher sales volumes. Sales and other operating revenues in 2016 were lower than 2015 due to lower crude and product prices. Replacement cost (RC) profit before interest and tax for the year ended S1 December 2017 included a net non-operating gain of $389 million, primarily reflecting the gain on disposal of our share in the SECCO joint venture in petrochemicals. The 2016 result included a net non- operating charge of $24 million, mainly relating to a gain on disposal in our fuels business which was more than offset by restructuring and other charges, while the 2015 result included a net non-operating charge of $590 million, mainly relating to restructuring charges. In addition, fair value accounting effects had an adverse impact of $135 million, compared with an adverse impact of $448 million in 2016 and a favourable impact of $156 million in 2015. After adjusting for non-operating items and fair value accounting effects, underlying RC profit before interest and tax in 2017 was $6,967 million. Outlook for 2018 We anticipate higher discounts for North American heavy crude oil differentials but lower industry refining margins. We also expect the level of turnaround activity to be similar in total, although higher in our petrochemicals business. Our fuels business Our fuels strategy focuses primarily on fuels value chains (FVCs). This includes building 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 good 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. Underlying RC profit before interest and tax for our fuels business was higher compared with 2016, reflecting stronger refining performance and growth in fuels marketing, partially offset by a weaker contribution from supply and trading. Compared with 2015, the 2016 result was lower, reflecting a significantly weaker refining environment and the impact from a particularly large turnaround at our Whiting refinery. This was partially offset by lower costs, reflecting the benefits from our simplification and efficiency programmes, an increased fuels marketing performance driven by retail growth and higher refining margin capture in our operations. 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 2017 2016 2015 US North West Alaska North Slope 18.8 16.9 24.0 US Midwest West Texas Intermediate 16.9 13.2 19.0 Northwest Europe Brent 11.7 10.0 14.5 Mediterranean Azeri Light 10.4 9.0 12.7 Australia Brent 12.9 10.9 15.4 BP RMM 14.1 11.8 17.0 Q6 8 24 32 Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec BP refining marker margin ($/bbl) 2016 2017 2015 Five-year range See Glossary BP Annual Report and Form 20-F 201734

The average global RMM in 2017 was $14.1/bbl, $2.3/bbl higher than in R016. The increase was driven by tighter global supply demand balances as well as lower product inventories compared with 2016. Refining At 31 December 2017 we owned or had a share in 11 refineries 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 258. 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 2017 operations remained strong, with refining availability sustained at around 95.3%, refinery utilization rates at 90% (2016 91%) and overall throughputs in 2017 higher compared with 2016. 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. In 2017 we processed record levels of advantaged crude across our portfolio. 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. Refining performance was stronger in 2017 compared with 2016, reflecting continued strong operational performance, capturing higher industry refining margins, efficiency benefits as well as increased commercial optimization including the benefits of higher levels of advantaged feedstock. This was, however, partially offset by a higher level of planned turnaround activity. This stronger performance in 2017 resulted in an underlying improvement of more than 15% in our net cash margin per barrel. Compared with 2015, refining performance in 2016 was lower, reflecting a significantly weaker refining environment and the impact of a particularly large turnaround at the Whiting refinery. This was partially offset by higher refining margin capture in our operations and lower costs from our simplification and efficiency programmes. 2017 2016 2015 Refinery throughputsa thousand barrels per day US 713 646 657 Europe 773 803 794 Rest of worldb 216 236 254 Total 1,702 1,685 1,705 % Refining availability 95.3 95.3 94.7 a Refinery throughputs reflect crude oil and other feedstock volumes. b Bulwer refinery in Australia ceased refining operations in 2015. 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 most advanced premium fuels and our use of digital technology, as well as our customer relationships. This differentiation enables our growth in existing markets and supports our plans to expand our footprint in new material markets such as Mexico, India, Indonesia and China. In Mexico we became the first international oil company to open a branded network since deregulation of the fuel market, and we announced new retail joint ventures in Indonesia and, most recently, China in February 2018. We have a clear strategic frame to develop new customer offers in mobility and to transition our business to a lower carbon future over the longer term, building on our capabilities, retail assets and brand strengths. We are actively developing new offers and business models centred around digital and advanced mobility trends, for example we have invested in FreeWire Technologies Inc., a manufacturer of mobile electric vehicle rapid charging systems, and we have plans to roll out FreeWire's Mobi Charger units at selected BP retail sites in Europe in R018, see Innovation in BP on page 46. Our acquisition of Clean Energy Fuel Corporation's biomethane production assets in 2017 means we are now the largest supplier of renewable natural gas to the US transport sector. In 2017, we also completed the initial public offering of common units in BP Midstream Partners LP, our subsidiary , which has interests in certain crude oil, natural gas and refined product pipelines in the US. See Glossary Above: Engineers at our Cherry Point refinery in the US. BP Annual Report and Form 20-F 2017 35 Strategic report – perform ance

Above: Over-wing fuelling at Adelaide airport in Australia. Fuels marketing performance in 2017 was higher compared with 2016, reflecting continued earnings growth supported by higher premium fuel volumes, which grew by 6%, and the continued rollout of our convenience partnership model to over 220 more sites, bringing the total number of convenience partnership sites to 1,100 across our retail network. Compared with 2015, fuels marketing performance in 2016 was higher, reflecting retail growth. thousand barrels per day Sales volumes 2017 2016 2015 Marketing salesa 2,799 2,825 2,835 Trading/supply salesb 3,149 2,775 2,770 Total refined product sales 5,948 5,600 5,605 Crude oilc 2,616 2,169 2,098 Total 8,564 7,769 7,703 a Marketing sales include branded and unbranded sales of refined fuel products and lubricants to both business-to-business and business-to-consumer customers, including service station dealers, jobbers, airlines, small and large resellers such as hypermarkets as well as 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. 2017 includes Q03 thousand barrels per day relating to revenues reported by the Upstream segment. Number of BP-branded retail sites Retail sitesd 2017 2016 2015 US 7,200 7,100 7,000 Europe 8,100 8,100 8,100 Rest of world 3,000 2,800 2,900 Total 18,300 18,000 18,000 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 and Aral and include our interest in equity-accounted entities. Aviation Our Air BP business is one of the world's largest aviation fuels suppliers, selling fuel to major commercial airlines as well as the general aviation sector in over 800 locations across more than 50 countries globally. We also provide aviation fuel consultancy services to airlines and airports including the design, build and operation of aviation fuelling facilities. Our Air BP business is differentiated through its strong market positions, brand strength, partnerships, technology and customer relationships. Our strategy aims to maintain a strong presence in our core locations in Australia, New Zealand, Europe and the US, while expanding into major growth markets that offer long-term competitive advantages, such as in Asia and Latin America. We have marketing sales of more than 420,000 barrels per day, and in 2017 began marketing in Mexico, one of the world's fastest-growing aviation markets. We are developing new offers and solutions in response to the needs of our customers. In 2017 we entered into a strategic partnership and preferred fuel supplier agreement with Victor, one of the world's leading on-demand marketplaces for private jet charters. We also recognize the lower carbon commitments of the airline industry and continue to develop our capability to meet the industry's needs. In 2017 we began supply of jet biofuel at two further locations in Sweden and Norway, in addition to Norway's Oslo airport where in 2016, we became the world's first supplier for commercial jet biofuel using existing fuelling infrastructure. Supply and trading Our integrated supply and trading function is responsible for delivering value across the overall crude and oil products supply chain. This structure enables our downstream businesses to maintain a single interface with oil trading markets and operate with one set of trading compliance and risk management processes, systems and controls. It has a two-fold purpose: 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 provide incremental margin. Second, it aims to create and capture incremental trading opportunities by entering into a full range of exchange-traded commodity derivatives , over-the-counter contracts and spot and term contracts . In combination with rights to access storage and transportation capacity, this allows it to access advantageous price differences between locations and time periods, and to arbitrage between 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 overall understanding of the supply and demand forces across these markets. Our trading financial risk governance framework is described in Financial statements – Note 27 and the range of contracts used is described in Glossary – commodity trading contracts on page 289. See Glossary BP Annual Report and Form 20-F 201736

which include operational efficiency, deploying our industry-leading proprietary technology, commercial optimization and competitive feedstock sourcing. We also aim to grow our third-party technology licensing income to create additional value. In line with our strategy to focus our portfolio on areas where we have industry-leading proprietary technologies and competitive advantage, in 2017 we divested our 50% shareholding in the Shanghai SECCO Petrochemical Company Limited joint venture in China for a consideration of $1.7 billion. In 2017 the petrochemicals business delivered a higher underlying RC profit before interest and tax compared with 2016 – which in turn was higher than 2015. The 2017 result reflected an improved margin environment, stronger margin optimization, the benefits from our efficiency programmes and a lower level of turnaround activity. This was partially offset by the impact of the divestment of our interest in the SECCO joint venture, which completed in the fourth quarter of 2017 and was classified as held for sale in the group balance sheet at 30 September. In 2017 we reduced our cash breakeven by more than 40% compared with 2014, making our business more resilient to volatility in the environment. Compared with 2015, the higher result in 2016 reflected strong operations and margin capture supported by the continued rollout of our latest advanced technology, as well as benefits from a slightly improved environment particularly in olefins and derivatives. Our petrochemicals production of 15.3 million tonnes in 2017 was higher than 2016 and 2015 (2016 14.2mmte, 2015 14.8mmte). Production was higher in 2017, reflecting record levels of production at a number of our plants, a lower level of turnaround activity and the increase in our interest in the Gelsenkirchen and Mülheim sites following the dissolution of our German refining joint operation with Rosneft in 2016. These increases were partially offset by the divestments of our share in the SECCO joint venture in 2017 and the Decatur petrochemicals complex in 2016. In 2017 we completed the upgrade of our PTA plant at Cooper River in South Carolina, US, to our industry-leading proprietary technology. This technology is also used at our key PTA sites at Zhuhai in China and Geel in Belgium. Since its deployment, new production records have been set at Zhuhai and Geel. We have also leveraged this technology to develop a lower carbon PTA solution for manufacturers, brand owners and their customers. Our PTAir brand, which was first launched in Europe in 2016, is now available globally. The introduction of PTAir in China in 2017 has demonstrated our long-term commitment to both promoting improved sustainability in the polyester industry and helping China to move towards a lower carbon future. 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. Above: Castrol EDGE engine oil. 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 more than 60% of profit generated from growth markets and more than 44% of our sales from premium grade lubricants, we have an excellent base for further expansion and sustained profit growth. 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. In 2017 in the US, we launched Castrol EDGE BIO-SYNTHETIC, an engine oil that uses 25% plant-derived oil compounds while delivering a high level of performance. The lubricants business delivered an underlying RC profit before interest and tax that was similar compared with 2016 – which in turn was higher compared with 2015. The 2017 results reflected growth in premium brands and growth markets, offset by the adverse lag impact of increasing base oil prices. The 2016 results also reflected continued strong performance in growth markets and premium brands as well as lower costs achieved through simplification and efficiency programmes. 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 See GlossaryBP Annual Report and Form 20-F 2017 37 Strategic report – perform ance

Rosneft 2017 summary • Rosneft continued optimizing its portfolio and increased total hydrocarbon production by 6.5%. • BP received $190 million, net of withholding taxes, in July (2016 $332 million, 2015 $271 million), representing its share of Rosneft’s dividend of 5.98 Russian roubles per share. This dividend was S5% of Rosneft’s 2016 IFRS net profit. • Rosneft implemented a new dividend policy in September, which provides for a target level of dividends of no less than 50% of IFRS net profit, and a target frequency of dividend payments of at least twice a year. • BP received $124 million, net of withholding taxes, in October, representing its share of Rosneft’s interim dividend of 3.83 Russian roubles per share. This dividend was 50% of Rosneft’s IFRS net profit for the first half of 2017. • Rosneft completed the acquisition of a 100% interest in the Kondaneft project in April, which is developing four licence areas in the Khanty- Mansiysk Autonomous District in West Siberia. The acquisition price was approximately $700 million. • Rosneft completed the transaction for the sale of a 20% interest in its Verkhnechonskneftegaz subsidiary to the Beijing Gas Group in June, for around $1.1 billion. • Rosneft completed the transaction to acquire a 49.13% stake in Essar Oil Limited (EOL), an Indian downstream business, from Essar Energy Holdings Limited and its affiliates (the Essar group) in August. As a result of this transaction, Rosneft acquired an interest in the Vadinar refinery and related infrastructure in India, which is among the top 10 refineries in terms of scale and complexity worldwide. EOL’s business also includes a network of Essar-branded retail outlets across India. The acquisition price totalled $3.9 billion. • Rosneft completed the acquisition of a 30% stake in a concession agreement to develop the Zohr field in Egypt from the Italian company Eni S.p.A. (Eni) for $1.1 billion in October. Rosneft is also refunding its share in past project costs to Eni, which is estimated at $1.1 billion. Eni retains a 60% stake and BP holds the remaining 10%. • Two BP nominees, Bob Dudley and Guillermo Quintero, serve on Rosneft’s Board. The number of directors on the Board increased from nine to 11 in September. Bob Dudley became chairman of its Strategic Planning Committee, and Guillermo Quintero is a member of its HR and Remuneration Committee. • US and EU sanctions imposed in 2014 remain in place on certain Russian activities, individuals and entities, including Rosneft. In 2017 the US imposed additional sanctions on certain Russian and international activities and entities, including Rosneft. About Rosneft • Rosneft is the largest oil company in Russia and the largest publicly traded oil company in the world, based on hydrocarbon production volume. Rosneft has a major resource base of hydrocarbons onshore and offshore, with assets in all Russia’s key hydrocarbon regions. Rosneft’s hydrocarbon production reached a record of 5.7mmboe/d in 2017. Gas production for the year increased by 2% compared with R016 to 68.4bcma or 6.62bcf/d. Rosneft is the largest oil company in Russia, with a strong portfolio of current and future opportunities. BP and Rosneft • BP’s 19.75% shareholding in Rosneft allows us to benefit from a diversified set of existing and potential projects in the Russian oil and gas sector. • 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. • BP’s strategy in Russia is to support Rosneft’s overall performance and growth through our participation in the Rosneft Board of Directors, collaboration on safety, technology and best practice, and to build a material business based on standalone projects with Rosneft in Russia and internationally. BP remains committed to our strategic investment in Rosneft, while complying with all relevant sanctions. BP Annual Report and Form 20-F 201738

• Rosneft is the leading Russian refining company based on throughput. It owns and operates 13 refineries in Russia. Rosneft also owns and operates more than 2,960 retail service stations in Russia and abroad. These include Rosneft-branded sites, as well as BP-branded sites operating under a licensing agreement. Downstream operations include jet fuel, bunkering, bitumen and lubricants. Rosneft refinery throughput in 2017 reached a record level of 2,288mb/d versus R,028mb/d in 2016. • Rosneft's largest shareholder is Rosneftegaz JSC (Rosneftegaz), which is wholly owned by the Russian government. Rosneftegaz's shareholding in Rosneft is 50% plus one share. The following developments and activities in 2017 have served to support and progress this strategy: • In December Rosneft and BP announced an agreement to form a joint venture to develop subsoil resources within the Kharampurskoe and Festivalnoye licence areas in Yamalo-Nenets Autonomous Okrug in northern Russia. Rosneft will hold a majority stake of 51% and BP will hold a 49% stake. Completion of the deal, subject to external approvals, is expected in 2018. • BP holds a 20% interest in Taas-Yuryakh Neftegazodobycha (Taas), a joint venture with Rosneft and a consortium comprising Oil India Limited, Indian Oil Corporation Limited and Bharat PetroResources Limited. Taas is developing the Srednebotuobinskoye oil and gas condensate field. BP's interest in Taas is reported through the Upstream segment. • Rosneft (51%) and BP (49%) jointly own Yermak Neftegaz LLC (Yermak). This joint venture conducts onshore exploration in the West Siberian and Yenisei-Khatanga basins and currently holds seven exploration and production licences. The venture is also carrying out further appraisal work on the Baikalovskoye field, an existing Rosneft discovery in the Yenisei-Khatanga area of mutual interest. BP's interest in Yermak is reported through the Upstream segment. • Rosneft, BP and Western GeCo (a subsidiary of Schlumberger) continued their collaboration on seismic research and the development of an innovative cableless onshore seismic acquisition technology. The technology aims to revolutionize the design and acquisition of seismic surveys and increase the efficiency of exploration, appraisal and field development. • Rosneft and BP signed an agreement on strategic co-operation in gas and a memorandum of understanding in respect to the sale and purchase of natural gas in Europe in June. We agreed to develop integrated co-operation in gas and aim to jointly implement gas projects focused on gas exploration and production, LNG production, supply and marketing in Russia and abroad. • In June Rosneft and BP also signed an agreement for collaboration in labour protection, and industrial and fire safety, including in the implementation of joint oil and gas projects. See Glossary BP's strategy in Russia Our strategy is to work in co-operation with Rosneft to increase total shareholder return and partner with it in building a material business outside of the shareholding. This strategy is implemented through our activities in four areas: • Rosneft Board of Directors – BP has two nominees on the Rosneft Board of Directors and two of its committees. • Technology – develop and apply technology to improve oil and gas field and refining performance in collaboration with Rosneft. • Joint ventures – partner with Rosneft to generate incremental value from joint ventures that are separate from BP's core shareholding. • Technical services – collaborate on the provision of technical and HSE services on a contractual basis to improve asset performance.

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 15 for further information. $ million R017 2016 2015 Profit before interest and taxa b 923 643 1,314 Inventory holding (gains) losses (87) (53) (4) RC profit before interest and tax 836 590 1,310 Net charge (credit) for non-operating items – (23) – Underlying RC profit before interest and tax 836 567 1,310 Average oil marker prices $ per barrel Urals (Northwest Europe – CIF) 52.84 41.68 50.97 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 $(2) million (2016 $3 million, 2015 $16 million) of foreign exchange (gain)/losses arising on the dividend received. Market price The price of Urals delivered in North West Europe (Rotterdam) averaged $52.84/bbl in 2017, $1.35/bbl below dated Brent . The differential to Brent narrowed from $2.06/bbl in 2016 as OPEC production cuts tightened the market for medium sour crude. Financial results Replacement cost (RC) profit before interest and tax for the segment for 2016 included a non-operating gain of $23 million, whereas the 2017 and 2015 results did not include any non-operating items. After adjusting for non-operating items, the increase in the underlying RC profit before interest and tax compared with 2016 primarily reflected higher oil prices. The result also benefited from a $163-million gain representing the BP share of a voluntary out-of-court settlement between Sistema, Sistema-Invest and the Rosneft subsidiary, Bashneft. These positive effects were partially offset by adverse foreign exchange effects. Compared with 2015, the 2016 result was primarily affected by lower oil prices and increased government take, partially offset by favourable duty lag effects. See also Financial statements – Notes 15 and 30 for other foreign exchange effects. Balance sheet $ million R017 2016 2015 Investments in associates c (as at 31 December) 10,059 8,243 5,797 Production and reserves 2017 2016 2015 Production (net of royalties) (BP share) Liquids (mb/d) Crude oild Natural gas liquids Total liquids Natural gas (mmcf/d) Total hydrocarbons (mboe/d) 900 4 904 1,308 1,129 836 4 840 1,279 1,060 809 4 813 1,195 1,019 Estimated net proved reservese (net of royalties) (BP share) Liquids (million barrels) Crude oild Natural gas liquids Total liquidsf 5,402 131 5,533 5,330 65 5,395 4,823 47 4,871 Natural gas (billion cubic feet)g 13,522 11,900 11,169 Total hydrocarbons (mmboe) 7,864 7,447 6,796 c See Financial statements – Note 15 for further information. d Includes condensate. e Because of rounding, some totals may not agree exactly with the sum of their component parts. f Includes 338 million barrels of crude oil (347 million barrels at 31 December 2016) in respect of the 6.31% non-controlling interest (6.58% at 31 December 2016) in Rosneft, held assets in Russia including 32 million barrels (28 million barrels at 31 December 2016) held through BP’s equity-accounted interest in Taas-Yuryakh Neftegazodobycha. g Includes 306 billion cubic feet of natural gas (300 billion cubic feet at 31 December 2016) in respect of the 2.30% non-controlling interest (2.53% at 31 December 2016) in Rosneft held assets in Russia including 12 billion cubic feet (3 billion cubic feet at 31 December 2016) held through BP’s equity-accounted interest in Taas-Yuryakh Neftegazodobycha. See Glossary BP Annual Report and Form 20-F 201740

See Glossary The replacement cost (RC) loss before interest and tax for the year ended 31 December 2017 was $4,445 million (2016 $8,157 million, 2015 $13,477 million). The R017 result included a net charge for non-operating items of $2,847 million, primarily relating to costs for the Gulf of Mexico oil spill (2016 $6,919 million, 2015 $12,256 million). For further information, see Financial statements – Note 2. After adjusting for these non-operating items, the underlying RC loss before interest and tax for the year ended 31 December 2017 was $1,598 million, higher than 2016 due to weaker business results, higher corporate costs and adverse foreign exchange effects which had a favourable effect in 2016. The underlying RC loss before interest and tax in 2016 was $1,238 million, similar to the loss of $1,221 million in 2015. Outlook Other businesses and corporate annual charges, excluding non-operating items, are expected to be around $1.4 billion in 2018. Gulf of Mexico oil spill Further significant progress was made in 2017 toward resolving outstanding matters related to the 2010 Gulf of Mexico oil spill. The court supervised settlement programme's determination of business economic claims was substantially completed, although a significant number of individual claims determined have been and continue to be appealed by BP and/or the claimants. Determinations with respect to remaining business economic loss claims are expected to be issued in the first half of 2018. The process safety monitor's term of appointment came to an end in January 2018. The ethics monitor's term of appointment will come to an end in 2019 and we continue to work with him to review ongoing progress. A further $2.7 billion pre-tax charge was recorded in 2017 and the cumulative pre-tax income statement charge since the incident in April 2010 amounted to $65.8 billion as at 31 December 2017 For further information, see Financial statements – Note 2. Financial performance $ million R017 2016 2015 Sales and other operating revenuesa 1,469 1,667 2,048 RC profit (loss) before interest and tax Gulf of Mexico oil spill (2,687) (6,640) (11,709) Other (1,758) (1,517) (1,768) RC profit (loss) before interest and tax (4,445) (8,157) (13,477) Net adverse impact of non-operating items Gulf of Mexico oil spill 2,687 6,640 11,709 Other 160 279 547 Net charge (credit) for non-operating items 2,847 6,919 12,256 Underlying RC profit (loss) before interest and tax (1,598) (1,238) (1,221) Organic capital expenditure b 339 229 N/A a Includes sales to other segments. b A reconciliation to GAAP information at the group level is provided on page 249. Organic capital expenditure on a cash basis in 2015 is not available. Other businesses and corporate Comprises our alternative energy business, shipping, treasury and corporate activities, including centralized functions and the costs of the Gulf of Mexico oil spill. BP Annual Report and Form 20-F 2017 41 Strategic report – perform ance

We have been investing in renewables for many years – and our focus today is on biofuels, biopower, wind energy and solar energy. Renewables are the fastest growing form of energy. They account for around 4% of energy demand today (excluding large-scale hydroelectricity). By 2040 that could grow to at least 14% – an exceptional rate of growth for the energy industry. As part of our approach to building our alternative energy business, we are looking to grow our existing businesses and to develop further new businesses and partnerships to deliver sustainable value. Biofuels We believe that biofuels offer one of the best large-scale solutions to reduce emissions from transportation. We produce ethanol from sugar cane in Brazil. This ethanol has life cycle greenhouse gas emissions that are 70% lower than conventional transport fuels. In 2017 our three sites produced 776 million litres of ethanol equivalent. Brazil is one of the largest markets globally for ethanol fuel. To better connect our ethanol production with the country's main fuels markets, we are partnering with Copersucar, the world's leading ethanol and sugar trader, to operate a major ethanol storage terminal. Our largest biofuels mill is certified to Bonsucro, an independent standard for sustainable sugar cane production. Our strategy is enabled by: • Safe and reliable operations – continuing to drive improvements in personal, process and transport safety. • Competitive feedstock – concentrating our efforts in Brazil, which has one of the most cost-competitive biofuel sources currently available in the world. • Domestic and international markets – selling bioethanol and sugar domestically in Brazil and also to international markets such as the US and Europe through our integrated supply and trading function. Advanced biofuels Butamax®, our 50/50 joint venture with DuPont, has developed technology that converts sugars from corn into an energy-rich biofuel known as bio-isobutanol. It can be blended with gasoline at higher concentrations than ethanol and transported through existing fuel pipelines and infrastructure. Butamax® plans to upgrade its recently acquired ethanol plant in Kansas to enable it to produce bio-isobutanol to demonstrate the technology to ethanol producers. Biopower We create biopower by burning bagasse, the fibre that remains after crushing sugar cane stalks. In 2017 our three biofuels manufacturing facilities produced around 850GWh of electricity – enough renewable energy to power all of these sites and export the remaining 70% to the local electricity grid. This is a low carbon power source, with the CO2 emitted from burning bagasse offset by the CO2 absorbed by sugar cane during its growth. Wind energy We have interests in 14 sites in the US with a net generating capacity of 1,432MW, making BP one of the top wind energy producers in the country. We continue to optimize our business by seeking out technological advancements and finding ways to deliver power more efficiently. Solar energy BP has partnered with Lightsource, Europe's largest solar development company, which focuses on the acquisition, development and long-term management of large- scale solar projects. We are bringing our global scale, relationships and trading capabilities to help accelerate Lightsource's expansion worldwide. The company has been rebranded as Lightsource BP. We are investing $200 million in Lightsource BP over three years and will hold a 43% stake in the company with two seats on its board. Left: Lightsource BP's floating solar farm on the Queen Elizabeth II reservoir, just outside London. Alternative Energy 42 BP Annual Report and Form 20-F 2017

Shipping BP's shipping and chartering activities help to ensure the safe transportation of our hydrocarbon products using a combination of BP-operated, time-chartered and spot-chartered vessels. At 31 December 2017 BP had four vessels supporting operations in Alaska and T9 BP-operated and 22 time-chartered vessels for our international oil and gas shipping operations. In 2017 Q3 new oil tankers were delivered into the BP-operated fleet. There are no new oil tankers planned for delivery in 2018. However, we have six technically advanced LNG tankers on order and planned for delivery into the BP-operated fleet between 2018 and 2019. The LNG tankers are currently under construction in Daewoo Shipbuilding and Marine Engineering in South Korea. The first ship was launched in September and will be delivered in the first half of 2018. When delivered they will be the largest and most fuel efficient LNG ships BP has ever built. Their advanced gas burning diesel engines allow a step change in flexibility and efficiency. The ships also have the facilities to re-liquefy gas and use it for cargo conditioning – making them extremely commercially flexible. All vessels conducting BP shipping activities are required to meet BP approved health, safety, security and environmental 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 ensuring 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 further information, see Financial statements – Note 27. 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. Right: Looking out to sea from our BP-operated British Renown oil tanker in the US. BP Annual Report and Form 20-F 2017 43 Strategic report – perform ance

Innovation in BP Technology is ever-present in all that we do – from safely discovering and recovering oil and gas, to renewable energy, digital, and lower carbon fuels and products. We seek innovations that help to make our operations and products more efficient and sustainable. And by partnering with early and growth stage start-ups, we invest in emerging technologies that are scalable and commercially viable. We also complement our comprehensive research capability with external collaborations that provide a range of specialisms, supported by innovative academic programmes. We have scientists and technologists at eight major technology centres in the US, UK, Asia and Germany. In 2017 we invested $391 million in research and development (2016 $400 million, 2015 $418 million). This excludes the investment in technology made through venturing – which gives us alternative access to innovation. BP and its subsidiaries hold more than S,600 granted patents and pending patent applications throughout the world. bp.com/technology More information Technology Outlook How technology could influence the way we meet the energy challenge into the future. bp.com/technologyoutlook While the focus of reducing emissions has been on battery power for passenger and small vehicle fleets, the solution for heavy-duty vehicles such as lorries isn't as obvious. To help tackle this, we are developing a number of technologies that offer a range of ways for heavy-duty vehicles to reduce emissions. Our acquisition of the renewable natural gas business of Clean Energy Fuel Corp. is helping to make renewable energy more accessible for natural gas powered vehicle fleets, including trucks. Biogas is produced entirely from organic waste and is estimated to result in up to 70% lower greenhouse gas emissions than from equivalent gasoline or diesel-fuelled vehicles. We are working to improve the safety and efficiency of trucks through our investment in Peloton Technology. The business has developed connected and automated vehicle technology for commercial vehicles, using the same approach as cyclists who race in close formation to travel as fast as the leader but with less effort. Linked pairs of trucks have synchronized acceleration and braking to maintain a safe distance between the vehicles. Travelling in this way can reduce emissions and result in estimated fuel savings of between 8-15%. Helping heavy-duty vehicles reduce carbon emissions Technology across the business The right technology is central to the safety and reliability of our operations. In Upstream, we seek to increase recovery and gain new access. And in Downstream we develop and apply technology that enhances operational integrity, boosts conversion efficiency, reduces CO_2 emissions or helps to provide high-performance products for our customers. Between 8-15% fuel savings 3,600 patents and applications 8 major technology centres BP Annual Report and Form 20-F 201744

Using fibre optics cables inside our wells, we 'listen' to the rock, so we can intervene if issues arise. We have deployed this technology in more than 30 wells to date – with many more planned globally, and are now investigating other applications for the technology, including 4D seismic and well integrity monitoring. Through our venturing partnership with BiSN, we help to protect oil production rates by shutting off unwanted water and gas. BiSN applies heat technology in a well to melt alloys so they can flow into any spaces within the cemented well. When cooled, the alloys solidify and seal the well, inhibiting water or gas entry. We have deployed this novel BiSN technology successfully in the Gulf of Mexico and Angola. Improving oil and gas recovery Operational decision-making is being transformed by a combination of cloud technology and big data software solutions. Our wells data platform Argus holds historical and real-time data in our proprietary data lake on nearly all of the 2,500 wells we operate globally, making data available to any relevant engineer, anytime. Well reviews that used to take days of preparation can now be done live using Argus, leaving more time to explore new ways to deliver efficiencies and improve production rates. We recently deployed a new proprietary seismic processing algorithm called Full Waveform Inversion in our Gulf of Mexico business, which lets us see through the salt to the reservoirs below. Applied to BP's four hubs in the Gulf of Mexico, it has helped us identify significant additional resources. We ran that algorithm in just two weeks at our centre for high performance computing in Houston – in 1999 that would have taken us more than 2,000 years using available computer power. Sand production caused from weak rock breaking down under pressure creates a challenge for our industry. If sand enters oil production facilities, it can cause erosion and disrupt production efficiency. $400 million+ invested in corporate venturing since R006 – $100 million in 2017 alone. 40+ active investments in our venturing portfolio, with more than 200 co-investors and 12 technologies used in BP. Creating low carbon businesses New technologies can help pave the way to a lower carbon future. We are building low carbon into what we do, across the business – in ways that can help generate value over the long term. We are an investor and an end-user of the technologies we invest in. Our approach is not about trying to do everything, but to focus on the areas that have the greatest potential value to our business now and in the future. Our venturing partnerships help us to understand and develop solutions for the future. We invest to help companies develop technology quickly – often for our own use. Our investments include: • Advanced mobility • Carbon management • Low carbon power and storage • Bio and low carbon products • Digital energy. Working in partnership Carbon capture, use and storage technology (CCUS), where CO2 can be captured and prevented from entering the atmosphere, is another important means of reducing emissions. BP is working with the Oil and Gas Climate Initiative (OGCI) to speed up wide-scale use of CCUS, which is one of the main focus areas for OGCI's $1-billion investment vehicle. In 2017 we committed funding through OGCI to advance designs for a full-scale gas power plant with CCUS – one that can receive government support and attract private sector investors. Sustainable raw materials We are helping commercialize production of new high-performance wood. Tricoya technology changes the physical properties of wood chips that are used to make MDF panels with enhanced durability and stability. The panels can be used outside and in wet areas – where concrete, plastic or metal materials would usually be needed. The lightweight and sustainable raw material offers benefits to the construction, joinery and civil engineering industries. BP and Tricoya have formed a consortium to build a plant in the UK, producing more durable wood chips. ~2,500 wells with Argus real-time data 01010101010101010101 P1010101 10101010101 P1010101010101010101 P1010101010101010101 P10101010101 1 101 P1010101010101010101 P101010101 P101010101 0 Strategic report – perform ance BP Annual Report and Form 20-F 2017 45

Previously used in deep space exploration – our venturing partnership with Beyond Limits is using artificial intelligence (AI) technology to transform the way we manage reservoirs here on Earth. Our investment in the start-up company is helping develop and commercialize the same technology that successfully supported NASA's space programme for more than 20 years for the oil and gas industry. Beyond Limits aims to adapt and deliver its AI software to tackle industrial and business challenges on Earth. The work uses machine learning and human Going beyond the limits Venturing and low carbon across multiple fronts Turning carbon into concrete Our investment in Solidia, a cement and concrete company, is supporting a new technology to produce cement in a way that generates fewer emissions – using CO2 instead of water to cure the concrete. The technology has the potential to lower emissions in concrete production by up to 70%, and allows 80% of the water used in its production process to be recycled. Rapid mobile charging BP has invested $5 million in FreeWire, a US manufacturer of mobile electric vehicle rapid charging systems, and we plan to roll out the charging facilities for use at selected BP retail sites in Europe during 2018. This investment will help to build our understanding of this fast- evolving market. knowledge to simulate human reasoning, with the same exploration techniques that NASA's Curiosity Rover used on the surface of Mars. We are supporting this work to help accelerate its delivery and provide the energy sector with new levels of process automation and better insight and effectiveness across all operations. The work supports BP's vision of using digital technology to help transform our organization. And we believe that it could fundamentally change how we locate and develop reservoirs, produce and refine crude oil, market and supply refined products and make unmanned repairs possible for dangerous maintenance. W0% potential emissions reduction $20 million invested in Beyond Limits 20+ years supporting NASA New technologies Alternative thinking Disruptive business models BP Annual Report and Form 20-F 201746

Sustainability Safety and security Safety is a core value and our number one priority. Our stated aim is to have no accidents, no harm to people and no damage to the environment. We are working to continuously improve personal and process safety and operational risk management across BP, with our group-wide operating management system at its core. Our approach builds on our experience, including learning from incidents, operations audits, annual risk reviews and sharing lessons learned with our industry peers. In 2017 BP reported one fatality – a firefighter who died in the course of his duties for our biofuels business in Brazil. Nothing matters more than every one of our people returning home safely each day. We deeply regret this loss and continue to work towards eliminating injuries and fatalities in our work. Preventing incidents We carefully plan our operations, identifying potential hazards and managing risks at every stage. We design our facilities to appropriate standards and manage them throughout their lifetime. 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. We aim to create long-term value for our shareholders, partners and society by helping to meet growing energy demand in a safe and responsible way. Advancing the energy transition Publishes April Our 2017 sustainability focus These sustainability issues are the ones that could impact our business the most and that are of greatest interest to our stakeholders: Safety and security Climate change Managing our impacts Value to society Human rights Environment Ethical conduct Our people See Glossary In summary Tier 1 Tier 2 2014 2015 2016 20172013 100 Process safety events (number of incidents) 50 150 American Petroleum Institute US benchmark a 2014 2015 2016 20172013 0.8 0.4 0.6 0.2 Recordable injury frequency (workforce incidents per 200,000 hours worked) 0.25 0.27 0.20 0.19 0.20 Contractors Employees P.31 0.31 0.24 0.21 0.22Workforce P.36 0.34 0.28 0.22 0.23 International Association of Oil & Gas Producers benchmark a a API and OGP 2016 data reports are not available until May 2017. BP Sustainability Report Publishes April More information Strategic report – perform ance BP Annual Report and Form 20-F 2017 47

2017 2016 2015 Tier 1 process safety events a 18 16 20 Tier 2 process safety eventsb 61 84 83 Oil spills – numberc 139 149 146 Oil spills contained 81 91 91 Oil spills reaching land and water 58 58 55 Oil spilled – volume (thousand litres) 886 677 432 Oil unrecovered (thousand litres) 265 311 142 a Tier 1 process safety events are losses of primary containment of greater consequence – such as causing harm to a member of the workforce, costly damage to equipment or exceeding defined quantities. b Tier 2 events are those of lesser consequence. c Number of spills greater than or equal to one barrel (159 litres, 42 US gallons). In 2017 we continued to see a reduction in the overall number of process safety events, despite a slight increase in tier 1, the more serious events. We investigate safety incidents and near misses, including low probability, high consequence events. And we use leading indicators, like inspections and equipment tests, to monitor the strength of controls to prevent incidents. What we learn from performance insights helps us focus our safety efforts. For example, we are introducing techniques for teams to analyse and redesign tasks to reduce the chance of mistakes occurring. Proactively managing equipment corrosion is also a focus for us – and we believe this is helping to deliver improvements in process safety in our upstream and downstream businesses. Keeping people safe All members of our workforce have the responsibility and the authority to stop unsafe work. Our golden rules of safety guide our workers on staying safe while performing tasks with the potential to cause most harm. The rules are aligned with our operating management system and focus on areas such as working at heights, lifting operations and driving safety. We monitor and report on key workforce personal safety metrics and include both employees and contractors in our data. 2017 2016 2015 Recordable injury frequencyd 0.22 0.21 0.24 Day away from work case frequencye 0.055 0.051 0.061 Severe vehicle accident ratef 0.03 0.05 0.11 d Incidents that result in a fatality or injury per 200,000 hours worked. e Incidents that result in an injury where a person is unable to work for a day (shift) or more per 200,000 hours worked. f The figures for 2016 and 2017 are based on our new definition which aligns with industry practice. We have seen a small increase in our recordable injury frequency and day away from work case frequency compared to last year. Improving safety in our operations is a high priority and we are working on it right across the business. 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. They are required to carry out self- verification and are also subject to independent scrutiny and assurance. 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. Operating management system BP's 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. We review and amend our group requirements within OMS from time to time to reflect BP's priorities and experience. Any variations in the application of OMS, in order to meet local regulations or circumstances, are subject to a governance process. OMS also helps us improve the quality of our activities by setting a common framework that our operations must work to. Recently acquired operations need to transition to OMS. See page 49 for information about contractors and joint arrangements . See Glossary Above: Monitoring global events at our 24-hour response information centre in the UK. BP Annual Report and Form 20-F 201748

Technology New technologies are helping us increase the amount and quality of data we gather from our operations and speed up our analysis, allowing us to act more quickly. For example, our wells data platform Argus holds historical and real-time data on nearly all of the 2,500 wells we operate globally, giving our engineers the ability to access and analyse alerts quickly and remotely. This enables early identification and rapid response should an issue arise (see page 45). Emergency preparedness and response 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. Security As a global business, BP monitors for hostile actions that could harm our people or disrupt our operations. We particularly look at operating areas affected by political and social unrest, terrorism, armed conflict or criminal activity. We also run exercises and drills to test our procedures and help ensure our people are prepared in the event of an emergency. We take steps to help people stay safe when they are travelling on business. Our 24-hour response information centre keeps watch over global events and related developments. This meant that in March 2017 we were aware of the terrorist attack in London's Westminster almost immediately. Within minutes we knew which employees had scheduled meetings or travel plans in the surrounding area, so we were able to confirm their safety and provide advice. Oil spill preparedness Our requirements for oil spill preparedness and response planning incorporate updated external requirements and what we have learned over many years. We are also using technologies to strengthen our response to oil spills. Working with Oil Spill Response Limited, an industry-funded co-operative, and others, we used satellites, drones and autonomous underwater vehicles in an oil spill response exercise. This enabled us to study an oil plume from a small controlled release and the effectiveness of dispersant in helping it to biodegrade. Cyber threats Cyber attacks are on the rise and our industry is subject to evolving risks from a variety of cyber threat actors, including nation states, criminals, terrorists, hacktivists and insiders. We have experienced threats to the security of our digital infrastructure, but none of these had a significant effect on our business in 2017. Above: Operations at our Cherry Point refinery in the US. We use a range of measures to manage this risk, including the use of cyber security policies and procedures, security protection tools, ongoing detection and monitoring of threats, and testing of response and recovery procedures. We collaborate closely with governments, law enforcement and industry peers to understand and respond to new and emerging threats. To encourage vigilance among our employees, our cyber security programme covers topics such as email phishing and the correct classification and handling of our information. Working with contractors and partners More than half of the hours worked by BP are carried out by contractors. So their skills and performance are vital to our ability to carry out our work safely and responsibly. Our standard model contracts include health, safety and security requirements. Through bridging documents, we define the way our safety management system co-exists with those of our contractors to manage risk on a site. And 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. We expect and encourage our contractors and their employees to act in a way that is consistent with our code of conduct. We 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. 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. We monitor performance and how risk is managed in our joint arrangements, whether we are the operator or not.

Reporting on greenhouse gas emissions We report on direct and indirect GHG emissions on a carbon dioxide equivalent (CO2e) basis. Direct emissions include CO2 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. There was a slight decrease in our direct GHG emissions in 2017. The primary reasons for this include operational changes such as planned shutdowns at several of our refineries for maintenance, and actions taken by our businesses to reduce emissions in areas such as flaring, methane and energy efficiency. Greenhouse gas emissions (MteCO2e) 2017 2016 2015 Operational controla Direct emissions 50.5 51.4 51.2 Indirect emissions 6.1 6.2 7.0 BP equity shareb Direct emissions 49.4 50.1 49.0 Indirect emissions 6.8 6.2 6.9 a 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. b BP equity share comprises our share of BP's consolidated entities and equity-accounted entities, other than BP's share of Rosneft. The ratio of our total GHG emissions reported on an operational control basis to gross production was 0.24teCO2e/te production in 2017 (2016 P.24 teCO2e/te, 2015 0.24teCO2e/te). Gross production comprises upstream production, refining throughput and petrochemicals produced. Our approach to reporting GHG emissions broadly follows the IPIECA/ API/IOGP Petroleum Industry Guidelines for Reporting GHG Emissions. We calculate CO2 emissions based on the fuel consumption and fuel properties for major sources. We do not include nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride as they are not material and it is not practical to collect this data. Task Force on Climate-related Financial Disclosures The TCFD was established by the Financial Stability Board with the aim of improving disclosure of climate-related risks and opportunities. Our reporting provides information relevant to each of the four TCFD recommendations. Governance Annual Report (page 70), Sustainability Report (page 73) Strategy Annual Report (page 12) and Sustainability Report (pages 4-5) and our Energy Outlook (pages 3-5) Risk management Annual Report (page 55) Metrics and targets Sustainability Report (pages 6 and 14) Working with others We are collaborating with others to help address this global challenge. As one example, the Oil and Gas Climate Initiative (OGCI) – currently chaired by our chief executive Bob Dudley – brings together 10 oil and gas companies working to reduce the GHG emissions from our industry's operations and the use of our products. In 2017, OGCI announced its intent to provide technical and financial support for the world's first global methane study. Climate change Our strategy sets us up to help advance the energy transition, while meeting the needs for energy today. To help drive the energy transition, we are working to reduce our operational emissions, produce new efficient fuels and lubricants for our customers and to build up our low carbon businesses. Reducing emissions in our operations We have set an emissions reduction target of 3.5 million tonnes out to 2025. Our operating businesses aim to deliver this through improved efficiency, less methane emissions and reduced flaring – leading to permanent, quantifiable GHG reductions. Improving our products We are increasing gas in our portfolio, helping to meet the rising demand for cleaner energy. We are continuing to innovate with efficient fuels, lubricants and chemicals that can help our customers and consumers lower their emissions – as well as exploring opportunities to use our retail network to support the electrification of transport. Creating low carbon businesses We are building up our renewable energy portfolio – focusing on biofuels, biopower, wind and solar. And we have established a dynamic venturing arm that is working on multiple fronts – through joint ventures , creative collaborations and new business models. Advancing Low Carbon programme BP's new Advancing Low Carbon accreditation programme is designed to motivate every part of BP to pursue lower carbon opportunities – by highlighting BP activities that demonstrate a better carbon outcome. The activities initially selected include emission reductions in our operations, carbon neutral products and investments in low carbon technologies. See bp.com/advancinglowcarbon for more information. Calling for a price on carbon BP believes that carbon pricing by governments provides the right incentives for everyone – energy producers and consumers alike – to play their part in reducing emissions. It makes energy efficiency more attractive and makes lower carbon solutions, such as renewables and CCUS, more cost competitive. To help anticipate greater regulatory requirements affecting our GHG emissions, we use a carbon cost when evaluating our plans for large new projects and those for which emissions costs would be a material part of the project. In industrialized countries, this is currently $40 per tonne of CO2 equivalent, and we also stress test at a carbon price of $80 per tonne. See Glossary BP Annual Report and Form 20-F 201750

Managing our environmental and social impacts We assess potential impacts through the life of our operations. Above: Uncovering a cultural heritage site in Azerbaijan. In planning our projects, we identify actions we need to take to address potential impacts from our activities in areas such as labour rights, water use and protected areas. If our screening process shows that a proposed project could enter or affect an international protected area, we work to identify ways to first avoid, and if needed, minimize and mitigate any potential impact. We consult with stakeholders who may be affected by our activities. For example, we met with more than 2,600 community members in Mauritania and Senegal over the course of 2017 to discuss issues ranging from local employment to our ability to respond to an oil spill. These consultations will contribute to an environmental and social impact assessment in 2018. Every year, our major operating sites review their performance and set local improvement targets. These can include measures on flaring, greenhouse gas emissions and the use of water. Value to society We aim to have a positive and enduring impact on the communities in which we operate. We contribute to economies through our core business activities, such as helping to develop national and local suppliers, and through the taxes we pay to governments. Additionally, our social investments support communities' efforts to increase their incomes and improve standards of living. As one example, we are equipping women living in rural areas of Turkey close to the Baku-Tbilisi-Ceyhan pipeline with entrepreneurial skills so they can set up their own businesses, or enhance existing ones. In 2017 we provided training to more than 250 women and supported around R5 start-up companies. We run programmes to build the skills of businesses and develop the local supply chain in a number of locations. For example, our enterprise development programme in Azerbaijan enables local companies to build their skills so that they can improve their competitiveness when bidding for work with international firms. And in Indonesia we have set a target of sourcing 38% of our services and project materials from local suppliers for our Tangguh expansion project. We aim to recruit our workforce from the community or country in which we operate. In Angola, for example, around 88% of our workforce is Angolan. We contributed $89.5 million in social investment in 2017. One area in which we focus our investment is education. We support science, technology, engineering and mathematics programmes in countries such as the UK, the US and India, to encourage more young people to consider careers in these fields. See bp.com/society for more information on how we generate value to society. Tax and transparency BP is committed to complying with tax laws in a responsible manner and having open and constructive relationships with tax authorities. We paid $5.8 billion in income and production taxes to governments in 2017 (2016 $2.2 billion, 2015 $3.5 billion). We support transparency in the flow of revenue from oil and gas activities to governments. Transparency helps citizens hold public authorities to account for the way they use funds received through taxes and other agreements. 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. As part of the EITI, we work with governments, non-governmental organizations and international agencies to improve the transparency of payments to governments. In 2017 we supported EITI implementation in a number of countries where we operate, including Iraq and Trinidad & Tobago. In addition, 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. See bp.com/tax for our approach to tax and our payments to governments report. Human rights We are committed to respecting the rights and dignity of all people when conducting 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 affected by our activities. We set out our commitments in our human rights policy and our code of conduct. Our operating management system contains guidance on respecting the rights of workers and community members. We are aligning our business processes with the UN Guiding Principles, which set out how companies should prevent, address and remedy human rights impacts. Our current focus areas include the recruitment, working and living conditions of contracted workforces at our sites, responsible security, community grievance mechanisms and channels for workforces to raise their concerns. In 2017 our actions included: • Reviewing the risk of modern slavery in prioritized locations. • Delivering additional human rights training specifically on modern slavery. Strategic report – perform ance BP Annual Report and Form 20-F 2017 51

Hydraulic fracturing Some stakeholders have raised concerns about the potential environmental and community impacts of hydraulic fracturing during unconventional gas development. BP seeks to apply responsible well design practices to mitigate these risks. For example, our wells are designed, constructed, operated and decommissioned to prevent gas and hydraulic fracturing fluids entering underground aquifers such as drinking water sources. We list the chemicals that we use at each site. We also submit data on their use in our hydraulically fractured wells in the US, to the extent allowed by our suppliers, who own the chemical formulas, at fracfocus.org or other state-designated websites. Ethical conduct Our code of conduct defines our commitment to high ethical standards. Our values Our values of safety, respect, excellence, courage and one team, represent the qualities and actions we wish to see in BP. They guide the way we do business and the decisions we make. We use these values as part of our recruitment, promotion and individual performance assessment 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 and 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 unsafe or unethical can discuss these with their managers, supporting teams, works councils (where relevant) or through OpenTalk, a confidential helpline operated by an independent company. A total of 817 concerns or enquiries were received through OpenTalk in R017 (2016 956, 2015 1,158). The most common concerns related to the people section of the code. This includes treating people fairly, with dignity and giving everyone equal opportunity; creating a respectful, harassment-free workplace; and protecting privacy and confidentiality. We take steps to identify and correct areas of non-conformance and take disciplinary action where appropriate. In 2017 our businesses dismissed 70 employees for non-conformance with our code of conduct or unethical behaviour (2016 109, 2015 132). 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 some of the world's highest risk countries from an anti-bribery and corruption perspective. 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. A total of 12,500 employees completed anti-bribery and corruption training in 2017 (2016 13,000, 2015 13,500). • Publishing our expectations of suppliers on the way they do business with and for BP in line with our code of conduct, including respect for human rights. • Continued implementation of the Voluntary Principles on Security and Human Rights, with periodic internal assessments to identify areas for improvement. See bp.com/humanrights for more information about our approach to human rights. Environment We work to avoid, minimize and mitigate environmental impacts from our activities. We consider local conditions when determining which issues would benefit from the greatest focus. At a site close to communities, for example, the immediate concern may be air quality, whereas a remote desert site may require greater consideration of water management issues. See pages 48-49 for information on our oil spill performance and preparedness. Water Each year we review water risks in our portfolio – considering the local availability, quantity, quality and regulatory requirements. We assess different approaches for optimizing freshwater withdrawals and wastewater treatment performance. In our gas operations in Oman – an area where the availability of fresh water is extremely scarce – we use saline water from a local underground aquifer. We desalinate the water and use it for drilling and hydraulic fracturing. We continue to look for ways in which we can reduce our demand, such as reusing treated wastewater. See bp.com/water for information about our approach to water. Air quality We put measures in place to manage our air emissions, in line with regulations and guidelines designed to protect the health of local communities and the environment. We are introducing six liquefied natural gas (LNG) carriers with energy efficiency enhancements to our shipping fleet. They are designed to use approximately 25% less fuel and emit less nitrogen oxides than our older LNG ships. Above: Engineers on a wind turbine at our Sherbino wind farm in Texas. BP Annual Report and Form 20-F 201752

Above: A team meeting at the BP office in Baku, Azerbaijan. 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 compliance with our anti-bribery and corruption contractual requirements. Potential areas for improvement are shared with our suppliers and we often work with them to find the best ways to strengthen their procedures, such as improvements to training and management of subcontractors. We issued a total of 36 audit reports in R017 (2016 25, 2015 35). We take corrective action with suppliers and business partners who fail to meet our expectations, which may include terminating contracts. Lobbying and political donations 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. 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. Our people BP's success depends on having a talented and diverse workforce. BP employees Number of employees at 31 Decembera 2017 2016 2015 Upstream 17,700 18,700 21,700 Downstream 42,100 41,800 44,800 Other businesses and corporate 14,200 14,000 13,300 Total 74,000 74,500 79,800 Service station staff 16,800 16,200 15,600 Agricultural, operational and seasonal workers in Brazil 4,300 4,600 4,800 Total excluding service station staff and workers in Brazil 52,900 53,700 59,400 a Reported to the nearest 100. For more information see Financial Statements – Note 33. We have reshaped our organization over the past few years to adapt to a lower oil price environment. Our focus is on retaining the skills we require to maintain safe and reliable operations while developing and attracting individuals with capabilities we judge important to growing the business in new ways. The group people committee helps facilitate the group chief executive's oversight of policies relating to employees. In 2017 the committee discussed remuneration policy, progress in our diversity and inclusion programme, modernizing and strengthening our attractiveness as an employer, and long-term people priorities. Attraction and retention A total of 314 graduates joined BP in 2017 (2016 231, 2015 298). We were named the UK's leading recruiter in the oil and gas sector in The Times newspaper's Graduate Employer rankings in 2017. We invest in our employees' development – with an average spend of around $3,300 per person. This includes online and classroom-based courses and resources, supported by a wide range of on-the-job learning and mentoring programmes. Diversity We are committed to making our workplaces reflect the communities in which we are based. The gender balance across BP as a whole is steadily improving, with women representing 34% of BP's total population (2016 33%, 2015 S2%). We are working to improve these numbers further by, for example, developing mentoring, sponsorship and coaching programmes to help more women advance. That said, we still have work to do at the executive and senior levels. We have published 2017 data on our gender pay gap in the UK at bp.com/ukgenderpaygap.

At the end of 2017 there were three female directors (2016 3, 2015 3) on our board of 13. Our nomination committee remains mindful of diversity when considering potential candidates. For more information on the composition of our board, see page 73. Workforce by gender Members as at 31 December Male Female Female % Board directors 10 3 23 Group leaders 310 84 21 Subsidiary directors 1,155 218 16 All employees 48,795 25,239 34 We are also committed to increasing the national diversity of our workforce to reflect the countries in which we operate. A total of 24% of our group leaders came from countries other than the UK and the US in 2017 (2016 23%, 2015 21%). Inclusion Our goal is to create an environment of inclusion and acceptance, where everyone is treated equally and without discrimination. To promote an inclusive culture we provide leadership training and support employee-run advocacy groups in areas such as gender, sexual orientation and parenting. As well as bringing employees together, these groups support BP's recruitment programmes and provide feedback on the potential impact of policy changes. Each group is sponsored by a senior executive. 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 provide continued employment, training and occupational assistance where needed. Employee engagement Managers hold regular team and one-to-one meetings with their staff, 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. Each year, we survey our employees to gauge how they feel about BP. The overall employee engagement score in 2017 was 73% – up from two years ago when we saw a decline which coincided with the uncertainties of a low oil price environment. Pride in working for BP increased to 75% in 2017, compared with 73% in R016 and 68% in 2015. Scores for diversity, inclusion and respect also recorded strong improvements. We are considering how to address employee dissatisfaction with opportunities to develop their skills – which had lower scores in 2017. Share ownership We encourage employee share ownership and have a number of employee share plans in place. For example, under our ShareMatch plan, which operates in more than 50 countries, we match 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. See Glossary BP Annual Report and Form 20-F 201754

BP manages, monitors and reports on the principal risks and uncertainties that can impact our ability to deliver our strategy of meeting the world's energy needs responsibly while creating long-term shareholder value. These risks are described in the Risk factors on page 57. 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 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 Business and strategic risk management Oversight and governance Identify, manage and report risks Plan, manage performance and assure Set policy and monitor principal risks Facilities, assets and operations Business segments and functions Executive and corporate functions Board 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 these 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 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. 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. Board and its committees • BP board. • Audit committee. • Safety, ethics and environment assurance committee. • Geopolitical committee. See Board activity in 2017 on page 72 and committee reports on pages 77-89. Risk management processes As part of BP's annual planning process, we review the group's principal risks and uncertainties. These may be updated throughout the year in response to changes in internal and external circumstances. We aim for a consistent basis of measuring risk to allow comparison on a like-for-like basis, taking into account potential impact and likelihood, and to inform how we prioritize specific risk management activities and invest resources to manage them. How we manage risk Strategic report – perform ance BP Annual Report and Form 20-F 2017 55

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. We identify high priority risks for particular oversight by the board and its various committees in the coming year. Those identified for 2018 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, for example technological change or the transition to a lower carbon economy, is undertaken in the normal course of business and in the executive team, the board and relevant committees. 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 57. Risks for particular oversight by the board and its committees in 2018 The risks for particular oversight by the board and its committees in R018 have been reviewed and updated. These risks remain the same as for 2017. 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, 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, regular reviews of market conditions and our planning and investment processes. 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. Cyber security The targeted and indiscriminate threats to the security of our digital infrastructure continue to evolve rapidly and are increasingly prevalent across industries worldwide. The oil and gas industry is subject to evolving risks from a variety of cyber threat actors, including nation states, criminals, terrorists, hacktivists and insiders. A cyber security breach could disrupt our business, injure people, harm the environment or our assets, or result in legal or regulatory breaches. 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. 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 advisers who advise and conduct assurance 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. Under the terms of the R014 settlement with the US Environmental Protection Agency, an ethics monitor is reviewing and providing recommendations concerning BP's ethics and compliance programme. 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 employees. 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. See Glossary BP Annual Report and Form 20-F 201756

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 sources, technological change, global economic conditions 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 – our inability to access, renew and progress upstream resources in a timely manner could adversely affect our long-term replacement of reserves. Delivering our group strategy depends on our ability to continually replenish a strong exploration pipeline of 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 and increasing technical challenges and capital commitments may adversely affect our strategic progress. 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. Operational challenges and poor investment choice, efficiency or delivery 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 and acts of war 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 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 credit ratings. This 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 251 and Financial statements – Note 27. 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 of our digital security or failure of our digital infrastructure 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 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 the cost of remediation or reputational consequences. Climate change and the transition to a lower carbon economy – policy, legal, regulatory, technology and market change related to the issue of climate change could increase costs, reduce demand for our products, reduce revenue and limit certain growth opportunities. Changes in laws, regulations, policies, obligations, social attitudes and customer preferences relating to the transition to a lower carbon economy could have a cost impact on our business, including increasing compliance and litigation costs, and could impact our strategy. Such changes could lead to constraints on production and supply and access to new reserves. Technological improvements or innovations that support the transition to a lower carbon economy, and customer preferences or regulatory incentives related to such changes that alter fuel or power choices, such as towards low emission energy sources, 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 financial performance and our competitiveness. See Climate change on page 50. 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 or new technologies lags the industry. Our performance could also be negatively impacted if we fail to protect our intellectual property. Risk factors See Glossary Strategic report – perform ance BP Annual Report and Form 20-F 2017 57

Our industry faces increasing challenge to recruit and retain 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. Safety and operational risks Process safety, personal safety, and environmental risks – exposure to a wide range of health, safety, security and environmental risks could 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 could lead to loss of containment of hydrocarbons or other hazardous materials or 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 will be conducted in conformance with these systems. See Safety and security on page 47. 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 because of a variety of factors, including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, adverse weather conditions and compliance with governmental requirements. Security – hostile acts against our 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 standards could cause harm to people and the environment, damage our reputation, result in regulatory action and legal liability, and impact financial performance. Compliance and control risks US government settlements – failure to comply with the terms of our settlement with the US Environmental Protection Agency related to the Gulf of Mexico oil spill may expose us to further penalties or liabilities or could result in suspension or debarment of certain BP entities. Failure to satisfy the requirements or comply with the terms of the administrative agreement with the US Environmental Protection Agency (EPA), under which BP agreed to a set of safety and operations, ethics and compliance and corporate governance requirements, could result in suspension or debarment of certain BP entities. 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. 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, or non-compliance with the recommendations of the ethics monitor appointed under the terms of the EPA settlements, could damage our reputation, result in litigation, regulatory action and penalties. 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 27. 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. See Glossary The Strategic report was approved by the board and signed on its behalf by David J Jackson, company secretary on 29 March 2018. BP Annual Report and Form 20-F 201758

BP Annual Report and Form 20-F 2017 59 C orporate governance al rt a r - V0 Board of directors 66 Executive team 68 Executive management teams 70 Introduction from the chairman 71 Governance framework 71 Board and committee attendance 72 Board activity in 2017 72 Role of the board 73 Skills and expertise 73 Diversity 73 Independence 73 Appointment and time commitment 74 Training and induction 74 Board evaluation 75 Site visits 76 Shareholder engagement 76 Institutional investors 76 Private investors 76 AGM 76 UK Corporate Governance Code compliance 76 International advisory board 77 Committee reports 77 Audit committee 84 Safety, ethics and environment assurance committee 86 Remuneration committee 87 Geopolitical committee 88 Chairman's committee 89 Nomination committee 90 Directors' remuneration report 93 Summary of pay and performance 94 Summary of policy approach 95 Single figure table 96 Alignment with strategy 98 Pay and performance for 2017 102 Implementation of policy for 2018 105 Stewardship 107 Non-executive directors 108 Executive directors' interests 110 Policy summary tables Corporate governance

BP Annual Report and Form 20-F 201760 Board of directors As at 29 March 2018 Carl-Henric Svanberg Chairman Chair of the nomination and chairman's committees; attends SEEAa, remuneration and geopolitical committees Bob Dudley Group chief executive Brian Gilvary Chief financial officer Nils Andersen Independent non-executive director Member of the audit and chairman's committees Paul Anderson Independent non-executive director Member of the SEEA, geopolitical and chairman's committees Alan Boeckmann Independent non-executive director Chair of SEEA committee; member of the remuneration, nomination and chairman's committees Admiral Frank Bowman Independent non-executive director Member of the SEEA, geopolitical and chairman's committees Ian Davis Senior independent non-executive director Member of the remuneration, geopolitical, nomination and chairman's committees Professor Dame Ann Dowling Independent non-executive director Chair of the remuneration committee; member of the SEEA, nomination and chairman's committees Melody Meyer Independent non-executive director Member of the SEEA, geopolitical and chairman's committees Brendan Nelson Independent non-executive director Chair of the audit committee; member of the chairman's and remuneration committees Paula Rosput Reynolds Independent non-executive director Member of the audit, chairman's and remuneration committees Sir John Sawers Independent non-executive director Chair of the geopolitical committee; member of the SEEA, nomination and chairman's committees David Jackson Company secretary See BP's board governance principles relating to director independence on page 275. a Safety, ethics and environment assurance

BP Annual Report and Form 20-F 2017 61 Corporate governance Carl-Henric Svanberg Chairman Tenure Appointed 1 September 2009 Board and committee activities Chair of the nomination and chairman's committees; attends the safety, ethics and environment assurance, remuneration and geopolitical committees Outside interests • Chairman of AB Volvo Age 65 Nationality Swedish Career Carl-Henric Svanberg became chairman of the BP board on 1 January 2010. He spent his early career at Asea Brown Boveri and the Securitas Group, before moving to the Assa Abloy Group as president and chief executive officer. From 2003 until December 2009, he was president and chief executive officer of Ericsson, also serving as the chairman of Sony Ericsson Mobile Communications AB. He was a non-executive director of Ericsson between 2009 and 2012. He was appointed chairman and a member of the board of AB Volvo in April 2012. He is a member of the External Advisory Board of the Earth Institute at Columbia University and a member of the Advisory Board of Harvard Kennedy School. He is also the recipient of the King of Sweden's medal for his contribution to Swedish industry. Relevant skills and experience Carl-Henric Svanberg is a highly experienced leader of global corporations. He has served as chief executive officer and chairman to several high profile businesses, leading them through both periods of growth and restructuring. These experiences bring not only a deep understanding of international strategic and commercial issues, but the skills to co-ordinate the diverse range of knowledge and perspectives provided by the board. He therefore enables the board to present clear and united leadership on behalf of shareholders. Carl-Henric has successfully led the board for the past eight years and has announced his intention to stand down before the AGM in 2019. Carl-Henric's performance has been evaluated by the chairman's committee, led by Ian Davis. Bob Dudley Group chief executive Tenure Appointed to the board 6 April 2009 Outside interests • Fellow of the Royal Academy of Engineering • Non-executive director of Rosneft • Member of the Tsinghua Management University Advisory Board, Beijing, China • Member of the BritishAmerican Business International Advisory Board • Member of the US Business Council • Member of the US Business Roundtable • Member of the UAE/UK CEO Forum • Member of the Emirates Foundation Board of Trustees • Member of the World Economic Forum (WEF) International Business Council • Chair of the WEF Oil and Gas Climate Initiative • Member of the Russian Geographical Society Board of Trustees Age 62 Nationality American and British Career Bob Dudley became group chief executive on 1 October 2010. Bob joined Amoco Corporation in 1979, working in a variety of engineering and commercial posts. Between 1994 and 1997 he worked on corporate development in Russia. In 1997 he became general manager for strategy for Amoco and in 1999, following the merger between BP and Amoco, was appointed to a similar role in BP. Between 1999 and 2000 he was executive assistant to the group chief executive, subsequently becoming group vice president for BP's renewables and alternative energy activities. In 2002 he became group vice president responsible for BP's upstream businesses in Russia, the Caspian region, Angola, Algeria and Egypt. From 2003 to 2008 he was president and chief executive officer of TNK-BP. On his return to BP in 2009, he was appointed to the BP board and oversaw the group's activities in the Americas and Asia. Between R3 June and 30 September 2010, he served as the president and chief executive officer of BP's Gulf Coast Restoration Organization in the US. He was appointed a director of Rosneft in March 2013 following BP's acquisition of a stake in Rosneft. Relevant skills and experience Bob Dudley has spent his whole career in the oil and gas industry. As group chief executive, Bob has transformed BP into a safer, stronger and simpler business. This approach, governed by a consistent set of values, has guided BP to a position of greater resilience, enabling it to continue delivering results in an uncertain economic environment. Bob has demonstrated excellent leadership and vision throughout. Bob continues to lead the development of the group's strategy, as we adapt to the challenges of the transition to a lower carbon economy. Under Bob's leadership, BP successfully delivered seven major projects in 2017. Bob Dudley's performance has been considered and evaluated by the chairman's committee. Brian Gilvary Chief financial officer Tenure Appointed to the board 1 January 2012 Outside interests • Non-executive director and member of audit committee of L'Air Liquide • Non-executive director and vice chair of audit committee of the Navy Board • Vice chair of the 100 Group Committee • Member of Trilateral Commission • Visiting professor at Manchester University • Great Britain Age Group triathlete Age 56 Nationality British Career Brian Gilvary was appointed chief financial officer on 1 January 2012. The role includes responsibility for finance, tax, treasury, mergers and acquisitions, investor relations, audit, global business services, information technology and procurement. He also has accountability for both integrated supply and trading, and the shipping division responsible for BP's tanker fleet. Brian joined BP in 1986 after obtaining a PhD in mathematics from the University of Manchester. Following a broad range of roles in upstream, downstream and trading in Europe and the US, he became downstream's commercial director from 2002 to 2005. From 2005 until 2009 he was chief executive of the integrated supply and trading function, BP's commodity trading arm. In 2010 he was appointed deputy group chief financial officer with responsibility for the finance function.

BP Annual Report and Form 20-F 201762 He was a director of TNK-BP over two 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 Gilvary has spent his entire career with BP. Brian has broad experience across the group which gives him a deep insight into BP's assets and businesses. This knowledge has been invaluable as BP has implemented its strategy to transform into a 'value not volume' based business where trading is a key creator of value. His strong 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 has been at the centre of the group's work on addressing cyber risk. Brian Gilvary's performance has been evaluated by the group chief executive and considered by the chairman's committee. Nils Andersen Independent non-executive director Tenure Appointed 31 October 2016 Board and committee activities Member of the audit and chairman's committees Outside interests • Non-executive director of Unilever Plc and Unilever NV • Chairman of Dansk Supermarked Group A/S • Chairman of Unifeeder Group A/S • Chairman of Faerch Plast A/S Age 59 Nationality Danish Career Nils Andersen was group chief executive of A.P. Møller-Mærsk from R007 to June 2016. Prior to this he was executive vice president of Carlsberg A/S and Carlsberg Breweries A/S from 1999 to 2001, becoming president and chief executive officer from 2001 to 2007. Previous roles include non-executive director of Inditex S.A. and William Demant A/S. He has also served as managing director of Union Cervecera, Hannen Brauerei and chief executive officer of the drinks division of the Hero Group. Nils has been nominated for election as a member and chairman of the supervisory board of Akzo Nobel N.V. following his successful appointment at their AGM in April 2018. Nils received his graduate degree from the University of Aarhus. Relevant skills and experience Nils Andersen has extensive experience in consumer goods, retail and logistics, having led global corporations with integrated operations worldwide. He has substantial skill, knowledge and experience in marketing, brand and reputation issues. He has broad shipping and upstream energy industry experience which aligns with BP's shipping business. His leadership earlier in his career focused on the transformation of businesses, leaner organizations and increasing competitiveness, as well as increasing transparency and communication with stakeholders. Nils' economics and broad financial background make him well suited to his role on the audit committee. Paul Anderson Independent non-executive director Tenure Appointed 1 February 2010 Board and committee activities Member of the safety, ethics and environment assurance, geopolitical and chairman's committees Outside interests No external appointments Age 73 Nationality American Career Paul Anderson was formerly chief executive at BHP Billiton and Duke Energy, where he also served as chairman of the board. Having previously been chief executive officer and managing director of BHP Limited and then BHP Billiton Limited and BHP Billiton Plc, he rejoined these latter two boards in 2006 as a non-executive director, retiring in January 2010. Previously he served as a non-executive director of BAE Systems PLC and on a number of boards in the US and Australia, and was also chief executive officer of Pan Energy Corp. Relevant skills and experience Paul Anderson has spent his career in the energy industry working with global organizations, and brings the skills of an experienced chairman and chief executive officer to the board. His specific experience of driving safety-related cultural change throughout a business has been invaluable during his tenure as chair of the safety, ethics, and environment assurance committee from 2012 to 2016, and he remains a valuable member of the committee. Paul's experience of business in the US and its regulatory environment is a great asset to the geopolitical committee. Paul Anderson will be retiring from the board at the 2018 AGM in May. Alan Boeckmann Independent non-executive director Tenure Appointed 24 July 2014 Board and committee activities Chair of the safety, ethics and environment assurance committee; member of the remuneration, nomination and chairman's committees Outside interests • Non-executive director of Sempra Energy • Non-executive director of Archer Daniels Midland Age 69 Nationality American Career Alan Boeckmann retired as non-executive chairman of Fluor Corporation in February 2012, ending a 35-year career with the company. Between R002 and 2011 he held the post of chairman and chief executive officer, having previously been president and chief operating officer from 2001 to 2002. His tenure with the company included responsibility for global operations. As chairman and chief executive officer, he refocused the company on engineering, procurement, construction and maintenance services. After graduating from the University of Arizona with a degree in electrical engineering, he joined Fluor in 1974 as an engineer and worked in a variety of domestic and international locations, including South Africa and Venezuela.

BP Annual Report and Form 20-F 2017 63 Corporate governance Alan was previously a non-executive director of BHP Billiton and the Burlington Santa Fe Corporation, and has served on the boards of the American Petroleum Institute, the National Petroleum Council, the Eisenhower Medical Center and the advisory board of Southern Methodist University's Cox School of Business. He led the formation of the World Economic Forum's 'Partnering Against Corruption' initiative in 2004. Relevant skills and experience Alan Boeckmann has worked in a wide range of industries including engineering, construction, chemicals and the energy sector. He has been involved in delivering very large projects particularly in the energy industry. In his senior roles he directed the focus of global corporations towards the advanced technology needed to remain competitive in response to the growth of the internet, e-commerce and the globalization of the workforce. At the same time he actively promoted fairness, transparency, accountability and responsibility in business dealings through the 'Partnering Against Corruption' initiative. This overall experience makes Alan ideal to lead the SEEAC. His remuneration experience on other boards means that he makes a strong contribution to the remuneration committee. Admiral Frank Bowman Independent non-executive director Tenure Appointed 8 November 2010 Board and committee activities Member of the safety, ethics and environment assurance, geopolitical and chairman's committees Outside interests • President of Strategic Decisions, LLC • Director of Morgan Stanley Mutual Funds • Director of Naval and Nuclear Technologies, LLP Age 73 Nationality American Career Frank L Bowman served for more than 38 years in the US Navy, rising to the rank of Admiral. He commanded the nuclear submarine USS City of Corpus Christi and the submarine tender USS Holland. After promotion to flag officer, he served on the joint staff as director of political-military affairs and as the chief of naval personnel. He served over eight years as director of the Naval Nuclear Propulsion Program where he was responsible for the operations of more than 100 reactors aboard the US Navy's aircraft carriers and submarines. After his retirement as an Admiral in 2004, he was president and chief executive officer of the Nuclear Energy Institute until 2008. He served on the BP Independent Safety Review Panel and was a member of the BP America External Advisory Council. He holds two masters degrees in engineering from the Massachusetts Institute of Technology. He was appointed Honorary Knight Commander of the British Empire in 2005. He was elected to the US National Academy of Engineering in 2009. Frank is a member of the US CNA military advisory board and has participated in studies of climate change and its impact on national security, and on future global energy solutions and water scarcity. Additionally he was co-chair of a National Academies study investigating the implications of climate change for naval forces. Relevant skills and experience Frank Bowman's exemplary safety record in running the US Navy's nuclear submarine program indicates his deep understanding of process safety and its implementation. Frank makes a substantial contribution to the safety culture within BP. Combined with his specific knowledge of BP's safety goals from his work on the BP Independent Safety Review Panel and his special interest in climate change, he brings an important perspective to the board and the SEEAC. He has led the oversight of BP's compliance with the agreements with the US government stemming from the Deepwater Horizon accident. Frank's experience of the US and global political and regulatory systems is a valuable asset to the geopolitical committee. Ian Davis Senior independent non-executive director Tenure Appointed 2 April 2010 Board and committee activities Member of the remuneration, geopolitical, nomination and chairman's committees Outside interests • Chairman of Rolls-Royce Holdings plc • Non-executive director of Majid Al Futtaim Holding LLC • Non-executive director of Johnson & Johnson, Inc. • Non-executive director of Teach for All Age 67 Nationality British Career Ian Davis is senior partner emeritus of McKinsey & Company. He was a partner at McKinsey for 31 years until 2010 and served as chairman and managing director between 2003 and 2009. Ian has a MA in Politics, Philosophy and Economics from Balliol College, University of Oxford. Relevant skills and experience Ian Davis 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. Ian led the board's oversight of the response in the Gulf and chaired the Gulf of Mexico committee from its formation in 2010 until it was stood down in 2016. He was previously a non-executive director in the Cabinet Office giving him an important perspective on government affairs which is an asset to both the board and the geopolitical committee. In his role as the senior independent director, Ian is responsible for the annual evaluation of the chairman's performance and is leading the search for the successor to the chairman.

BP Annual Report and Form 20-F 201764 Professor Dame Ann Dowling Independent non-executive director Tenure Appointed 3 February 2012 Board and committee activities Chair of the remuneration committee; member of the safety, ethics and environment assurance, nomination and chairman’s committees Outside interests • President of the Royal Academy of Engineering • Deputy vice-chancellor and professor of Mechanical Engineering at the University of Cambridge • Member of the Prime Minister’s Council for Science and Technology • Non-executive director of the Department for Business, Energy and Industrial Strategy (BEIS) Age 65 Nationality British Career Dame Ann Dowling is a deputy vice-chancellor at the University of Cambridge where she was appointed a professor of mechanical engineering in the department of engineering in 1993. She was head of the department of engineering at the university from 2009 to 2014. Her research is in fluid mechanics, acoustics and combustion, and she has held visiting posts at MIT and at Caltech. She chairs BP’s technical advisory council. 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 has honorary degrees from 15 universities, including the University of Oxford, Imperial College London and the KTH Royal Institute of Technology, Stockholm. She was elected President of the Royal Academy of Engineering in September 2014 and in December 2015 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 in these fields has been widely recognized by universities around the world. Her academic background provides balance to the board and brings a different perspective to the SEEAC and nomination committee. Dame Ann became chair of the remuneration committee in 2015. Following an extensive consultation, a revised remuneration policy was approved by shareholders at the 2017 AGM. This was a direct result of Dame Ann's leadership of the committee. Dame Ann will hand the chair of the committee to Paula Reynolds after the 2018 AGM. Melody Meyer Independent non-executive director Tenure Appointed 17 May 2017 Board and committee activities Member of the safety, ethics and environment assurance, geopolitical and chairman’s committees 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. • Senior Advisor to Cairn India Limited • Non-executive director of National Oilwell Varco, Inc. Age 60 Nationality American Career Melody Meyer started her career with Gulf Oil in Houston. Gulf Oil later merged with Chevron where Melody remained until her retirement in 2016. During her career with Chevron, Melody had key leadership roles in global exploration and production, working on international projects and operational assignments. In 2004 Melody became the vice president for the Gulf of Mexico business unit, and in 2008 became president of the Chevron Energy Technology Company. From 2011 Melody was president of Asia Pacific Exploration and Production, responsible for the financial and operating performance of the upstream assets in nine countries in Chevron’s Asia Pacific region. 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. She was recognized as a 2009 Trinity Distinguished Alumni, with the BioHouston Women in Science Award, was the ASME Rhodes Petroleum Industry Leadership Award recipient and in 2018 as an Influential Woman in Energy. Relevant skills and experience Melody Meyer 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. Brendan Nelson Independent non-executive director Tenure Appointed 8 November 2010 Board and committee activities Chair of the audit committee; member of the chairman’s and remuneration committees Outside interests • Non-executive director and chairman of the group audit committee of The Royal Bank of Scotland Group plc • Member of the Financial Reporting Review Panel Age 68 Nationality British

 Career Brendan Nelson is a chartered accountant. He was made a partner of KPMG in 1984. He served as a member of the UK board of KPMG from R000 to 2006, subsequently being appointed vice chairman until his retirement in 2010. At KPMG International he held a number of senior positions including global chairman, banking and global chairman, financial services. He served for six years as a member of the Financial Services Practitioner Panel and in 2013 was the president of the Institute of Chartered Accountants of Scotland. Relevant skills and experience Brendan Nelson 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 specializm in the financial services industry allows him to contribute insight into the challenges faced by global businesses by regulatory frameworks. Brendan led the successful tendering of BP's audit services and joined the remuneration committee in 2017. Paula Rosput Reynolds Independent non-executive director Tenure Appointed 14 May 2015 Board and committee activities Member of the audit and chairman's committees Outside interests • Non-executive director of BAE Systems Ltd • Non-executive director of TransCanada Corporation • Non-executive director of CBRE Group Age 61 Nationality American Career Paula Rosput Reynolds is the former chairman, president and chief executive officer of Safeco Corporation, a Fortune 500 property and casualty insurance company that was acquired by Liberty Mutual Insurance Group in 2008. She also served as vice chair and chief restructuring officer for American International Group (AIG) for a period after the US government became the financial sponsor from R008 to 2009. Previously Paula was an executive in the energy industry. She was chairman, president and chief executive officer of AGL Resources Inc., an operator of natural gas infrastructure in the US, now a subsidiary of Southern Company. Prior to this, she led a subsidiary of Duke Energy Corporation that was a merchant operator of electricity generation. She commenced her energy career at PG&E Corp. Paula was awarded the National Association of Corporate Directors (US) Lifetime Achievement Award in 2014. Relevant skills and experience Paula Rosput Reynolds 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 joined the remuneration committee in 2017. Paula currently serves as the chair of the remuneration committee of BAE Systems Ltd and will take the chair of BP's remuneration committee after the R018 AGM. Sir John Sawers Independent non-executive director Tenure Appointed 14 May 2015 Board and committee activities Chair of the geopolitical committee; member of the safety, ethics and environment assurance, nomination and chairman's committees Outside interests • Chairman and partner of Macro Advisory Partners LLP • Visiting professor at King's College London • Governor of the Ditchley Foundation Age 62 Nationality British Career Sir John Sawers spent 36 years in public service in the UK, working on foreign policy, international security and intelligence. Sir John was chief of the Secret Intelligence Service, MI6, from 2009 to R014 – a period of international upheaval and growing security threats, as well as closer public scrutiny of the intelligence agencies. Prior to that, the bulk of his career was in diplomacy, representing the British government around the world and leading negotiations at the UN, in the European Union and in the G8. He was the UK ambassador to the United Nations (2007-09), political director and main board member of the Foreign Office (2003-07), special representative in Iraq (2003), ambassador to Egypt (2001-03) and foreign policy adviser to the Prime Minister (1999-01). Earlier in his career, he was posted to Washington, South Africa, Syria and Yemen. Sir John is now chairman of Macro Advisory Partners, a firm that advises clients on the intersection of policy, politics and markets. Relevant skills and experience Sir John Sawers' 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 related to analysing and negotiating on a worldwide basis are invaluable to both the board and the SEEAC. David Jackson Company secretary Tenure Appointed 2003 David Jackson, a solicitor, is a director of BP Pension Trustees Limited. The ages of the board are correct as at 29 March 2018.

BP Annual Report and Form 20-F 201766 Tufan Erginbilgic Chief executive, Downstream Executive team tenure Appointed 1 October 2014 Outside interests • Independent non-executive director of GKN plc • Member of the Turkish-British Chamber of Commerce & Industry Board of Directors • Member of the Strategic Advisory Board of the University of Surrey Age 58 Nationality British and Turkish Career Tufan Erginbilgic was appointed chief executive, Downstream on Q 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. In 2004 he became head of the European fuels business. Tufan took up leadership of BP's lubricant business in 2006 before moving to head the group chief executive's office. In 2009 he became chief operating officer for the eastern hemisphere fuels value chains and lubricants businesses. Bob Fryar Executive vice president, safety and operational risk Executive team tenure Appointed 1 October 2010 Outside interests No external appointments Age 54 Nationality American Career Bob Fryar is responsible for strengthening safety, operational risk management and the systematic management of operations across the BP group. He is group head of safety and operational risk, with accountability for group-level disciplines including engineering, health, safety, security, remediation management and the environment. 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. Between 2010 and R013, Bob was executive vice president of the production division, accountable for safe and compliant exploration and production operations and stewardship of resources across all regions. Prior to this, Bob was chief executive of BP Angola and also held several management positions in Trinidad, including chief operating officer for Atlantic LNG and vice president of operations. Bob has also served in a variety of engineering and management positions in onshore US and the deepwater Gulf of Mexico. Andy Hopwood Executive vice-president, chief operating officer, strategy and regions, Upstream Executive team tenure Appointed 1 November 2010 Outside interests No external appointments Age 60 Nationality British Career Andy Hopwood is responsible for BP's upstream strategy, portfolio and leadership of its global regional presidents. 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. Andy held commercial leadership positions in Mexico and Venezuela before becoming the Upstream's planning manager. Following the BP-Amoco merger, Andy spent time leading BP's businesses in Azerbaijan, Trinidad & Tobago and onshore North America. In 2009 he joined the Upstream executive team as head of portfolio and technology and in 2010 was appointed executive vice president, exploration and production. Bernard Looney Chief executive, Upstream Executive team tenure Appointed 1 November 2010 Outside interests • Fellow of the Royal Academy of Engineering • Member of the Stanford University Graduate School of Business Advisory Council • Fellow of the Energy Institute Age 47 Nationality Irish Career Bernard Looney is responsible for the Upstream segment which consists of exploration, development and production. Bernard joined BP in 1991 as a drilling engineer, working in the North Sea, Vietnam and the Gulf of Mexico. In 2005 he became senior vice president for BP Alaska before becoming head of the group chief executive's office in 2007. In 2009 he became the managing director of BP's North Sea business in the UK and Norway. At the same time, Bernard became a member of the Oil & Gas UK Board. He became executive vice president, developments, in October 2010, and in February 2013 became chief operating officer, production, serving in the role until April 2016. Executive team As at 29 March 2018

 Lamar McKay Deputy group chief executive Executive team tenure Appointed 16 June 2008 Outside interests No external appointments Age 59 Nationality American Career Lamar McKay is accountable for group strategy and long-term planning, safety and operational risk and group technology. In addition to supporting the group chief executive, he also focuses on various corporate governance activities including ethics and compliance. Lamar started his career in 1980 with Amoco and held a range of technical and leadership roles. During 1998 to 2000, he worked on the BP-Amoco merger and served as head of strategy and planning for the exploration and production business. In 2000 he became business unit leader for the central North Sea. In 2001 he became chief of staff for exploration and production, and subsequently for BP's deputy group chief executive. Lamar became group vice president, Russia and Kazakhstan in 2003. He served as a member of the board of directors of TNK-BP between February 2004 and May 2007. In 2007 he was appointed executive vice president, BP America. In 2008 he became executive vice president, special projects where he led BP's efforts to restructure the governance framework for TNK-BP. In 2009 Lamar was appointed chairman and president of BP America, serving as BP's chief representative in the US. In January 2013, he became chief executive, Upstream, responsible for exploration, development and production, serving in the role until April 2016. Eric Nitcher Group general counsel Executive team tenure Appointed 1 January 2017 Outside interests No external appointments Age 55 Nationality American Career Eric Nitcher is responsible for legal matters across the BP group. Eric began his career in the late 1980s working as a litigation and regulatory lawyer in Wichita, Kansas. He joined Amoco in 1990 and over the years has held a wide variety of roles, both within and outside the US. In 2000, Eric moved to London to work in the mergers and acquisitions legal team where he played a key role in the formation of the Russian joint venture TNK-BP. Eric returned to Houston in 2007 where he served 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 government claims and resolution of most of the remaining private claims being litigated in New Orleans. Dev Sanyal Chief executive, alternative energy and executive vice president, regions Executive team tenure Appointed 1 January 2012 Outside interests • Independent non-executive director of Man Group plc • Member of the Accenture Global Energy Board • Member, International Advisory Board of the Ministry of Petroleum and Natural Gas, Government of India • Member of the Board of Advisors of the Fletcher School of Law and Diplomacy, Tufts University Age 52 Nationality British and Indian Career Dev Sanyal is responsible for alternative energy and for the Europe and Asia regions and functionally for risk management, government and political affairs, economics and policy. Dev joined BP in 1989 and has held a variety of international roles in London, Athens, Istanbul, Vienna and Dubai. He was general manager, Former Soviet Union and Eastern Europe, prior to being appointed chief executive, BP Eastern Mediterranean Fuels in 1999. In November 2003 he was appointed chief executive officer of Air BP International and in June 2006 was appointed head of the group chief executive's office. He was appointed group vice president and group treasurer in 2007. During this period, he was also chairman of BP Investment Management Ltd and was accountable for the group's aluminium interests. Until April 2016, Dev was executive vice president, strategy and regions. Helmut Schuster Executive vice president, group human resources Executive team tenure Appointed 1 March 2011 Outside interests • Non-executive director of Ivoclar Vivadent AG, Germany Age 57 Nationality Austrian Career Helmut Schuster became group human resources (HR) director in March 2011. In this role he is accountable for the BP human resources function. He completed his post graduate diploma in international relations and his PhD in economics at the University of Vienna and then began his career working for Henkel in a marketing capacity. Since joining BP in 1989 Helmut has held a number of leadership roles. He has worked in 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 the refining and marketing segment of BP and corporate and functions. That role saw him leading the people agenda for roughly 60,000 people across the globe that included businesses such as petrochemicals, fuels value chains, lubricants and functional experts across the group. Outside of his role, Helmut is a non-executive director of Ivoclar Vivadent. Additionally, he is an alumni and advocate of AFS, an international exchange organization. The executive team represents the principal executive leadership of the BP group. Its members include BP's executive directors (Bob Dudley and Dr Brian Gilvary whose biographies appear on pages 61-65) and the senior management listed on these pages. The ages of the executive team are correct as at 29 March 2018.

BP Annual Report and Form 20-F 201768 Upstream Other business and functions leaders 1. David Eyton Group head of technology 2. Dominic Emery Vice president, group strategic planning 3. Laura Folse Chief executive officer, wind, alternative energy 4. Richard Hookway Chief operating officer of global business services and information technology and systems 5. David Jardine Group head of audit 6. Robert Lawson Global head of mergers and acquisitions 7. Dev Sanyal Chief executive, alternative energy and executive vice president, regions 8. Joan Wales Head of safety and operational risk, alternative energy 9. Craig Marshall Group head of investor relations 10. Spencer Dale Group chief economist 11. Geoff Morrell Group head of communications and external affairs Q2. Lucy Knight Human resources vice president, corporate business activities and functions 13. Trudi Charles Associate general counsel, integrated supply and trading 1. Andy Hopwood Chief operating officer, strategy and regions 2. James Dupree Chief operating officer, developments and technology 3. Kerry Dryburgh Head of human resources 4. Tony Brock Head of safety and operational risk 5. Bernard Looney Chief executive 6. Murray Auchincloss Chief financial officer W. Nigel Jones Associate general counsel 8. Gordon Birrell Chief operating officer, production, transformation and carbon Q 2 1 2 4 5 6 8 3 3 7 5 7 9 10 12 4 6 8 11 13 Executive management teams

C orporate governance C orporate governance BP Annual Report and Form 20-F 2017 69 Downstream 1. Rita Griffin Chief operating officer, petrochemicals 2. Mike O'Sullivan Chief financial officer 3. Michael Sosso Associate general counsel, downstream and BP shipping 4. Doug Sparkman Chief operating officer, fuels, North America 5. Angela Strank Head of technology and BP chief scientist 6. Tufan Erginbilgic Chief executive 7. Mandhir Singh Chief operating officer, lubricants 8. Evelyn Gardiner Head of human resources 9. Guy Moeyens Chief operating officer, fuels, Europe and Southern Africa 10. Andy Holmes Chief operating officer, fuels ASPAC and Air BP Q4. David Anderson Chief financial officer, alternative energy 15. Ashok Pillai Vice president, group reward Q6. Kate Thomson Group treasurer 17. Rahul Saxena Group ethics and compliance officer 18. Mario Lindenhayn Chief executive officer, biofuels, alternative energy 19. Susan Dio Chief executive officer, shipping 20. Jan Lyons Group head of tax 21. Alan Haywood Chief executive officer, integrated supply and trading 22. William Lin Head of group chief executive's office 23. Carol Howle Head of group chief executive's office 24. Camille Drummond Head of global business services 25. David Bucknall Group controller and chief financial officer, other businesses and corporate 26. Nick Wayth Chief development officer, alternative energy Q 3 4 6 7 9 8 102 5 14 15 17 19 20 23 21 26 16 18 22 24 25 Our diverse and talented leaders have a wide range of skills and disciplines that support our executive team's work. These include experts in fields such as renewable energy, finance, trading, technology and digital, and tax and treasury. Job titles correct as at 1 January 2018.

Introduction from the chairman The work of the board continued to progress in 2017. We focused on the development and implementation of our strategy out to 2021 that we communicated to investors last year. We have seen substantial variations in the oil price and have had to ensure that BP is robust for all financial cycles. We believe there will be a continuing demand for hydrocarbons over the coming decades. Our strategy is designed to balance our role in supplying energy for the world with the growing need to be part of the transition to a lower carbon global economy. The board's focus has been on this dual challenge, which is crucial to the company's long-term sustainability. The role of business in society remains a major issue which all boards must address. In the UK, the Financial Reporting Council has published its consultation on a material revision to the UK Corporate Governance Code. There is a clear emphasis on the need for boards to focus on their relationship with all those with whom the company comes into contact. In particular, boards are encouraged to ensure they find ways to hear the voice of the employee in the board room. We are participating in this consultation and have already established a variety of ways to speak and listen to our employees around the world. We will need to ensure that all voices – those of shareholders, employees, customers and communities – find their way to the board. Our long-term investments and relationships in many countries have already helped with this. Remuneration continued to be an area of focus in the year. We are grateful to our shareholders for their support of the remuneration report at the 2017 AGM. This was very important to us. The remuneration committee continued its work this year, as it implements the new policy and some legacy awards from the 2014 policy. The committee has again had some challenging decisions to take. Dame Ann Dowling will be standing down from the committee at the 2018 AGM after three years in the chair. I would like to thank her and pay tribute to her work. Paula Reynolds, already an experienced remuneration committee chair, will succeed Dame Ann. I will be standing down as chairman at an appropriate time after the 2018 AGM. Ian Davis, the senior independent director, has already begun the search for my successor. I will have served as chairman for almost nine years by the time I stand down. The board has faced and risen to many challenges during that time and membership has evolved and remained balanced. I believe that we are well placed for the future – with the appropriate mix of skills, experience and diversity. Throughout I have wanted to ensure that we used our time wisely as it was essential that we had the space in our meetings to discuss strategy and the direction of the company. In 2010 we formed the Gulf of Mexico committee, originally to have oversight of our commitment on the ground following the accident. The work of this committee evolved into considering the reports on the causes of the accident and subsequently leading the work around the ensuing litigation. The committee sat for five years. We also formed a special committee to oversee negotiations in Russia which eventually led to our equity ownership in Rosneft. This experience led to the formation of the geopolitical committee which is now well in its stride. We have used the evaluations of the board and the committees to ensure that we have been focusing on the right issues and adding value. I am pleased that over the summer we will be carrying out an externally facilitated evaluation, which I am sure will assist my successor. I am very grateful to Bob, his executive colleagues and all my fellow directors for all the work that they have done during the year. BP has an exciting future and we have the right team to take advantage of the opportunities that it will bring. Carl-Henric Svanberg Chairman The board has a clear focus on the issues that are crucial to the long-term sustainability of the company. BP Annual Report and Form 20-F 201770

Board and committee attendance in 2017 BP board Owners/shareholders Group chief executive Nomination committee See page 89 D eleg atio n Remuneration committee See page 86 Chairman's committee See page 88 SEEAC See page 84 Geopolitical committee See page 87 Strategy/group risks/annual plan Group chief executive's delegations Audit committee See page 77 Monitoring, information and assurance BP board governance principles: • Group audit • Finance • Safety and operational risk • Group ethics and compliance • Business integrity • External market and reputation research • Independent auditor • Independent adviser • Independent advice (if requested) • BP goal • Governance process • Delegation model • Executive limitations Delegation Delegation of authority through policy with monitoring Accountability Assurance through monitoring and reporting A cc o u n ta b ili ty Resource commitments meeting (RCM) Group people committee (GPC) Group disclosure committee (GDC) Executive management Group financial risk committee (GFRC) Group operations risk committee (GORC) Group ethics and compliance committee (GECC) Board Audit committee SEEAC Joint audit/ SEEAC Remuneration committee Geopolitical committee Nomination committee Chairman's committee Non-executive directors A B A B A B A B A B A B A B Carl-Henric Svanberg+ 11 11 Nils Andersen 11 11 13 13 4 4 7 7 Paul Anderson 11 11 6 6 4 4 3 3 10 10 Alan Boeckmann+ 11 10 6 6 4 4 8 7 3 3 10 10 Frank Bowman 11 11 6 6 4 4 3 3 10 10 Cynthia Carroll 5 5 2 1 1 1 1 0 3 2 Ian Davis 11 11 8 8 3 3 3 3 10 10 Ann Dowling+ 11 11 6 6 4 4 8 8 3 3 10 10 Melody Meyer 6 6 4 4 3 3 2 2 7 7 Brendan Nelson+ 11 11 13 13 4 4 4 4 10 10 Paula Rosput Reynolds 11 10 13 13 4 3 2 2 10 9 John Sawers+ 11 11 6 6 4 4 3 3 3 3 10 10 Andrew Shilston 5 4 5 5 1 1 4 4 1 1 1 1 3 3 Executive directors A B Bob Dudley 11 11 Brian Gilvary 11 11 A = Total number of meetings the director was eligible to attend. B = Total number of meetings the director did attend. + Committee chair. Nils Andersen did not attend meetings of the chairman's committee when succession was discussed. Alan Boeckmann missed the telephone meetings of the board and remuneration committee that had been called at short notice, due to a clash with another board. Paula Reynolds missed a board, joint audit-SEEAC and chairman's committee meeting due to travel arrangements. Cynthia Carroll missed a SEEAC, geopolitical committee and chairman's committee meeting due to a clash with an external commitment. Andrew Shilston missed a board meeting immediately prior to the 2017 AGM as he was retiring from the board. BP governance framework The board operates within a system of governance that is set out in the BP board governance principles. These principles define the role of the board, its processes and its relationship with executive management. This system is reflected in the governance of the group's subsidiaries. See bp.com/governance for the board governance principles. C orporate governance BP Annual Report and Form 20-F 2017 71

Board activity in 2017 1 Role of the board The board is responsible for the overall conduct of the group's business. Directors have duties under both UK company law and BP's Articles of Association. The primary tasks of the board include: Active consideration and direction of long-term strategy and approval of the annual plan Monitoring of BP's performance against the strategy and plan Ensuring that the principal risks and uncertainties to BP are identified and that systems of risk management and control are in place Board and executive management succession Performance and monitoring The board reviews financial and operational performance at each meeting. It receives regular updates on the group's performance for the year across a range of metrics as well as the latest view on expected full-year delivery against external scorecard measures. 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. The board reviews the quarterly and full-year results, including the shareholder distribution policy. The 2017 annual report was assessed in terms of the directors' obligations and appropriate regulatory requirements. 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. Strategy During the year the board provided input on the group's strategy to senior management. This included a two-day strategy session in September where it examined developments in the wider environment and debated strategic themes relating to BP's segments, key functions and the impact of the lower carbon transition on the group's business model. The board discussed the transition to a lower carbon world frequently during the year. It received regular reports on the progress and implementation of the strategy – through updates from management and by means of a strategic performance scorecard which is discussed at each full board meeting. The board monitored the company's performance against the annual plan for 2017 and approved the forward framework for the annual plan in 2018. The board reviewed the BP Energy Outlook, updated in February 2018, which looks at long-term energy trends and projections for world energy markets. Risk The board, either directly or through its monitoring committees, regularly reviews the processes whereby risks are identified, evaluated and managed. Activities include: • Assessing the effectiveness of the group's system of internal control and risk management as part of the review of the BP Annual Report and Form R0-F 2017. • Identification and allocation of risks to the board and monitoring committees (the audit, SEEA and geopolitical committees) for 2017, and confirmation of the schedule for oversight. The board reviewed the group risk of cyber security in 2017 – with the audit committee and SEEAC assessing elements of cyber security risk in their work programme for the year. The allocation of the group cyber security risk to the board (with additional monitoring by the audit and SEEA committees) remains unchanged for 2018. The group risks allocated to the committees for review over the year are outlined in the reports of the committees on pages W7-89. Further information on BP's system of risk management is outlined in How we manage risk on page 55. Succession The board, in conjunction with the nomination and chairman's committees, reviews succession plans for executive and non- executive directors on a regular basis. The board needs to ensure that potential candidates are identified and evaluated as current directors reach the end of their recommended term of office, including in the event of a director leaving unexpectedly. The board employs executive search firms when it concludes that this is an effective way of finding suitable candidates. In R017 we appointed Egon Zehnder to assist in the search for non-executive directors. • Cynthia Carroll and Andrew Shilston stood down from the board at the 2017 AGM. • Melody Meyer was elected as a director at the 2017 AGM. On appointment she joined the SEEA and geopolitical committees. • Brendan Nelson and Paula Reynolds joined the remuneration committee in May and September 2017 respectively. • Paul Anderson will retire from the board at the 2018 AGM. • Ann Dowling will step down from the remuneration committee after the R018 AGM, having served three years as chair, and Paula Reynolds will then assume the role. BP Annual Report and Form 20-F 201772

Skills and expertise In order to carry out its duties on behalf of shareholders, the board needs to manage its non-executive membership and continuously maintain its knowledge and expertise to benefit the business. It does this through four activity sets: Succession planning to ensure future diversity and balance Diversity including skills, experience, gender, ethnicity and tenure EvaluationTraining including site visits and induction of new directors Diversity BP recognizes the importance of diversity, including gender, at the board and all levels of the group. We are committed to increasing diversity across our operations and have a wide range of activities to support the development and promotion of talented individuals, regardless of gender and ethnic background. The board operates a policy that aims to promote diversity in its composition. Under this policy, director appointments are evaluated against the existing balance of skills, knowledge and experience on the board, with directors asked to be mindful of diversity, inclusiveness and meritocracy considerations when examining nominations to the board. Implementation of this policy is monitored through agreed metrics. During its annual evaluation, the board considered diversity as part of the review of its performance and effectiveness. At the end of 2017, there were three female directors (2016 3, 2015 3) on our board of 13. Our nomination committee actively considers diversity in seeking potential candidates for appointment to the board. The board looked at gender and wider diversity across the group as part of its annual review of HR, capability and talent management. The remuneration committee and the board reviewed and discussed BP's data and report on the UK gender pay gap prior to its publication in February 2018. Focus was given to the data in the report, and what action BP is taking to address the gap and 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 NEDs, with the exception of the chairman, 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 the boards of other entities or who hold other external appointments. The nomination committee keeps the other interests of the NEDs under review to ensure that the effectiveness of the board is not compromised. Appointment and time commitment The chairman and NEDs 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 (a practice followed since 2004). While the chairman's letter of appointment sets out the time commitment expected of him, those for NEDs do not set a fixed-time commitment, but instead set a general guide of between 30-40 days per year. The time required of directors may fluctuate depending on demands of BP business and other events. They are expected to allocate sufficient time to BP to perform their duties effectively and make themselves available for all regular and ad hoc meetings. Background and diversity Non-executive director Background Diversity Oil & gas/ extractives/ energy Engineering/ technology Financial expertise Safety Brand/ marketing/ reputation Regulatory/ government affairs Female Non UK/US Tenure (years) Nils Andersen 2 Paul Anderson 8 Alan Boeckmann 4 Frank Bowman 7 Ian Davis 8 Ann Dowling 6 Melody Meyer 1 Brendan Nelson 7 Paula Reynolds 3 John Sawers 3 Carl-Henric Svanberg 9 C orporate governance BP Annual Report and Form 20-F 2017 73

Executive directors are permitted to take up one external board appointment, subject to the agreement of the chairman. Fees received for an external appointment may be retained by the executive director and are reported in the directors' remuneration report (see page 90). Neither the chairman nor the senior independent director are employed as an executive of the group. Training and induction To help develop an understanding of BP's business, the board continues to build its knowledge through briefings and site visits. In 2017 the board received training on ethics and compliance. NEDs are expected to visit at least one business a year as part of their learning programme. In 2017 the board visited the group's response information centre in Sunbury, operations of Aker in Norway and the trading business in London. Members of the SEEAC and other directors also visited the Cherry Point refinery in the US and the Glen Lyon FPSO vessel in the North Sea. Newly appointed NEDs follow a structured induction process. This includes one-to-one meetings with management and the external auditors and also covers the board committees that they join. Board evaluation BP undertakes an annual review of the board, its committees and individual directors. The chairman's performance is evaluated by the chairman's committee and his evaluation is led by the senior independent director. The evaluation operates on a three-year cycle, with one externally led evaluation followed by two subsequent years of internal evaluations carried out using a questionnaire prepared by an external facilitator. Activity following prior year evaluation Actions arising from the 2016 evaluation and how these were addressed included: • Focus on implementing the strategy, in particular the opportunities relating to the transition to a lower carbon economy: reporting on the implementation of the strategy was further developed and as a result the board receives updates from management and a strategic progress report at each meeting. The board held a number of discussions on the transition to a lower carbon economy, including a session at the strategy away day, with further sessions scheduled for R018. The group's quarterly results announcement was amended in R017 to include narrative on the implementation of strategy. • More detailed examination of the financial performance of the business, in particular capital allocation and returns: the board discusses financial performance at each board meeting and reviews the proposed disclosures and investor presentation for each quarter's results. A return on average capital employed measure was included in the 2017 remuneration policy and the board reviews this as part of its performance monitoring. A review of the group's capital allocation process and investment effectiveness was also held during the year. • Obtaining a better understanding of the group's ability to effectively deliver the strategy, including technology, digital and big data: this included a deep dive into technology trends and their potential impact on the group's business model. • Bringing wider perspectives into the board room and gaining deeper insight into shareholder views: the board considered output from BP's remuneration engagement programme as well as broader governance issues from investor meetings held throughout the year. Feedback from institutional investors on the group's performance and strategy – compiled by an independent third party – was discussed with the board following the strategy update. • Continued emphasis on improving operational excellence: the board received data and commentary on BP's operations through monthly reports and updates from management; and operational measures were included in the annual bonus scorecard as part of the remuneration assessment for the year. 2017 evaluation The evaluation was undertaken through a questionnaire facilitated by an external consultant (Lintstock) and individual interviews between the chairman and each director. The results of the evaluation and feedback from the interviews were collectively discussed by the board including: • Investment decisions: continue focusing on capital allocation and the way in which investment decisions are taken. • Longer-term vision and strategy: extend the timeframe of strategic discussions, including challenges faced by BP's core business and the lower carbon transition. • Geopolitics: consider how to further optimize the output of the work undertaken by the board, geopolitical committee and the international advisory board. • Improve the board's understanding of employees' views: expand the existing ways employee views are disseminated to the board to include more local and business based feedback. Director induction programme Melody Meyer, appointed in 2017, followed a tailored induction process, which also covered the SEEAC and geopolitical committee. The programme of topics included: Board and governance • BP's board governance model, directors' duties, interests and potential conflicts. Business introduction • BP's business • Upstream (exploration, development, production, overview of our operations) • Downstream (refining, marketing and lubricants) • Alternative Energy • Strategy and planning • Lower carbon transition • BP's performance relative to its competitors. Functional input • Human resources, including capability and reward • Ethics and compliance • Research and technology • Investor relations • Trading • Communications and corporate reporting • Group audit • External audit • BP women's network • Legal. SEEAC specific • Safety and operational risk (S&OR), BP's operating management system (OMS) and environmental performance • Operational, safety and environmental reporting • Group security and crisis management. Geopolitical committee specific • BP's regional businesses • Government affairs. BP executives devoted substantial time to ensure a high quality induction. Melody Meyer Non-executive director See Glossary BP Annual Report and Form 20-F 201774

Site visits Washington state, US Members of the SEEAC and other directors visited the Cherry Point refinery in Blaine, Washington in June. The visit focused on operating procedures and safety and risk mitigation. Investment was discussed, including technology enhancements to produce ultra-low sulphur diesel, increasing logistical optionality and a coker heater project. Other discussions included the cultural and environmental outreach projects in the area. They also took a tour of the refinery, control room, the operator training simulator and dock area. Global business services, Hungary The audit committee visited BP's global business service (GBS) centre located in Budapest in September, where standardized business services including finance, procurement, HR, trading settlement and tax are delivered for businesses across the BP group. The committee received presentations on the GBS strategy, business model and controls framework. They also met local staff across a range of job levels, including those involved in diversity and inclusion initiatives such as LGBT and working parent programmes. Integrated supply and trading, London Members of the board visited BP's trading operations in London in December to gain an insight into the group's approach to trading, oil and gas market fundamentals, risk profile and strategy. Directors received presentations from traders and originators on the trading floor and deepened their understanding of the group's oil products and LNG business models. North Sea, UK In July members of the SEEAC and other directors visited Glen Lyon – the floating, production, storage and offloading vessel for our Quad 204 major project start-up in the North Sea. The committee was the first to visit the vessel following production start-up. Discussions on board the vessel covered project completion and future plans including reviews of production efficiency, operational management, safety, risk mitigation and OMS conformance. They also visited key areas of the vessel including the control room and riser tower. Tranby, Norway The board visited Aker's Tranby technology centre near Oslo to see the manufacture of subsea well heads and the research and development centre. The Tranby site has been an established centre of excellence for subsea equipment manufacturing for over a decade. The board heard about the research being undertaken in subsea trees, workover systems and subsea pumps and saw new digital technologies to integrate engineering and manufacturing processes being tested. Non-executive directors are expected to visit at least one business per year, as part of their learning programme. In 2017 the board visited partner operations in Tranby, Norway and BP's trading business in London. Members of the SEEAC and other directors visited operations in the North Sea and Washington state, and the audit committee visited our global business services offices in Hungary. The board met local management at each visit, and after each one, the board or appropriate committee was briefed on the impressions gained by the directors during the visit.

Shareholder engagement Institutional investors The company operates an active investor relations programme. The board receives feedback on shareholder views through results of an anonymous investor audit and reports from management and those directors who meet with shareholders each year. In 2017 the chair of the remuneration committee undertook extensive engagement on the new remuneration policy prior to the AGM in May (see the remuneration committee report on page 86). The chair of the audit committee and the senior independent director also held one-to-one meetings with institutional investors during the year. Senior management regularly meets with institutional investors through roadshows, group and one-to-one meetings, events for socially responsible investors (SRIs) and oil and gas sector conferences throughout the year. In April the chairman and all board committee chairs held an annual investor event. This meeting enabled BP's largest shareholders to hear about the work of the board and its committees and for NEDs to engage with investors. 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. Private investors BP held a further event for private investors in conjunction with the UK Shareholders' Association (UKSA) in 2017. The chairman and head of 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 decreased in 2017 to 50.8% (of issued share capital, including votes cast as withheld), compared to 64.3% in 2016 and V2.3% in 2015. We believe this drop in vote levels was due to the late return of BP stock on loan, with voting deadlines for some custodians coinciding with the date that BP shares went 'ex-dividend'. The company is looking at future AGM voting deadlines against its financial calendar to mitigate this event recurring. All resolutions were passed at the meeting. Each year the board receives a report after the AGM giving a breakdown of the votes and investor feedback on their voting decisions to inform them on any issues arising. UK Corporate Governance Code compliance BP complied throughout 2017 with the provisions of the UK Corporate Governance Code except in the following aspects: B.3.2 Letters of appointment do not set out fixed-time commitments since the schedule of board and committee meetings is subject to change according to the demands of business and other events. Our letters of appointment set a general guide of a time commitment of between 30-40 days per year. All directors are expected to demonstrate their commitment to the work of the board on an ongoing basis. This is reviewed by the nomination committee in recommending candidates for annual re-election. D.2.2 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. International advisory board BP's international advisory board (IAB) advises the chairman, group chief executive and the board on geopolitical and strategic issues relating to the company. This group meets once or twice a year and between meetings IAB members remain available to provide advice and counsel when needed. The IAB was chaired by BP's previous chairman, the late Peter Sutherland. Its membership in 2017 comprised Lord Patten of Barnes, Josh Bolten, President Romano Prodi, Dr Ernesto Zedillo and Dr Javier Solana. The chairman, chief executive and Sir John Sawers attend meetings of the IAB. Issues discussed in 2017 included the global economy, developments in the Middle East, political events in Latin America and the political and economic outlook in the US. The IAB discussed the UK's potential exit from the European Union at both of its meetings during 2017. Shareholder engagement cycle 2017 Q1 • Fourth quarter results • BP Energy Outlook presentation • Strategy investor roadshows with executive management • US SRI meetings on remuneration • Investor meetings on remuneration, continuing into Q2 • SRI roadshow following the launch of the BP Sustainability Report 2016, continuing into Q2 Q2 • Chairman and board committee chairs meetings • UKSA private shareholders' meeting • First quarter results • Meetings with members of the Church Investors Group and Charities Responsible Network • Institutional Investors Group on Climate Change (IIGCC) meeting • Annual general meeting • BP Statistical Review of World Energy launch • Downstream investor day, Pangbourne Q3 • Second quarter results • Investor roadshows with the group chief executive and chief financial officer Q4 • Third quarter results • IIGCC meeting BP Annual Report and Form 20-F 201776

Committee reports Chairman's introduction Last year's report highlighted our monitoring of the group's financial performance in light of the demanding external environment. While this focus remains, the committee has continued to review the integrity of the group's financial reporting by challenging and debating the judgements made by management, including the estimates which are made. We receive reports from management and the external auditor each quarter highlighting significant accounting issues and judgements and have used these to inform our debate on whether BP's financial reporting is 'fair, balanced and understandable'. In 2017 the committee focused on the effectiveness of the group audit function. We reviewed its longer-term vision and capability and oversaw an externally facilitated review of its performance, the results of which we discussed in a joint session with colleagues from the SEEAC. We will continue to focus on the actions arising from the review in 2018. Following the 2016 tender process for the statutory audit, the committee has overseen the transition to Deloitte from EY in time for R018. We met with both EY and Deloitte during 2017 and monitored Deloitte's progress towards independence in time for their 'shadowing' of the 2017 year-end audit. The committee visited one of the group's global business service centres, located in Budapest, enabling us to see first hand the work undertaken by this growing part of BP's operations and to meet local staff. We found this direct contact added an important additional dimension to our review and understanding, and intend to hold further site visits in 2018. Andrew Shilston retired from the committee in May 2017. I would like to thank Andrew for his service to the committee, and for the challenge and perspective he provided as a member. Brendan Nelson Committee chair The committee continued to review the integrity of the group's disclosures by challenging and debating the judgements made by management. Audit committee 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 management or mitigation of financial risks is appropriately addressed by the group chief executive 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. Members Brendan Nelson Member since November 2010 and chair since April 2011 Nils Andersen Member since October 2016 Paula Reynolds Member since May 2015 Andrew Shilston Member since February 2012; retired May 2017 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 The Royal Bank of Scotland Group 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 13 committee meetings in 2017, of which six were by teleconference. All directors attended every meeting during the period in which they were committee members. Regular attendees at the meetings include the chief financial officer, group controller, chief accounting officer, group head of audit and external auditor. C orporate governance BP Annual Report and Form 20-F 2017 77

Activities during the year 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 reporting during the year. The committee reviewed the assessment and reporting of longer-term viability, risk management and the system of 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 R017 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 controls. The committee made a recommendation to the board, who 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. Risk reviews The principal risks allocated to the audit committee for monitoring in R017 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 – including new areas of activity and impacts on the control environment. The committee further considered updates in the trading function's risk management programme, including compliance with regulatory developments and activities in response to cyber threats. Compliance with applicable laws 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. Other reviews Other reviews undertaken in 2017 by the committee included: • Downstream: including strategy and strategic progress, financial performance, risk management and controls, audit findings, key litigation and ethics and compliance findings. • Upstream: including vision and priorities, structure and portfolio, financial controls and the balance sheet, an overview of intangible assets and a review of the segment's finance organization. • Shipping: including an overview of BP shipping's role and operating model, financial performance, strategy, risk management and controls and the impact of IFRS 16 (lease accounting standard). • Financial Stability Board's Task Force on Climate-related Financial Disclosures (TCFD): the origin, purpose and work of the TCFD along with its key recommendations and how BP's existing reporting compares to these recommendations, see page 50. • Non-operating items (NOIs): BP's policy for identifying and categorizing NOIs and an analysis of those NOIs impacting BP's reported results. • Blockchain: introduction to blockchain technology, its potential impacts on the oil and gas industry and an overview of BP's participation and approach to date. • Capability and succession in BP's finance function, including the group's finance modernization programme. • Assessment of financial metrics for executive remuneration: consideration of financial performance for the group's R017 annual cash bonus scorecard and performance share plan, including adjustments to plan conditions and NOIs. The committee reviewed key areas of BP's ethics and compliance programme, including the integration of the business integrity and ethics and compliance functions, development of the anti-bribery and corruption elements of the programme, enhanced policies, tools and training and strengthening of counterparty risk measures, including due diligence. Security threats against BP's digital infrastructure: including inappropriate access to or misuse of information and systems and disruption of business activity. The committee reviewed changes in the cyber security landscape, including events in the oil and gas industry and within BP itself. The review focused on the improvements made in managing cyber risk, including the application of the three lines of defence model and examining the indicators associated with risk management and barrier performance. Financial resilience: 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 price assumptions used by the group for investment appraisal and the judgements underlying those proposals, the cost of capital and its application as a discount rate to evaluate long-term BP business projects, liquidity (including credit rating, hedging, long-term commercial commitments and credit risk) and the effectiveness and efficiency of the capital investment into major projects . BP's principal risks are listed on page 57. For 2018, the board has agreed that the committee will continue to monitor the same four group risks as for 2017. The group risk financial resilience has been renamed 'financial liquidity' for R018. See Glossary BP Annual Report and Form 20-F 201778

In te rnal control and risk management The committee received quarterly reports on the findings of group audit in 2017. It reviewed group audit's vision for 2020, including the roadmap for 2017 and beyond. The committee met privately with the group head of audit and key members of his leadership team. The committee oversaw an external review of the effectiveness of the group audit function, which was awarded to Deloitte in July 2017 following a competitive tender process. Fieldwork and interviews with management and board members was completed by September 2017 and the results of the assessment were reviewed at a joint meeting of the audit and safety, ethics and environment assurance committees in December. The review concluded that the group audit function: • Performed strongly across Deloitte's assessment framework. • Demonstrated a high level of maturity when assessed against internal audit functions within large FTSE (non- financial services) companies. • Had a remit covering all risk categories (financial and operational) – a breadth seen as leading practice. • Had areas where continuous improvement activity and continued dialogue with the business could result in an even stronger performance. Implementation of the agreed actions arising from the review will be tracked during 2018. The audit committee also held private meetings with the group ethics and compliance officer during the year. Training The committee held a deep dive on reserves, covering resource definition and estimation, the group's governance processes, areas of focus for the regulator and how BP compared with its competitors in terms of approach. It received technical updates from the chief accounting officer on developments in financial reporting and accounting policy, including IFRS 9 'Financial Instruments', IFRS 15 Revenues from Contracts with Customers and IFRS 16 'Leases'. Site visits In September, the committee visited BP's global business services (GBS) centre in Hungary. During the visit the committee reviewed the function's strategy, context, and how it has grown in scope and scale. It looked at its risk management and controls processes, including understanding the risks around transition of activity from the business and the standardization of global processes. It also reviewed capability and human resources issues, including talent attraction and retention, met a range of staff and heard about the various GBS diversity programmes including LGBT, working parents and disability awareness. In December, members of the committee and wider board visited BP's integrated supply and trading (IST) business in London for a day that covered oil and gas market fundamentals, finance and risk, IST's strategy, and presentations on oil products and LNG trading. Accounting judgements and estimates Areas of significant judgement considered by the committee in 2017 and how these were addressed included: Key judgements and estimates in financial reporting Audit committee activity Conclusions/Outcomes Gulf of Mexico oil spill BP uses judgement in relation to the recognition of provisions relating to the Gulf of Mexico oil spill. The timing and amounts of the remaining cash flows are subject to uncertainty and estimation is required to determine the amounts provided for. A review of the provisioning for and disclosure of uncertainties relating to the Gulf of Mexico oil spill was undertaken each quarter as part of the review of the stock exchange announcement. Particular focus was given to updates to the provision related to business economic loss (BEL) and other claims related to the Gulf of Mexico oil spill, including the continuing effect of the Fifth Circuit May 2017 opinion on the matching of revenues with expenses when evaluating BEL claims. Following significantly higher average claims determinations issued by the Court Supervised Settlement Program (CSSP) in the fourth quarter 2017 and the continuing effect arising from the Fifth Circuit May 2017 opinion, BP recognized a post-tax charge of $1.7 billion for BEL and other claims associated with the CSSP. Disclosure includes information on remaining uncertainties.

Key judgements and estimates in financial reporting Audit committee activity Conclusions/Outcomes Oil and natural gas accounting, including reserves 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. 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. Judgement is required to determine whether it is appropriate to continue to carry intangible assets related to exploration costs on the balance sheet. 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 exploration write-offs as part of the group's quarterly due diligence process. Received briefings on the status of upstream intangible assets, including the status of items on the intangibles assets 'watch-list'. 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. Exploration write-offs totalling $1.6 billion were recognized during the year. Exploration intangibles totalled $17.0 billion at 31 December 2017. 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 pricing, discount rates, production profiles, reserves and the impact of inflation on operating expenses. Judgement is required in assessing the recoverability of overdue receivables, and deciding whether a provision is required. 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. Reviewed the group's credit risk management and reporting framework, including actual credit losses observed, expected loss delegations and utilization and changes in the credit portfolio quality. The group's long-term price assumptions for Brent oil, and Henry Hub gas were unchanged from 2016. The group's discount rates used for impairment testing were also unchanged. Impairments of $1.0 billion were recorded in the year, net of impairment reversals. The group had $1.5 billion of receivables which were not impaired but past due at 31 December 2017. 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 Q9.75% 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. Considered IFRS guidance on evidence of significant influence, including representation on the board and participation in policy-making processes. Received reports from management and the external auditor which assessed the extent of significant influence, including BP's participation in decision making through the continued service on the Rosneft board and key board committees of two BP-nominated directors and work on significant transactions and projects. This assessment considered the appointment of two additional non-BP directors to the Rosneft board but concluded that the assessment of significant influence remained unchanged. BP has retained significant influence over Rosneft throughout 2017 as defined by IFRS. See Glossary

Key judgements and estimates in financial reporting Audit committee activity Conclusions/Outcomes Derivative contracts In some instances, BP estimates the fair value of derivative contracts using internal models due to the absence of quoted market pricing or other observable, market-corroborated data. Judgement may also be required to determine whether contracts to buy or sell commodities meet the definition of a derivative. Received a briefing on the group's trading risks and reviewed the system of risk management and controls in place, including those covering the valuation of derivative instruments, using models where observable market pricing is not available. The committee annually reviews the control process and risks relating to the trading business. BP has assets and liabilities of $7.1 billion and $6.6 billion respectively recognized on the balance sheet for derivative contracts at S1 December 2017, 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 28 in the financial statements. Provisions BP's most significant provisions relate to decommissioning, the Gulf of Mexico oil spill (see above), environmental remediation 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 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 $16.1 billion were recognized on the balance sheet at 31 December 2017. The discount rate used by BP to determine the balance sheet obligation at the end of R017 was a real rate of 0.5% – based on long-dated US government bonds. 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 R016. 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 22. At 31 December 2017, surpluses of $4.2 billion and deficits of $9.1 billion were recognized on the balance sheet in relation to pensions and other post-retirement benefits. Income taxes Computation of the group's income tax expense and liability, the provisioning for potential tax liabilities and the level of deferred tax asset recognition are underpinned by management judgement and estimation of the amounts which could be payable. Received regular updates on the group's tax exposures and deferred tax asset recognition. Reviewed the judgement exercised on tax provisioning, including any material changes to deferred tax asset recognition. Reviewed the accounting treatment of taxes relating to renewal of the Abu Dhabi onshore concession. Reviewed the estimated impact of tax reforms arising from the US Tax Cuts and Jobs Act. Deferred tax assets amounting to $4.5 billion were recognized on the balance sheet at 31 December 2017. As a result of changes in the fiscal terms of the Abu Dhabi onshore concession following its renewal, the group's taxes payable relating to the concession are now principally reported as income taxes rather than as production taxes. Changes to the US corporate tax system resulted in a one-off deferred tax charge of $0.9 billion in the fourth quarter 2017 arising from a revaluation of BP's US deferred tax assets and liabilities. C orporate governance BP Annual Report and Form 20-F 2017 81

External audit Audit risk The external auditor set out its audit strategy for 2017, identifying key risks to be monitored during the year. These included: • Determining the liabilities, contingent liabilities and disclosures arising from the Gulf of Mexico oil spill. • Estimating oil and gas reserves and resources which has significant impact on the financial statements, particularly impairment testing and the calculation of depreciation, depletion and amortization. • Monitoring for unauthorized trading activity in the trading function and its potential impact on revenue. The committee received updates during the year on the audit process, including how the auditor had challenged the group's assumptions on these issues. 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 $47 million (2016 $47 million), of which 6% was for non-audit assurance work (see Financial statements – Note 34). 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 $3 million (2016 $2 million). The $1 million increase in non-audit fees primarily relates to non-audit related assurance services, offset by a reduction in tax compliance services. Non-audit or non-audit related services consisted of other assurance services. There were no new services contracted for tax compliance and advisory services for 2017. Audit effectiveness The effectiveness, performance and integrity of the external audit process was evaluated through separate surveys for committee members and those BP personnel impacted by the audit, including chief financial officers, controllers, finance managers and individuals responsible for accounting policy and internal controls over financial reporting. The survey sent to management comprised questions across five main criteria to measure the auditors' performance: • Robustness of the audit process. • Independence and objectivity. • Quality of delivery. • Quality of people and service. • Value added advice. Further questions were included on BP's attitude to the audit and the progress of the audit transition. The 2017 evaluation concluded that the external auditor's performance had remained largely constant in key areas compared with the previous year. Areas with high scores and favourable comments included quality of accounting and auditing judgement, the working relationship with management and the insight brought through EY's audit work. Areas of focus included the need for innovation in the audit and consistency of audit practices in locations further away from the UK and US. A further focus was BP's assessment of its own performance in relation to the audit. Results of the annual assessment were discussed with the external auditor who considered these themes for the 2017 audit service approach. A key area of focus from 2016 related to audit team turnover, particularly for junior members of the teams. Actions taken over the year resulted in an improvement in the related score for continuity and retention of key members of the audit team in 2017. 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 before each meeting. Audit transition Deloitte was appointed for the statutory audit, with effect from 2018 following a tender process in 2016. The committee monitored the transition of BP's statutory auditor from EY to Deloitte, including activity to enable Deloitte to achieve independence by October 2017. This included: • Receiving reports from the audit transition team, including an overview of operational activities and the termination of non-audit services being provided by Deloitte to BP – which would be prohibited when Deloitte becomes the group's statutory auditor. This included Deloitte stepping down as independent adviser to BP's remuneration committee. • Requiring management to report to the committee on any services undertaken by the statutory auditor in line with the group's policies relating to non-audit services. • Requiring confirmation of Deloitte's compliance with BP's independence and ethics and compliance rules. • Inviting Deloitte to attend meetings of the audit committee, joint audit and SEEA committees and the board from October 2017 as part of its 'shadowing' of the audit of the third and fourth quarters 2017. Deloitte confirmed its independence to the committee in October 2017. EY resigned on 29 March 2018 following completion of the 2017 audit. Deloitte will audit the 2018 financial year subject to shareholder approval at the 2018 AGM. Changes in Registrant's Certifying Accountant Following a competitive tender process and on the audit committee's recommendation, in November 2016 the board selected Deloitte as BP's independent external auditor for the financial year ending S1 December 2018. This change in external auditor is being made in accordance with UK and EU law requirements – in particular, the UK Corporate Governance Code and the reforms of the audit market by the Competition and Markets Authority and the European Union – which require that companies put their external audit out to tender at least every ten years. EY has served as BP's external auditor since 1909. EY continued to serve as BP's external auditor throughout the financial year ended 31 December 2017. The audit committee supervised the transition period of Deloitte, as new external auditor, to ensure the monitoring of Deloitte's independence and extended the audit committee's policy on non-audit services to Deloitte during the financial year ended 31 December 2017. The board appointed Deloitte as the company's new external auditor with effect from 29 March 2018 to fill the vacancy arising from EY's resignation following completion of their audit of BP's 2017 financial statements. At the 2018 AGM, EY will not stand for re-election and the board will seek shareholder approval for the appointment of Deloitte as the company's external auditor until the conclusion of the next AGM at which the company's accounts are laid before shareholders. In respect of the financial years ended 31 December 2016 and 2017, EY did not issue any report on the consolidated financial statements of the BP group that contained an adverse opinion or a disclaimer of opinion, nor were the auditor's report qualified or modified as to uncertainty, audit scope or accounting principles. There has not been any disagreement as defined in Item 16F(a)(1)(iv) of Form 20-F with EY over any matter of accounting principle or practice, financial statement disclosure, or auditing scope or procedure, which disagreement, if not resolved to EY's satisfaction, would have caused EY to make reference to the subject matter of the disagreement in connection with its BP Annual Report and Form 20-F 201782

auditor's reports, or any reportable event as defined in Item 16F(a)(1)(v) of Form 20-F. BP has provided EY with a copy of the foregoing disclosure and has requested that they furnish BP with a letter addressed to the US Securities and Exchange Commission (SEC) stating whether or not they agree with such disclosure and, if not, stating the respects in which they do not agree. A copy of EY's letter dated 29 March 2018, in which they stated that they agree with such disclosure, is filed as Exhibit 15.6. During the financial years ended 31 December 2016 and 2017 BP did not consult with Deloitte regarding: (i) the application of accounting principles to any specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on the consolidated financial statements of the BP group; or (ii) any matter that was either the subject of a disagreement as defined in Item 16F(a)(1)(iv) of Form R0-F or reportable event as defined in Item 16F(a)(1)(v) of Form 20-F. Auditor appointment and independence 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 seven years. The current lead partner has been in place since the start of 2013. No partners or senior staff associated with the BP audit may transfer to the group. 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 auditors may not perform non-audit services that are prohibited by the SEC, Public Company Accounting Oversight Board (PCAOB), UK Auditing Practices Board (APB) 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 only considered for permitted non-audit services when its expertise and experience of the company is important. For all other services which fall under the 'permitted services' categories, approval above a certain financial amount must be sought on a case-by-case basis. 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 accountants' fees and services on page 276. The committee's policies were updated in 2017 to reflect the revised regulatory guidelines of the FRC, including: • Adoption of the FRC's prohibited non-audit services list. • Prohibition of non-audit tax services by the audit firm. • Reduction of the pre-approval requirements for non-audit services in line with FRC guidance on 'non-trivial' engagements with the audit firm. Committee evaluation The audit committee undertakes an annual evaluation of its performance and effectiveness. 2017 evaluation For 2017 an internal questionnaire was used to evaluate the work of the committee. The review concluded that it had performed effectively. Areas of focus for 2018 include succession planning for membership of the committee and a further review of capital spending. Actions from the 2016 evaluation Priorities arising from the 2016 evaluation included a review of and visit to one of BP's global business service (GBS) centres, a focus on streamlining committee materials and further scrutiny on risk management when undertaking business or functional reviews. The committee visited GBS in Budapest in 2017, undertaking a review of the organization's activities and strategy. It also focused on improving committee pre-read materials, which received improved evaluation scores for the 2017 review. And an overview of risk management and controls was included in all segment and functional reviews. C orporate governance BP Annual Report and Form 20-F 2017 83

Safety, ethics and environment assurance committee (SEEAC) On site visits we look for ourselves and ask questions, and then we engage with management. Chairman's introduction The committee continued its work with executive management to drive safe, ethical and reliable operations. It has reviewed the company's management of the highest priority non-financial group risks and continues to provide constructive challenge to the risk management process. The risks under their remit remained the same as for 2016: marine, wells, pipelines, explosion or release at facilities and major security incidents and cyber security in process control network. The committee receives reports on each of these risks and monitors their management and mitigation. Following publication of the company's Modern Slavery Act (MSA) statement in 2017, the committee reviewed related work practices in BP and will continue to review progress in developing and embedding those practices. In 2017 it also reviewed the BP Sustainability Report 2017 and will review the annual update MSA statement to be published in 2018. The committee made two site visits in the year (see page 75). In June, members of the committee visited the Cherry Point refinery in Washington, and in July members were among the first to visit the newly operating Glen Lyon floating production, storage and offloading vessel in the UK North Sea. Our level of access into the operational side is extensive and gives the committee unique insight. On site visits, we look for ourselves and ask questions, and then we engage with management on what this means for the objectives we set. The committee also continued its schedule of regular meetings with executive management. In May, Cynthia Carroll retired from the board and the committee and in the same month Melody Meyer joined the committee. Melody brings with her valuable insight through many years of industry experience, and within a few weeks of joining, participated in her first committee site visit. Alan Boeckmann Committee chair Role of the committee The role of the SEEAC 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 and receiving assurance that processes to identify and mitigate such non-financial risks are appropriate in their design and effective in implementation. Key responsibilities The committee receives specific reports from the business segments as well as cross-business information from the functions. These include, but are not limited to, the safety and operational risk function, group audit, group ethics and compliance, business integrity and group security. The SEEAC can access any other independent advice and counsel it requires on an unrestricted basis. The SEEAC 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. Members Alan Boeckmann Member since September R014 and chair since May 2016 Paul Anderson Member since February 2010 Frank Bowman Member since November 2010 Cynthia Carroll Member since June 2007; retired May 2017 Ann Dowling Member since February 2012 Melody Meyer Member since May 2017 John Sawers Member since July 2015 Meetings and attendance There were six committee meetings in 2017. All directors attended every meeting for which they were eligible, apart from Cynthia Carroll who missed one meeting due to a conflicting meeting. In addition to the committee members, all SEEAC 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 attended some of the meetings and was briefed on the other meetings by the chair and secretary to the committee. The group general counsel and group ethics and compliance officer 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 was invited to join the private meetings on an ad hoc basis. BP Annual Report and Form 20-F 201784

Committee evaluation For its 2017 evaluation, the committee examined its performance and effectiveness through an internal questionnaire. Topics covered included the balance of skills and experience among its members, the quality and timeliness of information the committee receives, the level of challenge between committee members and management and how well the committee communicates its activities and findings to the board. The evaluation results continued to be generally positive. Committee members considered that they continued to possess the right mix of skills and background, had an appropriate level of support and received open and transparent briefings from management. All members emphasized that site visits remained an important element of the committee's work, particularly because they gave members the opportunity to examine how risk management is being embedded in businesses and facilities, including in the management culture. Joint meetings between the SEEAC and the audit committee were considered important in reviewing and gaining assurance around financial and operational risks where there was overlap between the committees, particularly in relation to ethics and compliance (see below). 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 their assurance work on the system to inform the review. The committee also received regular reports from the group chief executive on operational risk, and from the system of internal control and risk management function, including quarterly reports prepared for executive management on the group's health, safety and environmental performance and operational integrity. These included quarter-by-quarter measures of personal and process safety, environmental and regulatory compliance and audit findings, as well as quarterly reports from group audit. In addition, the group ethics and compliance officer and the group auditor 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. Corporate reporting The committee is responsible for the overview of the BP Sustainability Report 2017. The committee reviewed content and the revised presentation, and worked with the external auditor with respect to their assurance of the report. Site visits In June members of the committee, and other directors, visited the Cherry Point refinery in Blaine, Washington. The site visit included a tour of the dock, training simulator and control room. Meetings with senior leadership and representatives from across the site, including a local safety committee, were held. In July committee members, and other directors, visited the newly operational floating production, storage and offloading vessel, Glen Lyon, at our Quad 204 project in the UK North Sea. This was one of the seven major projects delivered during 2017 and the committee's visit was the first formal visit following its start-up. During visits 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 then reported back in detail about each visit to the committee and subsequently to the board. See page 75 for further details. Joint meetings of the audit and safety, ethics and environment assurance committees The audit committee and SEEAC hold joint meetings on a quarterly basis to simplify reporting of key issues that are within the remit of both committees and to make more effective use of the committees' time. Each committee retains full discretion to require a full presentation and discussion on any joint meeting topic at their respective meeting if deemed appropriate. The committees jointly met four times in 2017, with the chairmanship of the meetings alternating between the chairman of the audit committee and chairman of the SEEAC. Topics discussed at the joint meetings were the quarterly ethics and compliance reports (including significant investigations and allegations) and the 2018 forward programmes for the group audit and ethics and compliance functions. The committees reviewed the approach and disclosure statement under the UK Modern Slavery Act and the results of an externally facilitated review of the effectiveness and performance of group audit. See Glossary

Remuneration committee Key responsibilities The committee undertakes its tasks in accordance with applicable regulations, including those made from time to time under the Companies Act 2006, the UK Corporate Governance Code and the UK Listing Authority's Listing Rules in relation to the remuneration of directors of quoted companies. • Determine the remuneration policy for the chairman and the executive directors. • Review and determine the terms of engagement, remuneration and termination of employment for the chairman and the executive directors as appropriate and in accordance with the policy, and be responsible for compliance with all remuneration issues applicable to them. • 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. • Approve the terms of the remuneration of the executive team (including pension and termination arrangements) as proposed by the group chief executive. • Approve changes to the design of remuneration, for BP group leaders as proposed by the group chief executive. • Monitor implementation of remuneration for group leaders to ensure alignment and proportionality. • Engage independent consultants or other advisers as the committee may from time to time deem necessary, at the expense of the company. Members Ann Dowling Member since July 2012 and chair since May 2015 Alan Boeckmann Member since May 2015 Ian Davis Member since July 2010 Brendan Nelson Member since May 2017 Paula Reynolds Member since September 2017 Andrew Shilston Member since May 2015; retired from the committee May 2017 Meetings and attendance Carl-Henric Svanberg and Bob Dudley attend meetings of the committee except for matters relating to their own remuneration. Bob Dudley is consulted on the remuneration of other executive directors, 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. Chair's introduction I am pleased to report on the work of the committee in 2017. Following substantial engagement with our shareholders in 2016 and early 2017, we were pleased to receive their support at the 2017 AGM. We applied our new remuneration policy from the start of 2017 and during the year have been addressing some transitional arrangements from old to the new policies. We also reviewed BP pay below the executive team by region, job level and sector to give additional context to our decisions on executive pay. Having served on this committee for six years, and as chair for the last three, I am stepping down from the committee after the 2018 AGM. Paula Reynolds, who joined the committee in September 2017, will take the chair. She is currently chair of the remuneration committee at BAE Systems plc and has served on that committee since 2015. During the year, Deloitte LLP had to stand down as our independent adviser following their forthcoming appointment as auditor. Following a competitive tender process, we appointed PwC LLP in their place. Professor Dame Ann Dowling Committee chair 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. After extensive shareholder engagement, we were pleased to receive strong support for our new remuneration policy at the 2017 AGM.

The committee met eight times during the year. All directors attended each meeting that they were eligible to attend, either in person or by telephone, except that Alan Boeckman was not able to attend a telephone meeting on 27 February in 2017. Activities during the year In the period before the 2017 AGM, the committee focused on finalizing the proposed new remuneration policy and outcomes for 2016. This involved reviewing directors' salaries and the group's performance outcome which in turn determined the annual bonus and the performance share plan. From the 2017 AGM, the committee focused on implementing the new policy, in particular looking more broadly at remuneration of employees below the executive team and the measures that could be used to reflect the transition to a lower carbon world. It also considered the implications of the transition from the 2014 to the 2017 policies, in particular aspects relating to share grants, and reviewed potential outcomes for 2017 at the end of the year. Following the appointment of Deloitte as the group's statutory auditor from 2018 (subject to shareholder approval) and the need for the firm to be independent prior to the transition of the audit, the committee appointed PwC as its independent adviser effective September 2017. The committee continued to monitor developments in potential regulation and legislation and held early discussions on the possible implications for its work. It also considered the company's disclosure on the UK gender pay gap. In each of its meetings, the committee focused on the overall quantum of executive director remuneration and its alignment to the broader group of employees in BP. It has sought to reflect the views of shareholders and the broader societal context in its decisions. Shareholder engagement There was substantial engagement with shareholders and proxy voting agencies ahead of the 2017 AGM, primarily carried out by the chair of the committee, supported by the chairman and company secretary. The committee chair tested proposals and sought support for the new policy put to shareholders at the 2017 AGM. In order to understand evolving issues – particularly around climate change – engagement continued throughout the year, primarily with larger shareholders and representative bodies. Committee evaluation We undertook an internally facilitated evaluation to examine the committee's performance in 2017. The evaluation concluded that the committee had worked well and continued to evolve after its intense work leading up to the 2017 AGM. Focus areas for 2018 included improving oversight of stakeholders' views on remuneration and in particular, deepening the committee's understanding of remuneration below the executive level. In addition, we focussed on staying up to date with external developments and emerging 'best practice' and improving remuneration reporting. See page 90 for the Directors' remuneration report. Chairman's introduction I am pleased to report on the work of the geopolitical committee in 2017, which continued to develop and evolve during the year. In addition to our regular meetings, we visited the group's response information centre in Sunbury, where we were briefed on the group's practices and procedures. During 2017 I also joined discussions of the international advisory board. Cynthia Carroll and Andrew Shilston stood down from the board at the 2017 AGM, and Melody Meyer joined the committee in May. Other board members joined our meetings from time to time. 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: – 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. • 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. Geopolitical committee C orporate governance BP Annual Report and Form 20-F 2017 87

Members John Sawers Member since September 2015 and chair since April 2016 Paul Anderson Member since September 2015 Frank Bowman Member since September 2015 Ian Davis Member since September 2016 Melody Meyer Member since May 2017 Cynthia Carroll Member from September 2016 to May 2017 Andrew Shilston Member from September 2015; retired May 2017 Meetings and attendance Carl-Henric Svanberg and Bob Dudley attend all committee meetings. The executive vice president, regions and the vice president, government and political affairs attend meetings as required. The committee met three times during the year. All directors attended each meeting that they were eligible to attend except that Cynthia Carroll was unable to attend the meeting on 1 February 2017. Activities during the year The committee developed and broadened its work over the year. It discussed BP's involvement in the key countries where it has investment or is considering investment in detail. These included Angola, the US, Russia, Mexico, Brazil, India, Mauritania and Senegal. It considered broader policy issues such as the US domestic and foreign policy under the new administration and the political and economic impact of a low price on producing countries. We reviewed the geopolitical background to BP's global investments and the politics around climate change. Committee evaluation The committee reviewed its performance by means of an internally facilitated questionnaire, and discussed the outcome of that evaluation at its meeting in January 2018. The evaluation concluded that the committee was working well and considering the right issues, but stressed the importance of considering the geopolitics in a country before an investment is made. The committee currently meets three times a year and is considering additional meetings. The committee and board felt that there should be greater integration between the work of the board, the committee and the international advisory board. Chairman's introduction The chairman's and the nomination committees were actively involved in the evolution of the board in 2017. In October, I announced that I would be standing down as chairman at an appropriate time after the R018 AGM in May. As a result, the board has started the search for my successor. This is being carried out by the chairman's committee led by Ian Davis, the senior independent director. The nomination committee continues to focus on board renewal and diversity. Carl-Henric Svanberg Chair of the committees Chairman's committee 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 group chief executive. • Review the structure and effectiveness of the business organization. • Review the systems for senior executive development and determine succession plans for the group chief executive, 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. Members The committee comprises all non-executive directors. Directors join the committee immediately on their appointment to the board. The group chief executive attends meetings of the committee when requested. Chairman's and nomination committees BP Annual Report and Form 20-F 201788

Meetings and attendance The committee met 10 times in 2017. All directors attended all the meetings for which they were eligible, except that Cynthia Carroll was unable to attend the meeting on 1 February, as was Paula Reynolds for the 19 May 2017 meeting. Nils Andersen did not attend the meetings where succession was discussed. The chairman did not attend the meeting on 2 February when the committee, led by Andrew Shilston, the then senior independent director, carried out an evaluation of the chairman. Bob Dudley and Brian Gilvary joined meetings where the chairman's succession was discussed. Matters relating to the business of the nomination committee were also discussed at some meetings. Activities during the year • Evaluated the performance of the chairman and the group chief executive. • Considered the composition of and the succession plans for the executive team. • Determined the process for the search for a new chair and appointed advisers to support the committee. • Commenced the search for the new chair. • Discussed the strategy options for the company, including the lower carbon transition. Nomination committee Role of the committee The committee ensures an orderly succession of candidates for directors and the company secretary. Key responsibilities • Identify, evaluate and recommend candidates for appointment or reappointment as directors. • Identify, evaluate and recommend candidates for appointment as company secretary. • Keep the mix of knowledge, skills and experience of the board under review to ensure the orderly succession of directors. • Review the outside directorship/commitments of non-executive directors. Members Carl-Henric Svanberg Member since September R009 and chair since January R010 Alan Boeckmann Member since April 2016 Ann Dowling Member since May 2015 John Sawers Member since April 2016 Ian Davis Member since August 2010 Andrew Shilston Member between May 2015; retired May 2017 Andrew Shilston left the committee when he stood down from the board in May 2017. Meetings and attendance The committee met three times in 2017. During the second half of the year, matters relating to the appointment of new directors were considered jointly with the chairman's committee. All directors attended each meeting that they were eligible to attend. Activities during the year The committee monitored the composition and skills of the board. Paul Anderson will be retiring from the board at the 2018 AGM. The committee focused on ensuring that the board's composition is strong and diverse. As a result, the board is proposing Dame Alison Carnwath for election as a director at the 2018 AGM. Committee evaluation The committee generally continues to work well. Its balance of skills and experience needs to be maintained so that it is able to govern the company as it implements its strategy in the transition to the lower carbon world. It expressed a need to ensure that the board maintains strong former executive membership and this will be a focus in forthcoming appointments. C orporate governance BP Annual Report and Form 20-F 2017 89

We have made our decisions in a considered way, applying discretion where necessary, as we transition to the new policy. Professor Dame Ann Dowling Chair of the remuneration committee Directors' remuneration report Dear shareholder, Last year, we introduced a new remuneration policy. This followed extensive consultation with major shareholders and with their representative bodies. They were clear that they wanted our policy to be simple and transparent, with a strong link between pay and performance, and deliver reduced levels of reward. We listened and responded to those concerns. We were pleased to receive strong support for this policy at the 2017 AGM. It is clear to us that you, our shareholders, expect us to implement this policy in a considered way and to be ready to apply discretion when necessary. 2017 has been a transitional year as we have moved from the old policy to the new. We applied the new policy from the start of 2017 (see panel opposite). Therefore salary, the R017 annual bonus and long-term awards made in 2017, based on performance over the three-year period 2017-19, are all made under the new policy. However, the long-term awards granted under the 2015-17 plan were under our old policy and are based on measures in that policy. The committee scored the safety, operational and financial performance against targets set in 2015, before reviewing the result to see if discretion should be applied. Business performance over the period, and in particular for 2017, has been strong, reflected in the company's first place ranking for TSR among our peer group of major oil and gas companies. However, while returns, which have been explicitly included in the new policy through a ROACE measure have more than doubled over the last two years, there is room for further improvement and the company has continued to incur costs from the Gulf of Mexico oil spill payments. Taking these factors into account, the committee chose to reduce the level of payment for these long-term performance shares by 26%. In applying this reduction, the committee acted in accordance with the messages we received from shareholders and the principles that govern our new policy. In 2015 Bob Dudley received a maximum performance award of 550% of salary for the period 2015-17. In the spirit of applying the new policy early, he requested a reduction in his maximum award to 500% in line with the 2017 policy. The committee appreciates this request which, together with the committee's discretion, has reduced his payment by $4.2 million (24%) from the formulaic outcome. We believe that the outcome for executive directors, representing an increase on 2016 but moderated by discretion, fairly reflects management's performance and the experience of shareholders over this longer period, and is consistent with the aims of the policy approved by shareholders last year. Business performance 2017 has been one of the strongest years of operational delivery for BP. This has been reflected in our financial results, with a doubling of our underlying replacement Contents

93 Summary of pay and performance 94 Summary of policy approach 95 Single figure table 96 Alignment with strategy 98 Pay and performance for 2017 102 Implementation of policy for 2018 105 Stewardship 107 Non-executive directors 108 Executive directors' interests 110 Policy summary tables

More information Key performance indicators For an overview of the group's KPIs, with those featuring in the current and previous remuneration policies, see page 18. Key outcomes for 2017 Bob Dudley (GCE) – total pay $13.4m $19.4m 2015 $11.9m 2016 $17.6m 2017 Formulaic outcome -$0.8m GCE request for 2017 policy vesting (550% to 500%) -$3.4m Impact of committee discretion 2017 single figure outcome Discretion used to reduce outcome for performance. Total pay reduced by $4.2 million (24%) due to GCE request and committee discretion. First among peers for total shareholder return. Seven major projects delivered in the year.

Directors' remuneration report cost profit over the year to $6.2 billion and an underlying operating cash flow of $24.1 billion, excluding post-tax oil spill related payments. Over the year BP distributed $7.9 billion in dividends. Following consistent strong progress and the board's confidence in the growing organic free cash flow, we recommenced a share buyback programme in the fourth quarter to offset dilution from the scrip dividend paid to shareholders electing to receive shares rather than cash. Our TSR for the period 2015-17 was first among our peer group of major oil and gas companies. TSR on the UK shares has been 44% over the three-year period, significantly out-performing the UK market. Seventeen major projects have been delivered over the three-year period. This has contributed to a 10% increase in BP's reported production since 2016 and places us in a strong position for further growth. We have had our most successful year of exploration since 2004. The downstream business had an excellent year in terms of replacement cost profit, driven by strong earnings growth in our marketing and manufacturing businesses. Our Alternative Energy business grew and BP re-entered solar but in a new way, partnering with Lightsource to combine our scale, relationships and expertise in major projects with Lightsource's expertise in developing solar projects. Overall this has been a year of disciplined execution and growth across the business and BP has made a good start in delivering the company's five-year strategy out to 2021. Committee process for 2017 In order to gain a comprehensive perspective on performance, the remuneration committee sought the views of the board, audit committee and safety, ethics and environment assurance committee (SEEAC) to evaluate the group's performance against financial, operational and strategic measures for the purposes of executive remuneration. Incentive outcomes in 2017 2017 was a year of strong performance and achievements, where all targets were met or exceeded for the annual bonus, leading to a formulaic result of 1.54 out of 2. The audit committee and the SEEAC recommended an exercise of downward discretion. This resulted in the remuneration committee reducing the final bonus score to 1.43 out of 2. This results in a bonus of 71.5% of the maximum, half of which will be delivered as shares and held for three years. For the performance share award made in 2015, the measures are relative TSR, and various financial, safety and operational measures assessed over the three years from 2015 to 2017. The formulaic results led to an outcome of 96% of maximum, reflecting the fact that BP came in first place against the peer group on relative TSR and performed strongly against the other targets set. This outcome was considered by the committee and reviewed with the executive directors in the context of the overall levels of pay, the wider performance of the company, and the experience of shareholders over Performance assessed against safety, operational and financial measures. Determined outcomes against targets set. Sought input from the SEEAC and audit committee to ensure a holistic review of performance. Annual bonus scores reduced following the committees' review. The remuneration committee considered outcomes in the context of BP's group leaders and the broader comparator group of US and UK employees in professional and managerial roles. The committee used judgement to reflect the broader market environment and outcomes for shareholders. Downward discretion exercised for final outcomes. Assess performance Review outcomes with committees Alignment with employees Apply discretion 4321 How did we determine 2017 outcomes? Simplification • Reduction to two incentive plans – a short-term annual bonus and a long-term performance share plan – deferred shares no longer matched with additional shares. • Maximum bonus only earned where stretch performance is delivered on every measure. • Fewer measures. Eliminated duplication of measures between bonus and long-term incentives. Transparency • Total shareholder return (TSR) and return on average capital employed (ROACE) targets disclosed at the start of the three-year performance period. For awards granted in 2017 and 2018, these determine 80% of the available performance shares. • The group's quarterly results announcements now include updates on all of the KPIs on which remuneration is based other than TSR, with commentary on progress on our strategic priorities which, for awards granted in 2017 and 2018, determine 20% of the available performance shares. Reduced package • The level of bonus paid for an 'on-target' score reduced by 25%, and the mandatory bonus deferral increased to 50% of bonus with no matching shares. Bonus scale for executive directors now aligned with the wider managerial population. • The maximum longer-term incentives for the group chief executive (GCE) reduced from seven times salary (previously made up of matching shares on the deferred annual bonus and performance shares) to a maximum of five times salary. Link to strategy and shareholder outcome • Straightforward use of TSR and ROACE as measures of longer- term performance. • Performance shares vest based in part on strategic priorities which include BP's progress towards a lower carbon future. Stewardship • No change to the six-year period for performance shares (three-year holding period after three-year performance period), nor to the minimum shareholding requirement of 5x base salary. There is a new post-retirement holding expectation of 2.5x base salary. • Safety and the environment remain important considerations through bonus measures and the underpin on long-term incentives. • Remuneration committee has the responsibility of balancing the outcomes from quantitative results with discretion to adjust final results based on the broader environment and performance. For the full policy see bp.com/remuneration A summary of the 2017 policy is set out on page 110, including the following changes to the 2014 policy:

Directors' remuneration report the three-year period of the plan. In addition, the committee decided to incorporate early application of some of the principles of the new 2017 policy, for example the more stringent vesting scales. In light of these factors and an overall assessment of pay relative to performance, the committee applied its discretion to reduce the 2015 performance share award vesting from 96% to 70% of maximum. The exercise of committee discretion on annual bonus and performance share outcomes reduced the amount of variable pay by $3.4 million for Bob Dudley and £1.2 million for Brian Gilvary. Consistent with the approach of applying certain aspects of the new policy early, Bob Dudley has requested that his performance share vesting should be based on an award level of 500% of salary (from the R017 policy), rather than the 550% of salary that applied for the 2014 policy. Furthermore, demonstrating their commitment to delivering long-term sustainable value for BP shareholders, the executive directors have also voluntarily agreed to the extension of vesting periods for certain share awards under a discontinued plan as a transitional approach to the new policy. These share awards remain subject to continued application of a safety underpin. Following these decisions, the total reported single figure of pay for Bob Dudley and Brian Gilvary was $13.4 and £6.5 million. These are substantially below formulaic outcomes for 2017 but, because the business performance is much improved, are higher than the single figure outcomes for 2016. The committee believes that these outcomes appropriately reflect the strong operational and financial performance of BP this year and over the past three years whilst demonstrating a commitment to a considered approach. This year's single figure for Brian Gilvary is substantially affected by the inclusion of deferred bonus shares from 2014 which have now vested, and the 2017 bonus shares that are being deferred but we now report in the year the shares are granted. Implementation of the policy for 2018 We plan to make two changes to the performance measures in 2018. For the annual bonus, the upstream measure for 'reliable operations' will be changed from 'upstream operating efficiency' to 'BP-operated upstream plant reliability', creating comparability between our upstream and downstream measures. For performance shares granted in 2017, the ROACE target was based on the final year of the performance period. In response to investor feedback, we are moving progressively towards a three-year evaluation period to encourage steady and sustainable growth. For the 2018 awards, we will average ROACE over the final two years (2019 and 2020) and then use a three-year average for 2019 awards onwards. We reviewed base salaries for the Bob Dudley and Brian Gilvary, noting the salary increases for UK and US-based employees across the group. The committee has decided there should be no increase in annual salary for Bob Dudley. Brian Gilvary's salary will be increased by 2%, which was below the general increases for the UK and US based employees across the group. Alignment with strategy and the low carbon transition In 2017 BP announced details of our five-year strategy to 2021, focusing on strategic and investment choices that are resilient to a range of future outcomes whilst considering the dual challenge of meeting society's need for more energy while working to reduce carbon emissions. To reinforce the importance of the strategy for the group's long-term success, the 2017 policy introduced a balanced but stretching set of measures into the incentives to reflect BP's strategy. During the year we have included updates on our strategic progress in our quarterly results announcements. We also introduced an underpin for performance shares which includes absolute TSR, safety performance and consideration of issues around carbon and climate change. This framework will allow the committee to monitor progress against the broader approach we outlined in February R018 – reducing our emissions, improving our products and creating low carbon businesses. See 'Advancing the energy transition' on page 96. Wider workforce pay During the year the committee reviewed the group's approach to reward below board level across job levels and geographies. This wider environment provided important context for the committee's decisions on executive directors' remuneration. Last year, we voluntarily disclosed the GCE-to-employee pay ratio, using the employee comparator group of the professional/managerial grade employees based in the UK and US (representing some 30% of the global employee population). We are aware that regulations will be introduced to require companies to calculate and disclose a ratio. As the regulatory methodology is not yet final, we have continued the practice we adopted in 2017. Work undertaken by the group in preparation for UK regulatory requirements on gender pay gap reporting was reviewed with the committee, who considered the distribution of employees by grade and gender. In that context the committee received assurance that there was equal pay for equal or like work. Committee changes There have been changes to the membership of the committee during the year: Andrew Shilston retired from the board at the AGM in May R017, with Brendan Nelson and Paula Reynolds joining the committee during 2017. The chairs of both audit committee and SEEAC are now members of the remuneration committee which strengthens the committee's ability to take a wider perspective on the group's performance when discussing reward. I believe that we have a broad range of skills and experience amongst the membership upon which to draw on when looking at issues around remuneration. Following six years on this committee, the last three as chair, I have decided to step down from the committee following the AGM in May R018. Paula Reynolds will take the chair. I want to take the opportunity to thank my fellow committee members for their support and welcome Paula to the role of chair. I would also like to thank the executive directors for their positive engagement in the policy changes and exercise of discretion over the last two years. Conclusion The board continues to place a high priority on building confidence in the operation of our remuneration policy. This requires the remuneration committee to exercise discretion to align pay outcomes to performance, particularly as we navigate the transition from the pre-2017 policy to our new policy for the future. We have sought to do this in a considered way that reflects shareholder expectations, the performance of BP, and the commitments made to executives. In putting this report forward for an advisory vote at the AGM, we seek your support for the balance we have struck. Professor Dame Ann Dowling Chair of the remuneration committee R9 March 2018

Directors' remuneration report Summary of our pay and performance for 2017 2017 2016 2015 $13.4m $11.9m $19.4m 2014 $16.4m Bob Dudley, group chief executive Total remuneration 2017 2016 2015 2014 Brian Gilvary, chief financial officer Total remuneration £6.5m £ 4.2 m £ 5 .1m £ 3 .6m 2017 We have made good progress, with strong cash flow and share price growth and the announcement of a number of major investments, all aimed at contributing to returns over the medium and long term. $24.1bn Operating cash flow, excluding Gulf of Mexico payments. 1st Among peers for total shareholder return for R015-17. Bob Dudley, group chief executive Brian Gilvary, chief financial officer Business performance Remuneration outcomes Share ownership Key strategic highlights • Underlying replacement cost profit up 139%. • Organic cash flows back in balance. • Seven new major projects delivered. a The final outcome for part of this award is based on the company's relative RRR ranking, presently forecast to be second amongst its peers: this will not be known until after the publication of our peers' reports and will therefore be reported in the directors' remuneration report for 2018. Salary and benefits Retirement benefits Annual bonus Performance shares Discontinued plans $7.9bn Dividends paid, including scrip. Policy requirement: minimum of five times salary 3,065,694 sharesb 10.71 times salary 11.17 times salary1,825,299 shares bHeld as ADSs. Shareholding is a key means by which the interests of executive directors are aligned with those of shareholders. As at 14 March 2018 both directors had holdings in BP which significantly exceeded their shareholding requirement. Further details are set out on page 105. Annual bonus Performance shares Nil NilPerformance measures (% weighting) Performance measures (% weighting) Maximum Maximum Performance outcomes 77% Formulaic outcome (% of maximum) -5.5% Committee discretion to reduce award 71.5% Final outcome after committee discretion (% of maximum) 96% Formulaic outcome (% of maximum) -26% Committee discretion to reduce award 70% Expected outcome after committee discretiona (% of maximum) Financial Relative TSR (33.3%) Cumulative operating cash flow (33.3%) Reserves replacement ratioa (11.1%) Major project delivery (11.1%) Safety and operational risk – Tier 1 process safety events – Recordable injury frequency Strategic imperatives (11.1%) Safety Tier 1 process safety events (10%) Recordable injury frequency (10%) Refining availability (15%) Upstream operating efficiency (15%) Financial Operating cash flow (excluding Gulf of Mexico oil spill payments) (20%) Underlying replacement cost profit (20%) Upstream unit production costs (10%) Reliability Reduction in total remuneration BP Annual Report and Form 20-F 2017 93 C orporate governance $3.4 million Reduction due to committee discretion $0.8 million Bob Dudley's voluntary performance share reduction £1.2 million Reduction due to committee discretion

Summary of our remuneration policy and approach for 2018 Directors' remuneration report 2018 Competitive salary and benefits to reflect role and home country norms • Continuing requirement for directors to maintain a holding of five times salary. • It is expected that Bob Dudley and Brian Gilvary will maintain a holding of at least 250% of salary for two years following retirement. • In addition the executive directors have voluntarily agreed to extend the vesting periods of certain discontinued share awards, subject to a continued safety underpin. Share ownership Long-term shareholding Bonus aligned with annual objectives Share award for meeting three-year targets Fixed pay policy is unchanged. Salary and benefits are set at a level which reflects the scale and complexity of the role while recognizing competitive practice in the relevant market. • From September 2016, Bob Dudley has no further service accrual under the defined benefit pension arrangements. The T01(k) benefits have been partially capped for future years. • Brian Gilvary receives a cash supplement on the same terms as other participants in the BP UK defined benefit scheme. He receives no further service accrual under the defined benefit pension arrangements. The bonus links variable pay to safety, reliable operations and financial performance for the year. Stewardship and alignment with shareholders • The salary for the group chief executive will remain at $1,854,000 for 2018. Bob Dudley has not received a salary increase since July 2014. • With effect from the AGM, the salary for the chief financial officer will be £775,000. • The increase to Brian Gilvary's salary continues to reflect the changes to his role when he took on additional responsibilities for BP's trading and shipping functions. This increase of 2% is within the range used by the company for other UK and US employees. • Benefits will remain unchanged – these include car-related benefits, security assistance, insurance and medical benefits. • Maximum bonus only payable for outperformance on every measure. • Bonus payable for delivery of bonus scorecard of 1.0 out of 2.0 is half of maximum. • 50% of any bonus earned will be paid in cash; there will be a mandatory deferral of 50% into shares for three years. • Awards will be subject to clawback and malus provisions. • The measures for the bonus are set annually to reflect annual priorities. • For 2018, performance judged on three key areas: – safety (20%) – reliable operations (30%) – financial performance (50%). • Overall discretion to review outcomes in the context of annual performance. Directly linked to long-term performance and represents the largest part of the package. • Three-year performance period, with further three-year holding period. • Measures aligned to long-term strategy and shareholders' interests. • Awards will be subject to clawback and malus provisions. • For 2018 awards, performance judged on three key areas: – TSR relative to oil and gas majors over three years (50%) – ROACE based on the average of performance over 2019 and 2020 (30%) – strategic progress assessed over the performance period (20%). • Additional underpin – broader performance including absolute TSR performance and safety and environmental factors (including consideration of issues around carbon and climate change) to be considered before determining vesting outcomes. Elements of package BP's policy approach Salary and benefits Retirement benefits Annual bonus Performance shares Share ownership Approach Salary and benefits Retirement benefits Annual bonus Up to 225% of salary Performance shares GCE – 500% CFO – 450% of salary ar rship Simplification. Reduced package versus previous policy. Link to strategy. Stewardship. ? Annual Report and Form 20-F 201794

Directors' remuneration report Single figure table – executive directors' (audited) Bob Dudley (thousand) Remuneration is reported in the currency in which the individual is paid Brian Gilvary (thousand) 2017 2016 2017 2016 Salary and benefits Salary $1,854 $1,854 £752 £732 Benefits $73 $74 £38 £67 Retirement benefits Pension and retirement savings – value increasea $746 $2,205 £186 – Cash in lieu of future accrual – – £263 £256 Annual bonus Cash bonus $1,491 $1,696 £611 £669 Shares – deferred for three years $1,491 – £611 – Performance shares Performance shares $7,787b $4,024c £2,981b £1,455c Total remuneration (excluding discontinued plans)d $13,443 $9,852 £5,440 £3,179 Discontinued plans Deferred share awards from prior-year bonusese –f $2,052 £1,040 £1,065 Total remunerationd $13,443 $11,904 £6,481 £4,244 a Represents (1) the annual increase net of inflation in accrued pension multiplied by 20 as prescribed by UK regulations, and (2) the aggregate value of the company match and investment gains on the accumulating unfunded BP Excess Compensation (Savings) Plan (ECSP) account under Bob Dudley's US retirement savings arrangements. Full details are set out on page 101. b Represents the assumed vesting of shares in 2018 following the end of the relevant performance period, based on a preliminary assessment of performance achieved under the rules of the plan and includes reinvested dividends on shares vested. In accordance with UK regulations, the vesting price of the assumed vesting is the average market price for the fourth quarter of 2017 which was £5.01 for ordinary shares and $39.85 for ADSs. The final vesting will be confirmed by the committee in second quarter of 2018 and provided in the 2018 directors' remuneration report. Bob Dudley has requested that the EDIP performance share vesting in respect of the performance period 2015-17 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 applies under the 2014 directors' remuneration policy. c In accordance with UK regulations, in the 2016 single figure table, the performance outcome value was based on an estimated vesting at an assumed share price of £4.73 for ordinary shares and $35.39 for ADSs. In May 2017, after the external data became available, the committee reviewed the relative reserves replacement ratio position. This resulted in no adjustment to the final vesting of 40%. On 19 May 2017, 108,923 ADSs for Bob Dudley and 308,286 shares for Dr Brian Gilvary vested at prices of $36.94 and £4.72 respectively. This total includes the additional accrual of notional dividends which vested on 2 August 2017. The 2016 values for the total vesting have increased by $310,709 for Bob Dudley and by £67,820 for Dr Brian Gilvary. d Due to rounding, the total does not agree exactly with the sum of its component parts. e Value of vested deferred bonus and matching shares. The amounts reported for 2017 relate to the 2014 annual bonus deferred over three years, which vested on 20 February 2018 at the market price of £4.75 for ordinary shares and include reinvested dividends on shares vested. There was an additional accrual of notional dividends on 29 March 2018 which will vest in 2018 and will be provided in the 2018 directors' remuneration report. The amounts reported for 2016 relate to the 2013 annual bonus and have been adjusted from the number provided in the 2016 directors' remuneration report to include the accrual and vesting of notional dividends. f As stated in the 2016 directors' remuneration report, Bob Dudley has voluntarily agreed to defer vesting of these awards until after retirement, therefore the performance period is expected to exceed the minimum term of three years. BP Annual Report and Form 20-F 2017 95 C orporate governance Key outcomes for 2017 Bob Dudley (GCE) – total pay $13.4m $19.4m 2015 $11.9m 2016 $17.6m 2017 Formulaic outcome -$0.8m GCE request for 2017 policy vesting (550% to 500%) -$3.4m Impact of committee discretion 2017 single figure outcome Discretion used to reduce outcome for performance. Total pay reduced by $4.2 million (24%) due to GCE request and committee discretion. First among peers for total shareholder return. Seven major projects delivered in the year.

Alignment with strategy Directors' remuneration report How we align our strategy and remuneration measures 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 Safer Fit for future Focused on returns Element of remuneration BP set out an update of its strategy in 2017, which was reinforced in the results announcement in February 2018. The foundations for strong performance are safe and reliable operations, a balanced portfolio, and a focus on returns. Annual bonus Safety Reliable operations Financial performance Performance shares Total shareholder return Return on average capital employed Strategic priorities Underpin: absolute TSR and safety/environmental factors Low carbon transition BP's ambition is to provide more energy while advancing the energy transition. The focus on lower carbon has three main elements: Strategic priorities The strategic priorities component of the performance shares covers measurement across a range of objectives including: growing gas and advantaged oil in the upstream; market-led growth in the downstream; venturing and low carbon across multiple fronts; and gas, power and renewables trading growth. These priorities are aimed at growing sustainable value for our shareholders and increasing the proportion of lower carbon activities in our portfolio over time. The seven major project start-ups in 2017 (see page 14) have enabled a significant shift in the proportion of gas in our portfolio, laying a strong foundation for our gas business moving forwards. Progress against each of the strategic priorities is being monitored against a balanced set of measures that will be viewed in the round relative to strategy. For example, 'growing gas and advantaged oil in the upstream' will be assessed against a range of measures including the proportion of gas in the portfolio and the movement of unit production costs per barrel (which reflect how 'advantaged' the barrels are). Reducing our emissions in our operations Creating low carbon businesses More information Advancing the energy transition In this report, we examine how the energy world is rapidly changing, set out our low carbon ambitions and the changes we are making across our entire business to help advance the energy transition. Publishes April, see bp.com/energytransition Improving our products Reducing our emissions through operational emission reduction activities. Improving our products to enable customers to lower their emissions. Creating low carbon businesses to grow value and complement our existing portfolio. BP Annual Report and Form 20-F 201796

Directors' remuneration report The committee believes that BP's strategic priorities can help advance the energy transition. The measures related to our lower carbon activities – gas, venturing, renewables trading and renewable energy – underscore this commitment. These activities should grow over time. Our performance share plan features an underpin which will be applied after the formulaic outcome but before the final vesting outcome has been determined. This underpin takes into account absolute TSR, safety and environmental factors (including consideration of issues around carbon and climate change). In this regard, the committee will consider progress on matters such as reducing emissions, improving our products and creating low carbon businesses. Remuneration in the wider group During the year the committee has received detailed information on pay below the board by region and job level, including the cascade of pay mix and incentive structures, typical salary budgets, and approaches across different sectors of the group's business. This context has informed decision making on executive director pay, for example in relation to bonus outcomes, which are largely aligned across the group, and salary increases. UK gender pay gap The committee reviewed the data and methodology for the group's reporting against the UK gender pay gap regulations. These require the company to publish the difference in mean and median pay, mean and median bonus pay, proportion of male and female employees who received bonus pay and the number of male and female employees in quartile pay bands. The committee also looked at factors such as: • The uneven gender distribution of employees within BP job grades. • How certain roles with specific pay practices such as allowances (e.g. offshore/rotator allowances) and bonus structures (e.g. trading bonuses) have a disproportionally higher number of men and contribute to the pay and bonus gap. • How the gender pay gap analysis does not take grades and roles into consideration (as when analysing by internal grade, BP's pay gap falls significantly). The committee was assured that the group provides equal pay for equal or like work. Finally the committee and the board considered BP's initiatives to support long-term growth in female talent, including developing the technical talent pool, hiring, retention and progression. BP's gender pay gap in 2017 report was published on 21 February 2018 and can be found at bp.com/ukgenderpaygap. a Total remuneration reflects the reduction in number of employees and the total overall employee costs. See Financial statements – Note 33 for further information. b Capital investment is illustrated to reflect the overall scale of BP investment decisions. BP changed its reporting of organic capital expenditure to a cash basis in 2017; the 2016 number has been restated to be reported on a cash basis. GCE-to-employee pay ratio The committee commenced reporting on the GCE-to-employee pay ratio in 2017. The committee notes that regulations will be published during R018, setting out a methodology for the calculation of such a ratio. As the regulatory methodology to be used is not yet final, the committee has continued with the approach we used in 2017 and the comparator group which it believes is the most relevant for BP. This group is the professional/managerial grade employees based in the UK and US which represent some 30% of the global employee population and is used elsewhere in this report. The GCE-to-median worker pay ratio for this group was 92 to 1 in 2017 (71 to 1 in 2016). The ratio is based on a comparison of total compensation (base salary, actual annual bonus and vested equity awards) in the year. Percentage change in GCE remuneration Comparing 2017 to 2016 Salary Benefits Bonus % change in GCE remuneration 0% -0.6% 75.8% % change in comparator group remuneration 4.3% 0% 22.9% The comparator group used here is the same as that used in the pay ratio calculation above, and comprises some 30% of BP's global employee population being professional/managerial grades of employees based in the UK and US and employed on more readily comparable terms. Relative importance of spend on pay ($ million) Distributions to shareholders Remuneration paid to all employeesa Capital investmentb 2017 2017 20172016 7,469 11,233 16,501 16,675 7,867 10,204 2016 2016 BP Annual Report and Form 20-F 2017 97 C orporate governance

Pay and performance for 2017 Directors' remuneration report Base salary No salary increase was awarded to Bob Dudley for 2017 and his salary remained at $1,854,000. Bob Dudley has not received a salary increase since 2014. As was disclosed in the 2017 report to shareholders, Brian Gilvary's salary was increased with effect from May 2017 to £759,000 reflecting his additional responsibilities for BP's trading and shipping functions. Benefits Executive directors received car-related benefits, security assistance, insurance and medical benefits. Salary and benefits The targets for the 2017 annual bonus were set at the start of the year based on a combination of safety, reliability and financial performance. Targets were set in the context of the group's strategy and the annual plan. During 2017 BP's share price performed strongly. The group distributed $7.9 billion to shareholders in cash and scrip dividends. In the fourth quarter, the group commenced a share buyback programme to mitigate the dilutive effects of issuing shares under the scrip dividend programme. Overall it was one of the strongest years in BP's recent history. There was delivery of the group's strategy, particularly the delivery of seven major projects within the year and below the total budget. There were strong earnings in the downstream and a 10% year-on-year increase in production for the BP group as a whole. The group's operating cash flow was strong and well above plan. Underlying replacement cost profit was $6.2 billion, an increase of Q39% on 2016. Goals for reduction in controllable costs were delivered, together with good discipline on capital expenditure. Operational reliability was high and safety outcomes were above target. When reviewing performance over the period, the committee sought input from the chairs of the audit committee and the SEEAC to ensure a comprehensive review of performance. Following input from the audit committee on the treatment of certain accounting items for which it would not be appropriate for participants to benefit, for example a gain from a legal settlement, the formulaic score under the bonus was reduced from 1.54 to 1.49. In addition, the SEEAC recommended an exercise of downward discretion to the safety element for executive directors after taking a longer term view of safety performance to date. Following SEEAC's recommendation on the safety component of the scorecard, the remuneration committee exercised its discretion to reduce the score by 0.06, resulting in a final annual bonus scorecard outcome of 1.43 out of 2, a payout of 71.5% of maximum. Overall, the committee believes that the bonuses for 2017 fairly reflect performance over the period. Outcome

Name	Adjusted outcome after committee discretion (thousand)	Paid in cash (thousand)	Deferred into BP shares (thousand)
Bob Dudley	$2,983a	$1,491	$1,491
Brian Gilvary	£1,221a	£611	£611

a Due to rounding, the total does not agree exactly with the sum of its component parts. Under the terms of the 2017 policy, half of the bonus earned is deferred into shares that will vest after three years. Deferred bonus shares are now reported in the single figure for the bonus year to which they relate. This is different from the 2014 policy, when the shares were only reported on vesting at the end of the three-year period. For Brian Gilvary, the 2017 single figure includes both the 2017 bonus deferred to future years, and the deferred shares from the 2014 bonus vesting in the current period. Annual bonus BP Annual Report and Form 20-F 201798

2017 annual bonus Measures Weighting Threshold (0) Target (1) Maximum (2) Performance and outcome Tier 1 process safety event (defined by API) 10% 24 events 0 20 events P.1 14 events P.2 18 events P.13 Recordable injury frequency 10% 0.249/200k hrs 0 0.228/200k hrs 0.1 0.188/200k hrs 0.2 0.218/200k hrs P.12 Safety outcome 0.25 Downstream refining availability (Solomon Associates' operational availability) 15% 94.6% 0 95.1% 0.15 95.6% 0.3 95.3% P.21 Upstream operating efficiency 15% 77.3% 0 79.3% 0.15 81.3% 0.3 80.5% P.24 Reliable operations outcome 0.45 Operating cash flow (excluding Gulf of Mexico oil spill payments) 20% $19.9bn P $21.4bn P.2 $22.9bn P.4 $24.1bn P.4 Underlying replacement cost profit 20% $5.0bn P $5.8bn P.2 $6.6bn P.4 $6.2bn P.29 Upstream unit production costs 10% $7.7/bbl P $7.3/bbl P.1 $6.9/bbl P.2 $7.11/bbl P.15 Financial performance outcome 0.84 1.54 out of 2.0 Directors' remuneration report T1 Safety 0.25 Reliable operations P.45 Financial performance P.84 Formulaic score Q.54 out of 2.0 2 3 Scorecard Annual bonus – continued More information Key performance indicators page 18REM Measures used for the 2017 remuneration policy. Safety (20% weight)1 Financial performance (50% weight)3 Reliable operations (30% weight)2 Formulaic score4 71.5% outcome of maximum bonus Formulaic scorecard outcome 1.54 out of 2 Audit committee Discretion - 0.05 SEEAC Discretion - 0.06 1.43 out of 2 Final scorecard outcome For performance shares awarded in 2015, vesting was determined under the terms of the 2014 policy, by a combination of relative TSR, safety, financial and operational performance assessed over the three years from 2015 to 2017. The results are summarized in the table on page 100. TSR – the company's TSR over the three-year period was in first place. The TSR element is measured on a relative basis in common currency against the oil majors: Chevron, ExxonMobil, Shell and Total. Cumulative operating cash flow – under the 2014 policy, the outcome was measured by taking the cumulative operating cash flow for the three years. This measure was assessed by adjusting the target to the actual oil price as has been the case in previous years. Against this adjusted target, this element of the performance shares achieved maximum score of 33.3%. Without adjustment, the score would reduce from 33.3% to 32.4%, a reduction of 0.9%. Safety and operational risk – assessed through a look-back over tier 1 process safety events and recordable injury frequency (RIF) over the three-year period. The committee sought input from the SEEAC in making this subjective assessment. The SEEAC noted the reduction in tier 1 events, the trend in RIF and the high annual scores for both safety measures throughout the three-year period and recommended a score of 85% of maximum for this element of the performance shares. Performance shares BP Annual Report and Form 20-F 2017 99 C orporate governance

The committee's discretion and Bob Dudley's request together reduced the vesting value of his performance shares by $4.0 million Directors' remuneration report Project delivery – the vesting outcome reflects the strong progress over the three-year period with 17 projects delivered, seven within 2017. Further details of these projects are set out on page 14. Relative reserves replacement ratio – preliminary assessment indicates vesting for this measure. For the purpose of this report, a forecast of second place has been used. The final outcome for this measure will be confirmed later in the year, once competitor data is published in full. Contextual review The committee undertook a wider review of performance over the three-year performance period, in the context of the overall levels of pay, the wider performance of the company, and the experience of shareholders over the three-year period of the plan. While performance over the period, and in particular in 2017, has been strong, we also recognize that although returns have doubled over the past year, there is still room for further improvement and that the company has continued to Scorecard 1 Financial 66.6% 2 3 Strategic imperatives 29.4% Formulaic vesting 96.0% More information Key performance indicators page XX More information page 18These measures were used under the terms of our previous policy. 1 Financial Strategic imperatives2 Total formulaic vesting3 Performance shares – continued REM incur costs associated with Gulf of Mexico oil spill payments. The committee also sought where appropriate to apply principles of the new policy early to awards vesting in respect of 2017 performance. This included, for example, consideration of the more stringent vesting scales adopted in the 2017 policy. In light of these factors and an overall assessment of pay relative to performance, the committee determined that it would be appropriate to exercise downward discretion on this part of the award. It also determined that the vesting for the 2017 award should be reduced from the formulaic outcome of 96% of maximum to 70% of maximum. In addition, consistent with the approach of applying the principles of the 2017 policy to awards vesting in the year, Bob Dudley asked the committee to base his performance shares award on 500% of salary that applies under the terms of the 2017 policy, rather than the U50% of salary that was actually granted in 2015. The committee's discretion and Bob Dudley's request together reduced his performance shares by $4.0 million (34%). BP Annual Report and Form 20-F 2017100 2015-17 performance shares Measures Weighting at maximum Threshold performance Maximum performance Performance and outcome Relative total shareholder return 33.3% Third First First S3.3% Cumulative operating cash flow 33.3% $45.6bn $61.6bn $61.9bn S3.3% 66.6% Relative reserves replacement ratio 11.1% Third First Second 8.9% Major project delivery 11.1% 10 14 17 Q1.1% Safety and operational risk: – Process safety tier 1 events – Recordable injury frequency 11.1% Continuous improvement look back 85% of maximum 9.4% 29.4% 96.0% Formulaic vesting: 96% Committee review of context and shareholder experience over three-year period of plan 70% final vesting after committee discretion

Directors' remuneration report Both Bob Dudley and Brian Gilvary deferred two thirds of their 2014 annual bonus in accordance with the prevailing terms of the deferred bonus plan. The original three-year performance period for this deferred award ended on 31 December 2017. As required by the terms of the discontinued plan, the committee reviewed safety and environmental sustainability performance over this period and sought the input of the safety, ethics and environment assurance committee. This included an assessment of both actual outcomes under safety and sustainability measures and consideration of the long-term performance trend. Over the three-year period 2015-17 safety performance continued to demonstrate progress and improvement overall. The committee also noted the extent to which safety performance had become embedded into the culture of the organization and the degree to which this has supported stronger operational and financial performance. As a sign of their commitment to the long-term interests of the company, and to further align with the shareholder experience, both Bob Dudley and Brian Gilvary have requested that the committee delay the vesting of some of the awards under discontinued plans. In light of this request, the committee has approved the deferral of Bob Dudley's R014 deferred and matching awards until after his retirement from the group. The vesting of Brian Gilvary's 2014 matching award will also be deferred for a period of two years. The committee will extend the original safety and environmental sustainability performance condition for the same period. Following the committee's review, full vesting of Brian Gilvary's deferred shares in respect of the 2014 deferred bonus was approved. No further matching awards will be granted under the deferred bonus plan following approval of the 2017 remuneration policy by shareholders at the 2017 AGM. 2014 deferred bonus vesting – outcome Name Shares deferred Vesting agreed Total shares including dividends Total value at vesting Bob Dudleya 588,216 – – – Brian Gilvary 353,152 100% 219,004 £1,040,269 a Bob Dudley has voluntarily agreed to defer vesting of these awards until after retirement, therefore the performance period is expected to exceed the minimum term of three years. Discontinued plans: deferred bonus and matching shares 2017 outcomes Bob Dudley participates in the US pension and retirement savings plans described on page 104. In 2017, Bob Dudley's accrued defined benefit pension did not increase. In accordance with the requirements of the UK regulations, the value attributed to this accrued pension in the single figure table on page 95 is therefore zero. In relation to the retirement savings plans, Bob Dudley made contributions in 2017 to the ESP totalling $27,000. For 2017 the total value of BP matching contributions in respect of Bob Dudley to the ESP and notional matching contributions to the ECSP was $129,800, 7% of eligible pay. After adding the investment gains within his accumulating unfunded ECSP account (aggregating the unfunded arrangements relating to his overall service with BP and TNK-BP), the amount included in the single figure table on page 95 is $746,200. Brian Gilvary participates in the UK pension arrangements described on page 104 in common with over 4,500 UK employees employed prior to 2010. In 2017 as a result of his salary increase Brian Gilvary's accrued pension increased, net of inflation, by £9,280. This increase has been reflected in the single figure table on page 95 by multiplying it by a factor of 20 in accordance with the requirements of the UK regulations (giving £185,600). He has exceeded the lifetime allowance under UK pensions legislation and, in accordance with the policy, receives a cash supplement of 35% of base salary, which has been separately identified in the single figure table on page 95. The committee continues to keep under review the increase in the value of pension benefits for individual directors and its alignment to the broader workforce. • The BP defined benefit (DB) plan remains open for employees in the UK who were employed before 2010 (or before 2014 in the North Sea). The plan provides an inflation linked pension of 1/60th of final salary for each year of service. As of October 2017 over 4,500 active employees were members of the plan. • Currently over 800 employees have, like Brian Gilvary, elected to stop future service accrual under the DB plan and instead receive a cash allowance of 35% of base pay, reducing to 15% by April 2024. Brian Gilvary receives the same cash allowance as those 800 other employees. Retirement benefits No systemic issues identified No major incidents Safety culture and values embedded within the global organization Strong safety performance supports efficiency and financial results across the group Conclusions of the safety and sustainability assessment Performance shares – continued Preliminary outcome – 2015-17 performance shares Name Shares awarded Shares vesting including dividends Value of vested shares Bob Dudley 1,501,770 1,172,484 $7,787,248 Brian Gilvary 685,246 594,932 £2,980,609 These values are based on estimated vesting levels. As noted above, final vesting will be determined once competitor data is published in respect of relative reserves replacement (RRR). 2014-16 performance shares – final outcome Last year the committee made a preliminary assessment of third place for the relative RRR in the 2014-16 performance shares element. In April 2017 the committee reviewed the results for all comparator companies as published in their annual reports and assessed that BP was in third place relative to other oil majors and that no further adjustment was required.

2018 R017 2016 2015 2014 2018 R017 2016 2015 2014 Bob Dudley Salary increases over the last five years Brian Gilvary 3.0%3.0% Nil Nil Nil Nil Nil Nil 3.75% 2.0% Directors' remuneration report Salary with effect from AGM Increase Bob Dudley $1,854,000 Nil Brian Gilvary £775,000 2% The committee noted that salary increases for UK and US based employees across the group were generally around 3%. The committee has considered the salaries for Bob Dudley and Brian Gilvary and has decided that there will be no increase for 2018 for Bob Dudley. Brian Gilvary's salary will be increased by 2% to £775,000. Benefits for 2018 will remain broadly unchanged from prior years. Salary and benefits For 2018, the bonus measures will again focus on three areas: safety and operational risk, reliable operations and financial performance. This approach is intended to provide a balanced assessment of how the business has performed over the course of the year against stated objectives. Targets are aligned with the annual plan and strategic and operational priorities for the year. The safety element continues to focus on measures that are robust and externally comparable. In addition, the measures linked to reliable operations also require execution of good safety practices. The committee has agreed that the upstream measure for 'reliable operations' be amended from 'upstream operating efficiency' to 'BP-operated upstream plant reliability'. This latter measure is more comparable with the equivalent metric disclosed for the downstream. Although the detail of the targets is currently commercially sensitive, the committee intends to continue to provide retrospective disclosure following the year end. The targets have been agreed by the committee after consultation on the safety targets with the SEEAC and on the financial targets with the audit committee. One of the challenges faced in a commodity industry is to provide a fair assessment of underlying performance, and therefore changes in plan conditions (including oil and gas prices and refining margins) are considered when reviewing financial outcomes. The committee retains discretion to review outcomes in the context of overall performance. Awards will be subject to malus and clawback provisions as described in the 2017 policy. The maximum bonus opportunity is 225% of salary for a maximum bonus score of 2.0. In accordance with the 2017 policy, the bonus payable for performance which meets the annual plan (i.e. a bonus scorecard of 1.0 out of a maximum of 2.0) is half of maximum. For any bonus earned, 50% will be delivered in cash and 50% must be deferred into shares that will vest after three years. Annual bonus Recordable injury 10% frequency Tier 1 process safety events 10% Operating cash flow (excluding 20% Gulf of Mexico oil spill payments) Underlying replacement 20% cost profit Upstream unit production costs 10% Safety 20% 1 Reliable operations 30% 2 Financial performance 50% 3 Element Measures for 2018 annual bonus Measures include Measures include Measures include Weighting for 2018 Weighting for 2018 Weighting for 2018 BP-operated upstream 15% plant reliability Downstream refining 15% availability (Solomon Associates' operational availability) Implementation of the policy for 2018 BP Annual Report and Form 20-F 2017102

Directors' remuneration report Under the 2017 policy the measures for the performance shares focus on shareholder value, capital discipline and future growth. Shareholder value The TSR element is measured on a relative basis in common currency against the oil majors: Chevron, ExxonMobil, Shell and Total. The committee continues to believe that the current comparator group remains appropriate as it is used for benchmarking across a range of activities in other parts of the group. There will be no vesting of this element if BP's TSR is positioned below third place in the group. Capital discipline ROACE is calculated by dividing the underlying replacement cost profit (after adding back net interest) by average capital employed excluding cash and goodwill (for full definition, see the Glossary on page 289). ROACE is measured based on the actual price environment for each of the years in question; there will be no adjustments for changes to plan conditions. For the 2017-19 performance shares, this assessment will be based on the final year of the three-year period. The committee has reviewed this methodology in the light of engagement with shareholders and broader FTSE practice and has decided to move progressively to a determination of ROACE on a three-year average rather than being based on the final year. For the 2018-20 performance shares, the calculation of ROACE will be averaged over the last two years and for 2019-21 performance shares, the intention is that it will be averaged over the full three-year period. Targets for TSR and ROACE measures for 2018 – determining 80% of the performance shares available – are set out below at the start of the assessment period. Future growth Measures for the strategic element are directly focused on delivery of the company's long-term strategy, positioning the portfolio for resilience and future growth. We will be following the implementation of our strategy through the four measures relating to the strategic priorities set out below. The committee has also sought input from the board regarding the specific measures. Details of the strategic priorities targets – determining 20% of the performance shares available – are commercially sensitive and are not included in this report. However, the committee intends to provide detailed retrospective disclosure after the end of the performance period so that shareholders can understand the basis of payment. The board regularly reviews progress on the strategic priorities throughout the year and BP's quarterly results announcement includes updates on the group's strategic progress. Performance shares 25% of element Third out of five 100% of element Q1.5% return on average capital employed 0% of element V% return on average capital employed 100% of element First place Relative TSR versus oil majorsa 50% 1 Return on average capital employedb 30% 2 Strategic progress 20% 3 Element Measures for 2018 performance shares Threshold vesting Maximum vesting • Growing gas and advantaged oil in the upstream • Market led growth in the downstream • Venturing and low carbon across multiple fronts • Gas, power and renewables trading and marketing growth a Nil vesting for fourth and fifth place. Vesting of 80% for second place. b Based on the average of performance over 2019 and 2020. There will be straight-line vesting for performance between the threshold and maximum vesting level. Adjustments may be required in certain circumstances (e.g. to reflect changes in accounting standards). Operation of the performance share plan and the underpin Prior to approving vesting outcomes, the committee will additionally consider the broader performance of the business including absolute TSR performance, together with safety and environmental factors (including consideration of issues around carbon and climate change) over the three-year period as part of an underpin. The underpin will be applied after the formulaic outcome for the performance shares but before the final vesting outcome has been determined. In looking at environmental factors, the committee will consider the group's progress on issues such as reducing emissions, improving our products and creating low carbon businesses. In line with our new policy, share awards will be made at the level of U00% of salary for Bob Dudley and 450% of salary for Brian Gilvary. Performance will be measured over three years, with any vested shares being subject to a mandatory holding period for a further three years. Awards will be subject to malus and clawback provisions as set out in the policy. BP Annual Report and Form 20-F 2017 103 C orporate governance

Both executive directors exceed the share ownership requirements of five times salary. It is expected that Bob Dudley and Brian Gilvary will maintain a shareholding of at least 250% of salary for two years following retirement. Shareholding requirements Bob Dudley Bob Dudley is provided with pension benefits and retirement savings through a combination of tax-qualified and non-qualified benefit plans, consistent with applicable US tax regulations. The BP supplemental executive retirement benefit plan (SERB) is a non-qualified pension plan which provides a pension of 1.3% of final average earnings (as defined in plan rules) for each year of service, less benefits paid under all other BP (US) tax-qualified and non-qualified pension plans. Final average earnings include base salary and annual bonus. Service, including service with TNK-BP, is limited to 37 years. Bob Dudley completed 37 years of service in September 2016 and therefore will not receive any further service accrual under these arrangements. There will be no additional payment in lieu of any further service accrual. The benefit payable under the SERB is unreduced at age 60 or above. Bob Dudley is also a member of other tax-qualified and non-qualified pension plans. However, the benefits from those plans are offset against the SERB benefit and so his benefit entitlement is determined by his participation in the SERB. The BP Employee Savings Plan (ESP) is a US tax-qualified section T01(k) plan to which both Bob Dudley and BP contribute. BP matches contributions by Bob Dudley 1:1 up to 7% of eligible pay up to an IRS limit. The BP Excess Compensation (Savings) Plan (ECSP) is a non- qualified retirement savings plan under which BP provides a notional match in respect of eligible pay that exceeds the IRS limit. In common with other participants, Bob Dudley does not contribute to the ESCP. From 2017 onwards, for the purposes of both plans, eligible pay for Bob Dudley is base salary only. Under both tax-qualified and non-qualified savings plans, Bob Dudley is entitled to make investment elections, involving an investment in the relevant fund in the case of the ESP and a notional investment (the return on which would be delivered by BP under its unfunded commitment) in the case of the ECSP. Although investment returns on the ECSP relate to contributions made in previous years, UK disclosure rules for the single figure require these returns to be included in the single figure for the year. As Bob Dudley has a significant proportion of his notional ECSP investment in BP shares, an increase in the BP share price results in a contribution to the single figure through this component. Benefits payable under the ECSP are unfunded and therefore paid from corporate assets. Benefits are generally paid as a lump sum, with any pension benefit being converted to a lump sum equivalent. Retirement benefits Brian Gilvary Brian Gilvary participates in a UK final salary pension plan, the BP Pension Scheme (BPPS), along with over 4,500 other employees in service prior to 1 April 2011. The BPPS is closed to new hires but for existing participants the plan continues to provide a pension of one sixtieth of final base salary for each year of service, up to a maximum of two thirds of final base salary, and a dependant's benefit of two thirds of the member's pension. BPPS participants can elect to stop future service pension accrual and instead receive a cash allowance. On 1 April 2011 Brian Gilvary elected to stop future service pension accrual and receive the cash allowance of S5% of base salary. It has been agreed for all participants who have elected to receive the cash allowance, including Brian Gilvary, that a transition will take effect from April 2021 when the level of cash allowance will progressively reduce to 15% of base salary by 2024. Pension benefits in excess of the individual lifetime allowance set by legislation are provided to Brian Gilvary via an unapproved, unfunded pension arrangement provided directly by the company. The rules of the BPPS were amended in 2006 to introduce a normal retirement age of 65, but in common with other BPPS participants in service on 30 November 2006, Brian Gilvary has a normal retirement age of 60. If Brian Gilvary were to retire between age 55 and 60, then subject to the consent of the committee, he would be entitled to an immediate pension, with a reduction (currently 3%) for each year before normal retirement age in respect of the benefit that relates to service since Q December 2006 and no reduction in respect of the remainder of his benefit. Irrespective of this, on leaving in circumstances of total incapacity, an immediate unreduced pension would be payable as from his leaving date. Directors' remuneration report BP Annual Report and Form 20-F 2017104

Stewardship The committee places significant emphasis on executive directors having material interests in the shares of the company. Such shareholding not only provides direct alignment with the experience of shareholders, but also encourages a longer-term focus when considering the performance of BP. Executive directors are required to build a personal shareholding of five times salary within five years of their appointment. Both executive directors significantly exceed the minimum holding required. This ensures they are subject to any fluctuation in the share price and the wider shareholder experience. Post-retirement share ownership interests Given the long-term nature of the group's operations, the committee sees the merits of ensuring that executives have performance alignment beyond the timeframe of existing incentive plans. The executive directors have taken a number of steps in this respect. As reported last year, the current executive directors have indicated to the committee that they expect to maintain a shareholding of at least R50% of salary for two years following retirement. As a sign of their commitment to the long-term interests of the company, and to further align with the shareholder experience, both executive directors have requested that the committee delay the vesting of some of the awards under discontinued plans. Bob Dudley has voluntarily opted to delay the vesting of all outstanding deferred bonus and matching shares in respect of his 2014 and 2015 bonus (representing a total interest over 1,691,784 ordinary shares), which were originally due to vest in 2018 and 2019 respectively, so that vesting is delayed until after retirement. In a similar way, the vesting of Brian Gilvary's 2014 matching award will also be deferred for a period of two years. As per the original terms, the committee will extend the safety and environmental sustainability performance condition for the same period. These factors significantly extend the time horizons for both executive directors. The committee fully endorses the steps taken by both executive directors as they clearly demonstrate a continued commitment to the long-term stewardship of the group. Directors' shareholdings The table below shows the status of each of the executive directors in developing the required level of share ownership. These figures include the value as at 14 March 2018 of the directors' interests shown below excluding the assumed vesting of the 2015-17 performance shares. Current directors Appointment date Value of current shareholding % of policy achieved Bob Dudley October 2010 $19,860,588 214 Brian Gilvary January 2012 £8,483,077 223 The figures below indicate and include all beneficial and non-beneficial interests of each executive director of the company in shares of BP (or calculated equivalents) that have been disclosed to the company. Current directors Ordinary shares or equivalents at 1 Jan 2017 Ordinary shares or equivalents at S1 Dec 2017 Changes from S1 Dec 2017 to Q4 Mar 2018 Ordinary shares or equivalents total at Q4 Mar 2018 Bob Dudleya 2,509,500 3,065,520 174 3,065,694 Brian Gilvary 1,419,263 1,709,243 116,056 1,825,299 a Held as ADSs. The following table shows both the performance shares and the deferred bonus element awarded under the executive directors' incentive plan (EDIP) and yet to vest. These figures represent the maximum possible vesting levels. The actual number of shares/ADSs that vest will depend on the extent to which applicable performance conditions have been satisfied. Current directors Ordinary shares or equivalents at Q Jan 2017 Ordinary shares or equivalents at S1 Dec 2017 Changes from S1 Dec 2017 to Q4 Mar 2018 Ordinary shares or equivalents total at Q4 Mar 2018 Bob Dudleya 6,607,314 6,870,048 0 6,870,048 Brian Gilvary 3,259,891 3,329,274 (176,576) 3,152,698 a Held as ADSs. At 14 March 2018, the following directors held options under the BP group share plan schemes over ordinary shares or their calculated equivalent set out below. None of these are subject to performance conditions. Additional details regarding these plans can be found on page 109. Current director Share options Brian Gilvary 503,103 No director has any interest in the preference shares or debentures of the company or in the shares or loan stock of any subsidiary company. There are no directors or other members of senior management who own more than 1% of the ordinary shares in issue. At 14 March 2018, all directors and other members of senior management as a group held interests of 15,896,179 ordinary shares or their calculated equivalents, V,757,019 restricted share units (with or without conditions) or their calculated equivalents, 10,022,746 performance shares or their calculated equivalents and 5,012,307 options over ordinary shares or their calculated equivalents under the BP group share option schemes. Senior management comprises members of the executive team. See page 66 for further information. History of CEO remuneration Year CEO Total remuneration thousanda Annual bonus % of maximum Performance shares vesting % of maximum 2009 Hayward £6,753 89b 17.5 2010c Hayward £3,890 0 0 Dudley $8,057 0 0 2011 Dudley $8,439 67 16.7 2012 Dudley $9,609 65 0 2013 Dudley $15,086 88 45.5 2014 Dudley $16,390 73 63.8 2015 Dudley $19,376 100 74.3 2016 Dudley $11,904 61 40 2017 Dudley $13,443 71.5 70 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 or the adjusted outcome in subsequent years where a preliminary assessment of the performance for EDIP was made. For 2017, the preliminary assessment has been reflected. b 2009 annual bonus did not have an absolute maximum and so is shown as a percentage of the maximum established in 2010. c 2010 figures show full year total remuneration for both Tony Hayward and Bob Dudley, although Bob Dudley did not become CEO until October 2010. Directors' remuneration report BP Annual Report and Form 20-F 2017 105 C orporate governance

Directors' remuneration report R0092008 2010 2011 2012 2013 2014 2015 2016 2017 Va lu e of h yp ot he tic al £ 10 0 ho ld in g FTSE 100 BPHistorical TSR performance £50 £100 £150 £200 £250 This graph shows the growth in value of a hypothetical £100 holding in BP p.l.c. ordinary shares over nine years, relative to a hypothetical £100 holding in the FTSE 100 Index of which the company is a constituent. Further information 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, including activities during the year, advice received and shareholder engagement is set out in the remuneration committee report on page 86. During 2017 David Jackson, the company secretary, who is employed by the company and reports to the chairman of the board, acted as secretary to the remuneration committee. Deloitte LLP acted as independent adviser to the committee during the year until September 2017, when it stepped down as part of the transition process for its role as BP's statutory auditor for the financial year 2018. Following a competitive tender process, the committee appointed PwC as its independent adviser from September 2017. 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. Freshfields Bruckhaus Deringer LLP provided legal advice on specific compliance matters to the committee. Deloitte, PwC and Freshfields provide other advice in their respective areas to the group. During the year, Deloitte also provided BP with services including consulting on HR and upstream matters and PwC provided BP with services including subsidiary company secretarial support. Total fees or other charges (based on an hourly rate) for the provision of remuneration advice to the committee in 2017 (save in respect of legal advice) are as follows: Deloitte £164,280 PwC £62,213 Shareholder engagement As set out in last year's report, during 2017 we had extensive dialogue with many of our largest shareholders as well as representative bodies on remuneration matters, particularly in the run-up to the AGM. 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 2017 97.05% 2.95% 63,453,383 2016 40.7% 59.3% 464,259,340 2015 88.8% 11.2% 305,297,190 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 accept one non-executive appointment, from which they may retain any fee. 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 during 2017 are shown below. Director Appointee company Additional position held at appointee company Total fees Bob Dudley Rosnefta Director 0 Brian Gilvary L'Air Liquide Director Euros 64,310 a Bob Dudley holds this appointment as a result of the company's shareholding in Rosneft.

This section of the directors' remuneration report completes the directors' annual report on remuneration with details for the chairman and non-executive directors (NEDs). The board's remuneration policy for the NEDs was approved at the 2017 AGM. This policy was implemented during 2017. There has been no variance of the fees or allowances for the chairman and the NEDs during 2017. Chairman The fee structure for the chairman, which has been in place since Q May 2013, is £785,000 per year. He is not eligible for committee chairmanship and membership fees or intercontinental travel allowance. He has the use of a fully maintained office for company business, a car and driver, and security advice in London. He receives a contribution to an office and secretarial support as appropriate to his needs in Sweden. The table below shows the fees paid for the chairman for the year ended S1 December 2017. 2017 remuneration (audited) £ thousand Fees Benefitsa Total 2017 2016 2017 2016 2017 2016 Carl-Henric Svanberg 785 785 35 58 820 843 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. Chairman's interests 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 under the DTRs as at the applicable dates. The chairman's holdings represented as a percentage against policy achieved are 1,229%. Chairman Ordinary shares or equivalents at 1 Jan 2017 Ordinary shares or equivalents at 31 Dec 2017 Change from 31 Dec 2017 to 14 Mar 2018 Ordinary shares or equivalents total at 14 Mar 2018 Carl-Henric Svanberg 2,076,695 2,076,695 – 2,076,695 Non-executive directors Directors' remuneration report Non-executive director 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 2017 Ordinary shares or equivalents at 31 Dec 2017 Change from 31 Dec 2017 to 14 Mar 2018 Ordinary shares or equivalents total at 14 Mar 2018 Value of current shareholding % of policy achieved Nils Andersen 47,855 125,000 – 125,000 £580,938 645 Paul Anderson 30,000b 30,000b – 30,000b $194,350 168 Alan Boeckmann 44,772b 44,772b – 44,772b $290,048 250 Admiral Frank Bowman 24,864b 24,864b – 24,864b $161,077 139 Cynthia Carrolla 10,500b – – – – – Ian Davis 25,735 47,500 – 47,500 £220,756 184 Professor Dame Ann Dowling 22,320 22,320 – 22,320 £103,732 115 Melody Meyerc – 20,646b – 20,646b $133,752 115 Brendan Nelson 11,040 11,040 – 11,040 £51,308 57 Paula Rosput Reynolds 52,200b 58,200b 15,000 73,200b $474,214 409 Sir John Sawers 13,528 14,198 – 14,198 £65,985 73 Andrew Shilstona 15,000 – – – – – a Resigned on 17 May 2017. b Held as ADSs. c Appointed on 17 May 2017. Past 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 2017, he received £100,000 for this role. Non-executive directors Fee structure The table below shows the fee structure for non-executive directors: Fees £ thousand Senior independent directora 120 Board member 90 Audit, geopolitical, remuneration and SEEA committees chairmanship feesb 30 Committee membership feec 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, SEEA and remuneration committees. 2017 remuneration (audited) £ thousand Fees Benefitsa Total 2017 2016 2017 2016 2017 2016 Nils Andersen 115 23 17 6 132 29 Paul Anderson 155 165 27 32 182 197 Alan Boeckmann 165 168 11 17 176 185 Admiral Frank Bowman 155 162 15 14 170 176 Cynthia Carrollb 54 140 36 28 90 168 Ian Davis 154 136 2 2 156 138 Professor Dame Ann Dowlingc 145 150 5 2 150 152 Melody Meyerd 86 – 23 – 109 – Brendan Nelson 138 130 14 30 152 160 Paula Rosput Reynolds 140 140 8 17 148 157 Sir John Sawers 145 148 5 19 150 167 Andrew Shilstonb 75 190 1 5 76 195 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 Resigned on 17 May 2017. c In addition, Professor Dame Ann Dowling received £25,000 for chairing and being a member of the BP technology advisory council. d Appointed on 17 May 2017. BP Annual Report and Form 20-F 2017 107 C orporate governance

Directors' remuneration report Executive directors interests Deferred shares (audited)a Deferred share element interests Interests vested in 2017 and 2018 Bonus year Type Performance period Date of award of deferred shares Potential maximum deferred shares Number of ordinary shares vested Vesting date £ Face value of the award At 1 Jan R017 Awarded R017 At 31 Dec R017 Bob Dudleyb 2013 Comp 2014-2016 12 Feb 2014 149,628 – – 183,732c 24 Feb 2017 – Mat 2014-2016 12 Feb 2014 149,628 – – 183,732c 24 Feb 2017 – 2014 Comp 2015-2017d 11 Feb 2015 147,054 – 147,054 – – 655,861 Vol 2015-2017d 11 Feb 2015 147,054 – 147,054 – – 655,861 Mat 2015-2017d 11 Feb 2015 294,108 – 294,108 – – 1,311,722 2015f Comp 2016-2018d 4 Mar 2016 275,892 – 275,892 – – 1,015,283 Vol 2016-2018d 4 Mar 2016 275,892 – 275,892 – – 1,015,283 Mat 2016-2018d 4 Mar 2016 551,784 – 551,784 – – 2,030,565 2016g Comp 2017-2019 19 May 2017 – 147,642 147,642 – – 697,092 Mat 2017-2019d 19 May 2017 – 147,642 147,642 – – 697,092 Brian Gilvary 2013 Comp 2014-2016 12 Feb 2014 96,653 – – 119,157c 24 Feb 2017 – Mat 2014-2016 12 Feb 2014 96,653 – – 119,157c 24 Feb 2017 – 2014 Comp 2015-2017 11 Feb 2015 88,288 – 88,288 109,502c 20 Feb 2018 – Vol 2015-2017 11 Feb 2015 88,288 – 88,288 109,502c 20 Feb 2018 – Mat 2015-2017e 11 Feb 2015 176,576 – 176,576 – – 787,529 2015f Comp 2016-2018 4 Mar 2016 159,021 – 159,021 – – 585,197 Vol 2016-2018 4 Mar 2016 159,021 – 159,021 – – 585,197 Mat 2016-2018 4 Mar 2016 318,042 – 318,042 – – 1,170,395 2016g Comp 2017-2019 19 May 2017 – 73,070 73,070 – – 345,000 Mat 2017-2019h 19 May 2017 – 73,070 73,070 – – 345,000 Former executive directors Iain Conn 2013 Comp 2014-2016 12 Feb 2014 100,563 – – 123,977c 24 Feb 2017 – Mat 2014-2016 12 Feb 2014 33,521i – – 41,325c 24 Feb 2017 – Comp = Compulsory. Vol = Voluntary. Mat = Matching. a Since 2010, vesting of the deferred shares has been subject to a safety and environmental sustainability hurdle, and this will continue. 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 SEEAC. 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 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 dates of 24 February 2017 and 20 February 2018 were £4.47 and £4.75 respectively and for ADSs on 24 February 2017 was $33.50. These totals include the additional accrual of dividends which vested on 19 May 2017 and 2 August 2017. d Bob Dudley has voluntarily agreed to defer vesting of these awards until after retirement, therefore the performance period is expected to exceed the minimum term of three years. The market price of ordinary shares used to determine the total value at vesting on 11 February 2015 was £4.46. e Brian Gilvary has voluntarily agreed to defer vesting of these awards for five years with a further one year retention period. f The face value has been calculated using the market price of ordinary shares on 4 March 2016 of £3.68. g The market price at closing of ordinary shares on 19 May 2017 was £4.72 and for ADSs was $36.94. The sterling value has been used to calculate the face value. h Brian Gilvary has voluntarily agreed to defer vesting of these awards until the later of three years post award or one year post retirement, therefore the performance period is expected to exceed the minimum term of three years. i All matching shares have been pro-rated to reflect actual service during the performance period and these figures have been used to calculate the face value. 108 BP Annual Report and Form 20-F 2017

Directors’ remuneration report Performance shares (audited) Share element interests Interests vested in 2017 and 2018 Performance period Date of award of performance shares Potential maximum performance sharesa Number of ordinary shares vested Vesting date £ Face value of the award At 1 Jan R017 Awarded R017 At 31 Dec R017 Bob Dudleyb 2014-2016 12 Feb 2014 1,304,922 – – 653,538c 19 May 2017d – 2015-2017 11 Feb 2015 1,501,770 – 1,365,240e 1,172,484 May 2018 – 2016-2018f 4 Mar 2016 1,809,582 – 1,645,074e – – 6,053,872 2017-2019f 19 May 2017 – 1,571,628 1,428,750e – – 6,743,700 Brian Gilvary 2014-2016 12 Feb 2014 605,544 – – 308,286c 19 May 2017d – 2015-2017 11 Feb 2015 685,246 – 685,246 594,932 May 2018 – 2016-2018f 4 Mar 2016 786,559 – 786,559 – – 2,894,537 2017-2019f 19 May 2017 – 722,093 722,093 – – 3,409,362 Former executive directors Iain Conn 2014-2016 12 Feb 2014 220,043 – – 112,025c g 19 May 2017d – a For awards under the 2014-2016, 2015-2017 and 2016-2018 plans, performance conditions are measured one third on TSR relative to ExxonMobil, Shell, Total and Chevron; 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 T4.4%, 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 2017-2019 plan, performance conditions are measured 50% on TSR relative to ExxonMobil, Shell, Total and Chevron over three years; 30% on ROACE based on performance in 2019 and R0% on strategic progress assessed over the performance period. 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 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 at the vesting date of 19 May 2017 was £4.72 and for ADSs was $36.94. For the assumed vestings dated May 2018 a price of £5.01 per ordinary share and $39.85 per ADS has been used. These are the average prices from the fourth quarter of 2017. These totals include the additional accrual of dividends which vested on 2 August 2017. d The 2014-2016 award vested on 19 May 2017, which resulted in an increase in value at vesting of £24,644 for Iain Conn. Details for Bob Dudley and Brian Gilvary can be found in the single figure table on page 95. e Bob Dudley has requested that the EDIP performance shares vestings in respect of the performance periods 2015-2017 and 2016-2018 are 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 applies under the 2014 directors’ remuneration policy. f The market price at closing of ordinary shares on 4 March 2016 was £3.68 and for ADSs was $31.15 and on 19 May 2017 was £4.72 and for ADSs was $36.94. g Potential maximum of performance shares element has been pro-rated to reflect actual service during the performance period. Share interests in share options plans (audited) Option type At 1 Jan 2017 Granted Exercised At 31 Dec R017 Option price Market price at date of exercise Date from which first exercisable Expiry date Brian Gilvary BP 2011 500,000 – – 500,000 £3.72 – 07 Sep 2014 07 Sep 2021 SAYE 3,103 – – 3,103 £2.90 – 01 Sep 2019 28 Feb 2020 The closing market prices of an ordinary share and of an ADS on 29 December 2017 were £5.227 and $42.03 respectively. During 2017 the highest market prices were £5.247 and $42.03 respectively and the lowest market prices were £4.3975 and $33.31 respectively. BP 2011 = BP 2011 plan. These options were granted to Brian Gilvary prior to his appointment as a director and are not subject to performance conditions. BP Annual Report and Form 20-F 2017 109 C orporate governance

Directors' remuneration report Remuneration policy table – executive directors A summary of the remuneration policy approved by shareholders at the 2017 AGM is set out below. For the full remuneration policy, please refer to the 2016 Directors' remuneration report at bp.com/remuneration. Salary and benefits 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. Salary • Salary levels take into account the nature of the role, performance of the business and the individual, market positioning and pay conditions in the wider BP group. 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. • 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. • Salary levels are specific to the role and individual and therefore there is no maximum salary under the policy. However, when reviewing salaries for executive directors, the committee will consider salary increases for the most senior management and for employees in relevant countries. Percentage increases for executive directors will not exceed that of the broader employee population, other than in specific circumstances identified by the committee (e.g. in response to a substantial change in responsibilities). • Following the 2018 AGM, the annual salaries for the executive directors will be: – Group chief executive – Bob Dudley: $1,854,000. – Chief financial officer – Brian Gilvary: £775,000. Benefits • The committee expects to maintain benefits at the current level. • 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 maternity pay. 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, driver, 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. Performance framework • Not applicable Annual bonus To provide variable remuneration dependent on performance against annual financial, operational and safety 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. • 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. • Typically the annual bonus earned would be 50% of the maximum available for delivery of performance in line with the annual plan. The level of bonus payable may vary depending on the nature of the performance measure and level of target set. • Executive directors may earn a maximum annual bonus (including any deferral) of up to 225% of salary for stretching performance against the objectives set for the year. The committee intends to set demanding requirements for maximum payment. • 50% of the bonus earned is required to be 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 in policy, see bp.com/remuneration. Performance framework • The committee determines specific measures, weightings and targets each year to reflect the priorities in the annual plan, which is designed to deliver the group's strategy and is approved by the board. • Measures will typically include a balance of financial, operational and safety measures. Details of the measures will be reported in advance each year in the annual report on remuneration. The committee intends to disclose targets for the annual bonus retrospectively. Purpose Operation and opportunity Purpose Operation and opportunity

Directors' remuneration report 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 linked directly to strategic priorities. Operation and opportunity • Annual awards of shares will vest based on performance relative to measures and targets that reflect the delivery of BP's strategy. Performance will normally be measured over a period of at least three years. • The maximum annual award level for the group chief executive will be 500% of salary and 450% of salary for the chief financial officer. • Performance shares will only vest to the extent that performance targets are met. The level of vesting for performance will depend on the stretch of the objective set, but the threshold level would normally not be expected to exceed 25% of the maximum opportunity for the relevant element. • Once performance has been measured, a proportion of the shares that will vest are subject to a holding period. The combined length of the performance and holding periods will be normally six years. • Dividends (or equivalents, including the value of reinvestment) may accrue in respect of vested shares. • Awards are subject to malus and clawback provisions, See bp.com/remuneration. Performance framework • Performance shares may vest based on a combination of total shareholder return, financial and strategic measures. • For 2018 awards, the measures and weightings will be: – total shareholder return relative to oil and gas majors (50%) – return on average capital employed (30%) – strategic progress (20%) • Details of 2018 targets relating to the total shareholder return and return on average capital employed measures are outlined in the remuneration report. Details relating to strategic progress will be disclosed retrospectively. • Prior to granting each award the committee will review the measures, weightings and targets to ensure they remain focused on delivering the strategy and are in the interests of shareholders. • At least 40% of any award will be subject to measures linked to shareholder returns and the proportion linked to strategic progress will not exceed 30%. The committee would consult appropriately with major shareholders regarding any material changes to the measures. Retirement benefits 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. • Senior executives in BP have generally been employees of the group for a number of years. They often remain participants in long-standing arrangements in which other group employees continue to participate, but which are no longer offered to new employees. The maximum opportunity will vary depending on the terms of these arrangements. • UK participants may remain members of the company's defined benefit plan. In common with other employees in this plan, they may choose to receive up to 35% of salary in lieu as a cash supplement but do not receive further service accrual under this plan. The level of this allowance is expected to reduce in future, in line with the proposed reduction for other UK employees who participate in this arrangement. • US executive directors participate in long-standing plans of Amoco and Arco and other BP defined benefit and retirement savings plans for US employees. • For future appointments, the committee will carefully review any retirement benefits to be granted to a new director. This will take account of retirement policies across the wider group, any arrangements currently in place, local market practice and individual circumstances. The committee will consider retirement benefits in the context of the overall approach to remuneration. Performance framework • Retirement benefits in the UK are not directly linked to performance. Reflecting local market practice, legacy arrangements in the US may reference bonuses when determining the benefit level. Shareholding requirements To provide alignment between the interests of executive directors and our other shareholders. Operation and opportunity • An executive director is expected to build up and maintain a minimum shareholding of five times their base salary within five years of their appointment. Performance framework • Not applicable. Purpose Purpose

Directors' remuneration report Remuneration policy table – non-executive directors The maximum fees for non-executive directors are set in accordance with the Articles of Association. 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 GCE 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. Other fees and benefits Intercontinental allowance Approach Non-executive directors receive an allowance to reflect the global nature of the company's business. The intercontinental travel allowance is payable for the purpose of attending board or committee meetings or site visits. Operation and opportunity The allowance is 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. The reimbursement of professional fees incurred by non-executive directors based outside the UK in connection with advice and assistance on UK tax compliance matters. BP Annual Report and Form 20-F 2017112 This directors' remuneration report was approved by the board and signed on its behalf by David J Jackson, company secretary on 29 March 2018.

Pages 113-114 have been removed as they do not form part of BP's Annual Report on Form 20-F as filed with the SEC. C orporate governance

Financial statements

123 Consolidated financial statements of the BP group

Independent auditor's reports	123	Group statement of changes in equity	127
Group income statement	125	Group balance sheet	128
Group statement of comprehensive income	126	Group cash flow statement	129

130 Notes on financial statements

1. Significant accounting policies	130	21. Provisions	162
2. Significant event - Gulf of Mexico oil spill	143	22. Pensions and other post-retirement benefits	162
3. Disposals and impairment	145	23. Cash and cash equivalents	168
4. Segmental analysis	147	24. Finance debt	168
5. Income statement analysis	150	25. Capital disclosures and analysis of changes in net debt	169
6. Exploration expenditure	150	26. Operating leases	169
7. Taxation	151	27. Financial instruments and financial risk factors	170
8. Dividends	153	28. Derivative financial instruments	173
9. Earnings per share	153	29. Called-up share capital	177
10. Property, plant and equipment	155	30. Capital and reserves	178
11. Capital commitments	155	31. Contingent liabilities	181
12. Goodwill	156	32. Remuneration of senior management and non-executive directors	182
13. Intangible assets	157		
14. Investments in joint ventures	158	33.	

15. Investments in associates 158
16. Other investments 160
17. Inventories 160
18. Trade and other receivables 161
19. Valuation and qualifying accounts 161
20. Trade and other payables 161

Employee costs and numbers 183
34. Auditor's remuneration 183
35. Subsidiaries, joint arrangements and associates 184
36. Condensed consolidating information on certain US subsidiaries 185

191 Supplementary information on oil and natural gas (unaudited)

Oil and natural gas exploration and production activities 192
Movements in estimated net proved reserves 198
Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves 213
Operational and statistical information 216

Pages 116-122 have been removed as they do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

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

Consolidated financial statements of the BP group
Report of Independent Registered Public Accounting Firm
To the shareholders and board of directors of BP p.l.c.

Opinion on the financial statements
We have audited the accompanying group balance sheets of BP p.l.c. (the Company) as of 31 December 2017 and 2016, and the related group income statement, group statement of comprehensive income, group statement of changes in equity and group cash flow statement for each of the three years in 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 2016 and the results of its operations and its cash flows for each of the three years in 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.
We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), BP p.l.c.'s internal control over financial reporting as of 31 December 2017, based on criteria established in the UK Financial Reporting Council's Guidance on Risk Management, Internal Control and Related Financial and Business Reporting and our report dated 29 March 2018 expressed an unqualified opinion thereon.
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 audits. 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 audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP
We have served as the Company's auditor since 1909.
London, United Kingdom
29 March 2018

Consolidated financial statements of the BP group
Report of Independent Registered Public Accounting Firm
To the shareholders and board of directors of BP p.l.c.

Opinion on internal control over financial reporting

We have audited BP p.l.c.'s internal control over financial reporting as of 31 December 2017, based on criteria established in the UK Financial Reporting Council's Guidance on Risk Management, Internal Control and Related Financial and Business Reporting. In our opinion, BP p.l.c. maintained, in all material respects, effective internal control over financial reporting as of 31 December 2017, based on the UK Financial Reporting Council's Guidance.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the group balance sheets of BP p.l.c. as of 31 December 2017 and 2016, the related group income statement, group statement of comprehensive income, group statement of changes in equity and group cash flow statement for each of the three years in the period ended 31 December 2017, and our report dated 29 March 2018 expressed an unqualified opinion thereon.

Basis for opinion

BP p.l.c.'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 on page 275. 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/ Ernst & Young LLP
London, United Kingdom
29 March 2018

Consent of independent registered public accounting firm

We consent to the incorporation by reference of our reports dated 29 March 2018, with respect to the group financial statements of BP p.l.c., and the effectiveness of internal control over financial reporting of BP p.l.c., included in this Annual Report and Form 20-F for the year ended 31 December 2017 in the following Registration Statements:

Registration Statements on Form F-3 (File Nos. 333-208478 and 333-208478-01) of BP p.l.c. and BP Capital Markets p.l.c.; and Registration Statements on Form S-8 (File Nos. 333-67206, 333-79399, 333-103924, 333-123482, 333-123483, 333-131583, 333-131584, 333-132619, 333-146868, 333-146870, 333-146873, 333-173136, 333-177423, 333-179406, 333-186462, 333-186463, 333-199015, 333-200794, 333-200795, 333-207188, 333-207189, 333-210316 and 333-210318) of BP p.l.c.

/s/ Ernst & Young LLP

London, United Kingdom

29 March 2018

Group income statement
For the year ended 31 December

				$ million
	Note	2017	2016	2015
Sales and other operating revenues	4	240,208	183,008	222,894
Earnings from joint ventures – after interest and tax	14	1,177	966	(28)
Earnings from associates – after interest and tax	15	1,330	994	1,839
Interest and other income	5	657	506	611
Gains on sale of businesses and fixed assets	3	1,210	1,132	666
Total revenues and other income		244,582	186,606	225,982
Purchases	17	179,716	132,219	164,790
Production and manufacturing expenses[a]		24,229	29,077	37,040
Production and similar taxes	4	1,775	683	1,036
Depreciation, depletion and amortization	4	15,584	14,505	15,219
Impairment and losses on sale of businesses and fixed assets	3	1,216	(1,664)	1,909
Exploration expense	6	2,080	1,721	2,353
Distribution and administration expenses		10,508	10,495	11,553
Profit (loss) before interest and taxation		9,474	(430)	(7,918)
Finance costs[a]	5	2,074	1,675	1,347
Net finance expense relating to pensions and other post-retirement benefits	22	220	190	306
Profit (loss) before taxation		7,180	(2,295)	(9,571)
Taxation[a]	7	3,712	(2,467)	(3,171)
Profit (loss) for the year		3,468	172	(6,400)
Attributable to				
BP shareholders		3,389	115	(6,482)
Non-controlling interests		79	57	82
		3,468	172	(6,400)
Earnings per share				
Profit (loss) for the year attributable to BP shareholders				
Per ordinary share (cents)				
Basic	9	17.20	0.61	(35.39)
Diluted	9	17.10	0.60	(35.39)
Per ADS (dollars)				
Basic	9	1.03	0.04	(2.12)
Diluted	9	1.03	0.04	(2.12)

[a] See Note 2 for information on the impact of the Gulf of Mexico oil spill on these income statement line items.

Group statement of comprehensive income[a]

For the year ended 31 December

	Note	2017	2016	$ million 2015
Profit (loss) for the year		3,468	172	(6,400)
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss				
Currency translation differences		1,986	254	(4,119)
Exchange (gains) losses on translation of foreign operations reclassified to gain or loss on sale of businesses and fixed assets		(120)	30	23
Available-for-sale investments		14	1	1
Cash flow hedges marked to market	28	197	(639)	(178)
Cash flow hedges reclassified to the income statement	28	116	196	249
Cash flow hedges reclassified to the balance sheet	28	112	81	22
Share of items relating to equity-accounted entities, net of tax	14, 15	564	833	(814)
Income tax relating to items that may be reclassified	7	(196)	13	257
		2,673	769	(4,559)
Items that will not be reclassified to profit or loss				
Remeasurements of the net pension and other post-retirement benefit liability or asset	22	3,646	(2,496)	4,139
Share of items relating to equity-accounted entities, net of tax	14, 15	—	—	(1)
Income tax relating to items that will not be reclassified	7	(1,303)	739	(1,397)
		2,343	(1,757)	2,741
Other comprehensive income		5,016	(988)	(1,818)
Total comprehensive income		8,484	(816)	(8,218)
Attributable to				
BP shareholders		8,353	(846)	(8,259)
Non-controlling interests		131	30	41
		8,484	(816)	(8,218)

[a] See Note 30 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 1 January 2017	46,122	(18,443)	(6,878)	(1,153)	75,638	95,286	1,557	96,843
Profit (loss) 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)
Repurchase 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
At 1 January 2016	43,902	(19,964)	(7,267)	(823)	81,368	97,216	1,171	98,387
Profit (loss) for the year	—	—	—	—	115	115	57	172
Other comprehensive income	—	—	389	(330)	(1,020)	(961)	(27)	(988)
Total comprehensive income	—	—	389	(330)	(905)	(846)	30	(816)
Dividends[b]	—	—	—	—	(4,611)	(4,611)	(107)	(4,718)
Share-based payments, net of tax	2,220	1,521	—	—	(750)	2,991	—	2,991
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	106	106	—	106
Transactions involving	—	—	—	—	430	430	463	893

non-controlling interests, net of tax								
At 31 December 2016	46,122	(18,443)	(6,878)	(1,153)	75,638	95,286	1,557	96,843
At 1 January 2015	43,902	(20,719)	(3,409)	(897)	92,564	111,441	1,201	112,642
Profit (loss) for the year	—	—	—	—	(6,482)	(6,482)	82	(6,400)
Other comprehensive income	—	—	(3,858)	74	2,007	(1,777)	(41)	(1,818)
Total comprehensive income	—	—	(3,858)	74	(4,475)	(8,259)	41	(8,218)
Dividends[b]	—	—	—	—	(6,659)	(6,659)	(91)	(6,750)
Share-based payments, net of tax	—	755	—	—	(99)	656	—	656
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	40	40	—	40
Transactions involving non-controlling interests, net of tax	—	—	—	—	(3)	(3)	20	17
At 31 December 2015	43,902	(19,964)	(7,267)	(823)	81,368	97,216	1,171	98,387

[a] See Note 30 for further information.
[b] See Note 8 for further information.

Group balance sheet
At 31 December

			$ million
	Note	2017	2016
Non-current assets			
Property, plant and equipment	10	129,471	129,757
Goodwill	12	11,551	11,194
Intangible assets	13	18,355	18,183
Investments in joint ventures	14	7,994	8,609
Investments in associates	15	16,991	14,092
Other investments	16	1,245	1,033
Fixed assets		185,607	182,868
Loans		646	532
Trade and other receivables	18	1,434	1,474
Derivative financial instruments	28	4,110	4,359
Prepayments		1,112	945
Deferred tax assets	7	4,469	4,741
Defined benefit pension plan surpluses	22	4,169	584
		201,547	195,503
Current assets			
Loans		190	259
Inventories	17	19,011	17,655
Trade and other receivables	18	24,849	20,675
Derivative financial instruments	28	3,032	3,016
Prepayments		1,414	1,486
Current tax receivable		761	1,194
Other investments	16	125	44
Cash and cash equivalents	23	25,586	23,484
		74,968	67,813
Total assets		276,515	263,316
Current liabilities			
Trade and other payables	20	44,209	37,915
Derivative financial instruments	28	2,808	2,991
Accruals		4,960	5,136
Finance debt	24	7,739	6,634
Current tax payable		1,686	1,666
Provisions	21	3,324	4,012
		64,726	58,354
Non-current liabilities			
Other payables	20	13,889	13,946
Derivative financial instruments	28	3,761	5,513
Accruals		505	469
Finance debt	24	55,491	51,666
Deferred tax liabilities	7	7,982	7,238
Provisions	21	20,620	20,412
Defined benefit pension plan and other post-retirement benefit plan deficits	22	9,137	8,875
		111,385	108,119
Total liabilities		176,111	166,473
Net assets		100,404	96,843
Equity			
BP shareholders’ equity	30	98,491	95,286

Non-controlling interests	30	1,913	1,557
Total equity	30	100,404	96,843

C-H Svanberg Chairman
R W Dudley Group chief executive
29 March 2018

Group cash flow statement

For the year ended 31 December

	Note	2017	2016	$ million 2015
Operating activities				
Profit (loss) before taxation		7,180	(2,295)	(9,571)
Adjustments to reconcile profit (loss) before taxation to net cash provided by operating activities				
Exploration expenditure written off	6	1,603	1,274	1,829
Depreciation, depletion and amortization	4	15,584	14,505	15,219
Impairment and (gain) loss on sale of businesses and fixed assets	3	6	(2,796)	1,243
Earnings from joint ventures and associates		(2,507)	(1,960)	(1,811)
Dividends received from joint ventures and associates		1,253	1,105	1,614
Interest receivable		(304)	(200)	(247)
Interest received		375	267	176
Finance costs	5	2,074	1,675	1,347
Interest paid		(1,572)	(1,137)	(1,080)
Net finance expense relating to pensions and other post-retirement benefits	22	220	190	306
Share-based payments		661	779	321
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	22	(394)	(467)	(592)
Net charge for provisions, less payments		2,106	4,487	11,792
(Increase) decrease in inventories		(848)	(3,681)	3,375
(Increase) decrease in other current and non-current assets		(4,848)	(1,172)	6,796
Increase (decrease) in other current and non-current liabilities		2,344	1,655	(9,328)
Income taxes paid		(4,002)	(1,538)	(2,256)
Net cash provided by operating activities		18,931	10,691	19,133
Investing activities				
Expenditure on property, plant and equipment, intangible and other assets		(16,562)	(16,701)	(18,648)
Acquisitions, net of cash acquired		(327)	(1)	23
Investment in joint ventures		(50)	(50)	(265)
Investment in associates		(901)	(700)	(1,312)
Total cash capital expenditure		(17,840)	(17,452)	(20,202)
Proceeds from disposals of fixed assets	3	2,936	1,372	1,066
Proceeds from disposals of businesses, net of cash disposed	3	478	1,259	1,726
Proceeds from loan repayments		349	68	110
Net cash used in investing activities		(14,077)	(14,753)	(17,300)
Financing activities				
Net issue (repurchase) of shares		(343)	—	—
Proceeds from long-term financing		8,712	12,442	8,173
Repayments of long-term financing		(6,276)	(6,685)	(6,426)
Net increase (decrease) in short-term debt		(158)	51	473
Net increase (decrease) in non-controlling interests		1,063	887	(5)
Dividends paid				
BP shareholders	8	(6,153)	(4,611)	(6,659)
Non-controlling interests		(141)	(107)	(91)
Net cash provided by (used in) financing activities		(3,296)	1,977	(4,535)
Currency translation differences relating to cash and cash equivalents		544	(820)	(672)
Increase (decrease) in cash and cash equivalents		2,102	(2,905)	(3,374)
Cash and cash equivalents at beginning of year		23,484	26,389	29,763

Cash and cash equivalents at end of year	25,586	23,484	26,389

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 the BP group for the year ended 31 December 2017 were approved and signed by the group chief executive and chairman on 29 March 2018 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. 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 2017. The accounting policies that follow have been consistently applied to all years presented.

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 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 could 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 interests in other entities; oil and natural gas accounting, including the estimation of reserves; the recoverability of asset carrying values, including trade receivables; derivative financial instruments; provisions and contingencies, including provisions and contingencies related to the Gulf of Mexico oil spill; pensions and other post-retirement benefits; and income taxes. 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. Whilst the impact of the application of hedge accounting on the group's financial statements can be significant, the group no longer considers the decision to apply such accounting to represent one of its significant accounting judgements.

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. 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 12 for further information.

Goodwill may also 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.

Interests in joint arrangements

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

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

Interests in associates

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

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

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 available-for-sale financial asset 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 2017. 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, Bob Dudley, has been a member of the board of directors of Rosneft since 2013 and he is 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 directly 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 events or changes in circumstances indicate that the carrying value may not be recoverable. If any such indication 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 4.

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. On disposal or partial disposal 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.

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.

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

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 acquired separately from a business are carried initially at cost. An intangible asset acquired as part of a business combination is measured at fair value at the date of acquisition 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 are reviewed on an annual basis and, if necessary, changes in useful lives 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 recognition of proved reserves and internal approval for development, 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. When proved reserves of oil and natural gas are determined and development is approved by management, 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.

Significant judgement: oil and natural gas accounting

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. 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. 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.

One of the circumstances that indicate an entity should test such assets for impairment is that the period for which the entity has a right to explore in the specific area has expired or will expire in the near future, and is not expected to be renewed. BP has leases in the Gulf of Mexico making up a prospect, some with terms that were scheduled to expire at the end of 2013 and some with terms that were scheduled to expire at the end of 2014. A significant proportion of our capitalized exploration and appraisal costs in the Gulf of Mexico relate to this prospect. This prospect requires the development of subsea technology to ensure that the hydrocarbons can be extracted safely. BP is in negotiation with the US Bureau of Safety and Environmental Enforcement in relation to seeking extension of these leases so that the discovered hydrocarbons can be developed. BP remains committed to developing this prospect and expects that the leases will be renewed and, therefore, continues to carry the capitalized costs on its balance sheet.

Property, plant and equipment

Property, plant and equipment 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 finance costs. The purchase

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

price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. The capitalized value of a finance lease is also included within property, plant and equipment.

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 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.

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 of property, plant and equipment are reviewed on an annual basis and, if necessary, changes in useful lives 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.

Significant estimate: estimation of oil and natural gas reserves

Significant technical and commercial judgements 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, drilling of new wells, and commodity prices 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.

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 191, which is unaudited. Details on BP's proved reserves and production compliance and governance processes are provided on page 260. The 2017 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 191.

Estimates of oil and natural gas reserves determined by applying US Securities and Exchange Commission regulations are used to calculate depreciation, depletion and amortization charges for the group's oil and gas properties. 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.

Oil and natural gas reserves estimates based upon 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. If proved reserves estimates determined by applying management's assumptions are revised downwards, earnings could be affected by changes in depreciation expense or an immediate write-down of the property’s carrying value. Changes in proved reserves, therefore, could result in a material change in those properties' carrying values within the next financial year. See also Significant judgements and estimates: recoverability of asset carrying values.

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 10 and Note 4 respectively.

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. 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 and are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money.

1. Significant accounting policies, judgements, estimates and assumptions – continued
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.
An assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such an indication exists, the recoverable amount is estimated. A previously recognized impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognized. If that is the case, the carrying amount of the asset is increased to the lower of its recoverable amount and the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years. Impairment reversals are recognized in profit or loss. After a reversal, the depreciation charge is adjusted in future periods to allocate the asset's revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.
Goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate the recoverable amount of the group of CGUs to which the goodwill relates should be assessed. In assessing whether goodwill has been impaired, the carrying amount of the group of CGUs to which goodwill has been allocated is compared with its recoverable amount. Where the recoverable amount of the group of CGUs is less than the carrying amount (including goodwill), an impairment loss is recognized. An impairment loss recognized for goodwill is not reversed in a subsequent period.
Significant judgements and estimates: recoverability of asset carrying values
Determination as to whether, and by how much, an asset, CGU, or group of CGUs containing goodwill is impaired involves management estimates on highly uncertain matters such as the effects of inflation and deflation on operating expenses, discount rates, 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. See Note 12 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 similar recent market transaction data or, where recent market transactions for the asset are not available for reference, using discounted cash flow techniques. Where discounted cash flow analyses are used to calculate fair value less costs of disposal, judgements 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.
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 $11.6 billion on its balance sheet (2016 $11.2 billion), principally relating to the Atlantic Richfield, Burmah Castrol, Devon Energy and Reliance transactions. In testing goodwill for impairment, the group uses the approach described above to determine recoverable amount. If there are low oil or natural gas prices for an extended period, the group may need to recognize goodwill impairment charges against its Upstream segment goodwill. Sensitivities relating to impairment testing of goodwill in the Upstream segment are provided in Note 12.
Details of impairment charges and reversals recognized in the income statement are provided in Note 3 and details on the carrying amounts of assets are shown in Note 10, Note 12 and Note 13.
Assumptions made in impairment tests in 2017 relating to discount rates, oil and gas properties and oil and gas prices 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 value-in-use calculations, future cash flows are adjusted for risks specific to the cash-generating unit and are discounted using a pre-tax discount rate. The pre-tax discount rate is based upon the cost of funding the group derived from an established model, adjusted to a pre-tax basis. 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 2017 the discount rate used to determine recoverable amounts based on fair value less costs of disposal was 6% (2016 6%). The discount rate used to determine recoverable amounts based on value in use was 9% (2016 9%). In both cases, where the cash-generating unit is located in a country which is judged to be higher risk an additional 2% premium was added to the discount rate (2016 2%).

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.

Reserves assumptions for value-in-use tests are restricted to proved and probable reserves.

When estimating the fair value of our Upstream assets, assumptions reflect all reserves and resources that management believe a market participant would consider when valuing the asset, which in some cases are broader in scope than the reserves used in a value-in-use test. In determining a fair value, risk factors may be applied to reserves and resources which do not meet the criteria to be treated as proved. Depending upon the classification of the reserves and resources, this can result in associated forecast cash flows being reduced by a factor of between 10% and 90% from their estimated full potential value. Changing the risk factor applied will in some cases have an impact upon the carrying value of the asset concerned. Based on tests performed in 2016 and 2017, a 10% increase in the risk factors used in any single test could have an impact of up to $0.4 billion upon the carrying value of that asset.

The recoverability of intangible exploration and appraisal expenditure is covered under Oil and natural gas exploration, appraisal and development expenditure above.

Oil and gas prices

The long-term price assumptions used to determine recoverable amount based on fair value less costs of disposal from 2023 onwards are derived from $75 per barrel for Brent and $4/mmBtu for Henry Hub, both in 2015 prices, inflated for the remaining life of the asset (2016 $75 per barrel and $4/mmBtu, both in 2015 prices, from 2022 onwards). To determine recoverable amount based on value in use, the price assumptions were inflated to 2023 but from 2023 onwards were not inflated.

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

For both value-in-use and fair value less costs of disposal impairment tests, the price assumptions used for the five-year period to 2022 have been set such that there is a gradual transition from current market prices to the long-term price assumptions as noted above, with the rate of increase reducing in the later years.

Oil prices have firmed somewhat in the wake of the extension of OPEC and non-OPEC production cuts and the gradual adjustment in oil inventories from elevated levels. BP's long-term assumption for oil prices is higher than recent market prices reflecting the judgement that recent prices are not consistent with the market being able to produce sufficient oil to meet global demand sustainably in the longer term.

US gas prices have been affected by short-term volatility in winter demand although remain relatively muted. BP's long-term price assumption for US gas is higher than recent market prices as US gas production is expected to grow strongly, supported by increased exports of liquefied natural gas, absorbing the lowest cost resources and requiring increased investment in infrastructure.

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 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.

Financial assets

Financial assets are recognized initially at fair value, normally being the transaction price plus, in the case of financial assets not at fair value through profit or loss, directly attributable transaction costs. 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 financial asset is transferred to a third party.

Loans and receivables

Loans and receivables are carried at amortized cost using the effective interest method if the time value of money is significant. Gains and losses are recognized in income when the loans and receivables 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 at fair value through profit or loss

Financial assets at fair value through profit or loss 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 classified as held for trading and are included in this category.

Derivatives designated as hedging instruments in an effective hedge

These derivatives 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.

Held-to-maturity financial assets

Held-to-maturity financial assets are measured at amortized cost, using the effective interest method, less any impairment.

Available-for-sale financial assets

Available-for-sale financial assets are measured at fair value, with gains or losses recognized within other comprehensive income, except for impairment losses, and, for available-for-sale debt instruments, foreign exchange gains or losses, interest recognized using the effective interest method, and any changes in fair value arising from revised estimates of future cash flows, which are recognized in profit or loss.

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 loans and receivables, held-to-maturity financial assets or available-for-sale financial assets.

Impairment of loans and receivables

The group assesses at each balance sheet date whether a financial asset or group of financial assets is impaired. If there is objective evidence that an impairment loss on loans and receivables carried at amortized cost has been incurred, the amount of the loss is measured as the difference between the asset's carrying amount and the present value of estimated future cash flows discounted at the financial asset's original effective interest rate. The carrying amount of the asset is reduced, with the amount of the loss recognized in the income statement.

Significant judgement: recoverability of trade receivables

Judgements are required in assessing the recoverability of overdue trade receivables and determining whether a provision against those receivables is required. In particular, judgements are required in the current oil and gas price environment relating to amounts due from countries that are reliant on revenues from hydrocarbon-producing activities. Factors considered include the credit rating of the counterparty, the amount and timing of anticipated future payments and any possible actions that can be taken to mitigate the risk of non-payment. See Note 27 for information on overdue receivables.

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

Financial liabilities

The measurement of financial liabilities depends on their classification, as follows:

Financial liabilities at fair value through profit or loss

Financial liabilities at fair value through profit or loss 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 classified as held for trading and are included in this category.

Derivatives designated as hedging instruments in an effective hedge

These derivatives 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 transaction costs. For interest-bearing loans and borrowings this is 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, except finance debt designated in a fair value hedge relationship.

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 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, and how the entity will assess the hedging instrument effectiveness in offsetting the exposure to changes in the hedged item's fair value or cash flows attributable to the hedged risk. Such hedges are expected at inception to be highly effective in achieving offsetting changes in fair value or cash flows. Hedges meeting the criteria for hedge accounting are accounted for as follows:

Fair value hedges

The change in fair value of a hedging derivative is recognized in profit or loss. The change in the fair value of the hedged item attributable to the risk being hedged is recorded as part of the carrying value of the hedged item and is also recognized in profit or loss. The group applies fair value hedge accounting when hedging interest rate risk and

certain currency risks on fixed rate borrowings.
If the criteria for hedge accounting are no longer met, or if the group revokes the designation, the accumulated adjustment to the carrying amount of a hedged item at such time is then amortized to profit or loss over the 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 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 reclassified 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, except for cash flow hedges of variable interest rate risk which are reclassified to finance costs.
If the hedging instrument expires or is sold, terminated or exercised without replacement or rollover, or if its designation as a hedge is revoked, amounts previously recognized within other comprehensive income remain in equity until the forecast transaction occurs and are reclassified to the income statement or 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 the income statement.

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

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 judgement and estimate: derivative contracts

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 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 and modelled using the maximum available external pricing information. Additionally, where limited data exists for certain products, prices are determined using historic and long-term pricing relationships. Price volatility is also an input for options models. Changes in the key assumptions could have a material impact on the carrying amounts of derivative assets and liabilities in the next financial year. For more information see Note 28.

In some cases, judgement is required to determine whether contracts to buy or sell commodities meet the definition of a derivative. Contracts to buy and sell LNG are not considered to meet the definition as they are not considered capable of being net settled and so are accounted for on an accruals basis.

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. A provision is discounted using either a nominal discount rate of 2.5% (2016 2%) or a real discount rate of 0.5% (2016 0.5%), as appropriate. Provisions are split between amounts expected to be settled within 12 months of the balance sheet date (current) and amounts expected to be settled later (non-current).

Contingent liabilities are possible obligations whose existence will only be confirmed by future events not wholly within the control of the group, or present obligations where it is not probable that an outflow of resources will be required or the amount of the obligation cannot be measured with sufficient reliability. Contingent liabilities are not recognized in the 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 current prices or future assumptions, depending on the expected timing of the activity, and discounted using the real discount rate. The weighted average period over which these costs are generally expected to be incurred is estimated to be approximately 17 years.

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 the provision, any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding asset.

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 current prices and discounted using a real discount rate. The weighted average period over which these costs are generally expected to be incurred is estimated to be approximately five years.

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

Significant judgements and estimates: provisions

For information on estimates and judgements relating to the Gulf of Mexico oil spill, see Note 2.

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.

Decommissioning provisions associated with downstream 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 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 2017 was a real rate of 0.5% (2016 0.5%), which was based on long-dated US government bonds.

Further information about the group’s provisions is provided in Note 21. 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.

As described in Note 31, the group is subject to further claims and actions for which no provisions have been recognized. The facts and circumstances relating to particular cases are evaluated regularly in determining whether a provision relating to a specific litigation should be recognized or revised. Accordingly, significant management judgement relating to provisions and contingent liabilities is required, since the outcome of litigation is difficult to predict.

Employee benefits

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

Share-based payments

Equity-settled transactions

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

For other equity-settled share-based payment transactions, the goods or services received and the corresponding increase in equity are measured at the fair value of the goods or services received unless their fair value cannot be reliably estimated. If the fair value of the goods and services received cannot be reliably estimated, the transaction is measured by reference to the fair value of the equity instruments granted.

Cash-settled transactions

The cost of cash-settled transactions is recognized as an expense over the vesting period, measured by reference to the fair value of the corresponding liability which is recognized on the balance sheet. The liability is remeasured at fair value at each balance sheet date until settlement, with changes in fair value recognized in the income statement.

Pensions and other post-retirement benefits

The cost of providing benefits under the group's defined benefit plans is determined separately for each plan using the projected unit credit method, which attributes entitlement to benefits to the current period to determine current service cost and to the current and prior periods to determine the present value of the defined benefit obligation. Past service costs, resulting from either a plan amendment or a curtailment (a reduction in future obligations as a result of a material reduction in the plan membership), are recognized immediately when the company becomes committed to a change.

Net interest expense relating to pensions and other post-retirement benefits, which is recognized in the income statement, represents the net change in present value of plan obligations and the value of plan assets resulting from the passage of time, and is determined by applying the discount rate to the present value of the benefit obligation at the start of the year, and to the fair value of plan assets at the start of the year, taking into account expected changes in the obligation or plan assets during the year.

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

Remeasurements of the defined benefit liability and asset, comprising actuarial gains and losses, and the return on plan assets (excluding amounts included in net interest described above) are recognized within other comprehensive income in the period in which they occur and are not subsequently reclassified to profit and loss.

The defined benefit pension plan surplus or deficit recognized on the balance sheet for each plan comprises the difference between the present value of the defined benefit obligation (using a discount rate based on high quality corporate bonds) and the fair value of plan assets out of which the obligations are to be settled directly. Fair value is based on market price information and, in the case of quoted securities, is the published bid price. Defined benefit pension plan surpluses are only recognized to the extent they are recoverable, typically by way of refund.

Contributions to defined contribution plans are recognized in the income statement in the period in which they become payable.

Significant estimate: pensions 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. 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 22.

Income taxes

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

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

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

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

- where the deferred tax liability arises on the initial recognition of goodwill
- where the deferred tax liability arises on the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither accounting profit nor taxable profit or loss
- in respect of taxable temporary differences associated with investments in subsidiaries and associates and interests in joint arrangements, where the group is able to control the timing of the reversal of the temporary differences and it is probable that the temporary differences will not reverse in the foreseeable future.

Deferred tax assets are recognized for deductible temporary differences, carry-forward of unused tax credits and unused tax losses, to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax credits and unused tax losses can be utilized except where the deferred tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither accounting profit nor taxable profit or loss. In respect of deductible temporary differences associated with investments in subsidiaries and associates and interests in joint arrangements, deferred tax assets are recognized only to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available against which the temporary differences can be utilized.

The carrying amount of deferred tax assets is reviewed at each balance sheet date and reduced to the extent that it is no longer probable 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 using either the most likely amount or an expected value, depending on which method better predicts the resolution of the uncertainty.

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

Significant judgements and estimates: income taxes

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.

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 7.

The United States Tax Cuts and Jobs Act (‘the Act’) was signed into US law on 22 December 2017 and introduces significant modifications to income tax rates and the overall basis for determining tax payable on the foreign earnings of US group companies. Changes to current and deferred tax have been made based on the newly enacted law which is still subject to further clarification. Estimates and assumptions have been made where necessary to assess the impact of the Act on the group's tax balances and positions. These calculations will continue to be refined as information and clarifications from US legislative and regulatory bodies become available. See Note 7 for further information on the impact for the year ended 31 December 2017.

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 on an appropriate basis. In December 2016 BP renewed its onshore concession in Abu Dhabi. As a result of changes in the fiscal terms of the arrangement, the group's taxes payable relating to the concession are now principally reported as income taxes rather than as production taxes.

Customs duties and sales taxes

Customs duties and sales taxes which are passed on 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 at cost. 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 financial statements as treasury shares. Consideration, if any, received for the sale of such shares is also recognized in equity, with any difference between the proceeds from sale and the original cost being taken to the profit and loss account reserve. No gain or loss is recognized in the income statement on the purchase, sale, issue or cancellation of equity shares. Shares repurchased under the share buy-back programme which are immediately cancelled are not shown as treasury shares, but are shown as a deduction from the profit and loss account reserve in the group statement of changes in equity.

Revenue

Revenue arising from the sale of goods is recognized when the significant risks and rewards of ownership have passed to the buyer, which is typically at the point that title passes, and the revenue can be reliably measured.

Revenue is measured at the fair value of the consideration received or receivable and represents amounts receivable for goods provided in the normal course of business, net of discounts, customs duties and sales taxes.

Physical exchanges are reported net, as are sales and purchases made with a common counterparty, as part of an arrangement similar to a physical exchange. Similarly, 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. Additionally, 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.

Generally, revenues from the production of oil and natural gas properties in which the group has an interest with joint operation partners are recognized on the basis of the group's working interest in those properties (the entitlement method). Differences between the production sold and the group's share of production are not significant.

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

The group adopted Disclosure Initiative: Amendments to IAS 7 'Statement of cash flows' with effect from 1 January 2017. The amendments require the disclosure of information that enables users of the financial statements to evaluate changes in liabilities arising from financing activities, including changes arising from cash flows and non-cash changes. The amendments do not have any impact upon the primary financial statements. See Note 25 for further information.

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

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

Not yet adopted

The following three pronouncements from the IASB will become effective for future financial reporting periods and have not been adopted by the group in these financial statements. Each of the standards has been adopted by the EU. There are no other standards and 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 9 'Financial Instruments'

IFRS 9 ‘Financial Instruments’ was issued in July 2014 and replaces IAS 39 ‘Financial Instruments: Recognition and Measurement.’ BP will adopt IFRS 9 in the financial reporting period commencing 1 January 2018.

IFRS 9 provides a single classification and measurement approach for financial assets that reflects the business model in which they are managed and their cash flow characteristics. Under the new standard the group’s financial assets will be classified as measured at amortised cost, fair value through profit or loss, or fair value through other comprehensive income. For financial liabilities the existing classification and measurement requirements of IAS 39 are largely retained. Whilst financial assets will be reclassified into the categories required by IFRS 9, the group has not identified any significant impacts on the measurement of its financial assets and financial liabilities as a result of the classification and measurement requirements of the new standard. However, for existing equity instruments classified as available-for-sale investments under IAS 39, we intend to recognize fair value gains and losses in profit or loss under IFRS 9, rather than in other comprehensive income as was the case under IAS 39. An adjustment to the 2018 opening balance sheet is expected to be made to transfer $17 million of fair value gains net of related tax from the available-for-sale investments reserve to the profit and loss account reserve. Prospectively, fair value gains and losses on new equity instruments may be recognized either in profit or loss or in other comprehensive income as an election on an instrument-by-instrument basis on initial recognition.

The financial asset impairment requirements of IFRS 9 introduce a forward-looking expected credit loss model that results in earlier recognition of credit losses than the incurred loss model of IAS 39. Given the short-term nature of the majority of its financial assets and the group’s active management of credit risk, the group does not expect a significant impact on adoption of IFRS 9’s impairment requirements. The adjustment to the 2018 opening balance sheet, which will reduce both the carrying amounts of financial assets and the profit and loss account reserve, makes up the majority of the adjustment on adoption of IFRS 9 in the table below. Subsequent movements in the expected loss reserve will be recognized in profit or loss.

The hedge accounting requirements of IFRS 9 have been simplified and are more closely aligned to an entity’s risk management strategy. Under IFRS 9 all existing hedging relationships will qualify as continuing hedging relationships and the group also intends to apply hedge accounting prospectively to certain of its commodity price risk management activities for which hedge accounting was not possible under IAS 39. This will have no impact on the 2018 opening balance sheet.

IFRS 9 also introduces a new way of treating fair value movements on the time value and cross currency basis spreads of certain hedging instruments. Whereas under IAS 39 these movements were recognized in profit or loss, the group is either required, or will elect, to initially recognize these movements within equity to the extent that they relate to the hedged item. An adjustment to the 2018 opening balance sheet is expected to be made to transfer $37 million of losses net of related tax from the profit and loss account reserve to the costs of hedging reserve for relevant hedging instruments existing on transition.

The expected overall impact of transition on 2018 opening net assets is summarized below.

	$ million Net assets
At 31 December 2017	100,404
Adjustment on adoption of IFRS 9 net of tax and including the group's share of equity-accounted entities[a]	(180)
At 1 January 2018	100,224

[a] The adjustment on adoption of IFRS 9 mainly relates to an increase in the credit reserve of financial assets in the scope of IFRS 9’s impairment requirements. IFRS 9 requires credit losses to be recognized on an expected rather

than incurred loss basis as was the case under IAS 39. The profit and loss account reserve is expected to reduce by an equivalent amount.

Other minor reserves adjustments, as described above, are expected to result in an increase to the profit and loss reserve of $54 million offset by a reduction in the available-for-sale reserve of $17 million and creation of the costs of hedging reserve of $37 million.

Under IAS 39 the effective portion of the gain or loss on a cash flow hedging instrument is reported in other comprehensive income and is reclassified to the balance sheet as part of the initial carrying amount of the corresponding non-financial asset or liability. Under IFRS 9 the effective portion of the gain or loss continues to be reported in the statement of other comprehensive income but the transfer to the balance sheet will be shown in the statement of changes in equity.

IFRS 15 ‘Revenue from Contracts with Customers’

IFRS 15 ‘Revenue from Contracts with Customers’ was issued in May 2014 and replaces IAS 18 ‘Revenue’ and certain other standards and interpretations. IFRS 15 provides a single model of accounting for revenue arising from contracts with customers, focusing on the identification and satisfaction of performance obligations. BP will adopt IFRS 15 in the financial reporting period commencing 1 January 2018 and has elected to apply the 'modified retrospective' transition approach to implementation.

Under IFRS 15, revenue from contracts with customers is recognized when or as the group satisfies a performance obligation by transferring a promised good or service to a customer. A good or service is transferred when the customer obtains control of that good or service. The transfer of control of oil, natural gas, natural gas liquids, LNG, petroleum and chemical products, and other items sold by the group 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 and the amounts of revenue recognized relating to performance obligations satisfied over time are not significant. The accounting for revenue under IFRS 15 does not, therefore, represent a substantive change from the group’s current practice for recognizing revenue from sales to customers.

Certain changes in accounting arising from the implementation of IFRS 15 have been identified but the new standard has had no material effect on the group’s net assets as at 1 January 2018 and so no transition adjustment will be presented.

The most significant change identified is the accounting for revenues relating to oil and natural gas properties in which the group has an interest with joint operation partners. From 1 January 2018, BP ceased recognizing revenue in relation to the group's entitlement to the production from oil and gas properties based on its working interest, irrespective of whether the production was taken and sold to customers.

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

In its 2018 financial statements the group will recognize revenue when sales are made to customers and production costs will be accrued or deferred to reflect differences between volumes taken and sold to customers and the group's ownership interest in total production volumes. This may result in changes in revenues and profits recognized in each period, but there will be no change in the total revenues and profits over the duration of the joint operation. Variability in oil and gas prices and the timing of when each partner in a joint operation takes its share of production mean that the precise impact on the group's revenues and profits in any particular future period is uncertain. However, the impact on the group's reported net assets as at 31 December 2017 and its reported profit for the year ended 31 December 2017 of applying this accounting would not have been material.

IFRS 15 requires the disclosure of revenue from contracts with customers disaggregated into categories that depict how the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors. It is the group's intention to provide additional disclosure of revenue from contracts with customers disaggregated by product grouping. The group's sales and other operating revenues as reported for 2016 and 2017 by product grouping are presented below:

		$ million
	2017	2016
Crude oil	49,670	32,284
Oil products	159,821	126,465
Natural gas and NGLs	16,196	11,337
Non-oil products and other operating revenues from contracts with customers	12,538	11,487
Revenue from contracts with customers[a]	238,225	181,573
Other revenues	1,983	1,435
Sales and other operating revenues[a]	240,208	183,008

a Amounts presented for 2016 and 2017 include revenues from the production of oil and natural gas properties in which the group has an interest with joint operation partners determined using the entitlements method in accordance with the group's accounting policy for those periods (see Revenue above). The amounts presented do not, therefore, represent the Revenue from contracts with customers or Sales and other operating revenues that would have been reported for those periods had IFRS 15 been applied using a fully retrospective transition approach. The differences are not significant. No restatement of prior periods will be made in relation to this change.

IFRS 16 'Leases'

IFRS 16 'Leases' provides a new model for lessee accounting in which all leases, other than short-term leases and leases of low-value items, will be accounted for by the recognition on the balance sheet of a right-to-use asset and a lease liability. The subsequent amortization of the right-to-use asset and the interest expense related to the lease liability will be recognized in profit or loss over the lease term. IFRS 16 replaces IAS 17 'Leases' and IFRIC 4 'Determining whether an arrangement contains a lease' and will be effective for financial reporting periods beginning on or after 1 January 2019.

BP will adopt IFRS 16 on 1 January 2019. An implementation project was initiated in 2016 and work is progressing including a system solution to hold lease data and generate accounting entries. Work streams have also been initiated to cover data and processes, accounting policy development and the impacts on key performance indicators and financial metrics.

On transition, BP intends to use the modified retrospective approach permitted by the standard in which the cumulative effect of initially applying the standard is recognized in opening retained earnings at the date of initial application with no restatement of comparative periods' financial information.

IFRS 16 introduces a revised definition of a lease. As permitted by the standard, BP does not intend to reassess the existing population of leases under the new definition and will only apply the new definition for the assessment of contracts entered into after the transition date.

The group's evaluation of the effect of adoption of the standard is ongoing but it is expected that it will have a material effect on the group's financial statements, significantly increasing the group's recognized assets and liabilities. It is expected that the presentation and timing of recognition of charges in the income statement will also change as the operating lease expense currently reported under IAS 17, typically on a straight-line basis, will be replaced by depreciation of the right-to-use asset and interest on the lease liability. In the cash flow statement operating lease payments are currently presented within cash flows from operating activities but under IFRS 16 payments will be presented as financing cash flows, representing repayments of debt, 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.

Information on the group’s leases currently classified as operating leases, which are not recognized on the balance sheet, is presented in Note 26 and provides an indication of the magnitude of assets and liabilities that will be recognized on the balance sheet from 2019. However, the commitments information provided in Note 26 is on an undiscounted basis whereas the amounts recognized under the new standard will be on a discounted basis. The discount rates to be used on transition will be incremental borrowing rates as appropriate for each lease based on factors such as the lessee legal entity, lease term and currency. Currently the range of such incremental borrowing rates applicable for the majority of the leases for the group is 2% to 7%, with the rate primarily determined by the country of operation. There will likely be other differences in the amounts recognized and our evaluation of the precise impacts is ongoing. In particular, we are considering the accounting for leases of assets within joint operations within the Upstream segment. The operating lease commitments for leases within joint operations are included on the basis of BP’s net working interest for the information provided in Note 26, irrespective of whether BP is the operator and whether the lease has been co-signed by the joint operators or not. In certain circumstances, where BP is the operator, it may be appropriate under IFRS 16 to recognize 100% of the future lease payments as the right-of-use asset and/or the lease liability. Similarly, it may be appropriate under IFRS 16 to recognize no right-of-use asset or lease liability in cases where BP is not the operator and is not a signatory to the lease. Our evaluation of this aspect is not yet complete. This could materially affect the amounts recognized relating to leases of drilling rigs for which BP's share of operating lease commitments at 31 December 2017 amounted to $2,088 million on an undiscounted basis.

2. Significant event – Gulf of Mexico oil spill

As a consequence of the Gulf of Mexico oil spill in April 2010, BP continues to incur costs and has also recognized liabilities for certain future costs.

The impacts of the Gulf of Mexico oil spill on the income statement, balance sheet and cash flow statement of the group are included within the relevant line items in those statements and are shown in the table below.

			$ million
	2017	2016	2015
Income statement			
Production and manufacturing expenses	2,687	6,640	11,709
Profit (loss) before interest and taxation	(2,687)	(6,640)	(11,709)
Finance costs	493	494	247
Profit (loss) before taxation	(3,180)	(7,134)	(11,956)
Less: Taxation	(2,222)	3,105	3,492
Profit (loss) for the period	(5,402)	(4,029)	(8,464)
Balance sheet			
Current assets			
Trade and other receivables	252	194	
Current liabilities			
Trade and other payables	(2,089)	(3,056)	
Provisions	(1,439)	(2,330)	
Net current assets (liabilities)	(3,276)	(5,192)	
Non-current assets			
Deferred tax	2,067	2,973	
Non-current liabilities			
Other payables	(12,253)	(13,522)	
Provisions	(1,141)	(112)	
Deferred tax	3,634	5,119	
Net non-current assets (liabilities)	(7,693)	(5,542)	
Net assets (liabilities)	(10,969)	(10,734)	
Cash flow statement			
Profit (loss) before taxation	(3,180)	(7,134)	(11,956)
Net charge for interest and other finance expense, less net interest paid	493	494	247
Net charge for provisions, less payments	2,542	4,353	11,296
(Increase) decrease in other current and non-current assets	(1,738)	(3,210)	—
Increase (decrease) in other current and non-current liabilities	(3,453)	(1,608)	(732)
Pre-tax cash flows	(5,336)	(7,105)	(1,145)

Income statement

The group income statement for 2017 includes a pre-tax charge of $3,180 million (2016 pre-tax charge of $7,134 million) in relation to the Gulf of Mexico oil spill. The charge within production and manufacturing expenses in 2017 of $2,687 million (2016 $6,640 million) relates mainly to an increase in the provision relating to business economic loss (BEL) and other claims associated with the Deepwater Horizon Court Supervised Settlement Program (DHCSSP). The increase in the provision is primarily a result of significantly higher average claims determinations issued by the DHCSSP in the fourth quarter of the year and the continuing effect of the Fifth Circuit's May 2017 opinion on the matching of revenues with expenses when evaluating BEL claims. Finance costs of $493 million (2016 $494 million) reflect the unwinding of the discount on payables and, for 2016, provisions. Taxation includes a charge of $3,012 million in respect of the revaluation of US deferred tax assets related to the Gulf of Mexico oil spill following the reduction in the US federal corporate income tax rate from 35% to 21% enacted in December 2017.

The cumulative amount charged to the income statement to date comprises spill response costs arising in the aftermath of the incident, amounts charged for the 2012 agreement with the US government to resolve all federal criminal claims arising from the incident, amounts charged for the 2016 consent decree and settlement agreement with the

United States and the five Gulf coast states including amounts payable for natural resource damages, state claims and Clean Water Act penalties, operating costs, amounts charged upon initial recognition of the trust obligation, other litigation, claims, environmental and legal costs and estimated obligations for future costs, net of settlements agreed with the co-owners of the Macondo well and other third parties.

The cumulative pre-tax income statement charge since the incident amounts to $65.8 billion and is analysed in the table below.

				$ million
	2017	2016	2015	Cumulative since the incident
Environmental costs	—	—	5,303	8,526
Spill response costs	—	—	—	14,304
Litigation and claims costs	2,647	6,596	5,758	41,781
Clean Water Act penalties	—	—	551	4,061
Other costs	40	44	97	1,309
Settlements credited to the income statement	—	—	—	(5,681)
(Profit) loss before interest and taxation	2,687	6,640	11,709	64,300
Finance costs	493	494	247	1,465
(Profit) loss before taxation	3,180	7,134	11,956	65,765

2. Significant event – Gulf of Mexico oil spill – continued

Provisions and contingent liabilities

Provisions

Movements during the year in the remaining provision, which relates to litigation and claims, are presented in the table below.

	$ million
	2017
	Litigation and claims
At 1 January	2,442
Increase in provision	2,647
Reclassified to other payables	(759)
Utilization	(1,750)
At 31 December	2,580
Of which – current	1,439
– non-current	1,141

Litigation and claims – PSC settlement

The Economic and Property Damages Settlement Agreement (EPD Settlement Agreement) with the Plaintiffs' 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 270.

The litigation and claims provision reflects the latest estimate for the remaining costs associated with the PSC settlement. These costs relate predominantly to BEL claims and associated administration costs. The amounts ultimately payable may differ from the amount provided and the timing of payments is uncertain.

The increase in the provision in the year is primarily a result of significantly higher average BEL claims determinations issued by the DHCSSP during the fourth quarter of the year and the effect of the May 2017 Fifth Circuit opinion on the policy addressing the matching of revenue with expenses in relation to BEL claims. See Legal proceedings on page 270 for further details on the May 2017 Fifth Circuit opinion and related appeals.

The DHCSSP's determination of BEL claims was substantially completed by the end of 2017. Nevertheless, a significant number of BEL claims determined by the DHCSSP have been and continue to be appealed by BP and/or the claimants, with the total value of claims under appeal or eligible for appeal approximately doubling during the fourth quarter of the year. The DHCSSP has reported that the total determinations for all economic and property damages claims amounted to $14.2 billion and the total amount paid with respect to such claims was $11.2 billion, in each case as at 31 December 2017. The difference in the above DHCSSP amounts primarily relates to determinations of BEL claims under appeal or eligible for appeal, along with certain other items, including claims determined eligible for payment and which are not being appealed.

The amount provided for includes the latest estimate of the amounts that are expected ultimately to be paid to resolve outstanding BEL claims. 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 (including how such resolution may be impacted by the May 2017 Fifth Circuit opinion), the amounts payable may differ from those currently provided.

The DHCSSP is expected to issue determinations with respect to remaining BEL claims in the first half of 2018. Whilst BP has a better understanding of the total population of remaining claims, there is uncertainty around how these claims will ultimately be determined, including in relation to the impact of the May 2017 Fifth Circuit opinion on the determination of such claims.

Payments to resolve outstanding claims under the PSC settlement are now expected to be made over a number 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.

Contingent liabilities

For information on legal proceedings relating to the Deepwater Horizon oil spill, see Legal proceedings on pages 270-273. Any further outstanding Deepwater Horizon related claims are not expected to have a material impact on the group's financial performance.

Other payables

Other payables 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 $5,556 million, $2,841 million and $4,047 million respectively at 31 December 2017. For full details of these agreements, see BP Annual Report and Form 20-F 2015.

In addition, other payables at 31 December 2017 also includes $1,209 million in relation to the 2012 agreement with the US government to resolve all federal criminal claims arising from the incident, which falls due in 2018.

Cash flow statement

The impact on net cash provided by operating activities on a pre-tax basis amounted to an outflow of $5,336 million (2016 outflow of $7,105 million, 2015 outflow of $1,145 million). On a post-tax basis, the amounts were an outflow of $5,167 million (2016 outflow of $6,892 million and 2015 outflow of $1,130 million).

Cash outflows in 2016 and 2017 include payments made under the 2012 agreement with the US government to resolve all federal criminal claims arising from the incident and the 2016 consent decree and settlement agreement with the United States and the five Gulf coast states.

3. Disposals and impairment

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

			$ million
	2017	2016	2015
Gains on sale of businesses and fixed assets			
Upstream	526	557	324
Downstream	674	561	316
Other businesses and corporate	10	14	26
	1,210	1,132	666

			$ million
	2017	2016	2015
Losses on sale of businesses and fixed assets			
Upstream	127	169	124
Downstream	88	89	98
Other businesses and corporate	—	3	41
	215	261	263
Impairment losses			
Upstream	1,138	1,022	2,484
Downstream	69	84	265
Other businesses and corporate	32	11	155
	1,239	1,117	2,904
Impairment reversals			
Upstream	(176)	(3,025)	(1,080)
Downstream	(62)	(17)	(178)
	(238)	(3,042)	(1,258)
Impairment and losses on sale of businesses and fixed assets	1,216	(1,664)	1,909

Disposals

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

			$ million
	2017	2016	2015
Proceeds from disposals of fixed assets	2,936	1,372	1,066
Proceeds from disposals of businesses, net of cash disposed	478	1,259	1,726
	3,414	2,631	2,792
By business			
Upstream	1,183	839	769
Downstream	2,078	1,646	1,747
Other businesses and corporate	153	146	276
	3,414	2,631	2,792

At 31 December 2017, deferred consideration relating to disposals amounted to $259 million receivable within one year (2016 $255 million and 2015 $41 million) and $268 million receivable after one year (2016 $271 million and 2015 $385 million). In addition, contingent consideration receivable relating to the disposals amounted to $237 million at 31 December 2017 (2016 $131 million and 2015 $292 million).

Upstream

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.

In 2016, gains principally resulted from the contribution of BP's Norwegian upstream business into Aker BP ASA and from the sale of certain properties in the UK.

In 2015, gains principally resulted from the sale of our interests in the Central Area Transmission System in the North Sea, and from adjustments to prior year disposals in Canada.

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.

In 2016, gains principally resulted from the disposal of certain US and non-US midstream assets in our fuels business and the dissolution of our German refining joint operation with Rosneft.

In 2015, gains principally resulted from the disposal of our investment in the UTA European fuel cards business and our Australian bitumen business.

3. Disposals and impairment – continued

Summarized financial information relating to the sale of businesses is shown in the table below. 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. The principal transactions categorized as business disposals in 2016 were the contribution of BP's Norwegian upstream business into Aker BP ASA and the dissolution of the group's German refining joint operation with Rosneft. The principal transactions categorized as business disposals in 2015 were the sales of our interests in the Central Area Transmission System in the North Sea and in the UTA European fuel cards business.

			$ million
	2017	2016	2015
Non-current assets	735	4,794	154
Current assets	57	1,202	80
Non-current liabilities	(173)	(2,558)	(70)
Current liabilities	(86)	(532)	(50)
Total carrying amount of net assets disposed	533	2,906	114
Recycling of foreign exchange on disposal	—	25	16
Costs on disposal[a]	3	229	8
	536	3,160	138
Gains on sale of businesses[b]	44	593	446
Total consideration	580	3,753	584
Non-cash consideration[c]	(216)	(2,698)	—
Consideration received (receivable)[d]	121	223	1,116
Proceeds from the sale of businesses related to completed transactions	485	1,278	1,700
Deposits[e]	(7)	(19)	26
Proceeds from the sale of businesses, net of cash disposed[f]	478	1,259	1,726

[a] 2016 includes amounts relating to the remeasurement to fair value of certain assets as a result of the dissolution of our German refining joint operation with Rosneft.

[b] 2016 gains on sale of businesses include deferred amounts not recognized in the income statement.

[c] 2016 non-cash consideration principally relates to the contribution of BP's Norwegian upstream business into Aker BP ASA in exchange for 30% interest in Aker BP ASA and the dissolution of the group's German refining joint operation with Rosneft.

[d] Consideration received from prior year business disposals or to be received from current year disposals. 2015 included $1,079 million of proceeds from our Toledo refinery partner, Husky Energy, in place of capital commitments relating to the original divestment transaction that have not been subsequently sanctioned.

[e] Proceeds received in the current year in advance of business disposals, less deposits received in prior years in relation to business disposals completed in the current year.

[f] Proceeds are stated net of cash and cash equivalents disposed of $25 million (2016 $676 million and 2015 $9 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 10, Note 13 and Note 19 for further information on impairments by asset category.

Upstream

Impairment losses and reversals related primarily to producing and midstream assets.

The 2017 impairment losses of $1,138 million related to a number of different assets, with the most significant charges arising in Lower 48 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.

The 2016 impairment losses of $1,022 million related to a number of different assets, with the most significant charges arising in the North Sea. Impairment losses within Upstream arose primarily as a result of revised cost estimates and decisions to dispose of certain assets.

The 2016 impairment reversals of $3,025 million primarily related to the North Sea and Angola. The largest impairment reversals related to the Andrew area cash-generating unit (CGU) in the North Sea and the PSVM and Greater Plutonio CGUs in Angola but none of these were individually significant. In addition an impairment reversal was recorded in relation to the Block KG D6 CGU in India; and exploration costs were also written back during the period (see Note 6). The impairment reversals arose following a reduction in the discount rate applied, changes to future price assumptions, and also increased confidence in the progress of the KG D6 projects in India.

The 2015 impairment losses of $2,484 million included $761 million in Angola, of which $371 million related to the Greater Plutonio CGU. Impairment losses also included $830 million in relation to CGUs in the North Sea, of which $328 million related to the Andrew area CGU. The impairment losses primarily arose as a result of a lower price environment in the near term, and were also affected to a lesser extent by certain technical reserves revisions and increases in decommissioning cost estimates. The 2015 impairment reversals of $1,080 million included $945 million in the North Sea business, of which $473 million related to the Eastern Trough Area Project (ETAP) CGU. The impairment reversals mainly arose as a result of decreases in cost estimates and a reduction in the discount rate applied, offsetting the impact of lower prices in the near term.

Downstream

Impairment losses totalling $69 million, $84 million, and $265 million were recognized in 2017, 2016 and 2015 respectively. The amount for 2015 was principally in relation to certain manufacturing assets in our petrochemicals business and certain US midstream assets, where the expected disposal proceeds were lower than the book values.

Other businesses and corporate

Impairment losses totalling $32 million, $11 million, and $155 million were recognized in 2017, 2016 and 2015 respectively. The amount for 2015 was principally in respect of our US wind business.

4. Segmental analysis

The group's organizational structure reflects the various activities in which BP is engaged. At 31 December 2017, 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.

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

4. Segmental analysis – continued

By business	Upstream	Downstream	Rosneft	Other businesses and corporate	Consolidation adjustment and eliminations	$ million 2017 Total group
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 (loss) 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
Segment assets						
Investments in joint ventures and associates	12,093	2,349	10,059	484	—	24,985
Additions to non-current assets[b]	14,500	2,677	—	275	—	17,452

[a] See explanation of inventory holding gains and losses on page 147.

[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	$ million 2016 Total group

Segment revenues						
Sales and other operating revenues	33,188	167,683	—	1,667	(19,530)	183,008
Less: sales and other operating revenues between segments	(17,581)	(1,291)	—	(658)	19,530	—
Third party sales and other operating revenues	15,607	166,392	—	1,009	—	183,008
Earnings from joint ventures and associates – after interest and tax	723	608	647	(18)	—	1,960
Segment results						
Replacement cost profit (loss) before interest and taxation	574	5,162	590	(8,157)	(196)	(2,027)
Inventory holding gains (losses)[a]	60	1,484	53	—	—	1,597
Profit (loss) before interest and taxation	634	6,646	643	(8,157)	(196)	(430)
Finance costs						(1,675)
Net finance expense relating to pensions and other post-retirement benefits						(190)
Profit (loss) before taxation						(2,295)
Other income statement items						
Depreciation, depletion and amortization						
US	4,396	856	—	71	—	5,323
Non-US	7,835	1,094	—	253	—	9,182
Charges for provisions, net of write-back of unused provisions, including change in discount rate	352	758	—	6,719	—	7,829
Segment assets						
Investments in joint ventures and associates	10,968	3,035	8,243	455	—	22,701
Additions to non-current assets[b]	17,879	3,109	—	216	—	21,204

[a] See explanation of inventory holding gains and losses on page 147.

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

4. Segmental analysis – continued

By business	Upstream	Downstream	Rosneft	Other businesses and corporate	Consolidation adjustment and eliminations	$ million 2015 Total group
Segment revenues						
Sales and other operating revenues	43,235	200,569	—	2,048	(22,958)	222,894
Less: sales and other operating revenues between segments	(21,949)	(68)	—	(941)	22,958	—
Third party sales and other operating revenues	21,286	200,501	—	1,107	—	222,894
Earnings from joint ventures and associates – after interest and tax	192	491	1,330	(202)	—	1,811
Segment results						
Replacement cost profit (loss) before interest and taxation	(937)	7,111	1,310	(13,477)	(36)	(6,029)
Inventory holding gains (losses)[a]	(30)	(1,863)	4	—	—	(1,889)
Profit (loss) before interest and taxation	(967)	5,248	1,314	(13,477)	(36)	(7,918)
Finance costs						(1,347)
Net finance expense relating to pensions and other post-retirement benefits						(306)
Profit before taxation						(9,571)
Other income statement items						
Depreciation, depletion and amortization						
US	4,007	906	—	77	—	4,990
Non-US	8,866	1,162	—	201	—	10,229
Charges for provisions, net of write-back of unused provisions, including change in discount rate	824	611	—	11,781	—	13,216
Segment assets						
Investments in joint ventures and associates	8,304	3,214	5,797	519	—	17,834
Additions to non-current assets[b]	17,635	2,130	—	315	—	20,080

[a] See explanation of inventory holding gains and losses on page 147.

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

By geographical area	US	Non-US	$ 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
Results			

Replacement cost profit (loss) before interest and taxation	(266)	8,887	8,621
Non-current assets			
Non-current assets[b c]	61,828	123,646	185,474

[a] Non-US region includes UK $48,837 million.

[b] Non-US region includes UK $18,004 million.

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

			$ million 2016
By geographical area	US	Non-US	Total
Revenues			
Third party sales and other operating revenues[a]	65,132	117,876	183,008
Other income statement items			
Production and similar taxes	155	528	683
Results			
Replacement cost profit (loss) before interest and taxation	(8,311)	6,284	(2,027)
Non-current assets			
Non-current assets[b c]	64,628	118,152	182,780

[a] Non-US region includes UK $37,119 million.

[b] Non-US region includes UK $18,615 million.

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

4. Segmental analysis – continued

			$ million 2015
By geographical area	US	Non-US	Total
Revenues			
Third party sales and other operating revenues[a]	74,162	148,732	222,894
Other income statement items			
Production and similar taxes	215	821	1,036
Results			
Replacement cost profit (loss) before interest and taxation	(12,243)	6,214	(6,029)
Non-current assets			
Non-current assets[b c]	67,776	111,106	178,882

[a] Non-US region includes UK $51,550 million.
[b] Non-US region includes UK $19,152 million.
[c] Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

5. Income statement analysis

			$ million
	2017	2016	2015
Interest and other income			
Interest income	288	183	226
Other income	369	323	385
	657	506	611
Currency exchange losses charged to the income statement[a]	83	698	8
Expenditure on research and development	391	400	418
Finance costs			
Interest payable	1,718	1,221	1,065
Capitalized at 2.25% (2016 1.81% and 2015 1.75%)[b]	(297)	(244)	(179)
Unwinding of discount on provisions and other payables	653	698	461
	2,074	1,675	1,347

[a] Excludes exchange gains and losses arising on financial instruments measured at fair value through profit or loss.
[b] Tax relief on capitalized interest is approximately $64 million (2016 $56 million and 2015 $42 million).

6. 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 within Note 1.

			$ million
	2017	2016	2015
Exploration and evaluation costs			
Exploration expenditure written off[a]	1,603	1,274	1,829
Other exploration costs	477	447	524
Exploration expense for the year	2,080	1,721	2,353
Impairment losses	—	62	—
Intangible assets – exploration and appraisal expenditure	17,026	16,960	17,286
Liabilities	82	102	145

Net assets	16,944	16,858	17,141
Cash used in operating activities	477	447	524
Cash used in investing activities	1,901	2,920	1,216

[a] 2017 includes a write-off 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 includes 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. 2016 included a $601-million write-off in Brazil relating to the BM-C-34 licence and various write-offs in the Gulf of Mexico totalling $611 million and India totalling $216 million, partially offset by a write-back of $319 million in India relating to block KG D6 as a result of increased confidence in the progress of the projects. An impairment reversal of $234 million was also recorded in 2016 in relation to KG D6 in India. 2015 included a $432-million write-off in Libya as there was significant uncertainty about the timing of future drilling operations. It also included a $345-million write-off relating to the Gila discovery in the deepwater Gulf of Mexico and a $336-million write-off relating to the Pandora discovery in Angola as development of these prospects was considered challenging. For further information see Upstream – Exploration on page 29.

The carrying amount, by location, of exploration and appraisal expenditure capitalized as intangible assets at 31 December 2017 is shown in the table below.

Carrying amount	Location
$1 - 2 billion	Angola; India; Egypt; Middle East
$2 - 3 billion	US - Gulf of Mexico; Canada; Brazil

7. Taxation

Tax on profit

			$ million
	2017	2016	2015
Current tax			
Charge for the year	4,208	1,762	1,910
Adjustment in respect of prior years[a]	58	(123)	(329)
	4,266	1,639	1,581
Deferred tax[b]			
Origination and reversal of temporary differences in the current year	(503)	(3,709)	(5,090)
Adjustment in respect of prior years[c]	(51)	(397)	338
	(554)	(4,106)	(4,752)
Tax charge (credit) on profit or loss	3,712	(2,467)	(3,171)

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. 2017 includes a charge of $859 million in respect of the reduction in the US federal corporate income tax rate from 35% to 21%, effective from 1 January 2018; this 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 Deepwater Horizon Court Supervised Settlement Program (DHCSSP). The adjustments in respect of prior periods reflect the reassessment of deferred tax balances for prior years in light of all other changes in facts and circumstances during the year.

c 2016 included the reassessment of the recognition of deferred tax assets in relation to foreign tax credits in the US.

In 2017, the total tax charge recognized within other comprehensive income was $1,499 million (2016 $752 million credit and 2015 $1,140 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 30 for further information.

The total tax charge recognized directly in equity was $263 million (2016 $5 million credit and 2015 $9 million charge); for 2017 this relates to current tax on transactions with non-controlling interests.

For information on significant estimates and judgements made in relation to taxation see Income taxes within Note 1.

Reconciliation of the effective tax rate

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

For 2016 and 2015, the items presented in the reconciliation are affected as a result of the overall tax credit for the year and the loss before taxation. In order to provide a more meaningful analysis of the effective tax rate, the table also presents separate reconciliations for the group excluding the impacts of the Gulf of Mexico oil spill and impairment losses and reversals, and for the impacts of the Gulf of Mexico oil spill and impairment losses and reversals in isolation.

							$ million
	2017	2016 excluding impacts of Gulf of Mexico oil spill and impairments	2016 impacts of Gulf of Mexico oil spill and impairments	2016	2015 excluding impacts of Gulf of Mexico oil spill and impairments	2015 impacts of Gulf of Mexico oil spill and impairments	2015
Profit (loss) before taxation	7,180	2,914	(5,209)	(2,295)	4,031	(13,602)	(9,571)
Tax charge (credit) on profit or loss	3,712	(117)	(2,350)	(2,467)	945	(4,116)	(3,171)
Effective tax rate	52%	(4)%	45%	107%	23%	30%	33%

	% of profit or loss before taxation						
Tax rate computed at the weighted average statutory rate[a]	44	18	33	52	17	38	46
Increase (decrease) resulting from							
Tax reported in equity-accounted entities	(7)	(15)	—	19	(7)	—	3
Adjustments in respect of prior years	—	5	13	23	1	—	—
Deferred tax not recognized	9	26	3	(27)	17	(5)	(14)
Tax incentives for investment[b]	(6)	(9)	—	11	(10)	—	4
Gulf of Mexico oil spill non-deductible costs	1	—	(2)	(4)	—	(2)	(3)
Disposal impacts[c]	(1)	(24)	—	30	(3)	—	1
Foreign exchange	(4)	1	—	(2)	18	—	(8)
Items not deductible for tax purposes	5	8	—	(11)	10	—	(4)
Impact of US tax reform[d]	12	—	—	—	—	—	—
Decrease in rate of UK supplementary charge[e]	—	(15)	—	19	(23)	—	10
Other[b]	(1)	1	(2)	(3)	3	(1)	(2)
Effective tax rate	52	(4)	45	107	23	30	33

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. It reflects the mix of profits and losses arising in higher tax rate jurisdictions (primarily the Upstream segment) and lower tax rate jurisdictions (primarily the Downstream segment).

b A minor amendment has been made to 2015 to conform with current year presentation. There is no impact on 2016.

c In 2016 this related primarily to the tax impact on the contribution of BP's Norwegian upstream business into Aker BP ASA.

d 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.

e Relates to the deferred tax impact of the reductions in the UK supplementary charge rate applicable to profits arising in the North Sea from 20% to 10% in 2016 and from 32% to 20% in 2015.

7. Taxation – continued

Deferred tax

	$ million	
Analysis of movements during the year in the net deferred tax liability	2017	2016
At 1 January	2,497	8,054
Exchange adjustments	12	(71)
Charge (credit) for the year in the income statement	(554)	(4,106)
Charge (credit) for the year in other comprehensive income	1,503	(714)
Charge (credit) for the year in equity	1	(5)
Acquisitions and disposals	54	(661)
At 31 December	3,513	2,497

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

					$ million
		Income statement[a]			Balance sheet[a]
	2017	2016	2015	2017	2016
Deferred tax liability					
Depreciation	(3,971)	81	(102)	23,045	26,864
Pension plan surpluses	(12)	(12)	84	1,319	171
Derivative financial instruments	(27)	(230)	(326)	623	761
Other taxable temporary differences	(64)	(122)	59	1,317	1,254
	(4,074)	(283)	(285)	26,304	29,050
Deferred tax asset					
Pension plan and other post-retirement benefit plan deficits	340	98	12	(1,386)	(1,889)
Decommissioning, environmental and other provisions	3,503	591	(2,513)	(8,618)	(12,108)
Derivative financial instruments	(50)	(6)	62	(672)	(734)
Tax credits[b]	1,476	(5,177)	256	(3,750)	(5,225)
Loss carry forward	(964)	249	(2,239)	(6,493)	(5,458)
Other deductible temporary differences	(785)	422	(45)	(1,872)	(1,139)
	3,520	(3,823)	(4,467)	(22,791)	(26,553)
Net deferred tax charge (credit) and net deferred tax liability	(554)	(4,106)	(4,752)	3,513	2,497
Of which – deferred tax liabilities				7,982	7,238
– deferred tax assets				4,469	4,741

[a] The 2017 income statement and 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 2016 income statement reflected the impact of a loss carry-back claim in the US, displacing foreign tax credits utilized in prior periods which are now carried forward.

The recognition of deferred tax assets of $3,503 million (2016 $3,839 million), in entities which have suffered a loss in either the current or preceding period, is supported by forecasts which indicate that sufficient future taxable profits will be available to utilize such assets. For 2017, $2,067 million relates to the US (2016 $2,974 million) and $1,336 million relates to India (2016 $699 million).

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	2017	2016
Unused US state tax losses[a]	6.8	9.6
Unused tax losses – other jurisdictions[b]	4.5	5.2
Unused tax credits	20.1	19.2

of which – arising in the UK[c]	16.3	17.1
– arising in the US[d]	3.8	2.0
Deductible temporary differences[e]	31.4	26.7
Taxable temporary differences associated with investments in subsidiaries and equity-accounted entities	1.6	3.1

[a] These losses expire in the period 2018-2037 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] The US unused tax credits expire in the period 2018-2027.

[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	2017	2016	2015
Current tax benefit relating to the utilization of previously unrecognized deferred tax assets	22	40	123
Deferred tax benefit arising from the reversal of a previous write-down of deferred tax assets	—	269	—
Deferred tax benefit relating to the recognition of previously unrecognized deferred tax assets[a]	436	394	—
Deferred tax expense arising from the write-down of a previously recognized deferred tax asset	78	55	768

[a] 2017 includes the reassessment of prior year deferred tax balances in India in light of changes in facts and circumstances during the year.

8. Dividends

The quarterly dividend paid on 29 March 2018 in respect of the fourth quarter 2017 was 10 cents per ordinary share ($0.60 per American Depositary Share (ADS)). The corresponding amount in sterling was announced on 19 March 2018. A scrip dividend alternative is available, allowing shareholders to elect to receive their dividend in the form of new ordinary shares and ADS holders in the form of new ADSs.

	Pence per share			Cents per share			$ million		
	2017	2016	2015	2017	2016	2015	2017	2016	2015
Dividends announced and paid in cash									
Preference shares							1	1	2
Ordinary shares									
March	8.1587	7.0125	6.6699	10.00	10.00	10.00	1,303	1,099	1,708
June	7.7563	6.9167	6.5295	10.00	10.00	10.00	1,546	1,168	1,691
September	7.6213	7.5578	6.5488	10.00	10.00	10.00	1,676	1,161	1,717
December	7.4435	7.9313	6.6342	10.00	10.00	10.00	1,627	1,182	1,541
	30.9798	29.4183	26.3824	40.00	40.00	40.00	6,153	4,611	6,659
Dividend announced, paid in March 2018				10.00			1,828		

The details of the scrip dividends issued are shown in the table below.

	2017	2016	2015
Number of shares issued (thousand)	289,789	548,005	102,810
Value of shares issued ($ million)	1,714	2,858	642

The financial statements for the year ended 31 December 2017 do not reflect the dividend announced on 6 February 2018 and paid in March 2018; this will be treated as an appropriation of profit in the year ending 31 December 2018.

9. Earnings per share

	Cents per share		
Per ordinary share	2017	2016	2015
Basic earnings per share	17.20	0.61	(35.39)
Diluted earnings per share	17.10	0.60	(35.39)

	Dollars per share		
Per American Depositary Share (ADS)	2017	2016	2015
Basic earnings per share	1.03	0.04	(2.12)
Diluted earnings per share	1.03	0.04	(2.12)

Basic earnings per ordinary share amounts are calculated by dividing the profit (loss) for the year attributable to ordinary shareholders by the weighted average number of ordinary shares outstanding during the year.

The 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. A dilutive effect relating to potentially issuable shares has not been included, therefore, in the calculation of diluted earnings per share for 2015.

			$ million
	2017	2016	2015
Profit (loss) attributable to BP shareholders	3,389	115	(6,482)
Less: dividend requirements on preference shares	1	1	2
Profit (loss) for the year attributable to BP ordinary shareholders	3,388	114	(6,484)

			Shares thousand
	2017	2016	2015
Basic weighted average number of ordinary shares	19,692,613	18,744,800	18,323,646
Potential dilutive effect of ordinary shares issuable under employee share-based payment plans	123,829	110,519	—
Weighted average number of ordinary shares outstanding used to calculate diluted earnings per share	19,816,442	18,855,319	18,323,646

			Shares thousand
	2017	2016	2015
Basic weighted average number of ordinary shares - ADS equivalent	3,282,102	3,124,133	3,053,941
Potential dilutive effect of ordinary shares (ADS equivalent) issuable under employee share-based payment plans	20,638	18,420	—
Weighted average number of ordinary shares (ADS equivalent) outstanding used to calculate diluted earnings per share	3,302,740	3,142,553	3,053,941

9. Earnings per share – continued

The number of ordinary shares outstanding at 31 December 2017, excluding treasury shares, and including certain shares that will be issuable in the future under employee share-based payment plans was 19,817,325,868. Between 31 December 2017 and 8 March 2018, the latest practicable date before the completion of these financial statements, there was a net increase of 61,262,729 in the number of ordinary shares outstanding as a result of share issues in relation to employee share-based payment plans.

Employee share-based payment plans

The group operates share and share option plans for directors and certain employees to obtain ordinary shares and ADSs in the company. Information on these plans for directors is shown in the Directors remuneration report on pages 90-112.

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	2017		2016	
	Number of options[ab] thousand	Weighted average exercise price $	Number of options[ab] thousand	Weighted average exercise price $
Outstanding	22,399	4.34	26,284	3.85
Exercisable	1,112	4.46	498	4.59
Dilutive effect	5,145	n/a	3,380	n/a

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

[b] At 31 December 2017 the quoted market price of one BP ordinary share was £5.23 (2016 £5.10).

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	2017	2016
Vesting	Number of shares[a] thousand	Number of shares[a] thousand
Within one year	101,550	92,529
1 to 2 years	108,373	94,760
2 to 3 years	85,878	102,342
3 to 4 years	413	680
Over 4 years	166	319
	296,380	290,630
Dilutive effect	126,122	113,012

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

There has been a net decrease of 34,787,890 in the number of potential ordinary shares relating to employee share-based payment plans between 31 December 2017 and 8 March 2018.

10. Property, plant and equipment

	Land and land improvements	Buildings	Oil and gas properties[a]	Plant, machinery and equipment	Fittings, fixtures and office equipment	Transportation	Oil depots, storage tanks and service stations	$ million Total
Cost								
At 1 January 2017	3,066	2,235	215,564	43,725	2,670	14,000	7,623	288,883
Exchange adjustments	264	42	—	1,251	91	28	772	2,448
Additions	264	94	12,366	1,890	240	347	575	15,776
Acquisitions	—	—	—	41	—	228	1	270
Transfers	—	—	451	—	—	—	—	451
Deletions	(120)	(798)	(2,327)	(245)	(148)	(3,829)	(223)	(7,690)
At 31 December 2017	3,474	1,573	226,054	46,662	2,853	10,774	8,748	300,138
Depreciation								
At 1 January 2017	584	1,062	122,428	18,686	2,022	9,823	4,521	159,126
Exchange adjustments	33	27	—	647	67	19	466	1,259
Charge for the year	90	94	12,385	1,764	185	381	350	15,249
Impairment losses	3	35	624	35	—	479	17	1,193
Impairment reversals	—	—	(135)	—	—	(72)	—	(207)
Deletions	(27)	(400)	(1,976)	(136)	(138)	(3,107)	(169)	(5,953)
At 31 December 2017	683	818	133,326	20,996	2,136	7,523	5,185	170,667
Net book amount at 31 December 2017	2,791	755	92,728	25,666	717	3,251	3,563	129,471
Cost								
At 1 January 2016	3,194	2,877	215,566	45,744	2,866	14,038	8,418	292,703
Exchange adjustments	(119)	(37)	—	(342)	(127)	(9)	(375)	(1,009)
Additions	106	24	12,036	1,699	192	156	568	14,781
Acquisitions	46	—	—	793	—	—	—	839
Remeasurements[b]	—	—	—	(1,505)	—	—	—	(1,505)
Transfers	—	—	1,629	—	—	—	—	1,629
Deletions	(161)	(629)	(13,667)	(2,664)	(261)	(185)	(988)	(18,555)
At 31 December 2016	3,066	2,235	215,564	43,725	2,670	14,000	7,623	288,883
Depreciation								
At 1 January 2016	642	1,157	123,831	20,652	2,084	9,439	5,140	162,945
Exchange adjustments	(9)	(44)	—	(264)	(96)	(6)	(218)	(637)
Charge for the year	40	166	11,213	1,740	214	397	384	14,154

Remeasurements[b]	—	—	—	(1,319)	—	—	—	(1,319)
Impairment losses	9	123	518	11	79	256	4	1,000
Impairment reversals	(2)	—	(2,923)	(12)	—	(101)	(4)	(3,042)
Transfers	—	—	5	—	—	—	—	5
Deletions	(96)	(340)	(10,216)	(2,122)	(259)	(162)	(785)	(13,980)
At 31 December 2016	584	1,062	122,428	18,686	2,022	9,823	4,521	159,126
Net book amount at 31 December 2016	2,482	1,173	93,136	25,039	648	4,177	3,102	129,757
Assets held under finance leases at net book amount included above								
At 31 December 2017	—	2	16	238	—	233	7	496
At 31 December 2016	—	2	21	266	—	241	—	530
Assets under construction included above								
At 31 December 2017								23,789
At 31 December 2016								29,177

[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] Relates to the remeasurement to fair value of previously held interests in certain assets as a result of the dissolution on 31 December 2016 of the group’s German refining joint operation with Rosneft.

11. Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been signed at 31 December 2017 amounted to $11,340 million (2016 $11,207 million). BP’s share of capital commitments of joint ventures amounted to $483 million (2016 $522 million).

12. Goodwill and impairment review of goodwill

	$ million	
	2017	2016
Cost		
At 1 January	11,805	12,236
Exchange adjustments	336	(544)
Acquisitions	83	247
Deletions	(61)	(134)
At 31 December	12,163	11,805
Impairment losses		
At 1 January	611	609
Exchange adjustments	1	5
Deletions	—	(3)
At 31 December	612	611
Net book amount at 31 December	11,551	11,194
Net book amount at 1 January	11,194	11,627

Impairment review of goodwill

	$ million	
Goodwill at 31 December	2017	2016
Upstream	7,728	7,726
Downstream	3,758	3,401
Other businesses and corporate	65	67
	11,551	11,194

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 within Note 1.

Upstream

	$ million	
	2017	2016
Goodwill	7,728	7,726
Excess of recoverable amount over carrying amount	27,705	26,035

Consistent with the prior year the review for impairment was carried out during the third quarter. As permitted by IAS 36, the detailed calculations of recoverable amount performed in 2016 were used in the 2017 impairment test as the criteria in that standard were considered satisfied: the headroom was substantial in 2016; 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 at the time was remote. The table above shows the carrying amount of goodwill for the segment at year-end and the excess of the recoverable amount over the carrying amount at the date of the test (the headroom). The recoverable amount for 2017 is based upon the remaining future cash flows from the 2016 detailed calculation. The headroom presented for 2017 does not represent the headroom that would result if a test was run based on discounted future cash flows estimated using updated 2017 data and assumptions.

The fair value less costs of disposal 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, appropriately risked for the purposes of goodwill impairment testing. 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. The fair value calculation is based primarily on level 3 inputs as defined by the IFRS 13 ‘Fair value measurement’ hierarchy. As the production profile and related cash flows can be estimated from BP’s experience, management believes that the estimated cash flows expected to be generated over the life of each field is the appropriate basis upon which to assess goodwill 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. Estimated production volumes and cash flows up to the date of cessation of production on a field-by-field basis are developed to be 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. Exploration and appraisal assets are deemed to have a recoverable amount equal to their carrying amount.

The key assumptions used in the fair value less costs of disposal calculation are oil and natural gas prices, production volumes and the discount rate. The price and discount rate assumptions for 2016 were used as disclosed in Note 1. The fair value less costs of disposal calculations were 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 prior year 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, and future commodity prices may differ from the forecasts used in the calculations.

12. Goodwill and impairment review of goodwill – continued
The sensitivities to different variables were estimated for 2016 using certain simplifying assumptions. For example, lower oil and gas price sensitivities do not reflect the specific impacts for each contractual arrangement and will not capture fully any favourable impacts that may arise from cost deflation. Therefore a detailed calculation at any given price or production profile may produce a different result.
For 2016 it is estimated that if the oil price assumption for all future years was approximately $13 per barrel lower in each year, this 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 if the gas price assumption for all future years was approximately $2 per mmBtu lower in each year, this would 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. For 2016, the average production for the purposes of goodwill impairment testing over the following 15 years is 889mmboe per year and it is estimated that if production volume were to be reduced by approximately 4% for this period, this would cause the recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets of the segment.
For 2016 it is estimated that if the post-tax discount rate was approximately 9% for the entire portfolio, an increase of 3% for all countries not considered ‘higher risk’ and 1% for countries considered ‘higher risk’, this would cause the recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets of the segment.
Downstream

						$ million
			2017			2016
	Lubricants	Other	Total	Lubricants	Other	Total
Goodwill	2,849	909	3,758	2,571	830	3,401

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 2013 were used for the 2017 impairment test as the criteria in that standard were considered satisfied: the headroom was substantial in 2013; 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. The values assigned to these key assumptions reflect BP’s 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 two-year plan period were extrapolated using a nominal 3% growth rate.

13. Intangible assets

						$ million
			2017			2016
	Exploration and appraisal expenditure[a]	Other intangibles	Total	Exploration and appraisal expenditure[a]	Other intangibles	Total
Cost						
At 1 January	18,524	4,035	22,559	19,856	4,055	23,911
Exchange adjustments	—	197	197	—	(149)	(149)
Acquisitions	—	41	41	—	15	15
Additions	2,128	310	2,438	2,896	251	3,147
Transfers	(451)	—	(451)	(1,629)	—	(1,629)
Deletions	(2,315)	(95)	(2,410)	(2,599)	(137)	(2,736)

At 31 December	17,886	4,488	22,374	18,524	4,035	22,559
Amortization						
At 1 January	1,564	2,812	4,376	2,570	2,681	5,251
Exchange adjustments	—	107	107	—	(96)	(96)
Charge for the year	1,603	335	1,938	1,274	351	1,625
Impairment losses	—	—	—	62	—	62
Transfers	—	—	—	(5)	—	(5)
Deletions	(2,307)	(95)	(2,402)	(2,337)	(124)	(2,461)
At 31 December	860	3,159	4,019	1,564	2,812	4,376
Net book amount at 31 December	17,026	1,329	18,355	16,960	1,223	18,183
Net book amount at 1 January	16,960	1,223	18,183	17,286	1,374	18,660

[a] For further information see Intangible assets within Note 1 and Note 6.

14. Investments in joint ventures

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

			$ million
	2017	2016	2015[a]
Sales and other operating revenues	11,380	10,081	9,588
Profit before interest and taxation	1,394	1,612	785
Finance costs	100	156	188
Profit before taxation	1,294	1,456	597
Taxation	117	490	625
Profit (loss) for the year	1,177	966	(28)
Other comprehensive income	8	5	(1)
Total comprehensive income	1,185	971	(29)
Non-current assets	10,139	10,874	
Current assets	2,419	3,257	
Total assets	12,558	14,131	
Current liabilities	1,687	2,087	
Non-current liabilities	2,927	3,520	
Total liabilities	4,614	5,607	
Net assets	7,944	8,524	
Group investment in joint ventures			
Group share of net assets (as above)	7,944	8,524	
Loans made by group companies to joint ventures	50	85	
	7,994	8,609	

[a] The loss for 2015 shown in the table above included $711 million relating to BP`s share of impairment losses recognized by joint ventures, a significant element of which related to the Angola LNG plant.

In December 2017, BP completed a cash-free transaction with Bridas Corporation (Bridas) in which its interests in the oil and gas producer Pan American Energy (PAE) and Bridas' interest in the refiner and marketer Axion Energy (Axion) were combined to form a new integrated energy company. PAE was previously owned 60% by BP and 40% by Bridas. The new company, Pan American Energy Group, is owned equally by BP and Bridas.

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

						$ million
Sales to joint ventures		2017		2016		2015
Product	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
LNG, crude oil and oil products, natural gas	2,929	352	2,760	291	2,841	245

						$ million
Purchases from joint ventures		2017		2016		2015
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	1,257	176	943	120	861	104

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.

15. 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	
	2017	2016	2015	2017	2016
Rosneft	922	647	1,330	10,059	8,243
Other associates	408	347	509	6,932	5,849
	1,330	994	1,839	16,991	14,092

The associate that is material to the group at both 31 December 2017 and 2016 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 2017.

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 2017 compared

15. Investments in associates – continued
with 31 December 2016 principally relates to earnings from Rosneft and foreign exchange effects which have been recognized in other comprehensive income.
The value of BP's 19.75% shareholding in Rosneft based on the quoted market share price of $4.99 per share (2016 $6.50 per share) was $10,444 million at 31 December 2017 (2016 $13,604 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 2017, as shown in the table below, compared with the equivalent amount in Russian roubles that we expect Rosneft to report in its own financial statements under IFRS.

			$ million
			Gross amount
	2017	2016	2015
Sales and other operating revenues	103,028	74,380	84,071
Profit before interest and taxation	9,949	7,094	12,253
Finance costs	2,228	1,747	3,696
Profit before taxation	7,721	5,347	8,557
Taxation	1,742	1,797	1,792
Non-controlling interests	1,311	273	30
Profit for the year	4,668	3,277	6,735
Other comprehensive income	2,810	4,203	(4,111)
Total comprehensive income	7,478	7,480	2,624
Non-current assets	158,719	129,403	
Current assets	39,737	37,914	
Total assets	198,456	167,317	
Current liabilities	66,506	46,284	
Non-current liabilities	70,704	71,980	
Total liabilities	137,210	118,264	
Net assets	61,246	49,053	
Less: non-controlling interests	10,314	7,316	
	50,932	41,737	

The group received dividends, net of withholding tax, of $314 million from Rosneft in 2017 (2016 $332 million and 2015 $271 million).
Summarized financial information for the group's share of associates is shown below.

									$ million
									BP share
			2017			2016			2015
	Rosneft[a]	Other	Total	Rosneft[a]	Other	Total	Rosneft[a]	Other	Total
Sales and other operating revenues	20,348	7,600	27,948	14,690	5,377	20,067	16,604	6,000	22,604
Profit before interest and taxation	1,965	626	2,591	1,401	525	1,926	2,420	661	3,081
Finance costs	440	54	494	345	22	367	730	6	736
Profit before taxation	1,525	572	2,097	1,056	503	1,559	1,690	655	2,345
Taxation	344	164	508	355	156	511	354	146	500
Non-controlling interests	259	—	259	54	—	54	6	—	6
Profit for the year	922	408	1,330	647	347	994	1,330	509	1,839
Other comprehensive income	555	1	556	830	(2)	828	(812)	(2)	(814)
Total comprehensive income	1,477	409	1,886	1,477	345	1,822	518	507	1,025
Non-current assets	31,347	9,261	40,608	25,557	7,848	33,405			
Current assets	7,848	2,645	10,493	7,488	2,002	9,490			

Total assets	39,195	11,906	51,101	33,045	9,850	42,895
Current liabilities	13,135	2,501	15,636	9,141	1,827	10,968
Non-current liabilities	13,964	3,308	17,272	14,216	2,934	17,150
Total liabilities	27,099	5,809	32,908	23,357	4,761	28,118
Net assets	12,096	6,097	18,193	9,688	5,089	14,777
Less: non-controlling interests	2,037	—	2,037	1,445	—	1,445
	10,059	6,097	16,156	8,243	5,089	13,332
Group investment in associates						
Group share of net assets (as above)	10,059	6,097	16,156	8,243	5,089	13,332
Loans made by group companies to associates	—	835	835	—	760	760
	10,059	6,932	16,991	8,243	5,849	14,092

[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.

15. Investments in associates – continued

Transactions between the group and its associates are summarized below.

Sales to associates						$ million
		2017		2016		2015
Product	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
LNG, crude oil and oil products, natural gas	2,261	216	4,210	765	5,302	1,058

Purchases from associates						$ million
		2017		2016		2015
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	11,613	1,681	8,873	2,000	11,619	2,026

In addition to the transactions shown in the table above, in 2016 the group completed the dissolution of its German refining joint operation with Rosneft. In 2015, the group acquired a 20% participatory interest in Taas-Yuryakh Neftegazodobycha, a Rosneft subsidiary.

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 the sales to and purchases from associates relate to crude oil and oil products transactions with Rosneft.

BP has commitments amounting to $13,932 million (2016 $15,344 million), primarily in relation to contracts with its associates for the purchase of transportation capacity.

16. Other investments

				$ million
		2017		2016
	Current	Non-current	Current	Non-current
Equity investments[a]	15	418	2	405
Other	110	827	42	628
	125	1,245	44	1,033

[a] The majority of equity investments are unlisted.

Other non-current investments includes $662 million relating to life insurance policies in the US (2016 $628 million) which are financial assets measured at fair value through profit or loss. The fair value is determined using the higher of the amount that would be received if the policies were cashed in and discounted future cash flows that would be received on maturity of the policies. It is considered a level 3 valuation under the fair value hierarchy. Future cash flows are estimated based on inputs that include life expectancy, investment performance and the cost of insurance cover. The pre-tax discount rate is based on a third-party high-quality US insurance company corporate bond index.

17. Inventories

		$ million
	2017	2016
Crude oil	5,692	5,531
Natural gas	119	155
Refined petroleum and petrochemical products	10,694	9,198

	16,505	14,884
Supplies	2,211	2,388
	18,716	17,272
Trading inventories	295	383
	19,011	17,655
Cost of inventories expensed in the income statement	179,716	132,219

The inventory valuation at 31 December 2017 is stated net of a provision of $474 million (2016 $501 million) to write down inventories (principally supplies) to their net realizable value. The net credit to the income statement in the year in respect of inventory net realizable value provisions was $27 million (2016 $769 million credit).
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.

18. Trade and other receivables

				$ million
	2017		2016	
	Current	Non-current	Current	Non-current
Financial assets				
Trade receivables	18,912	4	13,393	—
Amounts receivable from joint ventures and associates	566	2	1,056	—
Other receivables	4,206	671	5,352	815
	23,684	677	19,801	815
Non-financial assets				
Gulf of Mexico oil spill trust fund reimbursement asset	252	—	194	—
Other receivables	913	757	680	659
	1,165	757	874	659
	24,849	1,434	20,675	1,474

Non-recourse arrangements to discount receivables, as part of discretionary funding in support of certain supply and trading activities and management of credit risk, included $1.7 billion relating to receivables based on provisional prices (2016 $1.3 billion). The group had continuing involvement in these receivables to the extent of movements in market prices after the date of discounting. The amounts which continued to be recognized on the balance sheet relating to the group's continuing involvement in these receivables totalled $0.2 billion, unchanged from 2016.
Trade and other receivables are predominantly non-interest bearing. See Note 27 for further information.

19. Valuation and qualifying accounts

						$ million
	2017		2016		2015	
	Accounts receivable	Fixed asset investments	Accounts receivable	Fixed asset investments	Accounts receivable	Fixed asset investments
At 1 January	392	335	447	435	331	517
Charged to costs and expenses	68	47	120	55	243	195
Charged to other accounts[a]	13	3	(7)	(2)	(23)	(4)
Deductions	(138)	(71)	(168)	(153)	(104)	(273)
At 31 December	335	314	392	335	447	435

[a] Principally exchange adjustments.
Valuation and qualifying accounts comprise impairment provisions for accounts receivable and fixed asset investments, and are deducted in the balance sheet from the assets to which they apply.
For information on significant judgements made in relation to the recoverability of trade receivables see Impairment of loans and receivables within Note 1.

20. Trade and other payables

				$ million
	2017		2016	
	Current	Non-current	Current	Non-current
Financial liabilities				
Trade payables	26,983	—	21,575	—
Amounts payable to joint ventures and associates	1,857	—	2,120	—
Other payables[a]	11,632	13,582	12,079	13,760
	40,472	13,582	35,774	13,760
Non-financial liabilities				
Other payables	3,737	307	2,141	186
	44,209	13,889	37,915	13,946

[a] The majority of non-current other payables relate to the Gulf of Mexico oil spill. See Note 2 for further information.

Trade and other payables, other than those relating to the Gulf of Mexico oil spill, are predominantly interest free. See Note 27 for further information.

21. Provisions

					$ million
	Decommissioning	Environmental	Litigation and claims	Other	Total
At 1 January 2017	16,442	1,584	3,162	3,236	24,424
Exchange adjustments	326	12	4	162	504
Acquisitions	—	2	—	—	2
Increase (decrease) in existing provisions	(228)	249	2,907	786	3,714
Write-back of unused provisions	—	(94)	(26)	(369)	(489)
Unwinding of discount	121	8	8	13	150
Change in discount rate	(106)	—	(13)	(14)	(133)
Utilization	(21)	(231)	(1,916)	(739)	(2,907)
Reclassified to other payables	(239)	—	(792)	(73)	(1,104)
Deletions	(195)	(14)	—	(8)	(217)
At 31 December 2017	16,100	1,516	3,334	2,994	23,944
Of which – current	378	269	1,738	939	3,324
– non-current	15,722	1,247	1,596	2,055	20,620
Of which – Gulf of Mexico oil spill[a]	—	—	2,580	—	2,580

[a] Further information on the financial impacts of the Gulf of Mexico oil spill is provided in Note 2.

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 2017 are provisions for deferred employee compensation of $391 million (2016 $422 million).

For information on significant estimates and judgements made in relation to provisions, including those for the Gulf of Mexico oil spill, see Provisions and contingencies within Note 1.

22. 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 within 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 employees now accrue benefits 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 composed of six BP employees appointed by the president of BP Corporation North America Inc. (the appointing officer). The Investment Committee is required by law to act in the best interests of the plan participants and is responsible for setting certain policies, such as the investment policies of the plan. US employees are also eligible to participate in a defined contribution (401k) plan in which employee contributions are matched with company contributions. In the US, group companies also provide post-retirement healthcare to 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 2017 the aggregate level of contributions was $637 million (2016 $651 million and 2015 $1,066 million). The aggregate level of contributions in 2018 is expected to be approximately $600 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. The current agreement covers the next five years. The funding agreement can be terminated unilaterally by either party with two years' notice. Contractually committed funding therefore represents seven years of future contributions, which amounted to $2,623 million at 31 December 2017, of which $106 million relates to past 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 252.

22. Pensions and other post-retirement benefits – continued

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. All of the contributions made into the US pension plan in 2017 were discretionary and no statutory funding requirement is expected in the next 12 months.

There was no minimum funding requirement for the US plan, and no significant minimum funding requirements in other countries at 31 December 2017.

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 2017. 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 2014, and a valuation as at 31 December 2017 is currently under way. A valuation of the US plan is 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
	2017	2016	2015	2017	2016	2015	2017	2016	2015
Discount rate for plan liabilities	2.5	2.7	3.9	3.5	3.9	4.0	1.9	1.7	2.4
Rate of increase in salaries	4.1	4.6	4.4	4.1	4.2	3.9	3.0	3.0	3.2
Rate of increase for pensions in payment	2.9	3.0	3.0	—	—	—	1.4	1.5	1.6
Rate of increase in deferred pensions	2.9	3.0	3.0	—	—	—	0.6	0.5	0.6
Inflation for plan liabilities	3.1	3.2	3.0	1.7	1.8	1.5	1.6	1.6	1.8

									%
Financial assumptions used to determine benefit expense		UK			US				Eurozone
	2017	2016	2015	2017	2016	2015	2017	2016	2015
Discount rate for plan service cost	2.7	4.0	3.9	4.1	4.2	3.8	2.1	2.7	2.3
Discount rate for plan other finance expense	2.7	3.9	3.6	3.9	4.0	3.7	1.7	2.4	2.0
Inflation for plan service cost	3.2	3.1	3.1	1.8	1.5	1.6	1.6	1.8	2.0

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
	2017	2016	2015	2017	2016	2015	2017	2016	2015
Life expectancy at age 60 for a male currently aged 60	27.4	28.0	28.5	25.1	25.7	25.7	25.1	25.0	24.9
Life expectancy at age 60 for a male currently aged 40	29.0	30.0	31.0	26.8	27.5	27.5	27.6	27.6	27.5

Life expectancy at age 60 for a female currently aged 60	28.8	29.5	29.5	28.4	29.3	29.2	29.0	28.9	28.8
Life expectancy at age 60 for a female currently aged 40	30.5	31.9	31.9	30.0	31.0	30.9	31.4	31.3	31.2

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

A significant proportion of the assets are held in equities, which are expected to generate a higher level of return over the long term, with an acceptable level of risk. In order to provide reasonable assurance that no single security or type of security has an unwarranted impact on the total portfolio, the investment portfolios are highly diversified.

The trustee's long-term investment objective for the primary UK plan as it matures is to invest in assets whose value changes in the same way as the plan liabilities, in order to reduce the level of funding risk. To move towards this objective, the UK plan uses a liability driven investment (LDI) approach for part of the portfolio, investing 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.

22. Pensions and other post-retirement benefits – continued

For the primary UK pension plan there is an agreement with the trustee to increase the proportion of assets included in the LDI portfolio over time 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 2017, the UK and the US plans switched 15% and 5% of plan assets respectively from equities to bonds.

The current asset allocation policy for the major plans at 31 December 2017 was as follows:

	UK	US
Asset category	%	%
Total equity (including private equity)	43	50
Bonds/cash (including LDI)	50	50
Property/real estate	7	—

The amounts invested under the LDI programme by the primary UK pension plan as at 31 December 2017 were $2,588 million (2016 $423 million) of government-issued nominal bonds and $16,177 million (2016 $9,384 million) of index-linked bonds.

In addition, the primary UK plan entered into interest rate swaps in the year to offset the long-term fixed interest rate exposure for $1,333 million (2016 $4,450 million) of the corporate bond portfolio. At 31 December 2017 the fair value liability of these swaps was $49 million (2016 $144 million fair value liability) and is included in other assets in the table below.

Some of the group's pension plans in other countries also use derivative financial instruments as part of their asset mix to manage the level of risk.

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 165.

					$ million
	UK[a]	US[b]	Eurozone	Other	Total
Fair value of pension plan assets					
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	2,663	1,777	941	545	5,926
Government issued index-linked bonds	16,177	—	2	—	16,179
Corporate bonds	4,682	2,024	546	272	7,524
Property[d]	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
At 31 December 2016					
Listed equities – developed markets	11,494	2,283	436	363	14,576
– emerging markets	2,549	220	54	46	2,869
Private equity[c]	2,754	1,442	1	—	4,197
Government issued nominal bonds	489	1,438	821	448	3,196
Government issued index-linked bonds	9,384	—	4	—	9,388
Corporate bonds	4,042	1,732	427	259	6,460
Property[d]	1,970	6	45	28	2,049
Cash	547	105	17	83	752
Other	(68)	90	74	83	179

Debt (repurchase agreements) used to fund liability driven investments	(2,981)	—	—	—	(2,981)
	30,180	7,316	1,879	1,310	40,685
At 31 December 2015					
Listed equities – developed markets	13,474	2,329	423	371	16,597
– emerging markets	2,305	226	49	50	2,630
Private equity[c]	2,933	1,522	1	4	4,460
Government issued nominal bonds	393	1,527	685	492	3,097
Government issued index-linked bonds	6,425	—	5	—	6,430
Corporate bonds	4,357	1,717	551	367	6,992
Property[d]	2,453	6	48	58	2,565
Cash	564	116	10	139	829
Other	110	67	102	50	329
Debt (repurchase agreements) used to fund liability driven investments	(1,791)	—	—	—	(1,791)
	31,223	7,510	1,874	1,531	42,138

[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 third-party net asset valuation.

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

22. Pensions and other post-retirement benefits – continued

	UK	US	Eurozone	Other	$ million 2017 Total
Analysis of the amount charged to profit (loss) before interest and taxation					
Current service cost[a]	357	292	85	46	780
Past service cost[b]	12	—	5	(1)	16
Settlement[b]	—	—	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
Movements in benefit obligation during the year					
Benefit obligation at 1 January	29,908	10,533	6,820	1,715	48,976
Exchange adjustments	2,886	—	915	89	3,890
Operating charge relating to defined benefit plans	369	292	103	45	809
Interest cost	831	393	121	71	1,416
Contributions by plan participants[c]	16	—	2	6	24
Benefit payments (funded plans)[d]	(1,903)	(641)	(75)	(89)	(2,708)
Benefit payments (unfunded plans)[d]	(5)	(239)	(302)	(20)	(566)
Acquisitions	—	1	—	—	1
Disposals	—	(1)	(9)	—	(10)
Remeasurements	(589)	482	(300)	56	(351)
Benefit obligation at 31 December[a e]	31,513	10,820	7,275	1,873	51,481
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	30,180	7,316	1,879	1,310	40,685
Exchange adjustments	3,048	—	264	72	3,384
Interest income on plan assets[a f]	845	266	37	48	1,196
Contributions by plan participants[c]	16	—	2	6	24
Contributions by employers (funded plans)	509	12	87	29	637
Benefit payments (funded plans)[d]	(1,903)	(641)	(75)	(89)	(2,708)
Remeasurements[f]	2,396	826	30	43	3,295
Fair value of plan assets at 31 December[g]	35,091	7,779	2,224	1,419	46,513
Surplus (deficit) at 31 December	3,578	(3,041)	(5,051)	(454)	(4,968)
Represented by					
Asset recognized	3,838	260	43	28	4,169
Liability recognized	(260)	(3,301)	(5,094)	(482)	(9,137)
	3,578	(3,041)	(5,051)	(454)	(4,968)

The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	3,838	238	(106)	(101)	3,869
Unfunded	(260)	(3,279)	(4,945)	(353)	(8,837)
	3,578	(3,041)	(5,051)	(454)	(4,968)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(31,253)	(7,541)	(2,330)	(1,520)	(42,644)
Unfunded	(260)	(3,279)	(4,945)	(353)	(8,837)
	(31,513)	(10,820)	(7,275)	(1,873)	(51,481)

[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 $3,235 million benefits and $2 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 $8,085 million for pension liabilities and $2,735 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $4,586 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 164.

22. Pensions and other post-retirement benefits – continued

	UK	US	Eurozone	Other	$ million 2016 Total
Analysis of the amount charged to profit (loss) before interest and taxation					
Current service cost[a]	333	310	76	71	790
Past service cost[b]	17	(24)	7	1	1
Settlement	—	—	9	(1)	8
Operating charge relating to defined benefit plans	350	286	92	71	799
Payments to defined contribution plans	30	194	7	33	264
Total operating charge	380	480	99	104	1,063
Interest income on plan assets[a]	(1,086)	(287)	(47)	(51)	(1,471)
Interest on plan liabilities	1,005	417	159	80	1,661
Other finance (income) expense	(81)	130	112	29	190
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	4,422	330	53	8	4,813
Change in financial assumptions underlying the present value of the plan liabilities	(6,932)	(239)	(622)	4	(7,789)
Change in demographic assumptions underlying the present value of the plan liabilities	430	9	12	(5)	446
Experience gains and losses arising on the plan liabilities	55	(62)	26	15	34
Remeasurements recognized in other comprehensive income	(2,025)	38	(531)	22	(2,496)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	28,974	10,643	6,640	2,089	48,346
Exchange adjustments	(5,688)	—	(282)	23	(5,947)
Operating charge relating to defined benefit plans	350	286	92	71	799
Interest cost	1,005	417	159	80	1,661
Contributions by plan participants[c]	18	—	2	6	26
Benefit payments (funded plans)[d]	(1,192)	(821)	(78)	(117)	(2,208)
Benefit payments (unfunded plans)[d]	(6)	(284)	(301)	(24)	(615)
Acquisitions	—	—	4	—	4
Disposals	—	—	—	(399)	(399)
Remeasurements	6,447	292	584	(14)	7,309
Benefit obligation at 31 December[a e]	29,908	10,533	6,820	1,715	48,976
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	31,223	7,510	1,874	1,531	42,138
Exchange adjustments	(5,916)	—	(76)	15	(5,977)
Interest income on plan assets[a f]	1,086	287	47	51	1,471
Contributions by plan participants[c]	18	—	2	6	26
Contributions by employers (funded plans)	539	10	57	45	651
Benefit payments (funded plans)[d]	(1,192)	(821)	(78)	(117)	(2,208)
Disposals	—	—	—	(229)	(229)
Remeasurements[f]	4,422	330	53	8	4,813
Fair value of plan assets at 31 December[g]	30,180	7,316	1,879	1,310	40,685
Surplus (deficit) at 31 December	272	(3,217)	(4,941)	(405)	(8,291)
Represented by					
Asset recognized	530	—	22	32	584
Liability recognized	(258)	(3,217)	(4,963)	(437)	(8,875)

	272	(3,217)	(4,941)	(405)	(8,291)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	519	(36)	(316)	(83)	84
Unfunded	(247)	(3,181)	(4,625)	(322)	(8,375)
	272	(3,217)	(4,941)	(405)	(8,291)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(29,661)	(7,352)	(2,195)	(1,393)	(40,601)
Unfunded	(247)	(3,181)	(4,625)	(322)	(8,375)
	(29,908)	(10,533)	(6,820)	(1,715)	(48,976)

[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. The UK also includes $12 million of cost resulting from benefit harmonization within the primary plan.

[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 $2,754 million benefits and $14 million settlements, plus $55 million of plan expenses incurred in the administration of the benefit.

[e] The benefit obligation for the US is made up of $7,902 million for pension liabilities and $2,631 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $4,289 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 164.

22. Pensions and other post-retirement benefits – continued

					$ million 2015
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit (loss) before interest and taxation					
Current service cost[a]	485	371	96	96	1,048
Past service cost[b]	12	(27)	47	(7)	25
Settlement	—	—	(1)	(3)	(4)
Operating charge relating to defined benefit plans	497	344	142	86	1,069
Payments to defined contribution plans	31	205	8	41	285
Total operating charge	528	549	150	127	1,354
Interest income on plan assets[a]	(1,124)	(289)	(37)	(55)	(1,505)
Interest on plan liabilities	1,146	423	151	91	1,811
Other finance expense	22	134	114	36	306
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	315	(139)	25	33	234
Change in financial assumptions underlying the present value of the plan liabilities	2,054	607	592	213	3,466
Change in demographic assumptions underlying the present value of the plan liabilities	—	60	15	—	75
Experience gains and losses arising on the plan liabilities	336	(48)	47	29	364
Remeasurements recognized in other comprehensive income	2,705	480	679	275	4,139

[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 Trinidad 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 2017 for the group's plans would have had the effects shown in the table below. The effects shown for the expense in 2018 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 and other post-retirement benefit expense in 2018	(366)	298
Effect on pension and other post-retirement benefit obligation at 31 December 2017	(7,532)	9,751
Inflation rate[b]		
Effect on pension and other post-retirement benefit expense in 2018	241	(200)
Effect on pension and other post-retirement benefit obligation at 31 December 2017	5,373	(4,690)
Salary growth		
Effect on pension and other post-retirement benefit expense in 2018	78	(68)
Effect on pension and other post-retirement benefit obligation at 31 December 2017	837	(747)

[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 2018 pension and other post-retirement benefit expense by $56 million and the pension and other post-retirement benefit obligation at 31 December 2017 by $1,694 million.

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 2027 and the weighted average duration of the defined benefit obligations at 31 December 2017 are as follows:

					$ million
Estimated future benefit payments	UK	US	Eurozone	Other	Total
2018	1,101	847	369	109	2,426
2019	1,087	815	359	110	2,371
2020	1,108	798	346	109	2,361
2021	1,148	853	336	109	2,446
2022	1,176	784	332	112	2,404
2023-2027	6,319	3,701	1,559	563	12,142
					Years
Weighted average duration	19.8	9.5	14.3	13.1	

23. Cash and cash equivalents

	$ million	
	2017	2016
Cash	4,592	5,592
Term bank deposits	17,324	15,947
Cash equivalents (excluding term bank deposits)	3,670	1,945
	25,586	23,484

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 2017 includes $1,488 million (2016 $2,059 million) that is restricted. The restricted cash balances include amounts required to cover initial margin on trading exchanges and certain cash balances which are subject to exchange controls.

The group holds $3,638 million (2016 $3,649 million) of cash and cash equivalents outside the UK and it is not expected that any significant tax will arise on repatriation.

24. Finance debt

						$ million
			2017			2016
	Current	Non-current	Total	Current	Non-current	Total
Borrowings	7,701	54,873	62,574	6,592	51,074	57,666
Net obligations under finance leases	38	618	656	42	592	634
	7,739	55,491	63,230	6,634	51,666	58,300

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 $6,849 million (2016 $5,587 million) and issued commercial paper of $744 million (2016 $971 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
						2017
US dollar	4	4	18,090	3	44,212	62,302
Other currencies	6	16	895	3	33	928
			18,985		44,245	63,230
						2016
US dollar	3	4	8,693	2	47,749	56,442
Other currencies	7	16	809	1	1,049	1,858
			9,502		48,798	58,300

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 2017, whereas in the 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 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. The fair value of the group's finance lease obligations is estimated using discounted cash flow analysis based on the group's current incremental borrowing rates for similar types and maturities of borrowing and are consequently categorized in level 2 of the fair value hierarchy.

				$ million
		2017		2016
	Fair value	Carrying amount	Fair value	Carrying amount
Short-term borrowings	852	852	1,006	1,006
Long-term borrowings	63,182	61,722	57,723	56,660
Net obligations under finance leases	1,131	656	1,097	634
Total finance debt	65,165	63,230	59,826	58,300

25. Capital disclosures and analysis of changes in 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 the basis of the net debt ratio, that is, the ratio of net debt to net debt plus equity. Net debt is calculated as gross 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 net debt ratio are non-GAAP measures. BP believes these measures provide useful information to investors. Net debt enables investors to see the economic effect of gross debt, related hedges and cash and cash equivalents in total. The net debt ratio 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 net debt ratio within a 20-30% band and maintain a significant liquidity buffer. At 31 December 2017, the net debt ratio was 27.4% (2016 26.8%).

		$ million
At 31 December	2017	2016
Gross debt	63,230	58,300
Less: fair value asset (liability) of hedges related to finance debt[a]	(175)	(697)
	63,405	58,997
Less: cash and cash equivalents	25,586	23,484
Net debt	37,819	35,513
Equity	100,404	96,843
Net debt ratio	27.4%	26.8%

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 $634 million (2016 liability of $1,962 million, 2015 liability of $1,617 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 outflow of $242 million (2016 net cash outflow $299 million) and fair value gains of $1,086 million (2016 fair value losses of $644 million).

An analysis of changes in net debt is provided below. Amendments have been made to the presentation of this analysis to eliminate movements related to non-hedge accounted derivatives.

								$ million
				2017				2016
Movement in net debt	Finance debt	Hedge-accounted derivatives	Cash and cash equivalents	Net debt	Finance debt	Hedge-accounted derivatives	Cash and cash equivalents	Net debt
At 1 January	(58,300)	(697)	23,484	(35,513)	(53,168)	(379)	26,389	(27,158)
Exchange adjustments	(1,324)	—	544	(780)	380	—	(820)	(440)
Net financing cash flow	(2,236)	(284)	1,558	(962)	(6,363)	256	(2,085)	(8,192)
Fair value gains (losses)	(1,314)	1,282	—	(32)	805	(896)	—	(91)
Other movements	(56)	(476)	—	(532)	46	322	—	368
At 31 December	(63,230)	(175)	25,586	(37,819)	(58,300)	(697)	23,484	(35,513)

26. Operating leases

The cost recognized in relation to minimum lease payments for the year was $4,423 million (2016 $5,113 million and 2015 $6,008 million).

The future minimum lease payments at 31 December 2017, before deducting related rental income from operating sub-leases of $188 million (2016 $186 million), are shown in the table below. This does not include future contingent rentals. Where the lease rentals are dependent on a variable factor, the future minimum lease payments are based on the factor as at inception of the lease.

	$ million	
Future minimum lease payments	2017	2016
Payable within		
1 year	2,969	3,315
2 to 5 years	6,387	6,651
Thereafter	4,614	4,289
	13,970	14,255

In the case of an operating lease entered into by BP as the operator of a joint operation, the amounts included in the totals disclosed represent the net operating lease expense and net future minimum lease payments. These net amounts are after deducting amounts reimbursed, or to be reimbursed, by joint operators, whether the joint operators have co-signed the lease or not. Where BP is not the operator of a joint operation, BP's share of the lease expense and future minimum lease payments is included in the amounts shown, whether BP has co-signed the lease or not.

Typical durations of operating leases are up to ten years for leases of plant and machinery, up to fifteen years for leases of ships and commercial vehicles and up to forty years for leases of land and buildings.

The most significant items of plant and machinery hired under operating leases are drilling rigs used in the Upstream segment. At 31 December 2017, the future minimum lease payments relating to these amounted to $2,088 million (2016 $2,969 million).

The group has entered into a number of structured operating leases for ships and in some cases the lease rental payments vary with market interest rates. The variable portion of the lease payments above or below the amount based on the market interest rate prevailing at inception of the lease is treated as contingent rental expense. The group also routinely enters into bareboat charters, time-charters and voyage-charters for ships on standard industry terms. The future minimum lease payments relating to operating leases for international oil and gas ships managed by the BP Shipping function amounted to $3,172 million (2016 $3,582 million).

26. Operating leases – continued

Commercial vehicles hired under operating leases are primarily railcars. Retail service station sites and office accommodation are the main items in the land and buildings category.

The terms and conditions of these operating leases do not impose any significant financial restrictions on the group. Some of the leases of ships and buildings allow for renewals at BP's option, and some of the group's operating leases contain escalation clauses.

BP will adopt IFRS 16 'Leases' on 1 January 2019. See Note 1 for further details.

27. 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 2017	Note	Loans and receivables	Available-for-sale financial assets	Held-to-maturity investments	At fair value through profit or loss	Derivative hedging instruments	Financial liabilities measured at amortized cost	Total carrying amount
Financial assets								
Other investments – equity shares	16	—	433	—	—	—	—	433
– other	16	—	275	—	662	—	—	937
Loans		836	—	—	—	—	—	836
Trade and other receivables	18	24,361	—	—	—	—	—	24,361
Derivative financial instruments	28	—	—	—	6,454	688	—	7,142
Cash and cash equivalents	23	21,916	2,270	1,400	—	—	—	25,586
Financial liabilities								
Trade and other payables	20	—	—	—	—	—	(54,054)	(54,054)
Derivative financial instruments	28	—	—	—	(5,705)	(864)	—	(6,569)
Accruals		—	—		—	—	(5,465)	(5,465)
Finance debt	24	—	—	—	—	—	(63,230)	(63,230)
		47,113	2,978	1,400	1,411	(176)	(122,749)	(70,023)
At 31 December 2016								
Financial assets								
Other investments – equity shares	16	—	407	—	—	—	—	407
– other	16	—	42	—	628	—	—	670
Loans		791	—	—	—	—	—	791
Trade and other receivables	18	20,616	—	—	—	—	—	20,616
Derivative financial instruments	28	—	—	—	6,490	885	—	7,375
	23	21,539	1,749	196	—	—	—	23,484

Cash and cash equivalents								
Financial liabilities								
Trade and other payables	20	—	—	—	—	—	(49,534)	(49,534)
Derivative financial instruments	28	—	—	—	(6,507)	(1,997)	—	(8,504)
Accruals		—	—		—	—	(5,605)	(5,605)
Finance debt	24	—	—	—	—	—	(58,300)	(58,300)
		42,946	2,198	196	611	(1,112)	(113,439)	(68,600)

The fair value of finance debt is shown in Note 24. For all other financial instruments, the carrying amount is either the fair value, or approximates the fair value.

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 and supply 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 monitors and validates limits and risk exposures, reviews incidents and validates risk-related policies, methodologies and procedures. A commitments committee approves value-at-risk delegations, 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.

27. Financial instruments and financial risk factors – continued

(a) Market risk

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

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

(i) Commodity price risk

The group's integrated supply and trading function uses conventional financial and commodity instruments and physical cargoes and pipeline positions available in the related commodity markets. Oil and natural gas swaps, options and futures are used to mitigate price risk. Power trading is undertaken using a combination of over-the-counter forward contracts and other derivative contracts, including options and futures. This activity is on both a standalone basis and in conjunction with gas derivatives in relation to gas-generated power margin. In addition, NGLs are traded around certain US inventory locations using over-the-counter forward contracts in conjunction with over-the-counter swaps, options and physical inventories.

The group measures market risk exposure arising from its trading positions in liquid periods using value-at-risk techniques. These techniques make a statistical assessment of the market risk arising from possible future changes in market prices over a one-day holding period. The value-at-risk measure is supplemented by stress testing. Trading activity occurring in liquid periods is subject to value-at-risk limits for each trading activity and for this trading activity in total. The board has delegated a limit of $100 million value at risk in support of this trading activity. Alternative measures are used to monitor exposures which are outside liquid periods and which cannot be actively risk-managed.

(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 2017, the total foreign currency borrowings not swapped into US dollars amounted to $928 million (2016 $809 million).

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. The most significant exposures relate to capital expenditure commitments and other UK, Eurozone and Australian operational requirements, for which hedging programmes are in place and hedge accounting is applied.

For highly probable forecast capital expenditures the group fixes the US dollar cost of non-US dollar supplies by using currency forwards. The exposures are sterling, euro, Australian dollar, Norwegian krone and Korean Won. At 31 December 2017 the most significant open contracts in place were for $437 million sterling (2016 $1,204 million sterling).

For UK, Eurozone and Australian operational requirements the group uses cylinders (purchased call and sold put options) to manage the estimated exposures. At 31 December 2017, there are no open positions hedging these

exposures (2016 cylinders consisted of receive sterling, pay US dollar cylinders $1,885 million; receive euro, pay US dollar cylinders for $585 million; receive Australian dollar, pay US dollar cylinders for $274 million).
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. Whilst 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 2017 was 70% of total finance debt outstanding (2016 84%). The weighted average interest rate on finance debt at 31 December 2017 was 3% (2016 2%) and the weighted average maturity of fixed rate debt was five years (2016 five years).
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 increased by one percentage point on 1 January 2018, it is estimated that the group's finance costs for 2018 would increase by approximately $442 million (2016 $488 million increase).

(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 2017 was $656 million (2016 $309 million) in respect of liabilities of joint ventures and associates and $382 million (2016 $370 million) in respect of liabilities of other third parties.

27. Financial instruments and financial risk factors – continued

The group has a credit policy, approved by the CFO that is designed to ensure that consistent processes are in place throughout the group to measure and control credit risk. Credit risk is considered as part of the risk-reward balance of doing business. On entering into any business contract the extent to which the arrangement exposes the group to credit risk is considered. Key requirements of the policy include segregation of credit approval authorities from any sales, marketing or trading teams authorized to incur credit risk; the establishment of credit systems and processes to ensure that all counterparty exposure is rated and that all counterparty exposure and limits can be monitored and reported; and the timely identification and reporting of any non-approved credit exposures and credit losses. While each segment is responsible for its own credit risk management and reporting consistent with group policy, the treasury function holds group-wide credit risk authority and oversight responsibility for exposure to banks and financial institutions.

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 2017, the group had in place credit enhancements designed to mitigate approximately $14.7 billion of credit risk (2016 $11.6 billion). 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 indicates that 77% (2016 79%) of total unmitigated credit exposure relates to counterparties of investment-grade credit quality.

		$ million
Trade and other receivables at 31 December	2017	2016
Neither impaired nor past due	22,858	19,459
Impaired (net of provision)	53	71
Not impaired and past due in the following periods		
within 30 days	637	446
31 to 60 days	130	116
61 to 90 days	114	56
over 90 days	569	468
	24,361	20,616

Movements in the impairment provision for trade receivables are shown in Note 19.

Financial instruments subject to offsetting, enforceable master netting arrangements and similar agreements

The following table shows the amounts recognized for financial assets and liabilities which are subject to offsetting arrangements on a gross basis, and the amounts offset in the balance sheet.

Amounts which cannot be offset under IFRS, but which could be settled net under the terms of master netting agreements if certain conditions arise, and collateral received or pledged, are also presented in the table to show the total net exposure of the group.

						$ million
				Related amounts not set off in the balance sheet		
At 31 December 2017	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	8,522	(1,380)	7,142	(1,554)	(321)	5,267
Derivative liabilities	(7,818)	1,380	(6,438)	1,554	—	(4,884)
Trade and other receivables	11,648	(5,311)	6,337	(2,156)	(114)	4,067
Trade and other payables	(12,543)	5,311	(7,232)	2,156	—	(5,076)
At 31 December 2016						
Derivative assets	9,025	(1,882)	7,143	(1,058)	(133)	5,952
Derivative liabilities	(10,236)	1,882	(8,354)	1,058	—	(7,296)

Trade and other receivables	8,815	(4,468)	4,347	(1,039)	(118)	3,190
Trade and other payables	(9,664)	4,468	(5,196)	1,039	—	(4,157)

(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.

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

During 2017, $8 billion of long-term taxable bonds were issued with terms ranging from one to twelve 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 $25.6 billion at 31 December 2017 (2016 $23.5 billion), primarily invested with highly rated banks or money market funds and readily accessible at immediate and short notice. At 31 December 2017, the group had substantial amounts of undrawn borrowing facilities available, consisting of $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.

The group also has committed letter of credit (LC) facilities totalling $9,400 million with a number of banks, allowing LCs to be issued for a maximum 23-month duration. There were also uncommitted secured LC facilities in place at 31 December 2017 for $1,560 million, which are secured against inventories or receivables when utilized. The facilities only terminate by either party giving a stipulated termination notice to the other.

27. Financial instruments and financial risk factors – continued

The amounts shown for finance debt in the table below include future minimum lease payments with respect to finance leases. The table also shows the timing of cash outflows relating to trade and other payables and accruals.

								$ million
				2017				2016
	Trade and other payables[a]	Accruals	Finance debt[b]	Interest on finance debt	Trade and other payables[a]	Accruals	Finance debt[b]	Interest on finance debt[c]
Within one year	40,472	4,960	7,626	1,757	35,774	5,136	6,620	1,217
1 to 2 years	1,693	135	7,331	1,537	2,005	186	5,909	1,083
2 to 3 years	1,413	83	7,068	1,321	1,278	91	6,624	942
3 to 4 years	1,378	70	6,766	1,114	1,239	53	6,201	801
4 to 5 years	1,368	54	7,986	894	1,229	33	6,564	658
5 to 10 years	6,181	115	24,162	1,951	5,826	75	22,190	1,446
Over 10 years	6,125	48	2,089	390	7,248	31	3,573	382
	58,630	5,465	63,028	8,964	54,599	5,605	57,681	6,529

[a] 2017 includes $18,918 million (2016 $21,644 million) in relation to the Gulf of Mexico oil spill.

[b] Fair value adjustments relating to hedging activity have been excluded from finance debt which therefore is not equal the amounts presented on the balance sheet. 2016 has been amended to conform with this presentation.

[c] 2016 has been amended to exclude interest payments that do not relate to finance debt. Interest on liabilities is included in trade and other payables.

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 28. 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.

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 net 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 $21,484 million at 31 December 2017 (2016 $18,014 million) to be received on the same day as the related cash outflows. For further information on our derivative financial instruments, see Note 28.

		$ million
Cash outflows for derivative financial instruments at 31 December	2017	2016
Within one year	1,505	2,677
1 to 2 years	1,700	1,505
2 to 3 years	1,678	1,700
3 to 4 years	2,384	1,678
4 to 5 years	2,838	2,384
5 to 10 years	11,238	9,985
Over 10 years	724	1,413
	22,067	21,342

28. 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 27. 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.

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.

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.

28. Derivative financial instruments – continued

				$ million
		2017		2016
	Fair value asset	Fair value liability	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	237	(756)	167	(2,000)
Oil price derivatives	1,637	(1,281)	1,543	(952)
Natural gas price derivatives	3,580	(2,844)	3,780	(2,845)
Power price derivatives	885	(693)	768	(560)
Other derivatives	115	—	232	—
	6,454	(5,574)	6,490	(6,357)
Embedded derivatives				
Commodity price contracts	—	(16)	—	(50)
Other embedded derivatives	—	(115)	—	(100)
	—	(131)	—	(150)
Cash flow hedges				
Currency forwards, futures and cylinders	35	(35)	32	(451)
Cross-currency interest rate swaps	—	—	—	(154)
	35	(35)	32	(605)
Fair value hedges				
Currency forwards, futures and swaps	460	(523)	22	(1,159)
Interest rate swaps	193	(306)	831	(233)
	653	(829)	853	(1,392)
	7,142	(6,569)	7,375	(8,504)
Of which – current	3,032	(2,808)	3,016	(2,991)
– non-current	4,110	(3,761)	4,359	(5,513)

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 27.

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
							2017
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	186	31	8	5	3	4	237
Oil price derivatives	1,280	177	99	66	14	1	1,637
Natural gas price derivatives	1,122	609	428	328	288	805	3,580
Power price derivatives	420	188	81	60	38	98	885
Other derivatives	—	—	—	—	—	115	115
	3,008	1,005	616	459	343	1,023	6,454

$ million
2016

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	102	34	20	2	7	2	167
Oil price derivatives	1,178	201	91	49	22	2	1,543
Natural gas price derivatives	1,238	647	424	313	267	891	3,780
Power price derivatives	305	164	114	58	53	74	768
Other derivatives	132	—	—	—	—	100	232
	2,955	1,046	649	422	349	1,069	6,490

At 31 December 2016 the group had a contingent consideration receivable in respect of the disposal of the Texas City refinery. The sale agreement contained an embedded derivative and had been designated at fair value through profit or loss and shown within other derivatives held for trading, within level 3 of the fair value hierarchy. The valuation was dependent on refinery throughput and future margins and final payment was received in 2017.

28. Derivative financial instruments – continued

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

							$ million 2017
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(92)	(232)	(66)	(188)	(99)	(79)	(756)
Oil price derivatives	(1,120)	(118)	(33)	(4)	(6)	—	(1,281)
Natural gas price derivatives	(973)	(410)	(334)	(224)	(194)	(709)	(2,844)
Power price derivatives	(337)	(134)	(63)	(39)	(29)	(91)	(693)
	(2,522)	(894)	(496)	(455)	(328)	(879)	(5,574)

							$ million 2016
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(379)	(36)	(402)	(101)	(338)	(744)	(2,000)
Oil price derivatives	(787)	(105)	(40)	(11)	(3)	(6)	(952)
Natural gas price derivatives	(947)	(421)	(257)	(258)	(197)	(765)	(2,845)
Power price derivatives	(201)	(126)	(81)	(39)	(31)	(82)	(560)
	(2,314)	(688)	(780)	(409)	(569)	(1,597)	(6,357)

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 2017
	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 2	3,663	1,003	438	244	140	135	5,623
Level 3	386	258	231	226	211	899	2,211
	4,049	1,261	669	470	351	1,034	7,834
Less: netting by counterparty	(1,041)	(256)	(53)	(11)	(8)	(11)	(1,380)
	3,008	1,005	616	459	343	1,023	6,454
Fair value of derivative liabilities							
Level 2	(3,338)	(953)	(358)	(289)	(163)	(166)	(5,267)
Level 3	(225)	(197)	(191)	(177)	(173)	(724)	(1,687)
	(3,563)	(1,150)	(549)	(466)	(336)	(890)	(6,954)
Less: netting by counterparty	1,041	256	53	11	8	11	1,380
	(2,522)	(894)	(496)	(455)	(328)	(879)	(5,574)
Net fair value	486	111	120	4	15	144	880

							$ million 2016
	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 2	3,962	1,035	509	208	117	189	6,020
Level 3	448	265	249	243	241	906	2,352
	4,410	1,300	758	451	358	1,095	8,372

Less: netting by counterparty	(1,455)	(254)	(109)	(29)	(9)	(26)	(1,882)
	2,955	1,046	649	422	349	1,069	6,490
Fair value of derivative liabilities							
Level 2	(3,610)	(778)	(701)	(249)	(401)	(872)	(6,611)
Level 3	(159)	(164)	(188)	(189)	(177)	(751)	(1,628)
	(3,769)	(942)	(889)	(438)	(578)	(1,623)	(8,239)
Less: netting by counterparty	1,455	254	109	29	9	26	1,882
	(2,314)	(688)	(780)	(409)	(569)	(1,597)	(6,357)
Net fair value	641	358	(131)	13	(220)	(528)	133

28. 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 2017	68	145	(147)	231	297
Gains (losses) recognized in the income statement	76	161	61	15	313
Settlements	(68)	(35)	(113)	(131)	(347)
Transfers out of level 3	(9)	(206)	(27)	—	(242)
Net fair value of contracts at 31 December 2017	67	65	(226)	115	21
Deferred day-one gains (losses)					503
Derivative asset (liability)					524

					$ million
	Oil price	Natural gas price	Power price	Other	Total
Fair value contracts at 1 January 2016	169	214	91	292	766
Gains (losses) recognized in the income statement	(37)	1	(82)	139	21
Settlements	(63)	(51)	(145)	(200)	(459)
Transfers out of level 3	(1)	(19)	(11)	—	(31)
Net fair value of contracts at 31 December 2016	68	145	(147)	231	297
Deferred day-one gains (losses)					427
Derivative asset (liability)					724

The amount recognized in the income statement for the year relating to level 3 held-for-trading derivatives still held at 31 December 2017 was a $234-million gain (2016 $253-million loss related to derivatives still held at 31 December 2016).

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 (excluding gains and losses on realized physical derivative contracts that have been reflected gross in the income statement within sales and purchases) was a net gain of $1,983 million (2016 $1,435 million net gain and 2015 $5,508 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 including futures, options, swaps and certain forward sales and forward purchase contracts primarily 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 $1,420 million (2016 $154 million net loss and 2015 $833 million net loss), 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

At 31 December 2017, the group held currency forwards used to hedge the foreign currency risk of highly probable forecast transactions. Note 27 outlines the group's approach to foreign currency exchange risk management. For cash flow hedges the group only claims hedge accounting for the spot value on the currency with any fair value attributable to forward points taken immediately to the income statement. The amounts remaining in equity at 31 December 2017 in relation to these cash flow hedges consist of deferred losses of $21 million maturing in 2018, deferred gains of $8 million maturing in 2019 and deferred gains of $2 million maturing in 2020 and beyond.

Fair value hedges

At 31 December 2017, 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 on fixed rate debt issued by the group. The gain on the hedging derivative instruments recognized in the income statement in 2017 was $364 million (2016 $316-million loss and 2015 $788-million loss) offset by a loss on the fair value of the finance debt of $394 million (2016 $270-million gain and 2015 $833-million gain).

The interest rate and cross-currency interest rate swaps mature within one to twelve years, and have the same maturity terms as the debt that they are hedging. They are used to convert sterling, euro, Swiss franc, Australian dollar, Canadian dollar, Norwegian krone and Hong Kong dollar denominated fixed rate borrowings into floating rate debt. Note 27 outlines the group's approach to interest rate and foreign currency exchange risk management.

29. Called-up share capital

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

Issued	2017 Shares thousand	2017 $ million	2016 Shares thousand	2016 $ million	2015 Shares thousand	2015 $ 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	21,049,696	5,263	20,108,771	5,028	20,005,961	5,002
Issue of new shares for the scrip dividend programme	289,789	72	548,005	137	102,810	26
Issue of new shares – other[b]	—	—	392,920	98	—	—
Repurchase of ordinary share capital	(51,292)	(13)	—	—	—	—
At 31 December	21,288,193	5,322	21,049,696	5,263	20,108,771	5,028
		5,343		5,284		5,049

[a] The nominal amount of 8% cumulative first preference shares and 9% cumulative second preference shares that can be in issue at any time shall not exceed £10,000,000 for each class of preference shares.

[b] Relates to the issue of new ordinary shares in consideration for a 10% interest in the Abu Dhabi onshore oil concession. See Note 30 for further information.

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 2017 the company repurchased 51 million ordinary shares for a total consideration of $343 million, including transaction costs of $2 million, as part of the share repurchase programme announced on 31 October 2017. All shares purchased were for cancellation. The repurchased shares represented 0.2% of ordinary share capital.

Treasury shares[a]

	2017 Shares thousand	2017 Nominal value $ million	2016 Shares thousand	2016 Nominal value $ million	2015 Shares thousand	2015 Nominal value $ million
At 1 January	1,614,657	403	1,756,327	439	1,811,297	453
Purchases for settlement of employee share plans	4,423	1	9,631	2	51,142	13
Shares re-issued for employee share-based payment plans[b]	(137,008)	(34)	(151,301)	(38)	(106,112)	(27)
At 31 December	1,482,072	370	1,614,657	403	1,756,327	439
Of which – shares held in treasury by BP	1,472,343	368	1,576,411	394	1,727,763	432
– shares held in ESOP trusts	9,705	2	21,432	5	18,453	4
– shares held by BP's US share plan administrator[c]	24	—	16,814	4	10,111	3

[a] See Note 30 for definition of treasury shares.

[b] A minor amendment has been made to the number of shares re-issued for employee share-based payment plans in 2016.

[c] 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 7.5% (2016 8.6% and 2015 8.9%) of the called-up ordinary share capital of the company. During 2017, the movement in shares held in treasury by BP represented less than 0.5% (2016 less than 0.8% and 2015 less than 0.2%) of the ordinary share capital of the company.

30. Capital and reserves

	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 recycling)	—	—	—	—	—
Available-for-sale investments (including recycling)	—	—	—	—	—
Cash flow hedges (including recycling)	—	—	—	—	—
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[c]	—	—	—	—	—
At 31 December 2017	5,343	12,147	1,426	27,206	46,122

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2016	5,049	10,234	1,413	27,206	43,902
Profit (loss) for the year	—	—	—	—	—
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including recycling)	—	—	—	—	—
Available-for-sale investments (including recycling)	—	—	—	—	—
Cash flow hedges (including recycling)	—	—	—	—	—
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	137	(137)	—	—	—
Share-based payments, net of tax[b d]	98	2,122	—	—	2,220
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	—
Transactions involving non-controlling interests	—	—	—	—	—
At 31 December 2016	5,284	12,219	1,413	27,206	46,122

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital

					reserves
At 1 January 2015	5,023	10,260	1,413	27,206	43,902
Profit (loss) for the year	—	—	—	—	—
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including recycling)[a]	—	—	—	—	—
Available-for-sale investments (including recycling)	—	—	—	—	—
Cash flow hedges (including recycling)	—	—	—	—	—
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	—	—	—	—	—
Share of items relating to equity-accounted entities, net of tax	—	—	—	—	—
Total comprehensive income	—	—	—	—	—
Dividends	26	(26)	—	—	—
Share-based payments, net of tax[b]	—	—	—	—	—
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	—
Transactions involving non-controlling interests	—	—	—	—	—
At 31 December 2015	5,049	10,234	1,413	27,206	43,902

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

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

[c] Principally relates to the initial public offering of common units in BP Midstream Partners LP for which net proceeds of $811 million were received.

[d] Includes ordinary shares issued to the government of Abu Dhabi in consideration for a 10% interest in the Abu Dhabi onshore oil concession. The share-based payment transaction was valued at the fair value of the interest in the assets, with reference to a market transaction for an identical interest.

30. Capital and reserves – continued

$ million

Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Total fair value reserves	Profit and loss account	BP shareholders' equity	Non-controlling interests	Total equity
(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

Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Total fair value reserves	Profit and loss account	BP shareholders' equity	Non-controlling interests	Total equity
(19,964)	(7,267)	2	(825)	(823)	81,368	97,216	1,171	98,387
—	—	—	—	—	115	115	57	172
—	389	—	—	—	—	389	(27)	362
—	—	1	—	1	—	1	—	1
—	—	—	(331)	(331)	—	(331)	—	(331)
—	—	—	—	—	833	833	—	833
—	—	—	—	—	(96)	(96)	—	(96)
—	—	—	—	—	(1,757)	(1,757)	—	(1,757)
—	389	1	(331)	(330)	(905)	(846)	30	(816)
—	—	—	—	—	(4,611)	(4,611)	(107)	(4,718)
1,521	—	—	—	—	(750)	2,991	—	2,991
—	—	—	—	—	106	106	—	106
—	—	—	—	—	430	430	463	893
(18,443)	(6,878)	3	(1,156)	(1,153)	75,638	95,286	1,557	96,843

Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Total fair value reserves	Profit and loss account	BP shareholders' equity	Non-controlling interests	Total equity
(20,719)	(3,409)	1	(898)	(897)	92,564	111,441	1,201	112,642

—	—	—	—	—	(6,482)	(6,482)	82	(6,400)
—	(3,858)	—	—	—	—	(3,858)	(41)	(3,899)
—	—	1	—	1	—	1	—	1
—	—	—	73	73	—	73	—	73
—	—	—	—	—	(814)	(814)	—	(814)
—	—	—	—	—	80	80	—	80
—	—	—	—	—	2,742	2,742	—	2,742
—	—	—	—	—	(1)	(1)	—	(1)
—	(3,858)	1	73	74	(4,475)	(8,259)	41	(8,218)
—	—	—	—	—	(6,659)	(6,659)	(91)	(6,750)
755	—	—	—	—	(99)	656	—	656
—	—	—	—	—	40	40	—	40
—	—	—	—	—	(3)	(3)	20	17
(19,964)	(7,267)	2	(825)	(823)	81,368	97,216	1,171	98,387

30. 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 recycled to the income statement.

Available-for-sale investments

This reserve records the changes in fair value of available-for-sale investments except for impairment losses, foreign exchange gains or losses, or changes arising from revised estimates of future cash flows. On disposal or impairment of the investments, the cumulative changes in fair value are recycled to the income statement.

Cash flow hedges

This reserve records the portion of the gain or loss on a hedging instrument in a cash flow hedge that is determined to be an effective hedge. 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.

Profit and loss account

The balance held on this reserve is the accumulated retained profits of the group.

30. 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
			2017
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including recycling)	1,866	(95)	1,771
Available-for-sale investments (including recycling)	14	—	14
Cash flow hedges (including recycling)	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

			$ million
			2016
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including recycling)	284	78	362
Available-for-sale investments (including recycling)	1	—	1
Cash flow hedges (including recycling)	(362)	31	(331)
Share of items relating to equity-accounted entities, net of tax	833	—	833
Other	—	(96)	(96)
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	(2,496)	739	(1,757)
Other comprehensive income	(1,740)	752	(988)

			$ million
			2015
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including recycling)	(4,096)	197	(3,899)
Available-for-sale investments (including recycling)	1	—	1
Cash flow hedges (including recycling)	93	(20)	73
Share of items relating to equity-accounted entities, net of tax	(814)	—	(814)
Other	—	80	80
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	4,139	(1,397)	2,742
Share of items relating to equity-accounted entities, net of tax	(1)	—	(1)
Other comprehensive income	(678)	(1,140)	(1,818)

31. Contingent liabilities

Contingent liabilities related to the Gulf of Mexico oil spill

See Note 2 for information on contingent liabilities related to the Gulf of Mexico oil spill.

Contingent liabilities not related to the Gulf of Mexico oil spill

There were contingent liabilities at 31 December 2017 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 27.
In the normal course of the group’s business, legal and regulatory proceedings are pending or may be brought against BP group entities 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 and environmental claims and allegations of exposures of third parties to toxic substances, such as lead pigment in paint, asbestos and other chemicals. BP believes that the impact of these legal 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 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, the group does not anticipate that there will be any material impact upon the group‘s results of operations, financial position or liquidity.

31. 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 cost are inherently difficult to estimate. However, the estimated cost of known environmental obligations has been provided in these accounts in accordance with the group's accounting policies. While the amounts of future costs that are not provided for could be significant and could be 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 effect on the group's 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. 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.

32. Remuneration of senior management and non-executive directors

Remuneration of directors

	$ million		
	2017	2016	2015
Total for all directors			
Emoluments	9	10	10
Amounts received under incentive schemes[a]	9	14	14
Total	18	24	24

[a] Excludes amounts relating to past directors.

Emoluments

These amounts comprise fees paid to the non-executive chairman and the non-executive directors and, for executive directors, salary and benefits earned during the relevant financial year, plus cash bonuses awarded for the year.

Pension contributions

During 2017, one executive director participated in a UK final salary pension plan in respect of service prior to 1 April 2011. During 2017, one executive director participated in retirement savings plans established for US employees and in a US defined 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 90.

Remuneration of directors and senior management

	$ million		
	2017	2016	2015
Total for all senior management and non-executive directors			
Short-term employee benefits	29	28	33
Pensions and other post-retirement benefits	2	3	4
Share-based payments	29	39	36
Total	60	70	73

Senior management comprises members of the executive team, see pages 66-67 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

2017 (2016 $2.2 million and 2015 $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’.

33. Employee costs and numbers

	$ million		
Employee costs	2017	2016	2015
Wages and salaries[a]	7,572	8,456	9,556
Social security costs	711	760	879
Share-based payments[b]	624	764	833
Pension and other post-retirement benefit costs	1,296	1,253	1,660
	10,203	11,233	12,928

	2017			2016			2015		
Average number of employees[c]	US	Non-US	Total	US	Non-US	Total	US	Non-US	Total
Upstream	6,200	12,200	18,400	6,700	13,500	20,200	7,900	15,100	23,000
Downstream[d e]	6,100	35,900	42,000	6,600	36,600	43,200	7,800	38,200	46,000
Other businesses and corporate[e f]	1,900	12,400	14,300	1,900	12,100	14,000	1,700	11,900	13,600
	14,200	60,500	74,700	15,200	62,200	77,400	17,400	65,200	82,600

[a] Includes termination costs of $189 million (2016 $545 million and 2015 $857 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 16,500 (2016 15,800 and 2015 15,000) service station staff.
[e] Around 800 centralized function employees were reallocated from Upstream and Downstream to Other businesses and corporate during 2016, and around 2,000 from the global business services organization were reallocated from Downstream to Other businesses and corporate during 2015.
[f] Includes 4,700 (2016 4,900 and 2015 5,300) agricultural, operational and seasonal workers in Brazil.

34. Auditor's remuneration

	$ million		
Fees – Ernst & Young	2017	2016	2015
The audit of the company annual accounts[a]	26	25	27
The audit of accounts of subsidiaries of the company	11	12	13
Total audit	37	37	40
Audit-related assurance services[b]	7	7	7
Total audit and audit-related assurance services	44	44	47
Taxation compliance services	—	1	1
Services relating to corporate finance transactions	—	—	1
Non-audit and other assurance services	3	1	1
Total non-audit or non-audit-related assurance services	3	2	3
Services relating to BP pension plans[c]	—	1	1
	47	47	51

[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.
[c] The pension plan services include tax compliance service of $nil (2016 $nil and 2015 $0.4 million).
2017 includes $1.6 million of additional fees for 2016 and 2016 includes $1 million of additional fees for 2015.
Auditors' remuneration is included in the income statement within distribution and administration expenses.
The tax services relate to income tax and indirect tax compliance, employee tax services and tax advisory services.
The audit committee has established pre-approval policies and procedures for the engagement of Ernst & Young to render audit and certain assurance and other services. The audit fees payable to Ernst & Young are reviewed by the audit committee in the context of other global companies for cost-effectiveness. Ernst & Young performed further assurance services that were not prohibited by regulatory or other professional requirements and were pre-approved by the Committee. Ernst & Young is engaged for these services when its expertise and experience of BP are important.

Most of this work is of an audit nature.

Under SEC regulations, the remuneration of the auditor of $47 million (2016 $47 million and 2015 $51 million) is required to be presented as follows: audit $37 million (2016 $37 million and 2015 $40 million); other audit-related $7 million (2016 $7 million and 2015 $7 million); tax $nil (2016 $1 million and 2015 $1 million); and all other fees $3 million (2016 $2 million and 2015 $3 million).

35. Subsidiaries, joint arrangements and associates

The more important subsidiaries and associates of the group at 31 December 2017 and the group percentage of ordinary share capital (to nearest whole number) are set out below. There are no individually significant joint arrangements. Those held directly by the parent company are marked with an asterisk (*), the percentage owned being that of the group unless otherwise indicated. A complete list of undertakings of the group is included in Note 14 in the parent company financial statements of BP p.l.c. which are filed with the Registrar of Companies in the UK, along with the group's annual report.

Subsidiaries	%	Country of incorporation	Principal activities
International			
BP Corporate Holdings	100	England & Wales	Investment holding
BP Exploration Operating Company	100	England & Wales	Exploration and production
*BP Global Investments	100	England & Wales	Investment holding
*BP International	100	England & Wales	Integrated oil operations
BP Oil International	100	England & Wales	Integrated oil operations
*Burmah Castrol	100	Scotland	Lubricants
Angola			
BP Exploration (Angola)	100	England & Wales	Exploration and production
Azerbaijan			
BP Exploration (Caspian Sea)	100	England & Wales	Exploration and production
BP Exploration (Azerbaijan)	100	England & Wales	Exploration and production
Canada			
*BP Holdings Canada	100	England & Wales	Investment holding
Egypt			
BP Exploration (Delta)	100	England & Wales	Exploration and production
Germany			
BP Europa SE	100	Germany	Refining and marketing
India			
BP Exploration (Alpha)	100	England & Wales	Exploration and production
Trinidad & Tobago			
BP Trinidad and Tobago	70	US	Exploration and production
UK			
BP Capital Markets	100	England & Wales	Finance
US			
*BP Holdings North America	100	England & Wales	Investment holding
Atlantic Richfield Company	100	US	Exploration and production, refining and marketing
BP America	100	US	
BP America Production Company	100	US	
BP Company North America	100	US	
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	20	Russia	Integrated oil operations

36. 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. 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

For the year ended 31 December					$ million 2017
	Issuer BP Exploration (Alaska) Inc.	Guarantor 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.

Statement of comprehensive income

For the year ended 31 December					$ million 2017
	Issuer	Guarantor			
	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	—	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

36. Condensed consolidating information on certain US subsidiaries – continued
Income statement continued

For the year ended 31 December					$ million 2016
	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	2,740	—	182,999	(2,731)	183,008
Earnings from joint ventures - after interest and tax	—	—	966	—	966
Earnings from associates - after interest and tax	—	—	994	—	994
Equity-accounted income of subsidiaries - after interest and tax	—	862	—	(862)	—
Interest and other income	94	343	899	(830)	506
Gains on sale of businesses and fixed assets	—	—	1,132	—	1,132
Total revenues and other income	2,834	1,205	186,990	(4,423)	186,606
Purchases	888	—	134,062	(2,731)	132,219
Production and manufacturing expenses	1,171	—	27,906	—	29,077
Production and similar taxes	102	—	581	—	683
Depreciation, depletion and amortization	673	—	13,832	—	14,505
Impairment and losses on sale of businesses and fixed assets	(147)	—	(1,517)	—	(1,664)
Exploration expense	—	—	1,721	—	1,721
Distribution and administration expenses	—	808	9,797	(110)	10,495
Profit (loss) before interest and taxation	147	397	608	(1,582)	(430)
Finance costs	103	311	1,981	(720)	1,675
Net finance (income) expense relating to pensions and other post-retirement benefits	—	(82)	272	—	190
Profit (loss) before taxation	44	168	(1,645)	(862)	(2,295)
Taxation	(41)	53	(2,479)	—	(2,467)
Profit (loss) for the year	85	115	834	(862)	172
Attributable to					
BP shareholders	85	115	777	(862)	115
Non-controlling interests	—	—	57	—	57
	85	115	834	(862)	172

Statement of comprehensive income continued

					$ million 2016
	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group

Profit (loss) for the year	85	115	834	(862)	172
Other comprehensive income	—	(1,505)	517	—	(988)
Equity-accounted other comprehensive income of subsidiaries	—	544	—	(544)	—
Total comprehensive income	85	(846)	1,351	(1,406)	(816)
Attributable to					
BP shareholders	85	(846)	1,321	(1,406)	(846)
Non-controlling interests	—	—	30	—	30
	85	(846)	1,351	(1,406)	(816)

36. Condensed consolidating information on certain US subsidiaries – continued
Income statement continued

	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	$ million 2015 BP group
Sales and other operating revenues	3,438	—	222,881	(3,425)	222,894
Earnings from joint ventures - after interest and tax	—	—	(28)	—	(28)
Earnings from associates - after interest and tax	—	—	1,839	—	1,839
Equity-accounted income of subsidiaries - after interest and tax	—	(5,404)	—	5,404	—
Interest and other income	29	185	671	(274)	611
Gains on sale of businesses and fixed assets	—	31	666	(31)	666
Total revenues and other income	3,467	(5,188)	226,029	1,674	225,982
Purchases	1,432	—	166,783	(3,425)	164,790
Production and manufacturing expenses	1,360	—	35,680	—	37,040
Production and similar taxes	140	—	896	—	1,036
Depreciation, depletion and amortization	569	—	14,650	—	15,219
Impairment and losses on sale of businesses and fixed assets	176	—	1,733	—	1,909
Exploration expense	—	—	2,353	—	2,353
Distribution and administration expenses	56	1,125	10,449	(77)	11,553
Profit (loss) before interest and taxation	(266)	(6,313)	(6,515)	5,176	(7,918)
Finance costs	35	36	1,473	(197)	1,347
Net finance (income) expense relating to pensions and other post-retirement benefits	—	20	286	—	306
Profit (loss) before taxation	(301)	(6,369)	(8,274)	5,373	(9,571)
Taxation	(129)	82	(3,124)	—	(3,171)
Profit (loss) for the year	(172)	(6,451)	(5,150)	5,373	(6,400)
Attributable to					
BP shareholders	(172)	(6,451)	(5,232)	5,373	(6,482)
Non-controlling interests	—	—	82	—	82
	(172)	(6,451)	(5,150)	5,373	(6,400)

Statement of comprehensive income continued

Issuer	Guarantor BP p.l.c.	$ million 2015

	BP Exploration (Alaska) Inc.		Other subsidiaries	Eliminations and reclassifications	BP group
Profit (loss) for the year	(172)	(6,451)	(5,150)	5,373	(6,400)
Other comprehensive income	—	1,863	(3,681)	—	(1,818)
Equity-accounted other comprehensive income of subsidiaries	—	(3,640)	—	3,640	—
Total comprehensive income	(172)	(8,228)	(8,831)	9,013	(8,218)
Attributable to					
BP shareholders	(172)	(8,228)	(8,872)	9,013	(8,259)
Non-controlling interests	—	—	41	—	41
	(172)	(8,228)	(8,831)	9,013	(8,218)

36. Condensed consolidating information on certain US subsidiaries – continued
Balance sheet

					$ million 2017
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Non-current assets					
Property, plant and equipment	6,973	—	122,498	—	129,471
Goodwill	—	—	11,551	—	11,551
Intangible assets	585	—	17,770	—	18,355
Investments in joint ventures	—	—	7,994	—	7,994
Investments in associates	—	2	16,989	—	16,991
Other investments	—	—	1,245	—	1,245
Subsidiaries - equity-accounted basis	—	161,840	—	(161,840)	—
Fixed assets	7,558	161,842	178,047	(161,840)	185,607
Loans	1	—	34,701	(34,056)	646
Trade and other receivables	—	2,623	1,434	(2,623)	1,434
Derivative financial instruments	—	—	4,110	—	4,110
Prepayments	—	—	1,112	—	1,112
Deferred tax assets	—	—	4,469	—	4,469
Defined benefit pension plan surpluses	—	3,838	331	—	4,169
	7,559	168,303	224,204	(198,519)	201,547
Current assets					
Loans	—	—	190	—	190
Inventories	274	—	18,737	—	19,011
Trade and other receivables	2,206	293	32,691	(10,341)	24,849
Derivative financial instruments	—	—	3,032	—	3,032
Prepayments	2	—	1,412	—	1,414
Current tax receivable	—	—	761	—	761
Other investments	—	—	125	—	125
Cash and cash equivalents	—	10	25,576	—	25,586
	2,482	303	82,524	(10,341)	74,968
Total assets	10,041	168,606	306,728	(208,860)	276,515
Current liabilities					
Trade and other payables	673	7,843	46,034	(10,341)	44,209
Derivative financial instruments	—	—	2,808	—	2,808
Accruals	115	60	4,785	—	4,960
Finance debt	—	—	7,739	—	7,739
Current tax payable	—	—	1,686	—	1,686
Provisions	1	—	3,323	—	3,324
	789	7,903	66,375	(10,341)	64,726
Non-current liabilities					
Other payables	—	34,104	16,464	(36,679)	13,889
Derivative financial instruments	—	—	3,761	—	3,761
Accruals	—	—	505	—	505
Finance debt	—	—	55,491	—	55,491
Deferred tax liabilities	838	1,337	5,807	—	7,982
Provisions	1,222	—	19,398	—	20,620

Defined benefit pension plan and other post-retirement benefit plan deficits	—	221	8,916	—	9,137
	2,060	35,662	110,342	(36,679)	111,385
Total liabilities	2,849	43,565	176,717	(47,020)	176,111
Net assets	7,192	125,041	130,011	(161,840)	100,404
Equity					
BP shareholders' equity	7,192	125,041	128,098	(161,840)	98,491
Non-controlling interests	—	—	1,913	—	1,913
	7,192	125,041	130,011	(161,840)	100,404

36. Condensed consolidating information on certain US subsidiaries – continued
Balance sheet continued

	Issuer	Guarantor			$ million 2016
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Non-current assets					
Property, plant and equipment	7,405	—	122,352	—	129,757
Goodwill	—	—	11,194	—	11,194
Intangible assets	578	—	17,605	—	18,183
Investments in joint ventures	—	—	8,609	—	8,609
Investments in associates	—	2	14,090	—	14,092
Other investments	—	—	1,033	—	1,033
Subsidiaries - equity-accounted basis	—	156,864	—	(156,864)	—
Fixed assets	7,983	156,866	174,883	(156,864)	182,868
Loans	9	—	34,941	(34,418)	532
Trade and other receivables	—	2,951	1,474	(2,951)	1,474
Derivative financial instruments	—	—	4,359	—	4,359
Prepayments	—	—	945	—	945
Deferred tax assets	—	—	4,741	—	4,741
Defined benefit pension plan surpluses	—	528	56	—	584
	7,992	160,345	221,399	(194,233)	195,503
Current assets					
Loans	—	—	259	—	259
Inventories	249	—	17,406	—	17,655
Trade and other receivables[a]	1,593	487	24,610	(6,015)	20,675
Derivative financial instruments	—	—	3,016	—	3,016
Prepayments	7	—	1,479	—	1,486
Current tax receivable	—	—	1,194	—	1,194
Other investments	—	—	44	—	44
Cash and cash equivalents	—	50	23,434	—	23,484
	1,849	537	71,442	(6,015)	67,813
Total assets	9,841	160,882	292,841	(200,248)	263,316
Current liabilities					
Trade and other payables[a]	672	4,096	39,162	(6,015)	37,915
Derivative financial instruments	—	—	2,991	—	2,991
Accruals	116	129	4,891	—	5,136
Finance debt	—	—	6,634	—	6,634
Current tax payable[a]	—	—	1,666	—	1,666
Provisions	2	—	4,010	—	4,012
	790	4,225	59,354	(6,015)	58,354
Non-current liabilities					
Other payables	20	34,389	16,906	(37,369)	13,946
Derivative financial instruments	—	—	5,513	—	5,513
Accruals	—	43	426	—	469
Finance debt	—	—	51,666	—	51,666
Deferred tax liabilities	1,279	179	5,780	—	7,238
Provisions	1,390	—	19,022	—	20,412

Defined benefit pension plan and other post-retirement benefit plan deficits	—	219	8,656	—	8,875
	2,689	34,830	107,969	(37,369)	108,119
Total liabilities	3,479	39,055	167,323	(43,384)	166,473
Net assets	6,362	121,827	125,518	(156,864)	96,843
Equity					
BP shareholders' equity[a]	6,362	121,827	123,961	(156,864)	95,286
Non-controlling interests	—	—	1,557	—	1,557
	6,362	121,827	125,518	(156,864)	96,843

[a] Amendments have been made to previously reported amounts for BP Exploration (Alaska) Inc., reducing current trade and other receivables by $990 million, current trade and other payables by $50 million and current tax payable by $11 million, with offsetting amendments to BP shareholders' equity. This relates to intra-BP group balances and, as such, amendments have also been made to the same line items presented for Other subsidiaries as well as eliminations amounts. The amendments represent the adjustment of amounts recorded in earlier periods by BP Exploration (Alaska) Inc. as intra-BP group balances relating to group re-organizations and the tax consequences thereon which are now considered to be more appropriately treated as shown by the amended amounts above.

36. Condensed consolidating information on certain US subsidiaries – continued

Cash flow statement

				$ million 2017
	Issuer	Guarantor		
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	BP group
Net cash provided by operating activities	227	6,456	12,248	18,931
Net cash provided by (used in) investing activities	(227)	—	(13,850)	(14,077)
Net cash provided by (used in) financing activities	—	(6,496)	3,200	(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

For the year ended 31 December				$ million 2016
	Issuer	Guarantor		
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	BP group
Net cash provided by operating activities	699	4,661	5,331	10,691
Net cash provided by (used in) investing activities	(699)	—	(14,054)	(14,753)
Net cash provided by (used in) financing activities	—	(4,611)	6,588	1,977
Currency translation differences relating to cash and cash equivalents	—	—	(820)	(820)
Increase (decrease) in cash and cash equivalents	—	50	(2,955)	(2,905)
Cash and cash equivalents at beginning of year	—	—	26,389	26,389
Cash and cash equivalents at end of year	—	50	23,434	23,484

For the year ended 31 December				$ million 2015
	Issuer	Guarantor		
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	BP group
Net cash provided by operating activities	925	6,628	11,580	19,133
Net cash provided by (used in) investing activities	(925)	—	(16,375)	(17,300)
Net cash provided by (used in) financing activities	—	(6,659)	2,124	(4,535)
Currency translation differences relating to cash and cash equivalents	—	—	(672)	(672)
Increase (decrease) in cash and cash equivalents	—	(31)	(3,343)	(3,374)
Cash and cash equivalents at beginning of year	—	31	29,732	29,763
Cash and cash equivalents at end of year	—	—	26,389	26,389

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 259-264.

Oil and natural gas exploration and production activities

$ 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] Decommissioning assets 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.

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[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)
	—	71	25	—	381	205	837	245	—	1,764

Total replacement cost profit (loss) after
interest and tax

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

[b] These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction and transportation operations as well as downstream activities of Rosneft and Pan American Energy Group are excluded. The amounts reported for equity-accounted entities exclude the corresponding amounts for their equity-accounted entities.

[c] Decommissioning assets 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 transportation costs and 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.

Oil and natural gas exploration and production activities – continued

	Europe		North America		South America	Africa	Asia		Australasia	Total
										$ million 2016
	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	34,171	—	81,633	3,622	12,624	46,892	—	30,870	5,752	215,564
Unproved properties	483	—	4,712	2,377	2,450	3,808	—	4,132	562	18,524
	34,654	—	86,345	5,999	15,074	50,700	—	35,002	6,314	234,088
Accumulated depreciation	21,745	—	44,988	272	6,764	31,456	—	15,942	2,826	123,993
Net capitalized costs	12,909	—	41,357	5,727	8,310	19,244	—	19,060	3,488	110,095
Costs incurred for the year ended 31 December[a b]										
Acquisition of properties[c]										
Proved	215	—	314	—	—	—	—	703	207	1,439
Unproved	—	—	38	10	10	181	—	1,728	—	1,967
	215	—	352	10	10	181	—	2,431	207	3,406
Exploration and appraisal costs[d]	165	5	391	70	123	297	10	252	89	1,402
Development	1,284	3	2,372	28	1,519	2,957	—	2,788	194	11,145
Total costs	1,664	8	3,115	108	1,652	3,435	10	5,471	490	15,953
Results of operations for the year ended 31 December[a]										
Sales and other operating revenues[e]										
Third parties	244	26	640	74	747	1,215	—	97	1,042	4,085
Sales between businesses	1,387	421	6,204	2	103	3,391	—	3,908	309	15,725
	1,631	447	6,844	76	850	4,606	—	4,005	1,351	19,810
Exploration expenditure	133	3	693	61	672	87	10	(27)	89	1,721
Production costs	619	208	2,524	114	476	1,220	—	691	154	6,006
Production taxes	(351)	—	155	—	38	—	—	800	41	683
Other costs (income)[f]	(215)	37	1,687	25	115	597	34	115	153	2,548
Depreciation, depletion and amortization	1,002	209	3,940	66	591	2,937	—	2,179	289	11,213
Net impairments and (gains) losses on sale of businesses and fixed assets	(809)	(345)	(627)	(5)	(77)	(765)	—	(182)	63	(2,747)
	379	112	8,372	261	1,815	4,076	44	3,576	789	19,424
Profit (loss) before taxation[g]	1,252	335	(1,528)	(185)	(965)	530	(44)	429	562	386
Allocable taxes[h]	(286)	(287)	(402)	(40)	(194)	670	(10)	(74)	288	(335)
Results of operations	1,538	622	(1,126)	(145)	(771)	(140)	(34)	503	274	721

Upstream and Rosneft segments replacement cost profit (loss) before interest and tax

Exploration and production activities – subsidiaries (as above)	1,252	335	(1,528)	(185)	(965)	530	(44)	429	562	386
Midstream and other activities – subsidiaries[i]	(417)	54	(14)	(137)	187	(142)	(2)	(81)	13	(539)
Equity-accounted entities[j k]	—	(1)	20	—	447	(12)	597	266	—	1,317
Total replacement cost profit (loss) before interest and tax	835	388	(1,522)	(322)	(331)	376	551	614	575	1,164

[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 Forties Pipeline System, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia, Australia and Angola.

[b] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

[c] Rest of Asia amounts include BP's participating interest in the Abu Dhabi ADCO concession.

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

[f] Includes property taxes, other government take and the fair value gain on embedded derivatives of $32 million. The UK region includes a $454-million gain which is offset by corresponding charges primarily in the US region, relating to the group self-insurance programme.

[g] Excludes the unwinding of the discount on provisions and payables amounting to $152 million which is included in finance costs in the group income statement.

[h] UK region includes the deferred tax impact of the enactment of legislation to reduce the UK supplementary charge tax rate applicable to profits arising in the North Sea from 20% to 10%.

[i] Midstream and other activities excludes inventory holding gains and losses.

[j] The profits of equity-accounted entities are included after interest and tax.

[k] Includes the results of BP's 30% interest in Aker BP ASA from 1 October 2016.

Oil and natural gas exploration and production activities – continued

										$ million 2016
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		
Equity-accounted entities (BP share)										
Capitalized costs at 31 December[b c]										
Gross capitalized costs										
Proved properties	—	2,702	—	—	10,211	—	19,558	3,009	—	35,480
Unproved properties	—	296	—	—	6	—	383	26	—	711
	—	2,998	—	—	10,217	—	19,941	3,035	—	36,191
Accumulated depreciation	—	48	—	—	4,615	—	4,401	3,035	—	12,099
Net capitalized costs	—	2,950	—	—	5,602	—	15,540	—	—	24,092
Costs incurred for the year ended 31 December[b d e]										
Acquisition of properties[c]										
Proved	—	—	—	—	—	—	1,576	—	—	1,576
Unproved	—	—	—	—	—	—	69	—	—	69
	—	—	—	—	—	—	1,645	—	—	1,645
Exploration and appraisal costs[d]	—	18	—	—	7	—	118	1	—	144
Development	—	54	—	—	559	—	2,070	371	—	3,054
Total costs	—	72	—	—	566	—	3,833	372	—	4,843
Results of operations for the year ended 31 December[b]										
Sales and other operating revenues[f]										
Third parties	—	162	—	—	1,865	—	—	876	—	2,903
Sales between businesses	—	—	—	—	—	—	8,088	16	—	8,104
	—	162	—	—	1,865	—	8,088	892	—	11,007
Exploration expenditure	—	13	—	—	—	—	50	—	—	63
Production costs	—	36	—	—	559	—	1,085	145	—	1,825
Production taxes	—	—	—	—	335	—	3,393	352	—	4,080
Other costs (income)	—	(13)	—	—	(429)	—	345	3	—	(94)
Depreciation, depletion and amortization	—	48	—	—	499	—	1,082	386	—	2,015
Net impairments and losses on sale of businesses and fixed assets	—	—	—	—	164	—	59	—	—	223
	—	84	—	—	1,128	—	6,014	886	—	8,112
Profit (loss) before taxation	—	78	—	—	737	—	2,074	6	—	2,895
Allocable taxes	—	75	—	—	319	—	435	3	—	832
Results of operations[g]	—	3	—	—	418	—	1,639	3	—	2,063
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)	—	3	—	—	418	—	1,639	3	—	2,063
Midstream and other activities after tax[h]	—	(4)	20	—	29	(12)	(1,042)	263	—	(746)
	—	(1)	20	—	447	(12)	597	266	—	1,317

Total replacement cost profit (loss) after
interest and tax

[a] Amounts reported for Russia in this table include BP's share of Rosneft's worldwide activities, including insignificant amounts outside Russia. Amounts also include certain adjustments, mainly related to purchase price allocations for 2016 acquisitions.

[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 are excluded. The amounts reported for equity-accounted entities exclude the corresponding amounts for their equity-accounted entities.

[c] Decommissioning assets 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 transportation costs and sales taxes.

[g] Includes the results of BP's 30% interest in Aker BP ASA from 1 October 2016.

[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 2015
	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	33,214	10,568	80,716	3,559	11,051	42,807	—	28,474	5,177	215,566
Unproved properties	437	168	5,602	2,377	2,964	4,635	—	2,740	933	19,856
	33,651	10,736	86,318	5,936	14,015	47,442	—	31,214	6,110	235,422
Accumulated depreciation	21,447	7,172	43,290	191	6,251	29,406	—	15,967	2,677	126,401
Net capitalized costs	12,204	3,564	43,028	5,745	7,764	18,036	—	15,247	3,433	109,021
Costs incurred for the year ended 31 December[a b]										
Acquisition of properties										
Proved	17	—	131	—	—	259	—	—	—	407
Unproved	—	—	56	—	(118)	8	—	—	—	(54)
	17	—	187	—	(118)	267	—	—	—	353
Exploration and appraisal costs[c]	178	11	651	75	114	533	5	102	125	1,794
Development	1,784	73	3,662	324	1,299	2,749	—	3,439	128	13,458
Total costs	1,979	84	4,500	399	1,295	3,549	5	3,541	253	15,605
Results of operations for the year ended 31 December[a]										
Sales and other operating revenues[d]										
Third parties	496	209	651	14	1,594	1,829	—	800	1,450	7,043
Sales between businesses	1,149	718	7,427	2	33	4,005	—	4,028	340	17,702
	1,645	927	8,078	16	1,627	5,834	—	4,828	1,790	24,745
Exploration expenditure	115	8	960	108	51	1,001	5	53	52	2,353
Production costs	879	313	2,777	77	703	1,521	—	1,083	166	7,519
Production taxes	(273)	—	215	—	214	—	—	834	46	1,036
Other costs (income)[e]	(795)	92	2,460	48	140	358	27	76	215	2,621
Depreciation, depletion and amortization	949	544	3,671	13	673	3,412	—	2,420	322	12,004
Net impairments and (gains) losses on sale of businesses and fixed assets	(390)	17	340	—	101	846	—	105	140	1,159
	485	974	10,423	246	1,882	7,138	32	4,571	941	26,692
Profit (loss) before taxation[f]	1,160	(47)	(2,345)	(230)	(255)	(1,304)	(32)	257	849	(1,947)
Allocable taxes[g]	(930)	159	(857)	(5)	(28)	694	(5)	(66)	472	(566)
Results of operations	2,090	(206)	(1,488)	(225)	(227)	(1,998)	(27)	323	377	(1,381)
Upstream and Rosneft segments replacement cost profit (loss) before interest and tax										
	1,160	(47)	(2,345)	(230)	(255)	(1,304)	(32)	257	849	(1,947)

Exploration and production activities – subsidiaries (as above)										
Midstream and other activities – subsidiaries[h]	401	110	43	10	211	(39)	(16)	67	14	801
Equity-accounted entities[i]	—	(7)	19	—	370	(552)	1,326	363	—	1,519
Total replacement cost profit (loss) before interest and tax	1,561	56	(2,283)	(220)	326	(1,895)	1,278	687	863	373

[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 Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia, Australia and Angola.

[b] Decommissioning assets 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 $120 million. The UK region includes a $832-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 $164 million which is included in finance costs in the group income statement.

[g] UK region includes the one-off deferred tax impact of the enactment of legislation to reduce the UK supplementary charge tax rate applicable to profits arising in the North Sea from 32% to 20%.

[h] Midstream and other activities excludes inventory holding gains and losses.

[i] BP's share of the profits of equity-accounted entities are included after interest and tax reported by those entities.

Oil and natural gas exploration and production activities – continued

$ million
2015

	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	—	—	—	—	9,824	—	12,728	3,486	—	26,038
Unproved properties	—	—	—	—	—	—	437	26	—	463
	—	—	—	—	9,824	—	13,165	3,512	—	26,501
Accumulated depreciation	—	—	—	—	4,117	—	2,788	3,458	—	10,363
Net capitalized costs	—	—	—	—	5,707	—	10,377	54	—	16,138
Costs incurred for the year ended 31 December[b d e]										
Acquisition of properties[c]										
Proved	—	—	—	—	—	—	16	—	—	16
Unproved	—	—	—	—	—	—	26	—	—	26
	—	—	—	—	—	—	42	—	—	42
Exploration and appraisal costs[d]	—	—	—	—	8	—	123	1	—	132
Development	—	—	—	—	1,128	—	1,702	443	—	3,273
Total costs	—	—	—	—	1,136	—	1,867	444	—	3,447
Results of operations for the year ended 31 December[b]										
Sales and other operating revenues[f]										
Third parties	—	—	—	—	2,060	—	—	1,022	—	3,082
Sales between businesses	—	—	—	—	—	—	8,592	19	—	8,611
	—	—	—	—	2,060	—	8,592	1,041	—	11,693
Exploration expenditure	—	—	—	—	3	—	52	—	—	55
Production costs	—	—	—	—	647	—	1,083	168	—	1,898
Production taxes	—	—	—	—	425	—	3,911	388	—	4,724
Other costs (income)	—	—	—	—	(381)	—	284	—	—	(97)
Depreciation, depletion and amortization	—	—	—	—	465	—	992	484	—	1,941
Net impairments and losses on sale of businesses and fixed assets	—	—	—	—	80	—	—	35	—	115
	—	—	—	—	1,239	—	6,322	1,075	—	8,636
Profit (loss) before taxation	—	—	—	—	821	—	2,270	(34)	—	3,057
Allocable taxes	—	—	—	—	504	—	449	1	—	954
Results of operations	—	—	—	—	317	—	1,821	(35)	—	2,103
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)	—	—	—	—	317	—	1,821	(35)	—	2,103
Midstream and other activities after tax[g]	—	(7)	19	—	53	(552)	(495)	398	—	(584)
	—	(7)	19	—	370	(552)	1,326	363	—	1,519

Total replacement cost profit (loss) after
interest and tax

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

[b] These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction and transportation operations as well as downstream activities of Rosneft are excluded. The amounts reported for equity-accounted entities exclude the corresponding amounts for their equity-accounted entities.

[c] Decommissioning assets 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 transportation costs and sales taxes.

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

Movements in estimated net proved reserves

Crude oil[a b]									million barrels 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[d]	(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[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 32 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

Natural gas liquids[a b]									million barrels 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[gh]										
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 32 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]

billion cubic feet
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	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 12 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

million barrels of oil equivalent[c]

Total hydrocarbons[a b]

2017

	Europe		North America		South America	Africa	Asia		Australasia	Total
	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 34 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.

Movements in estimated net proved reserves – continued

Crude oil[a b]									million barrels 2016	
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia[d]		
Subsidiaries										
At 1 January										
Developed	141	86	890	46	8	340	—	598	35	2,146
Undeveloped	298	19	577	205	18	89	—	192	16	1,414
	440	106	1,467	252	26	429	—	790	51	3,560
Changes attributable to										
Revisions of previous estimates[d]	13	—	(30)	—	(2)	22	—	543	2	548
Improved recovery	—	—	1	—	—	3	—	70	—	74
Purchases of reserves-in-place	3	—	3	—	—	—	—	25	1	32
Discoveries and extensions	2	—	—	4	—	—	—	—	—	6
Production[e]	(29)	(9)	(119)	(5)	(4)	(96)	—	(75)	(6)	(341)
Sales of reserves-in-place	—	(97)	(1)	—	—	—	—	(1)	(2)	(102)
	(11)	(106)	(145)	(1)	(6)	(71)	—	562	(5)	218
At 31 December[f]										
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
Equity-accounted entities (BP share)[g]										
At 1 January										
Developed	—	—	—	—	311	2	2,844	68	—	3,225
Undeveloped	—	—	—	—	311	—	1,981	—	—	2,292
	—	—	—	—	622	2	4,825	68	—	5,517
Changes attributable to										
Revisions of previous estimates	—	—	—	—	(2)	—	33	13	—	45
Improved recovery	—	—	—	—	1	—	4	—	—	5
Purchases of reserves-in-place	—	116	—	—	36	—	456	—	—	609
Discoveries and extensions	—	—	—	—	16	—	285	—	—	301
Production	—	(3)	—	—	(28)	—	(305)	(37)	—	(373)
Sales of reserves-in-place	—	—	—	—	—	—	(2)	(1)	—	(2)
	—	114	—	—	24	—	471	(25)	—	584
At 31 December[h]										
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
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	141	86	890	47	319	342	2,844	666	35	5,371
Undeveloped	298	19	577	205	329	89	1,981	192	16	3,707
	440	106	1,467	252	648	431	4,825	858	51	9,078
At 31 December										
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

[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] Rest of Asia includes additions from Abu Dhabi ADCO concession.
[e] Includes 6 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 347 million barrels of crude oil in respect of the 6.58% non-controlling interest in Rosneft, including 28 mmbbl held through BP's equity-accounted interest in Taas-Yuryakh Neftegazodobycha.
[h] Total proved crude oil reserves held as part of our equity interest in Rosneft is 5,330 million barrels, comprising less than 1 million barrels in Vietnam and Canada, 62 million barrels in Venezuela and 5,268 million barrels in Russia.

Movements in estimated net proved reserves – continued

Natural gas liquids[a] [b]										million barrels 2016
	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	5	11	269	—	7	5	—	—	9	308
Undeveloped	4	1	70	—	28	10	—	—	2	115
	10	12	339	—	35	15	—	—	12	422
Changes attributable to										
Revisions of previous estimates	7	—	(24)	—	—	1	—	—	—	(14)
Improved recovery	—	—	3	—	—	—	—	—	—	3
Purchases of reserves-in-place	1	—	4	—	—	—	—	—	—	6
Discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Production[c]	(2)	(1)	(24)	—	(2)	(2)	—	—	(1)	(34)
Sales of reserves-in-place	—	(10)	—	—	—	—	—	—	—	(10)
	7	(12)	(40)	—	(2)	(1)	—	—	(1)	(49)
At 31 December[d]										
Developed	13	—	226	—	5	13	—	—	9	266
Undeveloped	3	—	73	—	28	1	—	—	2	107
	16	—	299	—	33	14	—	—	11	373
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	—	—	—	—	—	13	32	—	—	45
Undeveloped	—	—	—	—	—	—	15	—	—	15
	—	—	—	—	—	13	47	—	—	60
Changes attributable to										
Revisions of previous estimates	—	—	—	—	—	(2)	18	—	—	16
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases of reserves-in-place	—	5	—	—	—	—	—	—	—	5
Discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—	—	—
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	5	—	—	—	(2)	18	—	—	21
At 31 December[f]										
Developed	—	3	—	—	—	11	50	—	—	65
Undeveloped	—	2	—	—	—	—	15	—	—	17
	—	5	—	—	—	11	65	—	—	81
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	5	11	269	—	7	18	32	—	9	352
Undeveloped	4	1	70	—	28	10	15	—	2	130
	10	12	339	—	35	28	47	—	12	482
At 31 December										
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

[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 10 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 65 million barrels, comprising less than 1 million barrels in Venezuela, Vietnam and Canada, and 65 million barrels in Russia.

Movements in estimated net proved reserves – continued

million barrels										
Total liquids[a b]										2016
	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	147	98	1,159	46	15	346	—	598	45	2,453
Undeveloped	303	20	647	205	46	99	—	192	18	1,529
	449	117	1,806	252	61	444	—	790	63	3,982
Changes attributable to										
Revisions of previous estimates[d]	20	—	(54)	—	(2)	23	—	543	3	533
Improved recovery	—	—	5	—	—	3	—	70	—	78
Purchases of reserves-in-place	5	—	7	—	—	—	—	25	1	38
Discoveries and extensions	2	—	—	4	—	—	—	—	—	6
Production[e]	(31)	(10)	(143)	(5)	(6)	(98)	—	(75)	(7)	(375)
Sales of reserves-in-place	—	(108)	(1)	—	—	—	—	(1)	(2)	(112)
	(4)	(117)	(185)	(1)	(8)	(72)	—	562	(5)	168
At 31 December[f]										
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
Equity-accounted entities (BP share)[g]										
At 1 January										
Developed	—	—	—	—	311	14	2,876	68	—	3,270
Undeveloped	—	—	—	—	312	—	1,996	—	—	2,307
	—	—	—	—	622	14	4,872	68	—	5,577
Changes attributable to										
Revisions of previous estimates	—	—	—	—	(2)	(2)	51	13	—	61
Improved recovery	—	—	—	—	1	—	4	—	—	5
Purchases of reserves-in-place	—	122	—	—	36	—	456	—	—	614
Discoveries and extensions	—	—	—	—	16	—	285	—	—	301
Production	—	(3)	—	—	(28)	—	(305)	(37)	—	(374)
Sales of reserves-in-place	—	—	—	—	—	—	(2)	(1)	—	(2)
	—	119	—	—	24	(2)	489	(25)	—	605
At 31 December[h i]										
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
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	147	98	1,159	47	326	360	2,876	666	45	5,723
Undeveloped	302	20	647	205	357	99	1,996	192	18	3,836
	449	117	1,806	252	684	459	4,872	858	63	9,560
At 31 December										
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

[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] Rest of Asia includes additions from Abu Dhabi ADCO concession.

[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 16 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 347 million barrels in respect of the non-controlling interest in Rosneft, including 28 mmboe held through BP’s equity accounted interest in Taas-Yuryakh Neftegazodobycha.

[i] Total proved liquid reserves held as part of our equity interest in Rosneft is 5,395 million barrels, comprising less than 1 million barrels in Canada, 62 million barrels in Venezuela, less than 1 million barrels in Vietnam and 5,333 million barrels in Russia.

Movements in estimated net proved reserves – continued

Natural gas[a b]

billion cubic feet
2016

	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	348	274	6,257	—	2,071	847	—	1,803	3,408	15,009
Undeveloped	343	14	2,105	—	5,989	2,305	—	3,455	1,343	15,553
	691	288	8,363	—	8,060	3,152	—	5,257	4,751	30,563
Changes attributable to										
Revisions of previous estimates	133	—	(231)	3	(1,042)	(19)	—	548	396	(211)
Improved recovery	—	—	469	—	42	1	—	22	—	534
Purchases of reserves-in-place	95	—	91	—	—	—	—	—	252	438
Discoveries and extensions	—	—	1	—	355	43	—	—	—	399
Production[c]	(71)	(33)	(676)	(4)	(624)	(219)	—	(152)	(306)	(2,085)
Sales of reserves-in-place	—	(256)	(2)	—	(37)	—	—	(17)	(439)	(750)
	158	(288)	(348)	—	(1,306)	(194)	—	401	(97)	(1,675)
At 31 December[d]										
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
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	—	—	—	1	1,463	386	4,962	44	—	6,856
Undeveloped	—	—	—	—	598	—	6,176	4	—	6,778
	—	—	—	1	2,061	386	11,139	48	—	13,634
Changes attributable to										
Revisions of previous estimates	—	—	—	—	62	34	736	5	—	836
Improved recovery	—	—	—	—	1	—	10	—	—	11
Purchases of reserves-in-place	—	115	—	—	19	—	81	—	—	216
Discoveries and extensions	—	—	—	—	128	—	343	—	—	471
Production[c]	—	(4)	—	—	(190)	(8)	(461)	(15)	—	(680)
Sales of reserves-in-place	—	—	—	—	—	—	(1)	(8)	—	(8)
	—	110	—	—	20	26	709	(18)	—	846
At 31 December[f g]										
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
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	348	274	6,257	1	3,534	1,233	4,962	1,847	3,408	21,865
Undeveloped	343	14	2,105	—	6,587	2,305	6,176	3,459	1,343	22,331
	691	288	8,363	1	10,121	3,538	11,139	5,305	4,751	44,197
At 31 December										

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

[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 176 billion cubic feet of natural gas consumed in operations, 145 billion cubic feet in subsidiaries, 31 billion cubic feet in equity-accounted entities.

[d] Includes 2,026 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 300 billion cubic feet of natural gas in respect of the 2.53% non-controlling interest in Rosneft including 3 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 11,900 billion cubic feet, comprising 1 billion cubic feet in Canada, 33 billion cubic feet in Venezuela, 23 billion cubic feet in Vietnam and 11,843 billion cubic feet in Russia.

Movements in estimated net proved reserves – continued

million barrels of oil equivalent[c]

Total hydrocarbons[a b]

2016

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	207	145	2,238	46	373	492	—	909	632	5,041
Undeveloped	362	22	1,010	205	1,078	496	—	788	250	4,211
	568	167	3,248	252	1,451	988	—	1,696	882	9,252
Changes attributable to										
Revisions of previous estimates[e]	43	—	(94)	1	(181)	20	—	637	71	497
Improved recovery	—	—	86	—	7	3	—	74	—	170
Purchases of reserves-in-place	21	—	23	—	—	—	—	25	44	113
Discoveries and extensions	2	—	—	4	61	8	—	—	—	75
Production[f g]	(43)	(16)	(260)	(5)	(114)	(136)	—	(101)	(60)	(735)
Sales of reserves-in-place	—	(152)	(1)	—	(7)	—	—	(4)	(78)	(241)
	23	(167)	(245)	(1)	(233)	(105)	—	631	(22)	(121)
At 31 December[h]										
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
Equity-accounted entities (BP share)[i]										
At 1 January										
Developed	—	—	—	—	563	81	3,732	76	—	4,452
Undeveloped	—	—	—	—	415	—	3,061	1	—	3,476
	—	—	—	—	978	81	6,792	77	—	7,928
Changes attributable to										
Revisions of previous estimates	—	—	—	—	9	4	178	14	—	205
Improved recovery	—	—	—	—	1	—	6	—	—	7
Purchases of reserves-in-place	—	142	—	—	39	—	470	—	—	652
Discoveries and extensions	—	—	—	—	38	—	344	—	—	382
Production[g]	—	(3)	—	—	(61)	(2)	(385)	(40)	—	(491)
Sales of reserves-in-place	—	—	—	—	—	—	(2)	(2)	—	(4)
	—	138	—	—	27	2	611	(28)	—	751
At 31 December[j k]										
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
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	207	145	2,238	47	936	573	3,732	984	632	9,493
Undeveloped	362	22	1,010	205	1,493	496	3,061	788	250	7,687
	568	167	3,248	252	2,429	1,069	6,792	1,773	882	17,180
At 31 December										

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

[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] Rest of Asia includes additions from Abu Dhabi ADCO concession.

[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 30 million barrels of oil equivalent of natural gas consumed in operations, 25 million barrels of oil equivalent in subsidiaries, 5 million barrels of oil equivalent in equity-accounted entities.

[h] Includes 366 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 402 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft, including 29 mmboe held through BP’s equity accounted interest in Taas-Yuryakh Neftegazodobycha.

[k] Total proved reserves held as part of our equity interest in Rosneft is 7,447 million barrels of oil equivalent, comprising less than 1 million barrels of oil equivalent in Canada, 68 million barrels of oil equivalent in Venezuela, 4 million barrels of oil equivalent in Vietnam and 7,375 million barrels of oil equivalent in Russia.

Movements in estimated net proved reserves – continued

million barrels
2015

Crude oil[a b]	Europe		North America		South America	Africa	Asia		Australia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia[d]		
Subsidiaries										
At 1 January										
Developed	159	95	1,030	9	10	317	—	384	40	2,044
Undeveloped	329	22	664	163	22	120	—	197	19	1,538
	488	117	1,694	172	32	437	—	581	59	3,582
Changes attributable to										
Revisions of previous estimates	(23)	2	(130)	39	(2)	80	—	295	(2)	260
Improved recovery	—	—	15	—	—	2	—	—	—	18
Purchases of reserves-in-place	1	—	—	—	—	6	—	—	—	7
Discoveries and extensions	—	—	3	42	—	2	—	—	—	47
Production[e]	(27)	(14)	(115)	(1)	(5)	(98)	—	(87)	(6)	(353)
Sales of reserves-in-place	(1)	—	—	—	—	—	—	—	—	(1)
	(48)	(12)	(227)	80	(6)	(8)	—	208	(8)	(21)
At 31 December[f]										
Developed	141	86	890	46	8	340	—	598	35	2,146
Undeveloped	298	19	577	205	18	89	—	192	16	1,414
	440	106	1,467	252	26	429	—	790	51	3,560
Equity-accounted entities (BP share)[g]										
At 1 January										
Developed	—	—	—	—	316	2	2,997	89	—	3,405
Undeveloped	—	—	—	—	314	—	1,933	11	—	2,258
	—	—	—	1	630	2	4,930	101	—	5,663
Changes attributable to										
Revisions of previous estimates	—	—	—	—	9	—	(23)	3	—	(11)
Improved recovery	—	—	—	—	3	—	—	—	—	3
Purchases of reserves-in-place	—	—	—	—	—	—	28	—	—	28
Discoveries and extensions	—	—	—	—	9	—	185	—	—	194
Production	—	—	—	—	(28)	—	(295)	(35)	—	(358)
Sales of reserves-in-place	—	—	—	—	—	—	(1)	—	—	(1)
	—	—	—	—	(8)	—	(105)	(32)	—	(146)
At 31 December[h]										
Developed	—	—	—	—	311	2	2,844	68	—	3,225
Undeveloped	—	—	—	—	311	—	1,981	—	—	2,292
	—	—	—	—	622	2	4,825	68	—	5,517
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	159	95	1,030	9	326	319	2,997	473	40	5,448
Undeveloped	329	22	664	164	336	120	1,933	208	19	3,796
	488	117	1,694	173	662	439	4,930	682	59	9,244
At 31 December										
Developed	141	86	890	47	319	342	2,844	666	35	5,371

Undeveloped	298	19	577	205	329	89	1,981	192	16	3,707
	440	106	1,467	252	648	431	4,825	858	51	9,078

[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 23 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] Production volume recognition methodology for our Technical Service Contract arrangement in Iraq was simplified in 2016 to exclude the impact of oil price movements on lifting imbalances. A minor adjustment has been made to comparative periods. There was no impact on 2015 proved reserves totals.

[e] Includes 8 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 70 million barrels of crude oil in respect of the 1.27% non-controlling interest in Rosneft, including 28 mmbbl held through BP's equity accounted interest in Taas-Yuryakh Neftegazodobycha.

[h] Total proved crude oil reserves held as part of our equity interest in Rosneft is 4,823 million barrels, comprising less than 1 million barrels in Vietnam and Canada, 26 million barrels in Venezuela and 4,797 million barrels in Russia.

Movements in estimated net proved reserves – continued

									million barrels 2015	
Natural gas liquids[a b]										
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	6	13	323	—	11	5	—	—	6	364
Undeveloped	3	1	104	—	28	7	—	—	3	146
	9	14	427	—	39	12	—	—	10	510
Changes attributable to										
Revisions of previous estimates	2	—	(80)	—	—	6	—	—	3	(69)
Improved recovery	—	—	12	—	—	—	—	—	—	12
Purchases of reserves-in-place	—	—	3	—	—	—	—	—	—	4
Discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Production[c]	(2)	(2)	(23)	—	(4)	(3)	—	—	(1)	(34)
Sales of reserves-in-place	—	—	(1)	—	—	—	—	—	—	(1)
	—	(2)	(88)	—	(4)	3	—	—	2	(88)
At 31 December[d]										
Developed	5	11	269	—	7	5	—	—	9	308
Undeveloped	4	1	70	—	28	10	—	—	2	115
	10	12	339	—	35	15	—	—	12	422
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	—	—	—	—	—	15	30	—	—	46
Undeveloped	—	—	—	—	—	—	16	—	—	16
	—	—	—	—	—	15	46	—	—	62
Changes attributable to										
Revisions of previous estimates	—	—	—	—	—	(3)	1	—	—	(2)
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—	—	—
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	—	—	—	—	(3)	1	—	—	(2)
At 31 December[f]										
Developed	—	—	—	—	—	13	32	—	—	45
Undeveloped	—	—	—	—	—	—	15	—	—	15
	—	—	—	—	—	13	47	—	—	60
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	6	13	323	—	11	20	30	—	6	410
Undeveloped	3	1	104	—	28	7	16	—	3	163
	9	14	427	—	39	27	46	—	10	572
At 31 December										
Developed	5	11	269	—	7	18	32	—	9	352

Undeveloped	4	1	70	—	28	10	15	—	2	130
	10	12	339	—	35	28	47	—	12	482

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

[d] Includes 11 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 47 million barrels, comprising less than 1 million barrels in Venezuela, Vietnam and Canada, and 47 million barrels in Russia.

Movements in estimated net proved reserves – continued

million barrels

Total liquids[a b]

2015

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia[d]		
Subsidiaries										
At 1 January										
Developed	166	108	1,352	9	21	322	—	384	46	2,407
Undeveloped	332	23	769	163	50	127	—	197	22	1,684
	497	131	2,121	172	71	449	—	581	68	4,092
Changes attributable to										
Revisions of previous estimates	(20)	2	(210)	39	(2)	86	—	295	1	191
Improved recovery	—	—	28	—	—	2	—	—	—	30
Purchases of reserves-in-place	1	—	3	—	—	6	—	—	—	11
Discoveries and extensions	—	—	4	42	—	2	—	—	—	48
Production[e]	(29)	(16)	(138)	(1)	(8)	(101)	—	(87)	(7)	(387)
Sales of reserves-in-place	(1)	—	(1)	—	—	—	—	—	—	(2)
	(48)	(14)	(315)	80	(10)	(5)	—	208	(6)	(109)
At 31 December[f]										
Developed	147	98	1,159	46	15	346	—	598	45	2,453
Undeveloped	302	20	647	205	46	99	—	192	18	1,529
	449	117	1,806	252	61	444	—	790	63	3,982
Equity-accounted entities (BP share)[g]										
At 1 January										
Developed	—	—	—	—	316	17	3,028	89	—	3,451
Undeveloped	—	—	—	—	314	—	1,949	11	—	2,274
	—	—	—	1	630	17	4,976	101	—	5,725
Changes attributable to										
Revisions of previous estimates	—	—	—	—	9	(3)	(22)	3	—	(13)
Improved recovery	—	—	—	—	3	—	—	—	—	3
Purchases of reserves-in-place	—	—	—	—	—	—	28	—	—	28
Discoveries and extensions	—	—	—	—	9	—	185	—	—	194
Production	—	—	—	—	(28)	—	(295)	(35)	—	(358)
Sales of reserves-in-place	—	—	—	—	—	—	(1)	—	—	(1)
	—	—	—	(1)	(8)	(3)	(104)	(32)	—	(147)
At 31 December[h i]										
Developed	—	—	—	—	311	14	2,876	68	—	3,270
Undeveloped	—	—	—	—	312	—	1,996	—	—	2,307
	—	—	—	—	622	14	4,872	68	—	5,577
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	166	108	1,352	9	337	339	3,028	473	46	5,858
Undeveloped	332	23	769	164	364	127	1,949	208	22	3,958
	497	131	2,121	173	701	466	4,976	682	68	9,817
At 31 December										
Developed	147	98	1,159	47	326	360	2,876	666	45	5,723

Undeveloped	302	20	647	205	357	99	1,996	192	18	3,836
	449	117	1,806	252	684	459	4,872	858	63	9,560

[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 23 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] Production volume recognition methodology for our Technical Service Contract arrangement in Iraq was simplified in 2016 to exclude the impact of oil price movements on lifting imbalances. A minor adjustment has been made to comparative periods. There was no impact on 2015 proved reserves totals.

[e] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 4 thousand barrels per day for equity-accounted entities.

[f] Also includes 19 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 70 million barrels in respect of the non-controlling interest in Rosneft, including 28 mmboe held through BP’s equity accounted interest in Taas-Yuryakh Neftegazodobycha.

[i] Total proved liquid reserves held as part of our equity interest in Rosneft is 4,871 million barrels, comprising less than 1 million barrels in Canada, 26 million barrels in Venezuela, less than 1 million barrels in Vietnam and 4,844 million barrels in Russia.

Movements in estimated net proved reserves – continued

Natural gas[a b]										billion cubic feet 2015
	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	382	300	7,168	17	2,352	901	—	1,688	3,316	16,124
Undeveloped	386	19	2,447	—	6,313	1,597	—	3,892	1,719	16,372
	768	318	9,615	17	8,666	2,497	—	5,580	5,035	32,496
Changes attributable to										
Revisions of previous estimates	(12)	14	(1,120)	(13)	132	203	—	(165)	13	(948)
Improved recovery	4	—	432	—	—	7	—	—	—	443
Purchases of reserves-in-place	—	—	65	—	29	554	—	—	—	648
Discoveries and extensions	—	—	5	—	—	174	—	—	—	179
Production[c]	(65)	(44)	(628)	(4)	(709)	(248)	—	(157)	(297)	(2,151)
Sales of reserves-in-place	(5)	—	(6)	—	(58)	(35)	—	—	—	(104)
	(77)	(30)	(1,252)	(17)	(605)	654	—	(322)	(284)	(1,933)
At 31 December[d]										
Developed	348	274	6,257	—	2,071	847	—	1,803	3,408	15,009
Undeveloped	343	14	2,105	—	5,989	2,305	—	3,455	1,343	15,553
	691	288	8,363	—	8,060	3,152	—	5,257	4,751	30,563
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	—	—	—	1	1,228	400	4,674	60	—	6,363
Undeveloped	—	—	—	1	717	—	5,111	9	—	5,837
	—	—	—	1	1,945	400	9,785	69	—	12,200
Changes attributable to										
Revisions of previous estimates	—	—	—	(1)	81	(14)	1,604	(2)	—	1,669
Improved recovery	—	—	—	—	8	—	—	—	—	8
Purchases of reserves-in-place	—	—	—	—	—	—	5	—	—	5
Discoveries and extensions	—	—	—	—	209	—	175	—	—	384
Production[c]	—	—	—	—	(182)	—	(430)	(19)	—	(632)
Sales of reserves-in-place	—	—	—	—	(1)	—	—	—	—	(1)
	—	—	—	(1)	116	(14)	1,354	(21)	—	1,434
At 31 December[f g]										
Developed	—	—	—	1	1,463	386	4,962	44	—	6,856
Undeveloped	—	—	—	—	598	—	6,176	4	—	6,778
	—	—	—	1	2,061	386	11,139	48	—	13,634
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	382	300	7,168	18	3,581	1,301	4,674	1,748	3,316	22,487
Undeveloped	386	19	2,447	1	7,030	1,597	5,111	3,901	1,719	22,209
	768	318	9,615	18	10,610	2,897	9,785	5,648	5,035	44,695
At 31 December										

Developed	348	274	6,257	1	3,534	1,233	4,962	1,847	3,408	21,865
Undeveloped	343	14	2,105	—	6,587	2,305	6,176	3,459	1,343	22,331
	691	288	8,363	1	10,121	3,538	11,139	5,305	4,751	44,197

[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 175 billion cubic feet of natural gas consumed in operations, 146 billion cubic feet in subsidiaries, 29 billion cubic feet in equity-accounted entities.

[d] Includes 2,359 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 129 billion cubic feet of natural gas in respect of the 0.23% non-controlling interest in Rosneft including 5 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 11,169 billion cubic feet, comprising 1 billion cubic feet in Canada, 13 billion cubic feet in Venezuela, 22 billion cubic feet in Vietnam and 11,133 billion cubic feet in Russia.

Movements in estimated net proved reserves – continued

million barrels of oil equivalent[c]

Total hydrocarbons[a b]

2015

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia[e]		
Subsidiaries										
At 1 January										
Developed	232	160	2,588	12	426	477	—	675	618	5,187
Undeveloped	398	26	1,191	163	1,139	403	—	868	319	4,507
	630	186	3,779	175	1,565	880	—	1,543	937	9,695
Changes attributable to										
Revisions of previous estimates	(22)	4	(403)	36	21	121	—	267	4	27
Improved recovery	1	—	102	—	—	3	—	—	—	106
Purchases of reserves-in-place	1	—	15	—	5	102	—	—	—	122
Discoveries and extensions	—	—	4	42	—	32	—	—	—	79
Production[f g]	(40)	(23)	(247)	(2)	(130)	(144)	—	(114)	(58)	(758)
Sales of reserves-in-place	(1)	—	(2)	—	(10)	(6)	—	—	—	(19)
	(62)	(19)	(531)	77	(114)	108	—	153	(55)	(443)
At 31 December[h]										
Developed	207	145	2,238	46	373	492	—	909	632	5,041
Undeveloped	362	22	1,010	205	1,078	496	—	788	250	4,211
	568	167	3,248	252	1,451	988	—	1,696	882	9,252
Equity-accounted entities (BP share)[i]										
At 1 January										
Developed	—	—	—	—	528	86	3,834	100	—	4,548
Undeveloped	—	—	—	1	438	—	2,830	13	—	3,280
	—	—	—	1	965	86	6,663	112	—	7,828
Changes attributable to										
Revisions of previous estimates	—	—	—	(1)	23	(5)	255	3	—	274
Improved recovery	—	—	—	—	5	—	—	—	—	5
Purchases of reserves-in-place	—	—	—	—	—	—	29	—	—	29
Discoveries and extensions	—	—	—	—	45	—	215	—	—	260
Production[g]	—	—	—	—	(60)	—	(369)	(39)	—	(467)
Sales of reserves-in-place	—	—	—	—	—	—	(1)	—	—	(1)
	—	—	—	(1)	12	(5)	129	(36)	—	100
At 31 December[j k]										
Developed	—	—	—	—	563	81	3,732	76	—	4,452
Undeveloped	—	—	—	—	415	—	3,061	1	—	3,476
	—	—	—	—	978	81	6,792	77	—	7,928
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	232	160	2,588	12	954	563	3,834	775	618	9,735
Undeveloped	398	26	1,191	164	1,576	403	2,830	881	319	7,788
	630	186	3,779	176	2,530	966	6,663	1,656	937	17,523
At 31 December										

Developed	207	145	2,238	47	936	573	3,732	984	632	9,493
Undeveloped	362	22	1,010	205	1,493	496	3,061	788	250	7,687
	568	167	3,248	252	2,429	1,069	6,792	1,773	882	17,180

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 23 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 Production volume recognition methodology for our Technical Service Contract arrangement in Iraq was simplified in 2016 to exclude the impact of oil price movements on lifting imbalances. A minor adjustment has been made to comparative periods. There was no impact on 2015 proved reserves totals.

f Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 4 thousand barrels per day for equity-accounted entities.

g Includes 30 million barrels of oil equivalent of natural gas consumed in operations, 25 million barrels of oil equivalent in subsidiaries, 5 million barrels of oil equivalent in equity-accounted entities.

h Includes 425 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 70 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft, including 28 mmboe held through BP’s equity accounted interest in Taas-Yuryakh Neftegazodobycha.

k Total proved reserves held as part of our equity interest in Rosneft is 6,796 million barrels of oil equivalent, comprising less than 1 million barrels of oil equivalent in Canada, 28 million barrels of oil equivalent in Venezuela, 4 million barrels of oil equivalent in Vietnam and 6,764 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 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 e]	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)
	9,800	4,200	14,000

Development costs for the current year as estimated in previous year			
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[j]	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 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

	Europe		North America		South America	Africa	Asia		Australasia	Total
										$ million 2016
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December										
Subsidiaries										
Future cash inflows[a]	21,600	—	72,400	4,500	11,700	23,600	—	78,100	24,000	235,900
Future production cost[b]	13,900	—	43,100	3,500	6,600	10,000	—	42,600	9,400	129,100
Future development cost[b]	3,000	—	14,300	1,100	3,700	5,100	—	15,400	3,500	46,100
Future taxation[c]	1,700	—	500	—	100	2,000	—	17,800	3,400	25,500
Future net cash flows	3,000	—	14,500	(100)	1,300	6,500	—	2,300	7,700	35,200
10% annual discount[d e]	900	—	4,900	—	200	2,800	—	(600)	4,100	12,300
Standardized measure of discounted future net cash flows[e f]	2,100	—	9,600	(100)	1,100	3,700	—	2,900	3,600	22,900
Equity-accounted entities (BP share)[g]										
Future cash inflows[a]	—	5,400	—	—	34,400	—	159,900	1,900	—	201,600
Future production cost[b]	—	3,000	—	—	16,500	—	84,300	1,200	—	105,000
Future development cost[b]	—	700	—	—	3,800	—	13,200	700	—	18,400
Future taxation[c]	—	1,300	—	—	3,600	—	10,100	—	—	15,000
Future net cash flows	—	400	—	—	10,500	—	52,300	—	—	63,200
10% annual discount[d]	—	200	—	—	6,100	—	30,700	—	—	37,000
Standardized measure of discounted future net cash flows[h i]	—	200	—	—	4,400	—	21,600	—	—	26,200
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	2,100	200	9,600	(100)	5,500	3,700	21,600	2,900	3,600	49,100

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

	Subsidiaries	Equity-accounted entities (BP share)	$ million Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	(15,200)	(5,400)	(20,600)
Development costs for the current year as estimated in previous year	13,100	3,500	16,600
Extensions, discoveries and improved recovery, less related costs	700	900	1,600
Net changes in prices and production cost	(25,500)	(5,900)	(31,400)
Revisions of previous reserves estimates	12,200	1,200	13,400
Net change in taxation	(2,500)	900	(1,600)
Future development costs	4,900	(2,500)	2,400
Net change in purchase and sales of reserves-in-place	1,800	2,900	4,700
Addition of 10% annual discount	3,000	2,800	5,800
	(7,500)	(1,600)	(9,100)

Total change in the standardized measure during the year[j]

[a] The marker prices used were Brent $42.82/bbl, Henry Hub $2.46/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. Depending on the timing of those cash flows the effect of discounting may be to increase the discounted future net cash flows.

[f] Non-controlling interests in BP Trinidad and Tobago LLC amounted to $300 million.

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

[h] Non-controlling interests in Rosneft amounted to $1,608 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 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
2015

	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]	27,500	7,800	98,100	7,200	20,100	32,800	—	65,200	32,000	290,700
Future production cost[b]	15,700	5,300	56,300	4,200	8,600	12,000	—	35,900	15,200	153,200
Future development cost[b]	4,700	700	18,800	1,700	7,000	8,100	—	18,200	4,500	63,700
Future taxation[c]	2,900	800	3,100	—	1,700	3,300	—	3,800	4,000	19,600
Future net cash flows	4,200	1,000	19,900	1,300	2,800	9,400	—	7,300	8,300	54,200
10% annual discount[d]	1,900	300	7,400	900	900	4,300	—	3,700	4,400	23,800
Standardized measure of discounted future net cash flows[e]	2,300	700	12,500	400	1,900	5,100	—	3,600	3,900	30,400
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	—	—	—	—	39,900	—	182,300	3,700	—	225,900
Future production cost[b]	—	—	—	—	20,200	—	101,200	2,200	—	123,600
Future development cost[b]	—	—	—	—	5,300	—	11,000	1,300	—	17,600
Future taxation[c]	—	—	—	—	3,900	—	12,400	100	—	16,400
Future net cash flows	—	—	—	—	10,500	—	57,700	100	—	68,300
10% annual discount[d]	—	—	—	—	6,700	—	33,800	—	—	40,500
Standardized measure of discounted future net cash flows[g h]	—	—	—	—	3,800	—	23,900	100	—	27,800
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	2,300	700	12,500	400	5,700	5,100	23,900	3,700	3,900	58,200

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	(27,900)	(7,300)	(35,200)
Development costs for the current year as estimated in previous year	15,000	4,500	19,500
Extensions, discoveries and improved recovery, less related costs	600	700	1,300
Net changes in prices and production cost	(100,400)	(24,700)	(125,100)
Revisions of previous reserves estimates	13,500	500	14,000
Net change in taxation	38,600	2,300	40,900
Future development costs	3,200	(100)	3,100
Net change in purchase and sales of reserves-in-place	(700)	300	(400)
Addition of 10% annual discount	8,000	4,700	12,700
Total change in the standardized measure during the year[i]	(50,100)	(19,100)	(69,200)

[a] The marker prices used were Brent $54.17/bbl, Henry Hub $2.59/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 $600 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 $93 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 2017, 2016 and 2015.
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[d]		
Subsidiaries[e]										
Crude oil[f]									thousand barrels per day	
2017	80	—	370	20	12	241	—	325	17	1,064
2016	79	24	335	13	10	263	—	204	16	943
2015	72	38	323	3	12	270	—	199	17	933
Natural gas liquids									thousand barrels per day	
2017	6	—	56	—	10	10	—	—	2	85
2016	6	4	56	—	8	5	—	—	3	82
2015	7	5	56	—	11	7	—	1	3	88
Natural gas[g]									million cubic feet per day	
2017	182	—	1,659	9	1,936	949	—	371	783	5,889
2016	170	82	1,656	10	1,689	513	—	363	820	5,302
2015	155	111	1,528	10	1,922	589	—	380	801	5,495
Equity-accounted entities (BP share)										
Crude oil[f]									thousand barrels per day	
2017	—	31	—	—	63	1	905	99	—	1,099
2016	—	7	—	—	65	—	840	102	—	1,015
2015	—	—	—	—	68	—	809	97	—	974
Natural gas liquids									thousand barrels per day	
2017	—	2	—	—	—	6	4	—	—	12
2016	—	—	—	—	1	4	4	—	—	8
2015	—	—	—	—	3	3	4	—	—	10
Natural gas[g]									million cubic feet per day	
2017	—	53	—	—	418	77	1,308	—	—	1,855
2016	—	12	—	—	449	18	1,279	15	—	1,773

2015	—	—	—	—	435	—	1,195	21	—	1,651

[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] Production volume recognition methodology for our Technical Service Contract arrangement in Iraq was simplified in 2016 to exclude the impact of oil price movements on lifting imbalances. A minor adjustment has been made to comparative periods.

[e] All of the oil and liquid production from Canada is bitumen.

[f] Crude oil includes condensate.

[g] Natural gas production excludes gas consumed in operations.

Operational and statistical information – continued

Productive oil and gas wells and acreage

The following tables show the number of gross and net productive oil and natural gas wells and total gross and net developed and undeveloped oil and natural gas acreage in which the group and its equity-accounted entities had interests as at 31 December 2017. 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 2017											
Oil wells[c]	– gross	130	47	2,365	166	5,145	693	62,492	2,250	12	73,300
	– net	78	14	817	41	2,337	466	12,342	482	2	16,579
Gas wells[d]	– gross	76	1	23,376	268	982	194	478	86	68	25,529
	– net	34	—	9,841	133	347	82	94	37	14	10,582
Oil and natural gas acreage at 31 December 2017										thousands of acres	
Developed	– gross	132	70	6,467	157	1,322	789	6,393	1,586	173	17,089
	– net	75	21	3,446	71	351	310	1,211	304	41	5,830
Undeveloped[e]	– gross	2,553	1,361	5,179	15,139	23,358	43,211	425,477	8,286	5,584	530,148
	– net	1,586	517	3,780	7,200	7,082	27,841	84,724	1,977	2,116	136,823

[a] Based on information received from Rosneft as at 31 December 2017.

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

[c] Includes approximately 8,890 gross (1,731 net) multiple completion wells (more than one formation producing into the same well bore).

[d] Includes approximately 2,827 gross (1,438 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		
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
2016										
Exploratory										
Productive	0.3	0.4	0.5	—	0.6	2.1	3.4	1.6	—	8.9
Dry	1.0	0.3	4.7	—	—	1.5	—	0.3	—	7.8
Development										
Productive	3.4	1.4	145.6	—	99.8	20.2	88.5	55.2	0.5	414.6
Dry	0.8	—	—	—	0.6	2.0	—	1.0	—	4.4
2015										
Exploratory										
Productive	—	—	4.0	—	1.1	2.6	4.5	—	—	12.2
Dry	—	—	—	—	0.4	1.0	—	—	0.2	1.6
Development										
Productive	1.6	0.4	235.6	—	143.1	20.7	91.4	51.2	0.9	544.7
Dry	—	—	—	—	2.3	1.3	—	—	—	3.5

[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 2017. 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 2017										
Exploratory										
Gross	1.0	—	4.0	—	4.0	4.0	—	4.0	—	17.0
Net	0.3	—	2.6	—	0.6	2.1	—	4.0	—	9.6
Development										
Gross	6.0	1.5	242.0	—	24.0	30.0	—	115.0	3.0	421.5
Net	2.3	0.4	113.6	—	7.8	18.2	—	22.6	0.5	165.4

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

Pages 219-245 have been removed as they do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

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Additional disclosures

248 Selected financial information
251 Liquidity and capital resources
253 Upstream analysis by region
258 Downstream plant capacity
259 Oil and gas disclosures for the group
265 Environmental expenditure
265 Regulation of the group's business
270 Legal proceedings
273 International trade sanctions
274 Material contracts
274 Property, plant and equipment
274 Related-party transactions
275 Corporate governance practices
275 Code of ethics
275 Controls and procedures
276 Principal accountants' fees and services
276 Directors' report information
277 Disclosures required under Listing Rule 9.8.4R
277 Cautionary statement

Selected financial information

This information, insofar as it relates to 2017, has been extracted or derived from the audited consolidated financial statements of the BP group presented on page 116. 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 elsewhere herein.

	$ million except per share amounts				
	2017	2016	2015	2014	2013
Income statement data					
Sales and other operating revenues	240,208	183,008	222,894	353,568	379,136
Profit (loss) before interest and taxation	9,474	(430)	(7,918)	6,412	31,769
Finance costs and net finance expense relating to pensions and other post-retirement benefits	(2,294)	(1,865)	(1,653)	(1,462)	(1,548)
Taxation	(3,712)	2,467	3,171	(947)	(6,463)
Non-controlling interests	(79)	(57)	(82)	(223)	(307)
Profit (loss) for the year[a]	3,389	115	(6,482)	3,780	23,451
Inventory holding (gains) losses«, before tax	(853)	(1,597)	1,889	6,210	290
Taxation charge (credit) on inventory holding gains and losses	225	483	(569)	(1,917)	(60)
RC profit (loss)«for the year	2,761	(999)	(5,162)	8,073	23,681
Net (favourable) adverse impact of non-operating items« and fair value accounting effects«, before tax[b]	3,730	6,746	15,067	8,234	(9,244)
Taxation charge (credit) on non-operating items and fair value accounting effects	(325)	(3,162)	(4,000)	(4,171)	(1,009)
Underlying RC profit«for the year	6,166	2,585	5,905	12,136	13,428
Earnings per share[c] – cents					
Profit (loss) for the year[a] per ordinary share					
Basic	17.20	0.61	(35.39)	20.55	123.87
Diluted	17.10	0.60	(35.39)	20.42	123.12
RC profit (loss) for the year per ordinary share«	14.02	(5.33)	(28.18)	43.90	125.08
Underlying RC profit for the year per ordinary share«	31.31	13.79	32.22	66.00	70.92
Dividends paid per share – cents	40.00	40.00	40.00	39.00	36.50
– pence	30.979	29.418	26.383	23.850	23.399
Capital expenditure«[d]					
Organic capital expenditure«	16,501	16,675	N/A	N/A	N/A
Inorganic capital expenditure«	1,339	777	N/A	N/A	N/A
	17,840	17,452	20,202	23,192	30,032
Balance sheet data (at 31 December)					
Total assets	276,515	263,316	261,832	284,305	305,690
Net assets	100,404	96,843	98,387	112,642	130,407
Share capital	5,343	5,284	5,049	5,023	5,129
BP shareholders' equity	98,491	95,286	97,216	111,441	129,302
Finance debt due after more than one year	55,491	51,666	46,224	45,977	40,811
Net debt to net debt plus equity«	27.4%	26.8%	21.6%	16.7%	16.2%
Ordinary share data[e]	Share million				
Basic weighted average number of shares	19,693	18,745	18,324	18,385	18,931
Diluted weighted average number of shares	19,816	18,855	18,324	18,497	19,046

[a] Profit attributable to BP shareholders.

[b] See pages 250 and 294 for further analysis of these items.

[c] A reconciliation to GAAP information is provided on page 294.

[d] From 2017 onwards we are reporting 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 now consistent with other

financial metrics used when comparing sources and uses of cash. An analysis of capital expenditure on a cash basis for 2015, 2014 and 2013 is not available.

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

Additional information

Capital expenditure

	2017	2016	$ million 2015
Capital expenditure			
Organic capital expenditure	16,501	16,675	N/A
Inorganic capital expenditure[a]	1,339	777	N/A
	17,840	17,452	20,202

	2017	2016	$ million 2015
Organic capital expenditure by segment			
Upstream			
US	2,999	3,415	N/A
Non-US	10,764	10,929	N/A
	13,763	14,344	N/A
Downstream			
US	809	774	N/A
Non-US	1,590	1,328	N/A
	2,399	2,102	N/A
Other businesses and corporate			
US	64	32	N/A
Non-US	275	197	N/A
	339	229	N/A
	16,501	16,675	N/A
Organic capital expenditure by geographical area			
US	3,872	4,221	N/A
Non-US	12,629	12,454	N/A
	16,501	16,675	N/A

[a] 2017 includes amounts paid to acquire interests in Mauritania and Senegal and in the Zohr gas field in Egypt.

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
	2017	2016	2015
Upstream			
Impairment and gain (loss) on sale of businesses and fixed assets[a b]	(563)	2,391	(1,204)
Environmental and other provisions	1	(8)	(24)
Restructuring, integration and rationalization costs[c]	(24)	(373)	(410)
Fair value gain (loss) on embedded derivatives	33	32	120
Other[b d]	(118)	(289)	(717)
	(671)	1,753	(2,235)
Downstream			
Impairment and gain (loss) on sale of businesses and fixed assets[a e]	579	405	131
Environmental and other provisions	(19)	(73)	(108)
Restructuring, integration and rationalization costs[c]	(171)	(300)	(607)
Fair value gain (loss) on embedded derivatives	—	—	—
Other	—	(56)	(6)
	389	(24)	(590)
Rosneft			
Impairment and gain (loss) on sale of businesses and fixed assets[a]	—	62	—
Environmental and other provisions	—	—	—
Restructuring, integration and rationalization costs[c]	—	—	—
Fair value gain (loss) on embedded derivatives	—	—	—
Other	—	(39)	—
	—	23	—
Other businesses and corporate			
Impairment and gain (loss) on sale of businesses and fixed assets[a]	(22)	—	(170)
Environmental and other provisions	(156)	(134)	(151)
Restructuring, integration and rationalization costs[c]	(72)	(90)	(71)
Fair value gain (loss) on embedded derivatives	—	—	—
Gulf of Mexico oil spill response[f]	(2,687)	(6,640)	(11,709)
Other[d]	90	(55)	(155)
	(2,847)	(6,919)	(12,256)
Total before interest and taxation	(3,129)	(5,167)	(15,081)
Finance costs[f]	(493)	(494)	(247)
Taxation credit (charge) on non-operating items[g]	1,172	2,833	4,056
Taxation - impact of US tax reform[h]	(859)	—	—
Total after taxation	(3,309)	(2,828)	(11,272)

[a] See Financial statements – Note 3 for further information on impairments.

[b] 2016 includes a $319-million exploration write-back relating to Block KG D6 in India. In addition, an impairment reversal of $234 million was also recorded in relation to this block.

[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 current restructuring programme, aimed at simplifying and improving the efficiency of operations across the group, commenced in the fourth quarter of 2014 and has

resulted in cumulative non-operating charges of $2.6 billion to 31 December 2017, principally relating to redundancy costs.

[d] 2017 includes BP's share of an impairment reversal recognized by the Angola LNG equity-accounted entity, partially offset by other items. 2017 also includes the write-off of $145 million in relation to the value ascribed to certain licences in the deepwater Gulf of Mexico as part of the accounting for the acquisition of upstream assets from Devon Energy in 2011. 2016 includes the write-off of $334 million in relation to the value ascribed to the licence in Brazil as part of the accounting for the acquisition of upstream assets from Devon Energy in 2011. 2015 principally relates to BP's share of impairment losses recognized by equity-accounted entities.

[e] 2017 primarily reflects the disposal of our shareholding in the SECCO joint venture.

[f] See Financial statements – Note 2 for further details regarding costs relating to the Gulf of Mexico oil spill.

[g] 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.

[h] 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. 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.

Following the strong progress made in 2017 in rebalancing organic sources and uses of cash flow«, we recommenced share buybacks during the fourth quarter of 2017, with the intent to offset any ongoing dilution from the scrip dividend programme over time. The shape of the programme will not necessarily match the dilution on a quarterly basis, but will reflect the ongoing judgement of factors including changes in the environment, the underlying performance of the business, the outlook for the group financial framework, and other market factors which may vary quarter to quarter.

We expect operating cash flow excluding amounts relating to the Gulf of Mexico oil spill to cover organic capital expenditure« of $15-16 billion and the full dividend« (including scrip) in 2018 at around $50 per barrel. Looking further out, this balancing point is expected to steadily reduce to $35-40 per barrel by 2021, with organic capital expenditure in a range of $15-17 billion, and not exceeding $17 billion in any one year. 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.

Gulf of Mexico oil spill payments are expected to be just over $3 billion in 2018, stepping down to around $2 billion in 2019 and around $1 billion per annum thereafter, with divestment proceeds« of around $2-3 billion per annum.

We continue to target a gearing« band of 20-30%, while maintaining strong liquidity and debt market access.

Return on average capital employed« is targeted to improve from 5.8%[a] in 2017 to over 10% by 2021 (at $55 per barrel real), as we continue to grow our underlying business.

[a] Nearest GAAP equivalent measures: Numerator – Profit attributable to BP shareholders $3.4 billion; Denominator – Average capital employed $159.4 billion.

Dividends and other distributions to shareholders

The dividend is determined in US dollars, the economic currency of BP, and the dividend level is regularly reviewed by the board. The quarterly dividend was 10 cents per share in 2017, the same as 2016.

The total dividend distributed to BP shareholders in 2017 was $7.9 billion (2016 $7.5 billion). Shareholders have the option to receive a scrip dividend in place of receiving cash. In 2017 the total dividend paid in cash was $6.2 billion (2016 $4.6 billion).

Details of share repurchases to satisfy the requirements of certain employee share-based payment plans are set out on page 286. As noted above, a share buyback programme to offset the dilutive impact of the scrip dividend recommenced in the fourth quarter of 2017 with 51 million ordinary shares at a cost of $343 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. The 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 57 for further information on risks associated with prices and markets and Financial statements – Note 27.

The group's gross debt at 31 December 2017 amounted to $63.2 billion (2016 $58.3 billion). Of the total gross debt, $7.7 billion is classified as short term at the end of 2017 (2016 $6.6 billion). See Financial statements – Note 24 for more information on the short-term balance. Net debt« was $37.8 billion at the end of 2017, an increase of $2.3 billion from the 2016 year-end position of $35.5 billion. The ratio of gross debt to gross debt plus equity at

31 December 2017 was 38.6% (2016 37.6%). The ratio of net debt to net debt plus equity« was 27.4% at the end of 2017 (2016 26.8%). See Financial statements – Note 25 for gross debt, which is the nearest equivalent measure on an IFRS basis, and for further information on net debt.

Cash and cash equivalents of $25.6 billion at 31 December 2017 (2016 $23.5 billion) are included in net debt. We manage our cash position to ensure the group has adequate cover to respond to potential short-term market illiquidity, and expect to maintain a robust cash position.

The group also has undrawn committed bank facilities of $7.6 billion (see Financial statements – Note 27 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.

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

The group's sources of funding, its access to capital markets and maintaining a strong cash position are described in Financial statements – Note 23 and Note 27. 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 24 and Note 27.

Off-balance sheet arrangements

At 31 December 2017, the group's share of third-party finance debt of equity-accounted entities was $18.0 billion (2016 $14.6 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 2017 were $656 million (2016 $309 million) in respect of liabilities of joint ventures«and associates«and $382 million (2016 $370 million) in respect of liabilities of other third parties. Of these amounts, $645 million (2016 $298 million) of the joint ventures and associates guarantees relate to borrowings and for other third-party guarantees, $350 million (2016 $338 million) relate to guarantees of borrowings. Details of operating lease commitments, which are not recognized on the balance sheet, are shown in the table below and provided in Financial statements – Note 26.

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 277 and Risk factors on page 57, 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.

Contractual obligations

The following table summarizes the group's capital expenditure commitments for property, plant and equipment at 31 December 2017 and the proportion of that expenditure for which contracts have been placed.

	$ million						
	Payments due by period						
Capital expenditure	Total	2018	2019	2020	2021	2022	2023 and thereafter
Committed	28,295	13,449	7,120	3,509	1,480	1,040	1,697
of which is contracted	11,340	7,384	2,562	923	178	75	218

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 2017, the group had committed to capital expenditure relating to investments in equity-accounted entities amounting to $1,724 million. Contracts were in place for $1,451 million of this total.

The following table summarizes the group's principal contractual obligations at 31 December 2017, 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 24 and more information on operating leases is given in Financial statements – Note 26.

							$ million
							Payments due by period
Expected payments by period under contractual obligations	Total	2018	2019	2020	2021	2022	2023 and thereafter
Balance sheet obligations							
Borrowings[a]	70,641	9,291	8,766	8,296	7,789	8,791	27,708
Finance lease future minimum lease payments[b]	1,351	92	102	93	91	89	884
Decommissioning liabilities[c]	18,111	433	253	173	119	212	16,921
Environmental liabilities[c]	1,550	268	264	218	180	134	486
Gulf of Mexico oil spill liabilities[d]	18,918	2,089	1,347	1,234	1,208	1,205	11,835
Pensions and other post-retirement benefits[e]	21,166	1,192	1,605	1,595	1,482	1,174	14,118
	131,737	13,365	12,337	11,609	10,869	11,605	71,952
Off-balance sheet obligations							
Operating lease future minimum lease payments[f]	13,970	2,969	2,309	1,777	1,255	1,046	4,614
Unconditional purchase obligations[g]	154,211	80,400	17,030	9,675	8,381	6,081	32,644
	168,181	83,369	19,339	11,452	9,636	7,127	37,258
Total	299,918	96,734	31,676	23,061	20,505	18,732	109,210

a Expected payments include interest totalling $8,269 million ($1,703 million in 2018, $1,485 million in 2019, $1,273 million in 2020, $1,070 million in 2021, $855 million in 2022 and $1,883 million thereafter).

b Expected payments include interest totalling $695 million ($54 million in 2018, $52 million in 2019, $48 million in 2020, $44 million in 2021, $39 million in 2022 and $458 million thereafter).

c The amounts 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 2 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 The future minimum lease payments are before deducting related rental income from operating sub-leases. In the case of an operating lease entered into solely by BP as the operator of a joint operation, the amounts shown in the table represent the net future minimum lease payments, after deducting amounts reimbursed, or to be reimbursed, by joint operation partners. Where BP is not the operator of a joint operation, BP's share of the future minimum lease payments are included in the amounts shown, whether BP has co-signed the lease or not. Where operating lease costs are incurred in relation to the hire of equipment used in connection with a capital project, some or all of the cost may be capitalized as part of the capital cost of the project.

g

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 2018 include purchase commitments existing at 31 December 2017 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 27.

The following table summarizes the nature of the group's unconditional purchase obligations.

							$ million
						Payments due by period	
Unconditional purchase obligations	Total	2018	2019	2020	2021	2022	2023 and thereafter
Crude oil and oil products	76,884	56,985	7,114	3,973	3,746	1,945	3,121
Natural gas	27,685	14,846	4,734	2,613	1,938	1,622	1,932
Chemicals and other refinery feedstocks	5,548	3,088	1,819	285	82	77	197
Power	4,464	2,610	965	283	151	99	356
Utilities	539	183	117	89	37	23	90
Transportation	20,426	1,264	947	1,095	1,314	1,277	14,529
Use of facilities and services	18,665	1,424	1,334	1,337	1,113	1,038	12,419
Total	154,211	80,400	17,030	9,675	8,381	6,081	32,644

Upstream analysis by region

Our upstream operations are set out below by geographical area, with associated significant events for 2017. 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 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. We market around 20% of our LNG production using BP LNG shipping and contractual rights to access import terminal capacity in the liquid markets of Italy (in Rovigo), Spain (in Bilbao), the UK (via the Isle of Grain) and the US (via Cove Point), with the remainder marketed directly to customers. LNG is supplied to customers in markets including Argentina, Chile, China, the Dominican Republic, India, Israel, Japan, Kuwait, South Korea and Taiwan.

Europe

BP is active in the North Sea and the Norwegian Sea. Our activities focus on maximizing recovery from existing producing fields and new field developments. BP's production in 2017 was generated from three key areas: the Shetland area - comprising the Clair, Foinaven, Magnus, and Schiehallion fields; the central area - comprising the Andrew, Bruce, ETAP, Keith, Kinnoull and Rhum fields; and Norway, through our equity accounted 30% interest in Aker BP established in 2016 (see below).

- In January 2017 we announced that we had agreed to sell 25% of our 100% stake in Magnus, a 25% interest in a number of associated pipelines and a 3% interest in the Sullom Voe Terminal (SVT) on Shetland to EnQuest. BP also agreed to transfer operatorship of these assets to EnQuest. The sale price of $85 million is expected to be met by EnQuest from future cash flows from the assets, without any upfront payment to BP. The transfer completed on 1 December. Under the terms of the agreement, EnQuest has an option, exercisable between 1 July 2018 and 15 January 2019, to purchase BP's remaining 75% interest in Magnus, a further 9% interest in SVT and the remainder of BP's interests in the associated pipelines for a consideration of $300 million.
- We were awarded 25 blocks or part blocks in the UK's 29th Offshore Licensing Round in March 2017, representing the largest acreage award for BP in the North Sea since the late 1990s. The licence award includes three exploration wells.
- We announced in April that we had agreed to sell our Forties Pipeline System (FPS) business (BP 100%) to INEOS for an upfront cash consideration at the economic date of $125 million, adjusted for net cash flows in the interim period, followed by contingent payments between 2022 and 2024 of up to a further $125 million. FPS is an integrated oil and NGLs transportation and processing system that handles production from around 80 fields in the central North Sea. As a result of this decision to sell, an impairment charge of $387 million was recorded. The sale completed on 31 October. BP's existing transportation and processing rights in the system are not affected by the divestment.
- Production from the redeveloped Schiehallion area started in May, following completion of the multi-billion-dollar Quad 204 project, designed to extend the life of the fields and unlock further resources. The Schiehallion area comprises the Schiehallion (BP 33%) and Loyal (BP 50%) fields. The project included the construction and installation of a floating, production, storage and offloading (FPSO) vessel, a major upgrade and replacement of subsea facilities and a continuous drilling programme of up to 20 new wells to enable full development of the associated reserves.
- We continued to progress development at the Maersk-operated Culzean field (BP 32%) during the year. The installation of the gas export pipeline and fixed jackets was completed in 2017, with development drilling ongoing. First production is expected in 2019. The field will be developed with three fixed platforms and a floating storage unit.
- Aker BP announced an agreement to acquire Hess Norge AS in October. On completion of the transaction in December, Aker BP became the sole owner of the Valhall and Hod fields but subsequently sold a 10% interest in each of these fields to Pandion Energy AS. BP subscribed for additional new shares in Aker BP as part of the financing of

the acquisition of Hess Norge AS, and remains an owner of 30% of the issued share capital in Aker BP.

- In November, we announced that we had agreed to sell a package of our interests in the Bruce assets in the North Sea to Serica Energy plc. We currently operate the assets, which comprise the Bruce (BP 37%), Keith (BP 35%) and Rhum (BP 50%) fields, three bridge-linked platforms and associated subsea infrastructure. Under the terms of the agreement, Serica will pay BP an upfront payment of £12.8 million (equivalent to $17.2 million), a share of cash flows over the next four years, a consideration equivalent to 30% of our post-tax decommissioning costs and several contingent payments dependent on future asset performance and product prices. Overall, we expect to receive payments of around £300 million (equivalent to $403 million), the majority of which will be received over the next four years. Subject to the receipt of regulatory and other third-party approvals, we expect to complete the sale and transfer of operatorship in the third quarter of 2018.
- The Clair field (BP 29% and operator) is the largest oilfield on the UK Continental Shelf. Production began at the field, located 75 kilometres west of the Shetland Islands, in 2005. Its physical size dictates development via a phased approach, with Clair Ridge as the second phase of development. This has involved the construction and installation of two new bridge-linked platforms, the legs of which were installed in 2013. The final topside modules were safely installed in 2016, completing the construction phase. Commissioning offshore is well under way, with first oil expected in late 2018.
- In September the US Office of Foreign Asset Control renewed BP's licence permitting certain US persons and US owned and controlled companies to support Rhum activities in compliance with US primary sanctions. The licence expires on 30 September 2018. The Rhum field is owned by BP (50%) and the Iranian Oil Company (IOC, 50%) under a joint operating agreement. EU sanctions and certain US secondary sanctions in respect of Iran have been lifted or suspended as part of the Joint Comprehensive Plan of Action. See International trade sanctions on page 273.
- During the year an exploration write-off of $178 million relating to the Southern North Sea Carboniferous appraisal programme, including the Ravenspurn North Deep well, was recognized. There were two exploration discoveries in 2017, namely Achmelvich and Capercaillie, both of which are currently being evaluated.

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 260 lease blocks in the deepwater Gulf of Mexico, and we operate four production hubs.

- We announced the start-up of the South Expansion major project at our Thunder Horse platform in January 2017. Three producing wells came online in 2017 and the final well followed in early 2018. The project scope includes a new subsea production system two miles to the south of the existing Thunder Horse platform. The system is a collection of four wells connected to the platform by two lines installed on the seabed.
- During the year, a $68-million charge was recognized for the West Capricorn rig while it was warm stacked awaiting transfer to other projects. The rig returned to drilling operations in the fourth quarter of 2017.

- In December BP completed the disposal of 26.5% of its 27.5% non-operated interest in the Perdido Regional Host to AL-Perdido Holdings LLC. Perdido is a regional floating production hub for three fields including Great White (BP 33%) in the Gulf of Mexico.
- In March 2017, we were awarded three leases in the OCS Central Sale 247, in Mississippi Canyon Block 867 and Green Canyon Blocks 738 and 870.
- We were also awarded three leases in the Gulf of Mexico Wide Sale 249, in Green Canyon Block 451 and Mississippi Canyon Blocks 820 and 864 in August.
- During the year exploration write-offs totalling $213 million were recognised, the most significant being $148 million in connection with the expiration of the Gila lease.
- See also Financial statements Note 1 for further information on exploration leases.

The US Lower 48 onshore business has significant operated and non-operated activities across Arkansas, Colorado, New Mexico, Oklahoma, Texas and Wyoming producing natural gas, oil, NGLs and condensate. It has a 1.4 billion boe proved reserve base as at 31 December 2017, predominantly in unconventional reservoirs (tight gas«, shale gas and coalbed methane). This resource spans 3.1 million net developed acres and has approximately 9,400 operated gross wells, with daily net production around 300mboe/d.

Since the beginning of 2015, our US Lower 48 onshore business has operated as a separate business while remaining part of our Upstream segment. It has its own governance, systems and processes, and was established to increase competitive performance through swift decision-making and innovation, while maintaining BP’s commitment to safe, reliable and compliant operations.

- In East Texas the Haynesville and Bossier development is underway. This material development increased BP’s net natural gas production for the fourth quarter of 2017 in the East Business Unit by around 50% compared to the previous year.
- In August, we announced that a natural gas well in the Mancos Shale, New Mexico (BP 100%) had been brought on line. We believe the field has the potential to be a significant new source of US gas supply.
- In the fourth quarter an impairment charge of $321 million was recognized as a result of changes in reserves estimates.

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. Our focus continues to be on safe and reliable operations, renewing Prudhoe Bay infrastructure and minimizing oil production decline. For the past three years BP has successfully combated decline at Prudhoe Bay through wellwork and improved operating field efficiencies, with production being largely maintained. Infrastructure renewal activities in 2017 included compressor replacements, fire and gas system upgrades, safety system upgrades, pipeline renewal, facility piping upgrades and facility-siting projects. BP also owns significant interests in eight producing fields operated by others, as well as a non-operating interest in the Liberty prospect.

- The Alaska LNG project concept includes a planned three-train North Slope gas treatment plant, approximately 800 miles of pipeline to tidewater and a three-train liquefaction facility, with an estimated capacity of 3 billion cubic feet per day (bcf/d) (up to 20 million tonnes per annum) supplied from the Prudhoe Bay and Point Thomson fields. In April, the Alaska Gasline Development Corporation (AGDC), a state entity which has led the project since December 2016, submitted a formal application for an authorization to site, construct, and operate an integrated LNG project. AGDC also conducted extensive marketing activities in Asia in 2017 including signing a memorandum of understanding with the Korea Gas Corporation (KOGAS), signing a joint development agreement with China Petroleum and Chemical Corporation (Sinopec), Bank of China, and the Chinese Investment Corporation, signing a memorandum of understanding with PetroVietnam and signing a Letter of Intent with Tokyo Gas Company. In January 2017 BP

Alaska LNG LLC (BPAL) executed a co-operation agreement with AGDC detailing BPAL's commitment to helping the state further develop Alaska LNG. This agreement has been extended to 30 June 2018.

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The Prudhoe Bay oil field (BP 26% and operator) on Alaska's North Slope reached 40 years of production in 2017, a milestone that highlights its important contribution to US energy security and the economy of the state. Since the field began production in 1977, it has recovered more than 12.5 billion barrels of oil. The original estimated recovery for Prudhoe Bay was 9.6 billion barrels, with an additional 3 billion barrels so far unlocked through innovations in oilfield technology. Prudhoe Bay remains the third largest oil field in the US on a proved reserves basis.

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 south-east 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 have not yet reached agreement regarding the terms for the transfer of Unocal's interest in TAPS.

- In 2017, the parties involved in TAPS tariff matters at the Federal Energy Regulatory Commission (FERC) and the Regulatory Commission of Alaska (RCA) reached an agreement to settle all challenges pending before FERC involving TAPS interstate rates for the years 2009-2015 and establish a mechanism for calculating interstate rate ceilings for TAPS for the period from 2016 through 2021, as well as subsequent years unless otherwise terminated. The agreement resolves all challenges pending before the RCA involving TAPS intrastate rates from 2008 to the present, and establish intrastate rate ceilings for the future through 30 June 2019. RCA approval was granted in January 2018 and FERC approval in February 2018. Once all appeal periods have run, if the agreements are approved, the parties will proceed with implementing the settlement agreements, including issuing tariff refunds. Implementation will result in production tax and royalty payments to the State of Alaska while releasing some previously accrued liability provisions within BP Alaska.

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 significant offshore exploration licences in Nova Scotia, Newfoundland and Labrador and the Canadian Beaufort Sea.

In Mexico, we have interests in two exploration joint ventures« in the Saline Basin with Statoil and Total, Block 1 (BP 33% and operator) and Block 3 (BP 33%). Both properties have submitted an exploration plan to Comisión Nacional de Hidrocarburos (CNH), the Mexican regulator, and approval was received in March 2018.

South America

BP has upstream activities in Brazil and Trinidad & Tobago, and through Pan American Energy Group (PAEG), in Argentina and Bolivia.

In Brazil BP has interests in 21 exploration concessions across five basins.

- In October, we won two licences in the third Pre-Salt Bid Round in Brazil, the Alto De Cabo Frio Central block (BP 50%), and the Peroba block (BP 40%).
- In the North Campos basin, we continue work on the BM-C-32 (Itaipu) and BM-C-30 (Wahoo) projects with the potential for a joint development or tie back between them. A decision to move into front-end engineering for a potential long-term test is planned for November 2018.
- Following the licence extension to 2019 which was approved in 2016, seismic processing and prospect inventory development progressed in 2017 in Block BAR-M-346 in the Barreirinhas basin.

- BP continues to progress the preparatory activities for drilling exploration wells in the Foz do Amazonas Basin, with a BP-operated well scheduled to spud in 2020. An extension request was submitted to the Brazilian National Petroleum Agency (ANP) regarding BP-operated block FZA-M-59. We also expect drilling activity to commence in 2019 on our other non-operated interests in Foz de Amazonas (BP 30%).
- In the South Campos basin, following approval of the revised appraisal plan by ANP in 2016, in Block BM-C-35 we have postponed the decision to move into Appraisal Plan Stage II and commit to an additional pre-salt well or relinquish the area, until October 2018.

In Argentina and Bolivia BP conducts activity through PAEG, which also has activities in Mexico.

- In December, we confirmed that the formation of Pan American Energy Group (PAEG) had completed. The new company, owned by BP (50%) and Bridas Corporation (50%), is now the largest privately owned integrated energy company operating in Argentina. PAEG was formed in a cash free transaction by the combination of Pan American Energy and Axion Energy (Axion). Pan American Energy had been owned 60:40 by BP and Bridas Corporation and Axion had been wholly-owned by Bridas Corporation.

In Trinidad & Tobago BP holds exploration and production licences and production-sharing agreements«(PSAs) covering 1.8 million acres offshore of the east and north-east coast. Facilities include 14 offshore platforms and two onshore processing facilities. Production comprises gas and associated liquids.

BP also has a shareholding in the Atlantic LNG liquefaction plant, BP's shareholding averages 39% across four LNG trains« with a combined capacity of 15 million tonnes per annum. We sell gas to each of the LNG trains, supplying 100% of the gas for train 1, 50% for train 2, 75% for train 3 and around 67% of the gas for train 4. All LNG from train 1 and most of the LNG from trains 2 and 3 is sold to third parties in the US and Europe under long-term contracts. We market the remaining equity LNG entitlement from trains 2, 3 and 4 to the US, UK, Spain and South America.

- The Trinidad onshore compression project (BP 70%) started up in April. The facility is expected to improve production capacity by increasing production from low-pressure wells in BP's existing acreage in the Columbus Basin using an additional inlet compressor at the Point Fortin Atlantic LNG plant.
- We announced the Savannah and Macadamia gas discoveries in June (both BP 70%). The Savannah exploration well was drilled east of the Juniper field into an untested fault block using a semi-submersible rig, and penetrated two hydrocarbon-bearing reservoirs. Based on the success of this well BP expects to develop these reservoirs through future tie-backs to the Juniper platform. The Macadamia well was drilled to test exploration and appraisal segments below the existing SEQB discovery south of the producing Cashima field. This discovery is expected to support a new platform in the future.
- Also in June, we announced that development of the Angelin offshore gas project had been sanctioned. The project will involve construction of a new platform, BP's 15th offshore production facility, 60 kilometres off the south-east coast of Trinidad in water depths of approximately 65 metres. The development will include four wells, with gas from Angelin flowing to the Cassia B hub for processing via a new pipeline to the Serrette platform. Drilling is expected to start in late 2018 with first gas expected in 2019.
- In August, we announced the start of production from our Juniper project. Juniper is BP's first subsea development in Trinidad and is expected to boost our gas production capacity by around 590 mmscf per day. The development produces gas from the Corallita and Lantana fields via the new Juniper platform, 80 kilometres off the south-east coast of Trinidad.

Africa

BP's upstream activities in Africa are located in Algeria, Angola, Côte d'Ivoire, Egypt, Libya, and Mauritania and Senegal.

In Algeria BP, Sonatrach and Statoil are partners in the In Salah (BP 33.15%) and In Amenas (BP 45.89%) projects that supply gas to the domestic and European markets.

- The Bourarhat production-sharing contract (PSC) expired in September 2014 and our exit concluded in 2017.
- In December, BP and Statoil signed an extension agreement for the In Amenas PSC with Sonatrach, the Algerian state-owned energy company. The agreement has been submitted to the Algerian authorities for ratification.

In Angola, BP owns an interest in six 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%).

- In June, we announced that as part of our ongoing portfolio evaluation we would relinquish our 50% interest in block 24/11 offshore. The Katambi gas discovery made in 2014 has not been determined to be commercial. As a result of this, and other exploration write-offs, a total of $729 million was recognized during the year.

In December, BP and Kosmos Energy (KE) announced that they had been awarded five new offshore oil blocks in Côte d'Ivoire, 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%, KE 45%, PETROCI 10%).

In Egypt, BP and its partners currently produce 10% of Egypt's liquids« production and almost 40% of its gas production.

- We announced the Qattameya discovery in March 2017, the third gas discovery in the North Damietta offshore concession in the East Nile Delta. Options to tie the discovery back to nearby infrastructure are being studied.
- In 2017 exploration write-offs of $368 million were recognized for a number of wells including GEB East, Mocha and Tarif Deep, as a result of unsuccessful exploration drilling and the relinquishment of exploration blocks.
- BP announced the start-up of gas production from the Taurus and Libra fields in the West Nile Delta development (BP 82.75%) in May. This development comprises five fields across the North Alexandria and West Mediterranean Deepwater offshore blocks and is being developed as three separate projects to enable BP and its partners to accelerate gas production commitments to Egypt. All projects are expected to be onstream by 2019. Development of the Taurus and Libra fields were fast-tracked following approval in 2015. It is a subsea greenfield development including nine wells and 42 kilometre tieback to existing onshore processing facilities.
- Also in May, development of the Baltim South West field was sanctioned. A dedicated mobile offshore production unit will be installed and tied back to existing infrastructure through a new offshore/onshore pipeline.
- In February 2018, we announced the start-up of the Atoll field in the North Damietta concession following the drilling of three deepwater wells 950 metres below the water's surface. Early production first started in December before the field came fully on line in January.
- In December, the first phase of well drilling operations at the Zohr gas field concluded and production has commenced. Production had reached 350 million cubic feet per day at year end. BP did not exercise the option to purchase an additional 5% interest in the field by the end of 2017. The final purchase consideration on the Zohr acquisition was $564 million. During 2017 Rosneft completed the acquisition of a 30% stake in a concession agreement to develop the Zohr field.

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%). The EPSA continues to be in force majeure. BP wrote off all balances associated with the Libya EPSA in 2015.

In Mauritania and Senegal, BP has partnered with Kosmos Energy and has a 62% participating interest in the C-6, C-8, C-12 and C-13 exploration blocks in Mauritania and a 60% participating interest in the Cayar Profond and St Louis Profond exploration blocks in Senegal. Together these blocks cover approximately 33,000km^2. In addition to the existing blocks, the companies have agreed to co-operate in areas of mutual interest in offshore Mauritania, Senegal and the Gambia, with Kosmos acting as the exploration operator and BP as the development operator.

- Under the terms of the agreements with Kosmos Energy, announced in December 2016, BP paid Kosmos cash bonuses of $162 million on completion. BP will carry exploration and appraisal costs of $228 million for Kosmos along with its development costs of $533 million, which include front-end engineering and design studies. Kosmos will also receive a contingent bonus of up to $2 per barrel for up to 1 billion barrels of liquids, as a production royalty, subject to a future liquids discovery and oil price. The Mauritania deal with Kosmos completed in December 2016 and the Senegal deal completed in February 2017.
- BP and Kosmos Energy announced the Yakaar-1 gas discovery offshore Senegal in the Cayar Offshore Profond block in May. This followed the earlier exploration success that led to the Tortue discovery, where we completed a drill stem test in 2017.
- In July, we completed a deal with Timis Corporation to acquire their 30% interest in the Cayar Profond and the St Loius Profond blocks, deepening our interest in these Senegal blocks.
- We completed the acquisition of a 15% participating interest in the C-18 exploration block in Mauritania from Tullow in September. This block is now operated by Total.
- In October, Kosmos Energy announced that the Hippocampe-1 exploration well, in the C-8 block was unsuccessful. As a result, an exploration write-off of $69 million was recognized.
- In December, Kosmos Energy announced that the Lamantin-1 exploration well in block C-12 was unsuccessful. As a result, an exploration write-off of $45 million was recognized.
- In February 2018, Kosmos Energy announced that the Requin Tigre-1 well in the Saint Louis Profond block, offshore Senegal, was fully tested but did not encounter hydrocarbons.
- In February 2018, the governments of Mauritania and Senegal signed an Inter-Government Cooperation Agreement (ICA) which will enable the development of the BP-operated Tortue/Ahmeyim gas project to continue to move towards a final investment decision. The ICA provides for development of the Tortue/Ahmeyim gas field through cross-border unitisation, with a 50%-50% initial split of resources and revenues and a mechanism for future equity redeterminations based on actual production and other technical data. The Tortue/Ahmeyim gas field is located offshore on the border between Mauritania and Senegal. BP has completed significant engineering design towards the project, an integrated gas value chain and near-shore liquefied natural gas (LNG) development which would export LNG to global markets as well as supplying gas to Senegal and Mauritania.

In Morocco, BP exited its final licence, the Essaouira offshore licence (BP 45%) in 2017. The majority of balances associated with the licence were written off in 2016, with the exception of a small payment for unfulfilled exploration commitments which was made in 2017.

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 640,000m^3. The project is supplied under a long-term contract with Australia's North West Shelf venture (BP 16.67%).

- BP has two PSCs for shale gas exploration, development and production in the Neijiang-Dazu block and Rong Chang Bei block in the Sichuan basin, China. The two blocks, both in the exploration phase, cover a total area of approximately 2,500km^2. China National Petroleum Corporation (CNPC) is the operator. In 2017, the seismic acquisition programme was completed in the Neijiang–

Dazu block, and drilling activity continued to progress in the two blocks in the Sichuan basin.

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.

- In 2012 certain EU and US regulations concerning restrictive measures against Iran were issued, which impact the Shah Deniz joint venture in which Naftiran Intertrade Co Ltd (NICO), a subsidiary of the National Iranian Oil Company, holds a 10% interest. The EU sanctions and certain US secondary sanctions in respect of Iran have been lifted or suspended as part of the Joint Comprehensive Plan of Action. For further information see International trade sanctions on page 273.

- The Shah Deniz Stage 2 project and associated South Caucasus Pipeline expansion project are now substantially complete in terms of engineering, procurement, construction and commissioning, and remain on target for first gas delivery in 2018. We achieved a number of major project milestones in 2017, including the installation of both processing and utilities platforms offshore, installation of all processing facilities at the onshore terminal and completion of pipeline construction in Azerbaijan and Georgia.
- In September, the joint development and PSA for the ACG fields was extended with the signing of an amended and restated PSA between the State Oil Company of the Republic of Azerbaijan (SOCAR) and the contractor parties. The renewed PSA has been ratified by the Azerbaijani parliament and was effective from 1 January 2018. It extends the PSA's term by 25 years to 2049 and includes an improved contractor parties' profit share at a fixed rate of 25%. Under the terms of the agreement, BP's interest changes from 35.78% to 30.37% from the agreement's effective date, with a bonus of $1.46 billion (BP net), payable to the government of Azerbaijan in equal instalments over eight years. Following signing of the PSA extension, BP and its partners approved the next stage of development of the Azeri-Central East project to examine the potential for a further production platform to be located between the existing Central Azeri and East Azeri platforms. A final investment decision on this project is anticipated in 2019.

BP holds a 30.1% interest in and operates the Baku-Tbilisi-Ceyhan (BTC) oil pipeline. The 1,768-kilometre pipeline transports oil from the 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 2017 of 694mboe/d.

BP is technical operator of, and currently holds a 28.83% interest in, the 693 kilometre South Caucasus Pipeline (SCP). The pipeline takes gas from Azerbaijan through Georgia to the Turkish border and has a capacity of 143mboe/d, with average throughput in 2017 of 125mboe/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 77mboe/d in 2017.

BP also holds a 12% interest in the Trans Anatolian Natural Gas Pipeline that will transport Shah Deniz gas across Turkey, and a 20% interest in the Trans Adriatic Pipeline that will take gas through Greece and Albania into Italy.

In Oman, BP operates the Khazzan field in block 61 (BP 60%).

- In September, we announced the start of production from the Khazzan gas field ahead of schedule and under budget. Khazzan is located in block 61 which is operated by BP in partnership with Oman Oil Company Exploration and Production. Phase one of the Khazzan development is made up of 200 wells feeding into a two-train central processing facility. Production from this phase at year end had reached 0.3 billion cubic feet of gas per day (BP net).
- In 2016 BP signed an agreement to extend block 61 and unlock Phase two of the Khazzan development, known as Ghazeer. This is expected to add a further 0.5 billion cubic feet of gas per day, and the final investment decision is expected in early 2018.

In Abu Dhabi, BP holds an equity interest of 14.67% in the ADNOC Offshore concession (formerly ADMA) and a 10% interest in the ADNOC Onshore concession (formerly ADCO). We also have a 10%

equity shareholding in ADNOC LNG (formerly ADGAS) that supplied approximately 5.6 million tonnes of LNG (263.6bcfe regasified) in 2017.

Our interest in the ADNOC Offshore concession expired in March 2018. Current production is approximately 670mb/d gross, with partners lifting according to equity participation. The concession, together with all related rights and obligations, has reverted back to the government of the Emirate of Abu Dhabi. Our interest in the ADNOC Onshore concession expires at the end of 2054.

In 2016 BP signed an enhanced technical service agreement for south and east Kuwait conventional oilfields, which includes the Burgan field, with Kuwait Oil Company. Implementation of the agreed 2017-2018 plan for the Burgan oil field is underway as planned.

In India, we have a 30% participating interest in two oil and gas PSAs and a 33.33% participating interest in one oil and gas PSA, all operated by Reliance Industries Limited (RIL). We also have a stake with RIL in a 50:50 joint venture (India Gas Solutions Private Limited) for the sourcing and marketing of gas in India.

- In 2017 BP recorded a $30-million impairment reversal and a $56-million reversal of exploration write-offs due to increased confidence in the progress of the projects in Block KG D6. This fully reverses all previously booked impairments on the block.
- In June, BP and its partners announced that they had taken an investment decision to progress development of the R-Series deepwater gas fields in Block KG D6 off the east coast of India. The R-Series fields will be developed as a subsea tieback to existing infrastructure in the block. The project is expected to come onstream in 2020 and is the first of three planned projects in Block KG D6 to be developed in an integrated manner. In October, field development plans for the Satellite Cluster and D55 developments were submitted for requisite approvals under the PSA.

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. Our operations are not impacted by the continued instability and sectarian violence in the north and west of the country. Production as at year end 2017 was 61 mboe/d (BP net).

- In January 2018, BP signed a Letter of Intent to support Iraq's North Oil Company with current operations and development plans for longer-term redevelopment of the Kirkuk field. This is an extension of a Letter of Intent signed in 2013.

In Russia, in addition to its 19.75% equity interest in Rosneft, BP holds a 20% interest in Taas-Yuryakh Neftegazodobycha (Taas), a joint venture with Rosneft that is developing the Srednebotuobinskoye oil and gas condensate field in East Siberia (see Rosneft on page 38 for further details). We also hold a 49% interest in Yermak Neftegaz LLC, another joint venture with Rosneft to conduct exploration in the West Siberian and Yenisei-Khatanga basins. Yermak Neftegaz LLC currently holds seven exploration and production licences. The venture is also carrying out further appraisal work on the Baikalovskoye field, an existing Rosneft discovery in the Yenisei-Khatanga area of mutual interest.

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.

- Following the decision taken in March 2016 not to progress with the floating LNG development, the Browse joint venture participants continue to evaluate a range of alternative development options, and are expecting to select one in 2018.
- We announced that production had commenced from the Persephone project on the North West Shelf (BP 16.67%) in August. The development comprises two subsea wells tied back to the existing North Rankin complex.

- Following the cancellation of the Great Australian Bight project, the Ocean Great White rig is currently warm stacked. A number of options for its deployment or renegotiation of the contractual terms remain under review and are being worked actively with the rig operator.

In Papua Barat, Eastern Indonesia, BP operates the Tangguh LNG plant (BP 40.22%). The asset comprises 14 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, China, South Korea, and Japan through a combination of long, medium and short-term contracts.

- The Tangguh expansion project, which was approved for final investment decision in 2016, is progressing on schedule. The project includes a third LNG processing train (train 3), adding 3.8 million tonnes per annum (mtpa) of production capacity to the existing facility, bringing total plant capacity to 11.4mtpa. The project also includes two offshore platforms, 13 new production wells, an expanded LNG loading facility, and supporting infrastructure. This will enable BP to continue playing an important role in supporting Indonesia's growing energy demand, with 75% of its annual LNG production sold to the Indonesian state electricity company PT. PLN (Persero). First production from train 3 is expected in 2020.

- Approval from the government of Indonesia to relinquish BP's 32% interest in the Chevron-operated West Papua III was received in November. Approval for the relinquishment of West Papua I (also BP 32%) has not yet been obtained.

Downstream plant capacity

The following table summarizes BP group's interests in refineries and average daily crude distillation capacities as at 31 December 2017.

			Crude distillation capacities[a]	
Fuels value chain	Country	Refinery	Group interest[b] (%)	BP share thousand barrels per day
US				
US North West	US	Cherry Point	100	236
US East of Rockies		Whiting	100	430
		Toledo	50	80
				746
Europe				
Rhine	Germany	Bayernoil[c]	10	22
		Gelsenkirchen	100	265
		Lingen	100	97
	Netherlands	Rotterdam	100	377
Iberia	Spain	Castellón	100	110
				871
Rest of world				
Australia	Australia	Kwinana	100	152
New Zealand	New Zealand	Whangarei[c d]	10.1	33
Southern Africa	South Africa	Durban[c]	50	90
				275
Total BP share of capacity at 31 December 2017				1,892

[a] Crude distillation capacity is gross rated capacity, which is defined as the highest average sustained unit rate for a consecutive 30-day period.

[b] BP share of equity, which is not necessarily the same as BP share of processing entitlements.

[c] Indicates refineries not operated by BP.

[d] 33mb/d 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 2017.

					BP share of capacity thousand tonnes per annum[b]		
Geographical area	Site	Group interest[c] (%)	PTA	PX	Acetic acid	Olefins and derivatives	Product 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]	85	2,500	—	—	—	—
Indonesia	Merak	100	500	—	—	—	—
South Korea	Ulsan[g]	34 to 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 2017							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 2017 BP had material volumes of proved undeveloped reserves held for more than five years in Russia, Trinidad, the North Sea, Egypt, Canada and the Gulf of Mexico. 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.

Over the past five years, BP has annually progressed a weighted average 18% (18% for 2016 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 about 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 2017 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 2017 we progressed 1,671mmboe of proved undeveloped reserves (1,119mmboe 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 $15,277 million in 2017 ($10,695 million for subsidiaries and $4,582 million for equity-accounted entities). The major areas with progressed volumes in 2017 were Argentina, Trinidad, Russia, the UK and the US. 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 revisions to our proved undeveloped resources in the UAE as a result of development expansion, Azerbaijan as a result of the extension of the production license and in Russia as a result of new gas contracts and 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 2017	7,797
Revisions of previous estimates	842
Improved recovery	236
Discoveries and extensions	769
Purchases	122
Sales	(65)
Total in year proved undeveloped reserves changes	1,904
Proved developed reserves reclassified as undeveloped	31
Progressed to proved developed reserves by development activities (e.g. drilling/completion)	(1,671)
Proved undeveloped reserves at 31 December 2017	8,060

Subsidiaries only	volumes in mmboe[a]
Proved undeveloped reserves at 1 January 2017	4,068
Revisions of previous estimates	402
Improved recovery	203
Discoveries and extensions	413
Purchases	57
Sales	(2)
Total in year proved undeveloped reserves changes	1,073
Proved developed reserves reclassified as undeveloped	31
Progressed to proved developed reserves by development activities (e.g. drilling/completion)	(1,119)
Proved undeveloped reserves at 31 December 2017	4,052

[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 30 years of diversified industry experience, with more than 10 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 Classification.

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 2017, 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 2017. 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.
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
88% of our total proved reserves of subsidiaries at 31 December 2017 were held through joint operations«(86% in 2016), and 34% of the proved reserves were held through such joint operations where we were not the operator (31% in 2016).
Estimated net proved reserves of crude oil at 31 December 2017[a b c]

	million barrels		
	Developed	Undeveloped	Total
UK	245	164	409
Rest of Europe	—	—	—
US[d]	932	492	1,423
Rest of North America[e]	54	195	248
South America[f]	10	6	16
Africa	281	28	309
Rest of Asia	1,040	642	1,682
Australasia	31	11	42
Subsidiaries	2,592	1,537	4,129
Equity-accounted entities	3,473	2,603	6,076
Total	6,064	4,140	10,205

Estimated net proved reserves of natural gas liquids at 31 December 2017[a b]

	million barrels		
	Developed	Undeveloped	Total
UK	11	3	14
Rest of Europe	—	—	—
US	177	69	246
Rest of North America	—	—	—
South America	2	28	30
Africa	21	—	21
Rest of Asia	—	—	—
Australasia	5	1	6
Subsidiaries	216	102	318
Equity-accounted entities	97	53	149
Total	313	154	467

Estimated net proved reserves of liquids«

	million barrels		
	Developed	Undeveloped	Total
Subsidiaries[f]	2,808	1,639	4,447
Equity-accounted entities[g]	3,569	2,656	6,225
Total	6,377	4,295	10,672

Estimated net proved reserves of natural gas at 31 December 2017[a b]

	billion cubic feet		
	Developed	Undeveloped	Total
UK	523	320	843
Rest of Europe	—	—	—
US	5,238	3,086	8,323
Rest of North America	(1)	—	(1)
South America[h]	2,862	3,330	6,193
Africa	1,159	1,510	2,670
Rest of Asia	2,755	4,245	7,000
Australasia	2,730	1,505	4,235
Subsidiaries	15,266	13,997	29,263
Equity-accounted entities[i]	7,955	7,841	15,796
Total	23,221	21,838	45,060

Estimated net proved reserves on an oil equivalent basis

	million barrels of oil equivalent		
	Developed	Undeveloped	Total
Subsidiaries	5,440	4,052	9,492
Equity-accounted entities	4,941	4,008	8,949
Total	10,381	8,060	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, 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 2017 marker prices used were Brent« $54.36/bbl (2016 $42.82/bbl and 2015 $54.17/bbl) and Henry Hub« $2.96/mmBtu (2016 $2.46/mmBtu and 2015 $2.59/mmBtu).

c Includes condensate.

d Proved reserves in the Prudhoe Bay field in Alaska include an estimated 9 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 14 million barrels of liquids in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[g] Includes 338 million barrels of liquids in respect of the non-controlling interest in Rosneft held assets in Russia including 32 million barrels held through BP's equity-accounted interest in Taas-Yuryakh Neftegazodobycha.

[h] Includes 1,860 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[i] Includes 306 billion cubic feet of natural gas in respect of the non-controlling interest in Rosneft held assets in Russia including 12 billion cubic feet held through BP's equity-accounted interest in Taas-Yuryakh Neftegazodobycha.

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 2017, on an oil equivalent basis including equity-accounted entities, increased by 4% (increase of 4% for subsidiaries and increase of 3% for equity-accounted entities) compared with 31 December 2016. Natural gas represented about 42% (53% for subsidiaries and 30% for equity-accounted entities) of these reserves. The change includes a net increase from acquisitions and disposals of 47mmboe (increase of 90mmboe within our subsidiaries and decrease of 43mmboe within our equity-accounted entities). Acquisition activity in our subsidiaries occurred in Egypt, the US and the UK, and divestment activity in our subsidiaries in the UK. In our equity-accounted entities acquisitions occurred in our Aker BP and Rosneft equity-accounted entities and divestments occurred in our Aker BP and in our Pan American Energy (PAE) equity-accounted entities.

The proved reserves replacement ratio«(RRR) 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 2017, the proved reserves replacement ratio excluding acquisitions and disposals was 143% (109% in 2016 and 61% in 2015) for subsidiaries and equity-accounted entities, 133% for subsidiaries alone and 159% for equity-accounted entities alone. There were material increases (264mmboe) of reserves due to extension of the date of cessation of production across the group due to higher oil and gas prices, but these were partially offset by decreases (150mmboe) in PSAs, principally in Azerbaijan, Indonesia and Iraq resulting from decreased cost recovery volumes due to higher oil and gas prices.

In 2017 net additions to the group's proved reserves (excluding production and sales and purchases of reserves-in-place) amounted to 1,926mmboe (1,084mmboe for subsidiaries and 842mmboe 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 through improved recovery from, and extensions to, existing fields and discoveries of new fields were in existing developments where they represented a mixture of proved developed and proved undeveloped reserves. Volumes added in 2017 principally resulted from the application of conventional technologies and extensions of the cessation of production as a result of higher prices. The principal proved reserves additions in our subsidiaries were in UAE, Oman, Azerbaijan and the US. We had material reductions in our proved reserves in Iraq principally due to higher oil and gas prices. The principal reserves additions in our equity-accounted entities were in PAE and Rosneft.

17% of our proved reserves are associated with PSAs. The countries in which we operated under PSAs in 2017 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.

Our Abu Dhabi offshore concessions are due to expire in 2018, we have no proved reserves associated with these concessions beyond their expiry date. The group holds no other licences due to expire within the next three years that would have a significant impact on BP's reserves or production.

For further information on our reserves see page 198.

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		
	2017	2016	2015	2017	2016	2015
Subsidiaries						
UK[c d]	80	79	72	6	6	7
Norway[c]	—	24	38	—	4	5
Total Rest of Europe	—	24	38	—	4	5
Total Europe	80	102	110	6	10	11
Alaska[c]	109	107	107	—	—	—
Lower 48 onshore[c]	10	12	14	34	36	37
Gulf of Mexico deepwater	251	216	203	21	20	19
Total US	370	335	323	56	56	56
Canada[e]	20	13	3	—	—	—
Total Rest of North America	20	13	3	—	—	—
Total North America	390	347	327	56	56	56
Trinidad & Tobago[c]	12	10	12	10	8	11
Total South America	12	10	12	10	8	11
Angola	192	219	221	—	—	—
Egypt[c]	40	39	42	—	—	—
Algeria	9	5	6	10	5	7
Total Africa	241	263	270	10	5	7
Abu Dhabi[c]	158	—	—	—	—	—
Azerbaijan	90	105	111	—	—	—
Western Indonesia[c]	—	2	2	—	—	—
Iraq	73	96	85	—	—	—
India	1	1	1	—	—	—
Oman	2	—	—	—	—	—
Total Rest of Asia	325	204	199	—	—	1
Total Asia	325	204	199	—	—	1
Australia[c]	15	15	15	2	3	3
Eastern Indonesia[c]	1	2	2	—	—	—
Total Australasia	17	16	17	2	3	3
Total subsidiaries	1,064	943	933	85	82	88
Equity-accounted entities (BP share)						
Rosneft (Russia, Canada, Venezuela, Vietnam)	900	836	809	4	4	4
Abu Dhabi[f]	99	101	96	—	—	—
Argentina[c]	60	62	65	—	1	3
Bolivia[c]	3	4	4	—	—	—
Egypt	—	—	—	2	3	3
Norway[c]	31	7	—	2	—	—
Russia[c]	5	4	—	—	—	—
Angola	1	—	—	4	1	—
Other	—	1	1	—	—	—
Total equity-accounted entities	1,099	1,015	974	12	8	10
Total subsidiaries and equity-accounted entities[g]	2,163	1,958	1,908	97	90	99

[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 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. In 2016, BP increased its interests in Tangguh in Indonesia and the Culzean asset in the UK North Sea, and in certain US onshore assets. It disposed of its interests in the Valhall, Skarv and Ula assets in the Norwegian North Sea and in return received an interest in Aker BP ASA, which operates in Norway. It also disposed of its interests in the Jansz-Io asset in Australia, and the Sanga Sanga conventional concession in Indonesia. It also decreased its interests in certain Trinidad and US onshore assets. In 2015, BP acquired an interest in Taas-Yuryakh Neftegazodobycha. It also increased its interest in the North Alexandria and West Mediterranean Deep Water Concessions of the West Nile Delta project in Egypt. It increased its interest in certain UK North Sea, Trinidad, and US onshore assets. It also decreased its interest in certain other assets in the same regions.

[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] BP holds interests, through associates, in offshore concessions in Abu Dhabi which expire in 2018.

[g] Includes 3 net mboe/d of NGLs from processing plants in which BP has an interest (2016 3mboe/d and 2015 4mboe/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]		
	2017	2016	2015
Subsidiaries			
UK[b]	182	170	155
Norway[b]	—	82	111
Total Rest of Europe	—	82	111
Total Europe	182	252	266
Lower 48 onshore[b]	1,467	1,476	1,353
Gulf of Mexico deepwater	186	173	168
Alaska	5	6	7
Total US	1,659	1,656	1,528
Canada	9	10	10
Total Rest of North America	9	10	10
Total North America	1,667	1,666	1,538
Trinidad & Tobago[b]	1,936	1,689	1,922
Total South America	1,936	1,689	1,922
Egypt[b]	745	305	402
Algeria	205	208	187
Total Africa	949	513	589
Azerbaijan	232	245	219
Western Indonesia[b]	—	35	48
India	60	84	113
Oman	79	—	—
Total Rest of Asia	371	363	380
Total Asia	371	363	380
Australia[b]	426	451	447
Eastern Indonesia[b]	357	369	354
Total Australasia	783	820	801
Total subsidiaries[c]	5,889	5,302	5,495
Equity-accounted entities (BP share)			
Rosneft (Russia, Canada, Egypt, Venezuela, Vietnam)	1,308	1,279	1,195
Argentina	329	354	341
Bolivia	89	95	93
Norway[b]	53	12	—
Angola	77	18	—
Western Indonesia	—	15	21
Total equity-accounted entities[c]	1,855	1,773	1,651
Total subsidiaries and equity-accounted entities	7,744	7,075	7,146

[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 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.In 2016, BP increased its interests in Tangguh in Indonesia and the Culzean asset in the UK North Sea, and in certain US onshore assets. It disposed of its interests in the Valhall, Skarv and Ula assets in the Norwegian North Sea and in return received an interest in Aker BP ASA, which operates in Norway. It also disposed of its interests in the Jansz-Io asset in Australia, and the Sanga Sanga concession in

Indonesia. It also decreased its interests in certain Trinidad and US onshore assets. In 2015, BP acquired an interest in Taas-Yuryakh Neftegazodobycha. It also increased its interest in the North Alexandria and West Mediterranean Deep Water Concessions of the West Nile Delta project in Egypt. It increased its interest in certain UK North Sea, Trinidad, and US onshore assets. It also decreased its interest in certain other assets in the same regions.
[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]

	Europe		North America		South America	Africa	Asia		Australasia	Total group average
										$ per unit of production
	UK	Rest of Europe	US	Rest of North America[b]			Russia	Rest of Asia		
Subsidiaries										
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
2016										
Crude oil[c]	42.80	40.16	39.65	26.11	45.64	40.83	—	39.29	41.52	39.99
Natural gas liquids	25.70	20.16	14.71	—	21.40	21.30	—	—	32.70	17.31
Gas	4.50	4.19	1.90	—	1.72	3.89	—	3.39	5.71	2.84
2015										
Crude oil[c]	52.42	50.68	49.84	26.71	53.19	49.09	—	49.33	50.64	49.72
Natural gas liquids	30.66	28.20	14.80	—	27.66	31.94	—	—	36.69	20.75
Gas	7.83	6.49	2.10	—	2.67	4.40	—	5.35	7.35	3.80
Equity-accounted entities[d]										
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
2016										
Crude oil[c]	—	50.71	—	—	48.88	—	36.36	12.92	—	34.04
Natural gas liquids[e]	—	—	—	—	34.51	—	N/A	—	—	34.51
Gas	—	5.16	—	—	4.21	—	1.39	6.11	—	2.20
2015										
Crude oil[c]	—	—	—	—	54.24	—	44.78	16.87	—	41.49
Natural gas liquids[e]	—	—	—	—	13.17	—	N/A	—	—	13.17
Gas	—	—	—	—	4.35	—	1.48	7.56	—	2.35

Average production cost per unit of production[f]

	Europe		North America		South America	Africa	Asia		Australasia	Total group average
										$ per unit of production
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
2017	14.58	—	8.68	15.02	4.41	6.47	—	6.37	2.79	7.11
2016	14.80	13.72	10.20	21.79	4.21	9.34	—	7.08	2.62	8.46
2015	22.95	13.80	11.84	43.56	5.44	11.02	—	11.22	2.88	10.46

Equity-accounted entities										
2017	—	10.33	—	—	11.92	—	3.19	3.27	—	4.32
2016	—	10.41	—	—	10.66	—	2.46	3.67	—	3.57
2015	—	—	—	—	12.10	—	2.60	4.59	—	3.93

[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

	2017	2016	$ million 2015
Environmental expenditure relating to the Gulf of Mexico oil spill	—	—	5,452
Operating expenditure	441	487	521
Capital expenditure	487	564	733
Clean-ups	22	27	34
Additions to environmental remediation provision	249	262	305
Increase (decrease) in decommissioning provision	(228)	(804)	972

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 $441 million in 2017 (2016 $487 million) showed an overall decrease of 9% which was primarily due to lower expenditures associated with BP's share of the TAPS pipeline.

Environmental capital expenditure in 2017 was lower overall than in 2016, largely due to lower spend as a result of the completion of the installation of the new LPG refrigeration plant for the North Sea Forties Pipeline System in the previous year and lower spend on Kuparuk field in Alaska driven by lower activity.

Clean-up costs decreased to $22 million in 2017 compared with $27 million in 2016, primarily due to decreased contractual rates and overall cost reductions. The numbers of oil spills are broadly similar and while the volume of oil has increased, this includes releases to secondary containment which do not reach the environment.

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 2017 included $8 million in respect of provisions for new sites (2016 $7 million and 2015 $6 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 2017, the net decrease in the decommissioning provision, similar to the decrease in 2016, was a result of detailed reviews of expected future costs, partially offset by increases to the asset base.

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 21.

Environmental expenditure relating to the Gulf of Mexico oil spill

For full details of all environmental activities in relation to the Gulf of Mexico oil spill, see Financial statements – Note 2.

Regulation of the group's business

BP's activities, including its oil and gas exploration and production, pipelines and transportation, refining and marketing, petrochemicals production, trading, biofuels, wind and shipping activities, are conducted in 70 countries and are subject to a broad range of EU, US, international, 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.

Upstream contractual and regulatory framework

The terms and conditions of the leases, licences and contracts under which our 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 the US government can be by lease. Arrangements with private property owners are usually in the form of leases.

Licences (or concessions) give the holder the right to explore for and exploit 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. Less typically, BP may explore for and exploit 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.

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.

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.

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 or licence 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 where it has exploration and production activities.

Frequently, work (including drilling and related activities) will be contracted out to third-party service providers who have the relevant expertise and equipment not available within the joint arrangement or the co-owning operator's organization. The relevant contract will specify the work to be done and the remuneration to be paid and will typically set out how major risks will be allocated between the joint arrangement or co-ownership and the service provider. Generally, the joint arrangement or co-owner and the contractor would respectively allocate responsibility for and provide reciprocal indemnities to each other for harm caused to and by their respective staff and property. Depending on the service to be provided, an oil and gas industry service 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 agreement came into force on 4 November 2016. For the first time this agreement applies to all countries, both developing and developed, although in some instances allowances or flexibilities are provided for developing nations. The Paris Agreement aims to hold global average temperature rise to well below 2°C above pre-industrial levels and to pursue efforts to limit temperature rise 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 over time towards them. 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. In the decision adopting the Paris Agreement, an earlier commitment by developed countries to mobilize $100 billion a year by 2020 was extended through 2025,

with a further goal with a floor of $100 billion to be set before 2025. On 1 June 2017, the US announced that it will withdraw from the Paris Agreement. This includes suspending the implementation of the US's NDC and funding for the Green Climate Fund. The process for withdrawal can be completed no earlier than 4 November 2020.

The United Nations climate change conference in Marrakech (COP22), held in November 2016, agreed a deadline of 2018 for countries to agree on the guidelines and rules that are needed to support implementation of the Paris

Agreement. At COP23, held in November 2017 in Bonn, the parties met to continue the negotiations; amongst other things, the parties agreed to launch the 2018 Talanoa Dialogue to review collective efforts in relation to progress towards the Paris Agreement objectives and to inform the preparation of NDCs, and to convene stocktakes on pre-2020 implementation and ambition at COP24 and 25.

More stringent national and regional measures relating to the transition to a lower carbon economy 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, the Obama administration adopted its Climate Action Plan in 2013 and had been using existing statutory authority to implement that plan, including the Clean Air Act (CAA) and the Mineral Leasing Act (MLA). On 28 March 2017 the Trump administration issued Executive Order (EO) 13783 rescinding major elements of the Climate Action Plan, and instructing the Environmental Protection Agency (EPA) to review and then commence the process of suspending, revising or rescinding certain regulations, including the Clean Power Plan and the EPA new source methane rule. EO 13783 also instructed the Department of Interior (DOI) to review and possibly suspend, revise or rescind the Bureau of Land Management (BLM) methane rule. The EPA and the DOI are taking steps to implement these aspects of EO 13783 and legal challenges have been brought by some US states and private parties regarding these proposed changes.

- Greenhouse gas (GHG) emissions are currently regulated in a number of ways under the CAA. As noted above, as a result of EO 13783, some of these regulations may be suspended, revised or rescinded resulting in complex compliance challenges for our affected businesses.
- Stricter GHG regulations, stricter limits on sulphur in fuels, emissions regulations in the refinery sector and a revised lower ambient air quality standard for ozone, finalized by the EPA in October 2015, are affecting our US operations.
- EPA regulations aimed at methane emissions are in place for new and modified sources and the BLM has issued methane regulations for existing sites located on federal lands. The Trump administration is seeking to rescind both of these rules but the timing of any rescission is subject to legal challenges and regulatory requirements.
- It is possible that EPA will be required by statute to propose regulations on existing sources of methane from onshore oil and natural gas sector activities, unless the EPA new source methane rule is revised or rescinded.
- States may also have separate, stricter air emission laws in addition to the CAA. Despite the US withdrawal from the Paris Agreement, a number of US states, cities and private organizations remain committed to meeting Paris Agreement goals. A number of states also belong to or are considering joining carbon trading markets (e.g. California).
- The Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007 impose a renewable fuel mandate (the federal Renewable Fuel Standard) as well as state initiatives that impose low GHG emissions thresholds for transportation fuels (currently

adopted in California, through the California Low Carbon Fuel Standard and Oregon).

- EPA regulations impose light, medium and heavy duty vehicle emissions standards for GHGs and permitting requirements for certain large GHG stationary emission sources. California and a number of other states impose different, stricter GHG emission limits on vehicles. These varying standards impact BP's product mix and overall demand.
- Under the GHG mandatory reporting rule (GHGMRR), annual reports on GHG emissions must be filed. 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.
- On 9 October 2017 the EPA announced its intention to repeal the Clean Power Plan (CPP) which was an important element of the Obama administration's Climate Action Plan. The CCP regulations are currently stayed pending resolution of existing legal challenges; the EPA may decline to defend certain of these legal challenges. The EPA's repeal proposal is likely to face legal challenges as well and repeal of the CPP regulations, or adoption of a narrower replacement rule, may not occur until well after 2018. The outcome with respect to these rules will 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.
- In June 2016 the EPA finalized rules 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 that would apply to existing sources in the sector. In January 2017 the BLM's methane rule, aimed at limiting methane emissions from oil and gas operations on federal lands also came into effect. Following the Trump administration's EO 13783, on 16 June 2017 the EPA proposed a two-year stay of portions of the methane regulations for new and modified oil and gas sources. In December 2017, the BLM proposed a 13 month delay of its methane rule. In February 2018, a federal court in California ruled against that 13 month delay. Also in February 2018, the BLM proposed to revise its methane rule. The final outcome of the rule revisions and legal challenges with respect to implementation of EO 13783 regarding these EPA and BLM rules is uncertain, but may affect our US upstream businesses' management of methane emissions in the US.
- A number of states, municipalities and regional organizations have responded to current and proposed federal changes in environmental regulation and a number of additional state and regional initiatives in the US will affect our operations. The California cap and trade programme started in January 2012 and expanded to cover emissions from transportation fuels in 2015, and the State of Washington adopted a carbon cap rule in 2017.

European Union

- The EU has agreed to an overall GHG reduction target of 20% by 2020. To meet this, a 'Climate and Energy Package' of regulatory measures was adopted that includes: a collective national reduction target for emissions not covered by the EU Emissions Trading System (EU ETS) Directive; binding national renewable energy targets to double usage of renewable energy sources in the EU, including at least a 10% share of renewable energy in the transport sector under the Renewable Energy Directive (a revision to which was proposed by the European Commission in November 2016); a legal framework to promote carbon capture and storage (CCS); and a revised EU ETS Phase 3. EU ETS revisions included a GHG reduction of 21% from 2005 levels; a significant increase in allowance auctioning; an expansion in the scope of the EU ETS to encompass more industrial sectors (including the petrochemicals sector) and gases; no free allocation for electricity generation (including that which is self-generated off-shore) or production, but sector benchmarked free allocation for all other installations, with sharply declining allocation for sectors deemed not exposed to carbon leakage. EU ETS revisions also included the adoption of a Market Stability Reserve to adjust the supply of auctioned allowances. This will take effect in 2019 and could potentially lead

to higher carbon costs. EU Energy efficiency policy is currently implemented via national energy efficiency action plans and the Energy Efficiency Directive adopted in 2012.

- 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.
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In October 2014 the EU also agreed to the 2030 Climate and Energy Policy framework with a goal of at least a 40% reduction in GHGs from 1990 and measures to achieve a 27% share of renewable energy and a 27% increase in energy efficiency. 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. While the European Commission has made legislative proposals, including proposed amended targets, specific EU legislation and agreements required to achieve these goals are still under discussion in the European Council and European Parliament.

- European regulations also establish passenger car performance standards for CO_2 tailpipe emissions (European Regulation (EC) No 443/2009). By 2021, the European passenger fleet emissions target for new vehicles will be 95 grams of CO_2 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 CO_2 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 CO_2 per kilometre, which is 19% below the 2012 fleet average.
- In addition, the Energy Efficiency Directive (EED), Industrial Emissions Directive (IED) 2010, Medium Combustion Plants Directive (MCPD) 2015 and EU regulation on ozone depleting substances 2009 (ODS Regulation) referenced below under ‘Other environmental regulation’ will also directly or indirectly require reductions in GHG emissions.

Other

- Canada’s highest emitting province, Alberta, has regulations targeting large final emitters (sites with over 100,000 tonnes of carbon dioxide equivalent per annum) with intensity targets of 2% improvement per year up to 20%. Compliance is possible via direct reductions, the purchase of offsets or the payment of C$30/tonne to a technology fund. In addition, the Alberta government implemented an economy-wide price of carbon policy that covers emissions not in the scope of the existing regulations for large final emitters (C$20/tonne in 2017; C$30/tonne in 2018 then escalating in line with Federal backstop pricing). Changes were also made to electricity generation sources, limits on overall oil sands emissions, and sector specific output-based-allocations (performance standards) have been set such that compliance requirements will now be based on emission intensity relative to top quartile performance in each sector. Compliance obligations, if required, can be satisfied through emission reductions, payments to the government or use of offsets. The Canadian federal government has announced climate change policy goals including a national backstop carbon price starting at C$10/tonne in 2018 and escalating to C$50/tonne by 2022 (or equivalent system for provinces with cap-and-trade systems), with implementation of the price and associated large emitters pricing system (modelled on the Alberta output-based-allocation system), use of any funds generated and outcome reporting being managed by each province.
- China is operating emission trading pilot programmes in five cities and two provinces and some selected non-pilot provinces have also been approved to engage in emission trading. One of BP's subsidiaries and one of BP’s joint venture« companies in China are participating in these schemes. A plan on establishing the nationwide carbon emissions trading market (covering power sector only) was promulgated in December 2017 by the National Development and Reform Commission, which will not supersede the above seven pilot programmes immediately but allow those pilot schemes to be incorporated into the national scheme gradually. In July 2016, China carried out pilot programmes on

compensation for and trading of energy quotas in four provinces which may be further expanded in or after 2020. In January 2017, a nationwide pilot scheme on the issuance and voluntary purchase and trading of renewable energy green power certificates was launched and it is expected that the evaluation on renewable energy power quotas and mandatory trading of green power certificates will be launched in 2018.

- 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 will accelerate 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 – Climate change on page 50.

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.

There are also environmental laws that 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 21 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 265.

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 includes the following:

United States

- Since taking office in January 2017, the Trump administration has issued a number of Executive Orders (EO) intended to reform the federal permitting and rulemaking processes to reduce regulatory burdens placed on manufacturing generally and the energy industry specifically. These EOs immediately rescind certain policies and procedures and order the commencement of a broad process to identify other actions that may be taken to further reduce these regulatory requirements. 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.
- The National Environmental Policy Act (NEPA) requires that the federal government gives proper consideration to the environment 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 projects. State law analogues to NEPA could also limit or delay our projects. On 15 August 2017 the Trump administration issued EO 13807 which directs federal agencies to take certain actions to

streamline the NEPA process although the effect of EO 13807 on our operations remains uncertain.

- The CAA regulates air emissions, permitting, fuel specifications and other aspects of our production, distribution and marketing activities.
- The Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007 affect our US fuel markets by, among other things, imposing the limitations discussed above under 'Greenhouse gas regulation'. California also imposes Low Emission Vehicle (LEV) and Zero Emission Vehicle (ZEV) standards on vehicle manufacturers. These regulations will have an impact on fuel demand and product mix in California and those states adopting LEV and

ZEV standards. The EPA is currently reassessing the Obama Administration's mid-term evaluation (MTE) of the 2022-25 automobile fuel economy (CAFE) standards. A reassessment of the standards could change original equipment manufacturer (OEM) compliance plans and consequently motor fuel demand. The EPA is expected to complete its assessment in April 2018.

- 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 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 under other federal and state laws, and to claims for natural resource damages under CERCLA, the Oil Pollution Act of 1990 (OPA 90) (discussed below) and other federal and state laws. CERCLA also requires notification of releases of hazardous substances to national, state and local government agencies, as applicable. In addition, the Emergency Planning and Community Right-to-Know Act requires notification of releases of designated quantities of certain listed hazardous substances to state and local government agencies, as applicable.
- The Toxic Substances Control Act (TSCA) regulates BP's manufacture, import, export, sale and use of chemical substances and products. In June 2016, the US enacted legislation to modernize and reform TSCA. The EPA has promulgated rules, processes and guidance to implement the reforms. Key components of the reform legislation include: (1) a reset of the TSCA chemical inventory, (2) new chemical management prioritization efforts expanding risk assessment and risk management practices, (3) new confidentiality provisions, and (4) new authority for the EPA to impose a fee structure. In 2017, the EPA finalized details regarding the process and requirements for execution of the TSCA inventory reset. BP is currently collecting the requisite information for submission to the EPA to assure that the chemical substances that are: (i) contained in our manufactured or imported products; (ii) used to manufacture our products; and (iii) used in our operations, continue to be included in the US TSCA inventory.
- The Occupational Safety and Health Act imposes workplace safety and health requirements on BP operations along with significant process safety management obligations, requiring continuous evaluation and improvement of operational practices to enhance safety and reduce workplace emissions at gas processing, refining and other regulated facilities. In 2016 the Obama administration announced that the US Occupational Safety and Health Administration (OSHA) would implement a 'National Emphasis Program' set of inspections aimed at refineries and petrochemical facilities. The Trump administration has not made any announcement regarding its intentions for this program.
- The US Department of Transportation (DOT) regulates the transport of BP's petroleum products such as crude oil, gasoline, petrochemicals and other hydrocarbon liquids.

- The Maritime Transportation Security Act and the DOT Hazardous Materials (HAZMAT) regulations impose security compliance regulations on certain BP facilities.
- OPA 90 is implemented through regulations issued by the EPA, the US Coast Guard, the DOT, the OSHA, the Bureau of Safety and Environmental Enforcement and various states. 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 on offshore and onshore operations on federal lands subject to DOI authority. New stricter regulations on operational practices, equipment and testing have been imposed on our operations in the Gulf of Mexico and elsewhere following the Deepwater Horizon oil spill.
- The Endangered Species Act and Marine Mammal Protection Act protect certain species from adverse human impacts. The species and their habitat may be protected thereby restricting operations or development at certain times and in certain places. With an increasing number of species being protected, we have increasing restrictions on our activities.

European Union

- The Energy Efficiency Directive (EED) was adopted in 2012. It requires EU member states to implement an indicative 2020 energy saving target and apply a framework of measures as part of a national energy efficiency programme, including mandatory energy efficiency audits. This directive has been implemented in the UK by the Energy Savings Opportunity Scheme Regulations 2014, which affects our offshore and onshore assets. The ISO50001 standard is being implemented by organizations in some EU states to meet some elements of the EED. A revision to the EED was proposed by the European Commission in November 2016, which includes a new energy efficiency target for 2030.
- 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, such as the BAT Conclusions for the refining sector, for large combustion plants as well as common waste water and waste gas treatment and management systems in the chemical sector. These may result in requirements for BP to further reduce its emissions, particularly its air and water emissions.
- The Medium Combustion Plants Directive (MCPD) came into force on 18 December 2015, with a deadline for implementation by member states of 19 December 2017. It applies to air emissions of sulphur dioxide (SO_2), nitrogen oxides (NOx) and particulates from the combustion of fuels in plants with a rated thermal input between one and 50MW. It also includes requirements to monitor emissions of carbon monoxide (CO) from such plant. Its requirements will be phased in – the emission limit values set in the Directive will apply from 20 December 2018 for new plants and by 2025 or 2030 for existing plants, depending on their size.
- The National Emission Ceiling Directive 2016 entered into force on 31 December 2016, replacing earlier legislation. It introduces stricter emissions limits from 2020 and 2030, with new indicative national targets applying from 2025. The new Directive must be implemented by EU member states by 1 July 2018.
- The EU regulation on ozone depleting substances 2009 (ODS Regulation) requires BP 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) will come into force from 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.
- 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. Since coming into force in 2007, REACH implementation has followed a phase-in schedule defined by the EU. The final phase-in implementation deadline requires registration of substances manufactured or imported in the tonnage-band of 1-100 tonnes per annum per legal entity by 31 May 2018. BP is in the process of preparing and submitting registration dossiers to meet this final REACH implementation milestone. For higher tonnage-band substances (i.e. 100 tonnes per annum or greater), 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 have undergone REACH compliance inspections by the competent authority for the respective EU member state.

- 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 ongoing implementation of the WFD and the related Environmental Quality Standards Directive 2008 as well as the planned review of the WFD in 2019 is likely to require additional compliance efforts and increased costs for managing freshwater withdrawals and discharges from BP's EU operations.

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 (superseded ED 12/05 on 1 January 2016).

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. It 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 2017, as the required minimum number of contracting states had not been achieved, the HNS Convention had not entered into force.
- A global sulphur cap of 0.5% will apply to marine fuel from January 2020 under MARPOL. In order to comply, ships will either need to

consume low sulphur marine fuels or implement approved abatement technology to enable them to meet the low sulphur emissions requirements whilst 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.

- Ships are required to have ballast water treatment systems in place within the time frame prescribed by the International Convention for the Control and Management of Ships' Ballast Water and Sediments 2004, which entered into force in September 2017.
- The Convention for the Protection of the Marine Environment of the North-East Atlantic (OSPAR), entered into force in March 1998, is an international convention which aims to protect the marine environment of the North-East Atlantic. OSPAR has 16 contracting parties, including the UK Government. Work carried out in accordance with OSPAR is managed by the OSPAR Commission, which is made up of government representatives of the 15 contracting parties and the European Union. OSPAR Recommendation 2001/1 relates to the management of produced water from offshore installations in the North Sea. The OSPAR Commission has set a target of a 15% reduction in the total quantity of oil in produced water discharged, and more recently, guidelines for the implementation of a risk-based approach to the management of produced water discharges from offshore installations were adopted (OSPAR Recommendation 2012/5).
- The EU shipping monitoring, reporting and verification (MRV) regulation entered into force in July 2015 and is aimed at gathering data on CO_2 emissions based on ships' fuel consumption. It is considered the first step of a staged approach for the inclusion of maritime transport emissions in the EU's GHG reduction commitment. In parallel, through amendments to MARPOL Annex VI, the IMO Data Collection System (DCS) for collecting and analysing fuel consumption data is due to come into effect in March 2018.

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 (Macondo), where the semi-submersible rig Deepwater Horizon was deployed at the time of the 20 April 2010 explosions and fire and resulting oil spill (the Incide