BP PLC
Form 20-F
March 06, 2013
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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

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

For the fiscal year ended 31 December 2012

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)

Dr Brian Gilvary

BP p.l.c.

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United Kingdom

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(Name, Telephone, E-mail and/or Facsimile number and Address of Company Contact Person)

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 June 2013	**New York Stock Exchange**
Floating Rate Guaranteed Notes due December 2013	**New York Stock Exchange**
Floating Rate Guaranteed Notes due 2014	**New York Stock Exchange**
5.250% Guaranteed Notes due 2013	**New York Stock Exchange**
3.625% Guaranteed Notes due 2014	**New York Stock Exchange**
1.700% Guaranteed Notes due 2014	**New York Stock Exchange**
0.700% Guaranteed Notes due 2015	**New York Stock Exchange**
3.875% Guaranteed Notes due 2015	**New York Stock Exchange**
3.125% Guaranteed Notes due 2015	**New York Stock Exchange**
2.248% Guaranteed Notes due 2016	**New York Stock Exchange**
3.200% Guaranteed Notes due 2016	**New York Stock Exchange**
1.375% Guaranteed Notes due 2017	**New York Stock Exchange**
1.846% Guaranteed Notes due 2017	**New York Stock Exchange**
4.750% Guaranteed Notes due 2019	**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**
2.500% Guaranteed Notes due 2022	**New York Stock Exchange**
3.245% Guaranteed Notes due 2022	**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	19,135,751,315
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 þ

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 þ

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 þ 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 ¨

* This requirement does not apply to the registrant in respect of this filing.

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

Large accelerated filer þ Accelerated filer ¨ Non-accelerated filer ¨

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

International Financial Reporting

Standards as issued by the

U.S. GAAP ¨ International Accounting Standards Board þ 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 þ

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Annual Report and

Form 20-F 2012

bp.com/annualreport

Building a stronger,

safer BP

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BP in 2012

The group made good progress this year. We worked to enhance safety and risk management. We continued to meet our commitments in the Gulf of Mexico. We sold assets and reduced complexity. And we focused investment on areas where we see higher margins. Over the following pages, we report on the actions taken to build a stronger, safer BP.

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Information about this report

Frequent abbreviations

ADR

American depositary receipt.

ADS

American depositary share.

Barrel (bbl)

159 litres, 42 US gallons.

b/d

Barrels per day.

boe

Barrels of oil equivalent.

GAAP

Generally accepted accounting practice.

Gas

Natural gas.

This document constitutes the Annual Report and Accounts in accordance with UK requirements and the Annual Report on Form 20-F in accordance with the US Securities Exchange Act of 1934, for BP p.l.c. for the year ended 31 December 2012. A cross reference to Form 20-F requirements is on page 20F.

This document contains the Directors Report, including the Business Review and Management Report, on pages 3-126 and 147-175 and 178. The Directors Remuneration Report is on pages 127-145. The consolidated financial statements of the group are on pages 177-286 and the corresponding reports of the auditor are on pages 179-181.

BP Annual Report and Form 20-F 2012 and *BP Summary Review 2012* may be downloaded from *bp.com/annualreport*. No material on the BP website, other than the items identified as *BP Annual Report and Form 20-F 2012* or *BP Summary Review 2012,* forms any part of those documents.

BP p.l.c. is the parent company of the BP group of companies. The company was incorporated in 1909 in England and Wales and changed its name to BP p.l.c. in 2001. Where we refer to the company, we mean BP p.l.c. Unless otherwise stated, the text does not distinguish between the activities and operations of the parent company and those of its subsidiaries, and information in this document reflects 100% of the assets and operations of the company and its subsidiaries that were consolidated at the date or for the periods indicated, including minority interests. BP s primary share listing is the London Stock Exchange. Ordinary shares are also traded on the Frankfurt Stock Exchange in Germany and, in the US, the company s securities are traded on the New York Stock Exchange in the form of ADSs (see page 154 for more details).

The term shareholder in this report means, unless the context otherwise requires, investors in the equity capital of BP p.l.c., both direct and indirect. As BP shares, in the form of ADSs, are listed on the New York Stock Exchange (NYSE), an Annual Report on Form 20-F is filed with the US Securities and Exchange Commission (SEC). Ordinary shares are ordinary fully paid shares in BP p.l.c. of 25 cents each. Preference shares are cumulative first preference shares and cumulative second preference shares in BP p.l.c. of £1 each.

Hydrocarbons

Crude oil and natural gas.

IFRS

International Financial Reporting Standards.

Liquids

Crude oil, condensate and natural gas liquids.

LNG

Liquefied natural gas.

LPG

Liquefied petroleum gas.

mb/d

Thousand barrels per day.

mboe/d

Thousand barrels of oil equivalent per day.

mmboe

Million barrels of oil equivalent.

Trade marks of the BP group appear throughout this Annual Report and Form 20-F in italics.

They include:

ampm

Aral

ARCO

BP

BP Ultimate

Castrol

Castrol CRB

Castrol EDGE

Castrol Magnatec

Designer Water

Field of the Future

LoSal

Project *20K*

Pushing Reservoir Limits

Veba Combi-Cracking (VCC)

EcoBoost is a trade mark of Ford Motor Company.

SkyMine is a trade mark of Skyonic Corporation.

Permasense is a trade mark of Permasense Limited.

mmBtu

Million British thermal units.

MW

Megawatt.

NGLs

Natural gas liquids.

PSA

Production-sharing agreement.

RC

Replacement cost.

SEC

The United States Securities and Exchange Commission.

Tonne

2,204.6 pounds.

Registered office and our worldwide headquarters:

BP p.l.c.
1 St James s Square
London SW1Y 4PD
UK
Tel +44 (0)20 7496 4000

Registered in England and Wales No. 102498.

Stock exchange symbol BP .

Our agent in the US:

BP America Inc.
501 Westlake Park Boulevard
Houston, Texas 77079
US
Tel +1 281 366 2000

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Chairman s letter

10-year dividend history

UK (pence per ordinary share)

US (cents per ADS)

1 ADS represents six 25 cent ordinary shares.

Board performance

For information about the board and its committees see pages 101-126.

Dear fellow shareholder

In 2012 the board had three priorities. First, to address uncertainty from ongoing litigation in the US and our partnership in Russia. Second, to reinforce the strategic direction of the group. Third, to accelerate the company s momentum and build confidence. All of these were pursued in the context of the board s active monitoring of safety and risk management.

Substantial progress has been made in meeting these priorities. This progress gave the board confidence to raise the quarterly dividend by 14% in February 2012 and by 12.5% in October. The increased dividend represents an important milestone on the road to improved shareholder value. We are maintaining a progressive dividend policy, increasing returns to you, in line with financial performance and outlook.

The pursuit of energy will always involve risk, so it is essential that safety remains front of mind. From safe and reliable operations comes trust, and we need that trust if BP is to create value for you and to help meet the world s energy needs.

Looking ahead, your board sees strong prospects for BP in a world that requires a growing supply of energy. We are aware that we still have some way to go. We continue to face a number of uncertainties in the US, for example. The board thanks you for your continued patience and support as we work to address these issues.

In working to resolve uncertainty, two matters demanded the close attention of your board.

In the US, the company has faced legal proceedings related to the Deepwater Horizon accident. Our settlements with the US government, the Securities and Exchange Commission and others were each important steps forward in reducing uncertainty.

In Russia, the agreed sale of our 50% shareholding in TNK-BP to Rosneft, and the settlement with our partners, have brought clarity. The disposal agreement will provide us with an increased stake in Rosneft, such that on completion, BP will have a 19.75% share of the biggest publicly traded oil company in the world in terms of oil production and reserves. In due course BP expects to have two seats on its nine-person board. BP has worked with Rosneft for some 15 years. Our joint ambition is that BP s people, processes and technologies will help to significantly enhance Rosneft s value over time, as they did at TNK-BP.

During the year the board supported Bob Dudley, our group chief executive, on the implementation of the 10-point plan and the further implementation of the functional organization. We worked with him to develop the group strategy beyond 2014. Bob, the executive team and all our employees have made a huge contribution, working to reach our milestones and secure a promising future for the company during a tough period. Bob has shown steady and determined leadership through this time. I thank him and everyone at BP for their hard work.

The qualities of BP s employees were once again demonstrated in January 2013, following the violent attack at In Amenas in Algeria. This shocking event deeply affected us all, but across the company people responded with great resilience. We will always remember those who lost their lives in this terrible incident.

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Our strategy
For more on our strategic priorities and longer-term objectives see pages 20-21.

As 2012 progressed the board saw the company start to move forward with greater confidence. It is important that this momentum continues.

Our board committees have provided effective oversight of the company and its operations, which has enabled the board to focus on its three priorities. Outside the boardroom, our non-executive directors have continued to pay visits to key parts of the business. My own visits this year included Angola, Azerbaijan, the North Sea, Japan and the US.

Carl-Henric Svanberg at the Sangachal terminal control room during his three-day trip to Azerbaijan (top); Professor Dame Ann Dowling on the Thunder Horse platform in the Gulf of Mexico (middle); Brendan Nelson and Phuthuma Nhleko at BP s North America Gas operations in east Texas, US (bottom).

The board has seen substantial change. For this reason, we have asked Antony Burgmans to serve for a further three years. I am pleased that we will continue to benefit from his experience and understanding of the company. Byron Grote is retiring after 33 years with BP, including more than 12 years on the board. I thank him for his dedication and the exceptional contribution he has made to this company. As we move through 2013, the board is well balanced, with deep experience in our industry and a broad range of skills across business and finance.

We will refresh the board as and when required. I believe board diversity including the representation of women at the top helps to make boards more effective. We will continue to work to identify candidates from a range of backgrounds who can make a unique and powerful contribution to BP.

One of the vital tasks of the board is to ensure strategy is matched to the world we see ahead. Energy remains the engine of progress, and we expect rising populations and increasing industrialization to generate strong demand to 2030 and beyond. The world will continue to be dependent on fossil fuels in the medium term. Along with providing the hydrocarbons needed, we are also involved in developing the resources, technologies and policies required over the long term.

Our industry keeps evolving. In the past international oil companies dominated access to resources. Then national oil companies took control of the greater share. But much of the easiest-to-reach oil has been developed. So we are now entering a third era, where co-operation between partners is the key to unlocking the resources found in the most challenging locations. For BP, advantage now comes from exceptional capability rather than exceptional scale. Our future is about high-margin, high-quality production, not simply volume.

Oil will continue to be BP s prime focus, and we aim to extend our extraordinary track record in finding and developing new resources. We will keep making selective investments in natural gas, with an emphasis on assets that generate good margins. And we will be selective in the Downstream too, choosing to operate where our refining and marketing assets are connected to attractive markets.

Over the past three years BP has had to change. Through our reorganization, we are a simpler company. Through our asset sales, we are stronger financially. Through our actions, we have reduced complexity and risk. Our plans, priorities and direction are clear. I see great opportunities ahead, as we continue to build a stronger, safer BP that meets the expectations of our shareholders and the wider world.

Carl-Henric Svanberg

Chairman

6 March 2013

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Group chief executive s letter

Carl-Henric Svanberg and Bob Dudley with Igor Sechin, President of Rosneft, on the day the BP board approved the transaction.

Dear fellow shareholder

BP made important progress in 2012. We achieved a series of strategic milestones and remained on course with our plans to 2014 and beyond. We made great strides forward in Russia and the US. We continued to enhance risk management. We focused on our areas of greatest strength. And we sold assets to capture value, simplify the business and reduce risk.

Before I say more about our activities and plans, I would like to reflect, with great sadness, on the terrible events that took place at the In Amenas joint venture facility in Algeria in January 2013. Our thoughts are with the families and friends of those who lost their lives in the attack. We are working with government agencies and others to determine what can be learned from this shocking incident.

Coming back to our work over the past few years, people may not be fully aware of the enormous scale of the change we have made. By the end of 2012 we had announced asset sales of $38 billion, essentially reaching our target a year early. Since the divestment programme began, we have sold around half our upstream installations and pipelines, and one-third of our wells while retaining roughly 90% of our proved reserves base and production. Meanwhile, we are gaining new exploration access, rolling out high value projects and upgrading assets.

Our Downstream segment has had an excellent year with strong operational performance and record underlying profits.[a] We made good progress on the modernization programme of our Whiting refinery and reached agreement on the divestment of two major refineries in the US, completing the sale of our Texas City refinery in February 2013.

There is more to do and there will always be new challenges to face, but we are steadily acting to build a stronger, safer BP.

We are addressing uncertainty in the US

In 2012 we resolved federal criminal charges with the Department of Justice and securities claims with the SEC. We continue to work with the Environmental Protection Agency to resolve suspension and debarment issues.

We have consistently said we are willing to settle all outstanding claims on reasonable terms, but we are also prepared to defend the company and its actions in court. We will do what is in the best interests of our shareholders. I recognize that ongoing proceedings prolong uncertainty, so we will endeavour to update you as events unfold.

Back in 2010 we said that we would help restore the environment and economy of the Gulf. We are holding true to that promise. In 2012 we made our final payment into the $20-billion Trust fund, from which $9.5 billion has been distributed to date. We supported environmental research and provided funds for the local tourism industry. Having grown up in the Gulf, I am heartened that the tourists are back, beaches are busy and the fishing is good. To date, BP has made total payments directly related to the accident and oil spill of $32.8 billion. We will continue to meet our commitments in the region.

We are repositioning BP in Russia

In 2012 we agreed to sell our 50% shareholding in TNK-BP to Rosneft. TNK-BP proved to be an outstanding investment, generating substantial value for BP. From an initial commitment of around $8 billion, it has returned some $19 billion of dividends to us. But the time had come to move on.

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$19 billion

Dividends received by BP from TNK-BP since 2003.

The new agreement will provide us with an 18.5% share in Rosneft and $12.3 billion of cash, including a dividend of $0.7 billion received from TNK-BP in December 2012. Combined with our existing 1.25% shareholding, we will own 19.75% of Rosneft. We expect the transaction to be completed in the first half of 2013. Through it, we will maintain a strong position in the world s largest oil and gas producing country. And we will be a major investor in a company transforming its asset base, management processes and corporate governance.

The new US-based High-Performance Computing centre, which is currently under construction, will enable BP scientists to complete an imaging project in one day whereas it would have taken four years nearly a decade ago.

We will use our experience in large acquisitions and mergers to support Rosneft as it assimilates TNK-BP s assets. We can also contribute technical skills in areas from exploration and enhanced oil recovery to integrating downstream businesses and international developments. We have confidence in the Russian business environment and we look forward to playing a valued role in the country s future.

We are enhancing safety and risk management

Our employees have been working systematically to enhance safety and risk management. We have changed how we are organized, bringing greater clarity and consistency across the company. In the Gulf of Mexico and elsewhere, we are holding our operations to standards that in many cases go beyond regulatory requirements. And we have turned lessons learned from the 2010 accident into new oil spill response plans and technologies, which we are adopting within BP and sharing with others. I take encouragement from our 19% reduction in loss of primary containment this past year, continuing a multi-year trend.

2012 saw the appointment of Carl Sandlin, who will oversee the implementation of the recommendations of the Bly Report, BP s internal accident investigation. In addition, following our agreement with the US government to resolve all federal criminal claims, we have agreed to take additional actions designed to further enhance the safety of drilling operations in the Gulf. Two independent monitors will be appointed to review and provide recommendations, one regarding process safety for deepwater drilling in the Gulf and the other BP s code of conduct. An independent auditor will review and report on BP s implementation of key terms of the agreement.

We are building a distinctive platform for growth

In shaping our portfolio, we are prioritizing shareholder value. Scale remains important, but we are focused on driving forward our financial performance rather than simply growing production volumes. Operating cash flow and replacement

[a] Downstream underlying profit is not a recognized GAAP measure. See page 27 for the equivalent measure on an IFRS basis, which is replacement cost profit before interest and tax. See Certain definitions on page 98 for further information on underlying profit.

[b] See footnote e on page 21 for a definition of free cash flow.

cost profit will take precedence over barrels of production. We are increasing investment in the areas with the greatest potential to generate strong and reliable growth in operating cash flow, from exploration and deepwater operations to giant fields and gas value chains. In the Downstream, we have a portfolio of world-class businesses that are positioned to deliver material and growing free cash flows.[b]

There is plenty for us to explore. During the year we gained new access in six countries. Since 2010 we have accessed around 400,000 square kilometres of new acreage. That is roughly the size of California and more than double the exploration acreage gained from 2000 to 2009.

We continue to have an important presence in many of the world s largest economies and in fast-developing countries too. BP s global footprint and prudent financial approach are important given the potential for turbulence in the world, including further economic and political upheaval. We are well placed to respond to unsettled conditions if and when they appear.

Looking ahead

While facing uncertainties and navigating through testing times, BP emerged from 2012 a somewhat smaller, but stronger company. As we move forward, you will see us keep working to focus, standardize and improve what we do and how we do it. We are building a platform for growth that should serve us well for many years to come.

I want to end by paying tribute to everyone here at BP. This has been another truly demanding year, and our employees have dedicated themselves to their jobs in a way that I find humbling. I am proud of the talent and the terrific spirit of determination to improve that is found within BP. Over the next 12 months and beyond, we will continue our work to enhance safety, earn back trust and create value.

Bob Dudley

Group Chief Executive

6 March 2013

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Energy outlook

Looking ahead, we expect demand for energy to grow

and the challenges facing our industry to be met by a diverse mix

of fuels and technologies.

Our market in 2012

Crude oil and gas prices, and refining margins ($ per barrel of oil equivalent)

Source: Platts/BP.

*See Downstream on page 73 for further information on RMM.

World economic growth was weak in 2012 below its historic trend and we expect subdued global growth to continue in 2013. Emerging economies with stronger productivity and rising populations, led by China and India, are set to drive growth. Developed countries may lag as they continue to address internal fiscal imbalances.

Global demand for energy, including oil, continued to expand modestly in 2012, with a weak economy and high oil prices weighing on demand.

As a result, the growth in world oil consumption remained weak in 2012, with continued growth in China and other non-OECD countries offsetting yet another decline in OECD countries. With oil markets balancing lower production from certain countries against weak consumption and high OPEC production, average crude oil prices in 2012 were similar to the

Globally, refining margins improved on average as refinery closures and operational issues reduced product supply. Demand continues to grow in non-OECD countries but the weak financial environment in OECD countries has seen demand growth weaken.

Refining margins

For more information on the BP refining marker margin and other measures see page 73.

Concerns about the volatility of commodity and financial markets, energy security and climate change have led to continued debate over the appropriate role of markets, government regulation and other policy measures that affect the supply and consumption of energy. Given the pressures in the sector, we expect regulation and taxation of the previous year, averaging $111.67 per barrel.

energy industry and energy users to increase in many areas in the future.

Natural gas prices continued to diverge globally in 2012, with lower prices in the US and increases in Europe and the Far East.

Crude prices

For more information on crude oil and natural gas prices see page 64.

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The facts and figures used in this section are derived from *BP Energy Outlook 2030,* published in January 2013, unless otherwise indicated, and represent a base case or most likely projection.

For more information see

bp.com/energyoutlook

Energy consumption by region

(billion tonnes of oil equivalent)

Source: *BP Energy Outlook 2030.*

Energy consumption by fuel

(billion tonnes of oil equivalent)

*Includes biofuels.

Source: *BP Energy Outlook 2030.*

1.6% per annum

Projected world primary energy consumption growth to 2030.

Longer-term outlook

Challenges and opportunities

The world s population is projected to increase by 1.3 billion from 2011 to 2030, with real income likely to double over the same period. These factors will lead to increased energy demand and consumption. Energy and climate policies, efficiency gains and a long-term structural shift in fast-growing economies away from industry and towards less energy-intensive activities will help to restrain any increase, but the overall trend is likely to be one of strong growth. We expect demand for energy to increase by as much as 36% between 2011 and 2030, with nearly 93% of the growth to occur in non-OECD countries.

We estimate that there are enough energy resources available to meet the increases in demand in the foreseeable future, but there will be challenges as well as opportunities.

Energy security represents a challenge. More than 60% of the world s natural gas is concentrated in just four countries. More than 80% of global oil reserves are located in nine countries, most of which are well away from the hubs of energy consumption.

Meeting the energy challenge

We believe that, increasingly, the global energy challenge can only be met through a diverse mix of fuels and technologies. A broad mix can enhance national and global energy security while supporting the transition to a lower-carbon economy. This is one reason why BP s portfolio includes oil sands, shale gas, deepwater oil and natural gas production, biofuels and wind.

We estimate that today s oil reserves could meet more than 45 years of demand at current consumption rates, while known supplies of natural gas could meet demand for nearly 60 years and coal could meet demand for up to 120 years.[a]

Our industry has a track record in expanding the availability of resources through investment and the application of technology. For example, in 1981 the world s oil reserves stood at an estimated 700 billion barrels. By 2011 this had risen to 1,650 billion barrels, even though 800 billion barrels had been consumed in the intervening three decades.

Oil and natural gas

We believe oil and natural gas are likely to represent about 53% of total energy consumption in 2030. Even under the International Energy

Meeting growing demand for secure and sustainable energy will also present an affordability challenge as the availability of easily accessible fossil fuels slowly diminishes, with many lower-carbon resources and technologies remaining costly to produce at scale.

While energy is available to meet growing demand, action is needed to limit carbon dioxide (CO_2) and other greenhouse gases being emitted through fossil fuel use. Burning fossil fuels can also raise local and regional air quality issues.

Agency s (IEA) most ambitious climate policy scenario (the 450 scenario), oil and gas would still make up 50% of the energy mix in 2030, with combined demand projected to exceed current levels in absolute terms.[b] The 450 scenario assumes governments adopt commitments to limit the long-term concentration of greenhouse gases in the atmosphere to 450 parts-per-million of CO_2 equivalent.

[a] *BP Statistical Review of World Energy June 2012.* These reserve estimates are compiled from official sources and other third-party data, which may not be based on proved reserves as defined by SEC rules.

[b] From *World Energy Outlook 2012©,* OECD/IEA 2012, page 553.

In the US, our biofuels business is focusing on the development of cellulosic ethanol technology at facilities in San Diego, California (right) and Jennings, Louisiana.

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New sources of hydrocarbons are more difficult to reach, extract and process. This will require BP and others in our industry to develop new technologies to boost recovery from declining fields and commercialize currently inaccessible resources. Greater energy intensity could be required to extract these resources, which means operating costs and greenhouse gas emissions from operations are likely to increase.

Renewables

Renewable energy is the fastest growing fuel and is projected to grow by 7.6% per annum to 2030. Renewable energies are starting from a low base however, and we project that they are only likely to meet around 6% of total energy demand by 2030. With a few exceptions, renewables are not yet competitive with conventional power and transportation fuels. Sufficient policy support is required to help commercialize effective lower-carbon options and technologies, but renewables will ultimately need to become free from subsidy and commercially self-sustaining.

Energy efficiency and innovation

While overall energy consumption is set to increase, economic growth is expected to become significantly less energy intensive, especially in non-OECD economies. In fact, globally, demand for energy is expected to rise at less than half the rate of gross domestic product

Policy, prices and access

If the world s growing demand for energy is to be met in a sustainable way, we believe that governments must set a stable and enduring framework for the private sector to invest and for consumers to choose wisely. As part of this, governments will need to provide secure access for exploration and development of energy resources; define mutual benefits for resource owners and development partners; and establish and maintain an appropriate legal and regulatory environment.

We believe open and competitive markets are the most effective way to encourage companies to find, produce and distribute diverse forms of energy sustainably. The US experience with shale gas shows how an open and competitive environment can drive technological innovation and unlock resources. We also believe that putting a price on carbon one that treats all carbon equally, whether it comes out of an industrial smokestack or a car exhaust will make energy efficiency and conservation more attractive to businesses and individuals, and lower-carbon energy sources more cost competitive.

Beyond 2030

We expect that growing population and per capita incomes will continue to drive growing demand for energy. These dynamics will be shaped by

(GDP). The amount of energy required to generate $1 million in China has already dropped from 350 tonnes of oil equivalent in 1980 to 200 tonnes of oil equivalent or less today.

Innovation can play a key role in improving technology design, process and use of materials, bringing down cost and increasing efficiency. In transport, for example, we believe that efficient combustion engines and power train technologies could offer the quickest and most effective pathway to a secure, lower-carbon future.

future technology developments, changes in tastes, and future policy choices all of which are inherently uncertain. Concerns about energy security, affordability and environmental impacts are all likely to be important considerations. These factors may accelerate the trend towards more diverse sources of energy supply, a lower average carbon footprint, increased efficiency and demand management.

BP is sensitive to the challenges and opportunities outlined here. We actively monitor developments and continually assess a range of potential outcomes and their implications for our strategy.

93%

Non-OECD countries share of energy consumption growth to 2030.

+45%

Net growth in unconventional global energy production from 2020 to 2030.

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Our business model

Through our business model we aim to create value across the hydrocarbon value chain. This starts with exploration and ends with the supply of energy and other products fundamental to everyday life.

BP is the largest foreign investor in Azerbaijan and operates two production-sharing agreements Azeri-Chirag-Gunashli and Shah Deniz and other exploration leases. Above is the West Azeri platform.

Who we are

BP is one of the world s leading integrated oil and gas companies.[a] We aim to create value for shareholders by helping to meet growing demand for energy in a responsible way. We strive to be a safety leader in our industry, a world-class operator, a responsible corporate citizen and a good employer.

Through our work we provide customers with fuel for transportation, energy for heat and light, lubricants to keep engines moving, and the petrochemicals products used to make everyday items as diverse as paints, clothes and packaging. Our projects and operations help to generate employment, investment and tax revenues in countries and communities around the world.

At each stage of the hydrocarbon value chain there are opportunities for us to create value both through the successful execution of activities

We also hold a 50% shareholding in the major Russian oil company TNK-BP, which owns upstream and downstream assets. In November, marking what we expect to be an exciting new future for BP in Russia, we signed final, binding agreements with Rosneft, Russia s leading oil company, for the sale of our share in TNK-BP for $12.3 billion in cash (which includes a dividend of $0.7 billion received from TNK-BP in December 2012) and an 18.5% stake in Rosneft. The transaction is expected to complete in the first half of 2013. Combined with BP s existing 1.25% shareholding, this will result in BP owning 19.75% of Rosneft.

In renewable energy, our investments and activities are focused on biofuels and wind. In addition, our emerging businesses and ventures unit invests in a broad range of energy projects and technologies. Our renewables and venturing activities are managed through our Alternative Energy business, which is reported in Other businesses and corporate on page 82.

that are core to our industry, and through the application of our own distinctive strengths and capabilities in performing those activities.

How we are organized

We have two main business segments: Upstream and Downstream. Through these we find, develop and produce essential sources of energy, and turn these sources into products that people need.

[a] On the basis of market capitalization, proved reserves and production.

Our commitments

Keeping a relentless focus on safety is the top priority for everyone at BP.

Rigorous management of risk helps to protect the people at the front line, the places in which we operate and the value we create. We understand that operating in politically complex regions and technically demanding geographies requires particular sensitivity to local environments.

Our business model continued

The relationships we form with shareholders, governments, regulators, non-governmental organizations, local communities, customers, franchisees, partners, contractors, suppliers and others in our industry are crucial to the success of our business. We are committed to building long-lasting relationships, meeting our obligations and acting responsibly.

We believe that the best way to achieve sustainable success as a group is to act in the long-term interests of our shareholders, our partners and society. Through our work we aim to create value for our investors and benefits for the communities and societies in which we operate, with the safe and responsible supply of energy playing a vital role in economic development.

Our people

We employ nearly 86,000 people, including 14,700 service station staff in Europe and Asia. The majority of our employees are located in the US and Europe. The qualities and abilities of our employees have a powerful effect on our ability to compete and meet our commitments to investors and the wider world. We provide a range of professional development programmes and training to help our employees develop their skills and capabilities. We are committed to creating an inclusive work environment where everyone is treated fairly, with

Our presence

As a global group, our interests and activities are held or operated through subsidiaries, branches, joint ventures or associates established in and subject to the laws and regulations of many different jurisdictions. Our worldwide headquarters is in London. The UK is a centre for trading, legal, finance and other business functions as well as three of BP s major global research and technology groups. We have well-established operations in Europe, the US, Canada, Russia, South America, Australasia, Asia and parts of Africa. BP has freehold and leasehold interests in real estate in numerous countries, but no individual property is significant to the group as a whole. For more on the significant subsidiaries of the group at 31 December 2012 and the group percentage of ordinary share capital see Note 45 on page 255. For information on significant jointly controlled entities and associates of the group, see Notes 24 and 25 on pages 218-220.

Value creation

We seek to add value at each stage of our operations, from exploration to marketing. We believe that by operating across the full hydrocarbon value chain we can create more value for shareholders, as benefits and costs can often be shared by our segments. Integration also enables us to develop shared dignity, respect and without discrimination.

functional excellence in areas such as safety and operational risk, environmental and social practices, procurement, technology and treasury management more efficiently.

Our employees

For more on BP s employees in 2012

see pages 55-56.

Our business model

For more information see BP at a glance on pages 4-5.

We aim to protect value by maintaining a rigorous focus on safety, reliability and efficiency across our range of activities. We often work with partners to mitigate risk or gain from complementary skills.

Finding oil and gas

First, we acquire the rights to explore for oil and gas. Through new access we are able to renew our portfolio, discover new resources and replenish our development options.

Developing and extracting oil and gas

When we are successful in finding hydrocarbon resources, we create value by seeking to progress them into proved reserves or by selling them on if they do not fit with our strategic objectives.

If we believe developing and producing the reserves will be advantageous for BP, we will produce the oil and gas, then sell it to the market or distribute it to our downstream facilities.

Transporting and trading oil and gas

Our distinctive strengths and capabilities

We consider our areas of distinctive strength to include:

Exploration acquiring access and searching for hydrocarbons.

Deep water we have a long track record in finding, developing and producing hydrocarbons in deep water.

Giant fields managing the scale and complexity of fields with resources believed to exceed 500 million boe.[a]

Gas value chains seeking to add value as gas moves from field to customer.

Downstream the pursuit of safe, reliable and efficient operations, and leading returns, across fuels, lubricants and petrochemicals.

These are underpinned by our development and application of technology and our ability to build strong relationships. In addition, we have a long-established integrated supply and trading function.

Strong relationships

We move oil and gas through pipelines and by ship, truck and rail. We use our trading and supply skills and knowledge to find the best routes to deliver supplies to the most attractive markets.

Manufacturing and marketing fuels and products

Using our technology and expertise, we manufacture fuels and products, creating value by seeking to operate a high-quality portfolio of well-located assets safely, reliably and efficiently. We market our products to consumers and other end-users and add value through the strength of our brands.

We are seeing an evolution in our industry, with international oil companies such as BP establishing new kinds of partnerships and co-operation with governments, national oil companies and other resource holders. The benefits of our value-creating activity are shared with governments and other partners.

We seek opportunities to develop and deploy distinctive capabilities that complement those of our partners. We also partner with universities and governments in pursuit of improving the technologies available to us, so we can enhance our operations and develop new products. We aim to support and improve standards in our

[a] Actual amount of proved reserves of such fields on a basis recognized by the SEC may be less than this.

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Upstream technology flagships

Technology

For more on the role of technology at BP

see pages 57-59.

Upstream

For more on our upstream activities in 2012

see pages 63-71.

We increased our acreage in Trinidad & Tobago, where our production comprises oil, gas and NGLs, by 889,000 acres in 2012. Below is the Rowan drilling platform, offshore Trinidad.

industry by participating in industry bodies, engaging with our peers on important issues, and where appropriate setting voluntary standards above those required by current regulation. And we carry out regular reviews and audit processes with contractors and suppliers, which help to maintain strong links across our operations and activities.

Technology

We believe our development and application of technology is central to our reputation and competitive advantage. For us, technology is the practical application of scientific knowledge to manage risks, capture business value and inform strategy development. This includes the research, development, demonstration and acquisition of new technical capabilities and support for the deployment of BP s know-how.

Our investments are focused on access to resources, process efficiency, product formulation and lower-carbon opportunities. We monitor the potential opportunities and risks presented by emerging science, interdisciplinary innovation and new players; natural resource issues and climate concerns; and evolving policy, including the

Upstream

Our Upstream segment is responsible for our activities in oil and natural gas exploration, field development and production, and midstream transportation, storage and processing. We also market and trade natural gas, including liquefied natural gas, power and natural gas liquids. We focus on areas that play to our strengths, particularly exploration, deep water, gas value chains and giant fields.

In 2012 our upstream and midstream activities took place in 28 countries including Angola, Azerbaijan, Canada, Egypt, Norway, Trinidad & Tobago, the UK, the US and other locations within Asia, Australasia, South America, North Africa and the Middle East.

Our Upstream segment manages its exploration, development and production activities through global functions with specialist areas of expertise.

We actively manage our portfolio and are placing increasing emphasis on accessing, developing and producing from fields able to current emphasis on energy security and efficiency.

BP s technology advisory council, comprised of eminent business and academic technology leaders, provides the board and executive management with an independent view of BP s capabilities judged against the highest industrial and scientific standards.

Supply and trading

We buy and sell at each stage in the value chain to optimize value for the group, often selling our own production and buying from elsewhere to satisfy demand from our refineries and customers. We also aim to create value through entrepreneurial trading, where our presence across major energy trading hubs gives us a good understanding of regional and international markets.

provide high-margin barrels (those with the potential to make the greatest contribution to our operating cash flow). We sell assets when we believe they may be more valuable to others. This allows us to focus our leadership, technical resources and organizational capability on the resources we believe are likely to add the most value to our portfolio.

Our upstream technologies support BP s business strategy by focusing on safety and operational risks, helping to obtain new access, increasing recovery and reserves and improving production efficiency. Our strengths in exploration, deep water, giant fields and gas value chains are underpinned by dedicated flagship technology programmes.

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Downstream technology

Downstream

For more on our downstream activities

in 2012 see pages 72-79.

The lubricants business is focusing on the growth markets of Brazil, India and China. Below, a Castrol laboratory technician in Brazil, where *Castrol* lubricants have been sold since the 1950s.

Downstream

Our Downstream segment is the product and service-led arm of BP, focused on fuels, lubricants and petrochemicals. It is responsible for the refining, manufacturing, marketing, transportation, and supply and trading of crude oil, petroleum, petrochemicals products and related services to wholesale and retail customers.

The Downstream segment markets products in over 70 countries and has significant operations in Europe, North America, Australasia and Asia. We also manufacture and market our products across southern Africa and Central and South America.

We aim to be excellent in the markets in which we choose to participate those that allow BP to serve the major energy markets of the world. Our aim is to operate all of our businesses as safe and reliable value chains, where we participate in multiple stages of each supply chain, as we believe that way we can deliver greater returns than would arise from owning a collection of discrete assets. These value chains, combined co-engineered with Ford during the development of its newly released EcoBoost engine, which offers a significant improvement in efficiency.

The segment comprises three businesses: fuels, lubricants and petrochemicals, each of which operates as a value chain.

Our fuels business sells refined petroleum products including gasoline, diesel and aviation fuel and liquefied petroleum gas. Within the fuels business, fuels value chains integrate the activities of refining, logistics, marketing, and supply and trading on a regional basis. This provides the opportunity to optimize our activities from crude oil purchases to end-consumer sales all the way through our refineries, terminals, pipelines and retail stations.

Our lubricants business is involved in manufacturing and marketing lubricants and related services to markets around the world. We add value through the strength of our brands and through strategic collaboration with original equipment manufacturing partners where we seek to develop new with our advantaged manufacturing operations and expertise in technology, allow us to pursue competitive returns and sustainable growth, as we serve customers and promote BP and our brands through high quality products. As in our Upstream segment, we will sell assets when we believe that to do so would generate more value than retaining them in our own portfolio.

Technology makes a critical contribution to our downstream activities. Through the research, development and deployment of a wide range of technologies, processes and techniques, we aim to enhance safety and risk management, improve our margins, increase efficiency and reliability, and create new market opportunities. For example, in lubricants we launched an oil high-performance lubricants such as *Castrol EDGE.*

Our global petrochemicals business manufactures and markets petrochemicals that are used in many everyday products, such as paints, plastic bottles and textiles. Value is derived from our strong customer relationships and joint-venture partners, and through the application of our world-class, proprietary technology.

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Our strategy

Through our strategy we aim to create a distinctive platform for value growth over the long term.

Our seismic technology helps minimize field appraisal and development risk. The above model of a hydrocarbon field in the Gulf of Mexico shows large salt deposits obscuring a hydrocarbon reservoir.

Upstream portfolio simplification

We have divested a significant proportion of our operated assets while still retaining virtually all our future major projects[a] and around 90% of our proved reserves.

[a] See pages 67-71 for information on our major Upstream projects.

[b] Since April 2010.

In 2011 we put forward a 10-point plan that outlined what could be expected from BP over the next three years. During 2012 we worked towards the milestones we had set out for 2014. We refined our plans and communicated further information on our longer-term strategic objectives beyond 2014.

Through this work and the actions taken to strengthen the group, BP enters 2013 a more focused oil and gas company with promising opportunities and a clear plan for the future. BP s strengthened position, distinctive capabilities, strong financial framework and vision for the future provide the foundation for our long-term strategy. This strategy is intended to ensure BP is well positioned for the world we see ahead.

Our financial framework

We expect our organic capital expenditure[a] to be in the range of $24-27 billion per year through to the end of the decade, with investment

Our strategic priorities

Our aim is to be an oil and gas company that grows over the long term. We will seek to continually enhance safety and risk management, earn and keep people s trust, and create value for shareholders. We will continue to simplify our organization and fine tune the portfolio. We will focus on efficient execution in our operations and our use of capital. We will build capability through the pursuit of greater standardization and increased functional expertise.

BP Energy Outlook 2030 projects that world demand for energy will continue to grow. In helping to meet this demand, BP has a large suite of opportunities the legacy of years of success in gaining access to and developing resources. This allows us to select and invest in those projects with the potential to provide the highest returns. We will prioritize value rather than seek to grow production volume for its own sake. We will concentrate on higher quality assets in both our Upstream and Downstream segments, starting prioritized towards the Upstream segment. All investments will continue to be subject to a rigorous capital allocation review process.

We expect to make around $2-3 billion of divestments per year in order to constantly optimize our portfolio. We will target gearing[b] in the 10-20% range while uncertainties remain. Our intention is to increase shareholder distributions in line with BP s improving circumstances.

with safety and the delivery of strong and growing cash flows to the group.

[a] Organic capital expenditure excludes acquisitions and asset exchanges.

[b] See footnote d on page 21.

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The Skarv floating production, storage and offloading unit one of the major project start-ups in 2012 on tow in a Norwegian fjord.

10-point plan

Launched in October 2011 and set out in *BP Annual Report and Form 20-F 2011*, our 10-point plan described our intentions for building a stronger, safer BP.

What you can expect

1 A relentless focus on safety and managing risk through the systematic application of global standards.

2 We will play to our strengths in exploration, deep water, giant fields and gas value chains.

3 Stronger and more focused with an asset base that is high graded and higher performing.

4 Simpler and more standardized with fewer assets and operations in fewer countries; more streamlined internal reward and performance management processes.

We will pursue new opportunities by applying our distinctive strengths of relationships, technology and a strong balance sheet. Our past experience of co-ordinating complex projects around the world can help us to gain access to new areas.

Business model

For more information on our distinctive strengths and how we create value see pages 15-19.

Upstream

Our analysis indicates that oil offers us the most attractive opportunities. Our investments will therefore be biased to oil. We also believe there will be opportunities to create high returns from advantaged gas assets.

We have a long track record of value creation through **exploration.** We will invest in our strong incumbent positions and look for new opportunities. **Deepwater** developments can provide good opportunities for companies with the requisite expertise. We will utilize our scale and capability as we invest further in this area. We believe we are able to manage scale and complexity, and improve the conventional and unconventional resources. We expect to continue to invest in **giant fields**, where this expertise is particularly valuable.

We believe our ability to integrate complex **gas value chains** is another key strength. We intend to hold a portfolio of gas positions selected according to expected returns, with a balance across conventional and unconventional gas. We will optimize these through our trading activities.

We are committed to Russia and the Middle East areas where we have a long history.

Downstream

We believe BP has world-class downstream operations with a strong and improving track record of performance in recent years. We will continue to focus on safe and reliable operations and excellent execution, together with disciplined investment and portfolio management. Our focus on portfolio quality will include improving the margin capability of all of our businesses, and a focus on investing in attractive markets.

As the world changes, we expect to increase our exposure to growth markets and demand from new consumers.

5 Improved transparency through reporting TNK-BP as a separate segment and breaking out the numbers for the three downstream businesses.

recovery of

What you can measure

6 Active portfolio management to continue by completing $38 billion of disposals over the four years to the end of 2013, in order to focus on our strengths.

7 We expect to bring new upstream projects onstream with unit operating cash margins[a] around double the 2011 average by 2014.[b]

8 We are aiming to generate an increase of around 50% in net cash provided by operating activities by 2014 compared with 2011.[c]

9 We intend to use half our incremental operating cash for reinvestment, half for other purposes.

10 Strong balance sheet with intention to target our level of gearing[d] in the lower half of the 10-20% range over time.

[a] Unit cash margin is net cash provided by operating activities for the relevant projects in our Upstream segment, divided by the total number of barrels of oil and gas equivalent produced for

Longer-term objectives

- Maintain momentum on safety and risk reduction.
- Develop and apply new technologies that access new hydrocarbons or extract and process them more efficiently.

Upstream

- Generate strong returns within a disciplined financial framework.

the relevant projects. It excludes dividends and production for TNK-BP.

[b] Assuming a constant oil price of $100 per barrel.

[c] Assuming an oil price of $100 per barrel and a Henry Hub gas price of $5/mmBtu in 2014. The projection assumes the completion of the agreed transaction with Rosneft and receipt of the projected Rosneft dividend and excludes BP s share of the TNK-BP dividends from operating cash flow for 2011 and 2014. The projection includes BP s payment commitments under the Department of Justice and SEC settlements. It does not reflect any cash flows relating to other liabilities, contingent liabilities, settlements or contingent assets arising from the Gulf of Mexico oil spill which may or may not arise at that time. We are not able to reliably estimate the amount or timing of a number of contingent liabilities. See Financial statements Note 43 on page 253 for further information.

[d] Gearing refers to the ratio of the group s net debt to net debt plus equity and is a non-GAAP measure. See Financial statements Note 35 on page 234 for further information including a reconciliation to gross debt, which is the nearest equivalent measure on an IFRS basis.

[e] Free cash flow: net cash provided by operating activities less net cash used in investing activities.

- g Deliver growth through increased reinvestment in higher return opportunities.
- g Maintain our strong incumbent positions and a diversified portfolio of deep water, giant fields and gas value chains.
- g Build material new positions for the long term.

Downstream

- g Grow free cash flow.[e]
- g Reduce our exposure to refining when not part of an integrated value chain.
- g Re-orientate the geographic mix of our downstream footprint to growth markets.

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Our performance

2012 saw BP build on the strong foundations laid in the previous year. Despite facing major uncertainties, we made progress against our 10-point plan and are reshaping our portfolio to increase efficiency, margins and cash flows.

In 2012 our refineries particularly Toledo (above) and Whiting in the US benefited from a location advantage, as they were able to access discounted crudes.

BP has been in Azerbaijan since 1992 and is the largest foreign investor in the country. Our assets include the West Chirag production and drilling platform (right) which is due to start up in late 2013.

Safety

For more information on our safety performance see pages 46-50.

During the year we made progress in our priority areas of enhancing safety and risk management, restoring trust by meeting our commitments in the Gulf of Mexico and delivering higher returns for shareholders, as evidenced by the increases in quarterly dividend announced in 2012 (see Dividends on page 25). We worked to resolve the uncertainties facing the company in the US and Russia. We continued the major programme of divestments announced in 2010, which we believe is making BP a more efficient organization. And we made investments in areas where we believe we have advantages and higher margin opportunities. Safety remained our number one priority throughout the year, across the company.

We reached the majority of the 2012 milestones that we set out when we launched our 10-point plan in October 2011 (see 2012 in summary) and believe we are on course to improve our margins and cash flow by 2014.

drive improvements to operational safety and reliability with enhanced independent assurance, improved engineering and operating practices, and training and coaching programmes. Our single global wells organization is driving greater consistency across our operations. Our performance and reward system is reinforcing that everyone at BP is responsible for safe operations.

BP s operating management system (OMS) provides us with a systematic and controlled approach to the way the company s operating facilities are managed. All of our operations, with the exception of those recently acquired, are now applying OMS and working to conform to these group-wide standards and practices.

We continue to make progress on all of the remaining recommendations from the Bly Report. As of December 2012, the total number of completed recommendations was 14 out of 26.

Safety

We continued our work to enhance safety and risk management in everything we do. In personal safety, sadly, we had four fatalities in our operations during 2012. We reported 43 Tier 1 process safety events in 2012 and 74 in 2011. Loss of primary containment was reduced by 19% compared with 2011. We continued our programme of major upstream turnarounds, with 30 turnarounds completed in 2012. We expect to carry out up to 22 further turnarounds in 2013.

Over the past 12 months, our safety and operational risk function (S&OR) continued to

Independent advice and monitoring

In June 2012 we appointed Carl Sandlin to track the company s implementation of the recommendations of the Bly Report, our internal investigation into the Deepwater Horizon incident. He brings extensive experience in overseeing global drilling operations. In this role, he will provide an objective and independent assessment to the board of BP s progress against the report s recommendations. He will also observe and report on process safety culture.

Following legal settlements with the US government, BP has agreed to take additional actions, enforceable by the court, to further

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$20 billion

Total BP payments made to the Deepwater Horizon Oil Spill Trust fund.

$11.6 billion

BP s profit[a] in 2012.

$12.0 billion

BP s replacement cost profit[a,b] in 2012.

[a] Profit attributable to BP shareholders. This is the measure of profit required for the group under IFRS.

[b] Replacement cost profit reflects the replacement cost of supplies and, for the group, is not a recognized GAAP measure. See footnote b on page 34.

High-margin production was brought back onstream in 2012 in Angola where the Deepsea Stavanger rig is currently operating at the Greater Plutonio development.

In 2012 we completed the acquisition of Shell and Cosan Industria e Commercio s interests in aviation fuels assets at seven Brazilian airports,

enhance the safety of drilling operations in the Gulf of Mexico (see US regulatory update on page 24). These actions include the appointment of two monitors, both with terms of four years. A process safety monitor will review, evaluate, and provide recommendations for the improvement of BP s process safety and risk management procedures concerning deepwater drilling in the Gulf of Mexico. An ethics monitor will review and provide recommendations for the improvement of BP s code of conduct and its implementation and enforcement. Additionally, an independent third-party auditor will review and report on BP s implementation of key terms of the agreement, including procedures and systems related to safety and environmental management, operational oversight, and oil spill response training and drills.

Trust

BP has continued to meet its commitments to the Gulf Coast. During the year we worked with state and federal trustees to assess impacts on natural resources and progress early environmental restoration work. We supported independent research through the Gulf of Mexico Research Initiative, so we can better understand and mitigate the potential impacts of future oil spills. And we continued to clean up the Gulf shoreline, which involved responding promptly when Hurricane Isaac brought deposits of buried residual

of response covered in the Shoreline Clean-up Completion Plan[a], 4,029 miles (6,484km) were deemed complete by the end of 2012.

We have continued to promote economic recovery by resolving legitimate claims and providing support to two of the region s most important industries tourism and seafood. In the fourth quarter we made a final payment into the Deepwater Horizon Oil Spill Trust fund (Trust), bringing our total payments to $20 billion. The Trust and BP had paid a total of $11.7 billion in claims, advances and other payments by the end of 2012.

Settlement reached with PSC

In April we announced we had reached definitive and fully documented agreements with the Plaintiffs Steering Committee (PSC) to resolve the substantial majority of eligible private economic loss and medical claims stemming from the Deepwater Horizon accident and oil spill. The agreements were approved by the court in December 2012 and January 2013 although BP is challenging a recent ruling by the court regarding the interpretation of certain protocols established in the economic and property damages settlement agreement. See Legal proceedings on page 167. The settlement includes BP s commitment of $2.3 billion to help resolve economic loss claims related to the Gulf seafood industry.

which is an important growth market (below).

oil to the surface at some beaches. Of the 4,376 miles (7,043km) that were in the area

[a] Approved by the US Coast Guard s Federal On-Scene Coordinator, the Shoreline Clean-up Completion Plan sets standards for the surveying, verification and completion of clean-up activities.

2012 in summary

g We drew our TNK-BP partnership in Russia to a close through an agreed transaction with Rosneft, which will provide BP with a net $12.3 billion in cash (which includes a dividend of $0.7 billion received from TNK-BP in December 2012) and an additional 18.5% share in Rosneft, bringing our total shareholding to 19.75%.

g We took the total of asset sales announced since the start of 2010 to around $38 billion, effectively reaching our target a year early.

g We gained new exploration access in six countries.

g Our 2012 reserves replacement ratio, on a combined basis of subsidiaries and equity-accounted entities, excluding acquisitions and disposals, was 77%, with net additions to reserves in 2012 being wholly from equity-accounted entities (see page 86).

The following points relate to particular milestones we set for 2012:

g High-margin production was brought back onstream successfully in Angola, the North Sea and other regions during 2012.

g Exploration drilling activity took place at nine wells against a target of 12 because additional time was required to ensure the rigs meet our enhanced safety standards.

g Five major project start-ups were achieved (against a target of six): at Galapagos in the Gulf of Mexico; Clochas Mavacola and block 31 in PSVM in Angola; Devenick in the North Sea; and Skarv in Norway. The Angola LNG plant is being commissioned and is expected to start production in 2013.

g Seven rigs were operational in the Gulf of Mexico in 2012 against a target of eight. An eighth rig is in place on the Mad Dog platform and is being commissioned and tested. It is expected to start up in 2013.

g We made the final payment to the Deepwater Horizon Oil Spill Trust, taking total payments to the Trust to $20 billion.

g In Downstream, we were unable to fully deliver the $2 billion of financial performance improvement[b] since 2009, which we had identified as an opportunity in 2010, due mainly to a significant reduction in the supply and trading contribution in 2012.

g Organic capital expenditure[c] during the year was $23.1 billion compared with our original expectation of around $22 billion.

[b] See page 74 for further information on Downstream s performance improvement, which is a non-GAAP measure.

[c] Organic capital expenditure excludes acquisitions and asset exchanges and, in 2012, expenditure associated with deepening our US natural gas and North Sea asset bases (see footnote b on page 35).

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Our performance continued

US legal proceedings

For more information on our US settlements for criminal and securities claims see pages 162-171.

Financial review

For more on our performance in 2012 see pages 34-37.

400,000 km^2
New exploration acreage accessed since 2010.

Significant uncertainties exist in relation to the amount of claims that are to be paid and will become payable through the claims process. There is significant uncertainty in relation to the amounts that ultimately will be paid in relation to current claims, and the number, type and amounts payable for claims not yet reported. In addition, there is further uncertainty in relation to interpretations of the claims administrator regarding the protocols under the settlement agreement and judicial interpretation of these protocols, and the outcomes of any further litigation including in relation to potential opt-outs from the settlement or otherwise. The PSC settlement is uncapped except for economic loss claims related to the Gulf seafood industry. There can be no certainty as to how BP s challenge to the court s ruling will ultimately be resolved or determined. To the extent that there are insufficient funds available in the Trust fund, payments under the PSC settlement will be made by BP directly and charged to the income statement. See Plaintiffs Steering Committee settlements on pages 60-61 for further information as well as Risk factors on pages 41-42 and Financial statements Note 36 on page 235.

See page 59 for information on the federal multi-district litigation proceeding in New Orleans (MDL 2179), the first phase of which began on 25 February 2013.

US regulatory update

During the year, the US Department of Justice (DoJ) continued to conduct an investigation into the Deepwater Horizon incident regarding possible violations of US civil and criminal laws. Similarly, the US Securities and Exchange Commission (SEC) continued their investigation regarding possible violations of US securities laws.

BP reached an agreement with the US government in November 2012 to resolve all federal criminal claims arising out of the incident. BP pleaded guilty to 11 felony counts of misconduct or neglect of ships officers

relating to the loss of 11 lives; one misdemeanour count under the Clean Water Act; one misdemeanour count under the Migratory Bird Treaty Act; and one felony count of obstruction of Congress. BP will pay $4 billion including criminal fines and payments to the National Fish & Wildlife Foundation and the National Academy of Sciences in instalments over a period of five years. The court also ordered, as previously agreed with the US government, that BP serve a term of five years probation. BP has agreed to take additional actions, enforceable by the court, to further enhance the safety of drilling operations in the Gulf of Mexico. These activities relate to BP s risk management processes, such as third-party auditing and verification, training, and well control equipment and processes such as blowout preventers and cementing.

BP reached a settlement with the SEC in November 2012, resolving the SEC s Deepwater Horizon-related civil claims. BP has agreed to a civil penalty of $525 million and to an injunction prohibiting it from violating certain US securities laws and regulations. BP made its first payment of $175 million in December 2012.

The US Environmental Protection Agency (EPA) announced in November 2012 that it had temporarily suspended BP p.l.c. and other BP companies from participating in new federal contracts. As a result of the temporary suspension, the notified BP entities are ineligible to receive any new US government contracts or renewal of an expiring contract. The suspension does not affect existing contracts BP has with the US government, including those relating to current and ongoing drilling and production operations in the Gulf of Mexico. In February 2013 the EPA issued a notice of mandatory debarment for BP Exploration & Production Inc at its Houston headquarters. Mandatory debarment prevents that company from entering into new contracts or new leases

We made good progress on the Whiting refinery modernization programme (right) in 2012, and the project is on track to come onstream in the second half of 2013.

BP is accelerating the commercialization of advanced biobutanol technology with partner Du Pont at a purpose-built development and demonstration facility at our Saltend site, near Hull, UK (above).

$22.5 billion

Our Upstream segment s replacement cost profit before interest and tax in 2012.

Upstream

For more on the segment s financial performance see page 65 and for information on segmental changes affecting Upstream at the beginning of 2012 see page 64.

with the US government at those premises. We continue to work with the EPA to resolve suspension and debarment issues.

Value

We achieved a profit of $11.6 billion in 2012 compared with $25.7 billion in 2011. Excluding inventory holding gains, our replacement cost (RC) profit[a] in 2012 was $12.0 billion compared with $23.9 billion in 2011. After adjusting for non-operating items and fair value accounting effects[b], our underlying RC profit[b] was $17.6 billion in 2012 compared with $21.7 billion in 2011. Underlying RC profit is a measure closely tracked by management to evaluate BP s operating performance and to make financial, strategic and operating decisions.

Our goal is to grow operating cash flow[c] to enable us to invest for future growth and increase distributions to shareholders. This year we generated operating cash flow of $20.4 billion, compared with $22.2 billion in 2011. The cash outflow in respect of the Gulf of Mexico oil spill reduced from $6.8 billion in 2011 to $2.4 billion in 2012. Cash and cash equivalents at the end of 2012 totalled $19.5 billion. Gross debt at 31 December 2012 was $48.8 billion compared with $44.2 billion at 31 December 2011. Net debt[a] was $27.5 billion at

Portfolio reshaped

During the year we strengthened the group s financial position, announcing further asset sales and, by the end of 2012, we had essentially reached our $38 billion target.

We began the divestment programme in 2010, increasing the focus of the company s core portfolio on BP s areas of distinctive strength and capability, while reducing operational complexity. We have since sold around 50% of our upstream installations, 32% of our wells and 50% of our pipelines, while only reducing our proved reserves base by approximately 10% and our production by about 9%. We have traded mature assets with declining cash flows so we can concentrate on assets with greater potential for growth.

In November 2012 we took a major step forward in repositioning BP within Russia, agreeing to sell our 50% shareholding in TNK-BP to Rosneft the world s largest publicly traded oil company in terms of oil production and reserves. Our intention is to use part of the cash proceeds from the agreed transaction to offset any dilution to BP s earnings per share.

31 December 2012, leaving our gearing (net debt ratio)[d] at 18.7% compared with 20.5% at the end of 2011. We continue to target gearing in the 10-20% range while uncertainties remain.

Dividends

Total dividends paid in 2012 were 33 cents per share, up 18% compared with 2011 on a dollar basis and 20% in sterling terms. This equated to a total cash distribution to shareholders of $5.3 billion during the year. We announced two increases in the quarterly dividend during 2012 by 14%, to 8 cents per share, in February and by a further 12.5%, to 9 cents per share, in October. These increases reflected our confidence in the company s progress against the 10-point plan and our growing belief in its longer-term prospects.

Upstream

We reported RC profit before interest and tax of $22.5 billion, compared with $26.4 billion in 2011. After adjusting for non-operating items and fair value accounting effects, underlying RC profit before interest and tax[e] was $19.4 billion in 2012, compared with $25.2 billion in 2011 reflecting higher costs, lower production and lower realizations.

[a] Replacement cost profit for the group is not a recognized GAAP measure. The equivalent measure on an IFRS basis is Profit for the year attributable to BP shareholders . See footnote b on page 34 and page 98 for further information.

[b] Underlying replacement cost profit and fair value accounting effects are not recognized GAAP measures. See pages 34, 37 and 98 for further information.

[c] Operating cash flow is shown in our cash flow statement as net cash provided by operating activities.

[d] Net debt and gearing are non-GAAP measures. See footnote d on page 21 for further information.

[e] See footnote b on page 34.

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Our performance continued

Downstream

For more on the segment s financial performance see pages 74-75.

$2.8 billion

Our Downstream segment s replacement cost profit before interest and tax in 2012.

94.8%

Our Solomon refining availability in 2012.

Our focus on safe, reliable and compliant operations has translated into improvements in both personal and process safety. We have seen a 16% improvement in our days away from work case frequency since the start of 2010, and a 22% improvement in our loss of primary containment incidents over the same period.

We have continued to open up new exploration opportunities. In 2012 we added almost 68,000 square kilometres (approximately 26,250 square miles) of new acreage in Brazil, Canada, Egypt, Namibia and Uruguay; and in the Gulf of Mexico and Ohio in the US. The Ohio acreage covers Utica/Point Pleasant, a promising shale basin. Since 2010 we have accessed around 400,000 square kilometres (approximately 154,500 square miles) of new acreage an area roughly the size of California. This is more than double the acreage accessed by BP from 2000 to 2009.

We made good progress in the four areas we believe most likely to provide us with higher margin barrels Angola, Azerbaijan, the North Sea and the Gulf of Mexico.

In Angola, we started production at two projects during 2012 (see page 23). We also continued a programme of exploration and appraisal.

In Azerbaijan, the Shah Deniz consortium a seven-member group led by BP selected Nabucco West as the single pipeline option for the potential export of gas to Central Europe, while the Trans-Adriatic Pipeline was selected as the potential route for exports to Italy. Negotiations on transit and marketing terms will

determine which project will be selected as the route to market, ahead of our final investment decision on Shah Deniz. We remain on course to start up the West Chirag production and drilling platform in late 2013.

In the North Sea, 2012 saw high levels of activity. We achieved start-ups, sold a number of non-strategic assets and moved forward with a major programme of long-term investment (see A new chapter in the North Sea, page 24). These actions reflect our strategy of focusing on higher margin projects.

Although uncertainties about the consequences of the Gulf of Mexico oil spill remain, we believe that the Gulf of Mexico remains an important source of medium and long-term growth. The sale of non-core assets in the region should allow us to concentrate on our four operated hubs, together with further exploration activity. In our existing Gulf of Mexico hubs, 80% of our estimated ultimate recovery is still in the ground. We are also continuing our Paleogene appraisal programme of high temperature/high pressure reservoirs in the Lower Tertiary area.

Following an 18-month review that reassessed the technical and economic challenges involved in developing the Liberty field in Alaska safely and profitably, we announced in June that we had suspended our development plans. We are working with regulators to develop alternative plans for the field.

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Investing in renewable energy

Since 2005 we have invested $7.6 billion in lower-carbon businesses and are on track to meet our commitment to invest $8 billion by 2015. In biofuels, our three sugar cane mills in Brazil now have a total crush capacity of 7.2 million tonnes and produce fuels for use in transport and power. At the end of 2012 we started up the Vivergo JV bioethanol plant in Hull, UK. We also have research, demonstration and production facilities planned or operating in the US, UK and Brazil. During the year we cancelled plans to build a commercial-scale cellulosic ethanol plant in Florida and refocused our cellulosic strategy on research, development and technology licensing. In wind we have interests in 16 wind farms in the US, which together provide BP with a net generating capacity of 1,558MW.[a]

Alternative Energy

For more on our activities see Other businesses and corporate page 82.

[a] Excludes 32MW of capacity in the Netherlands, which is managed by our Downstream segment.

TNK-BP

For more on the segment s financial performance see pages 80-81.

Downstream

RC profit before interest and tax for 2012 was $2.8 billion, compared with $5.5 billion in 2011. After adjusting for non-operating items and fair value accounting effects, underlying RC profit before interest and tax[b] in 2012 was an all-time record of $6.4 billion compared with $6.0 billion in 2011. This reflected a favourable refining environment, which we were able to capture by virtue of our strong operations, partly offset by weak petrochemicals margins and a significantly lower supply and trading contribution than in 2011. 2012 was also our fourth consecutive year of growth in underlying RC profit before interest and tax. We also continued to make good progress in repositioning Downstream to improve our margin quality and the efficiency of the portfolio.

Since the start of 2008, our focus on safe and reliable operations in Downstream has translated into improvements in process safety. We have seen a 55% reduction in loss of primary containment and a 40% reduction in our process safety incident index over the period.

Refinery operations were strong this year, with Solomon refining availability of 94.8%. (See refining availability on page 74.) Utilization

announcing the sale of our operations in a further three countries in 2012.

In petrochemicals we sold our PTA interest in Malaysia during the year and made progress on major new projects in China and India. We also signed two licensing agreements for our proprietary petrochemicals technology (see page 16 for further details).

TNK-BP

We began reporting TNK-BP as a separate operating segment with effect from 1 January 2012, reflecting the way in which we were managing our investment.

Following the announcement of our proposed transaction with Rosneft on 22 October 2012, BP s investment in TNK-BP met the criteria to be classified as an asset held for sale. Consequently, BP ceased equity accounting for its share of TNK-BP s earnings from the date of the announcement.

RC profit before interest and tax[bc] for 2012 was $3.4 billion, compared with $4.1 billion in 2011. After adjusting for non-operating items, underlying RC profit before interest

PSVM is one of the largest subsea developments in the world and was one of BP s key project start-ups for 2012. It is the second BP-operated development in Angola after Block 18 s Greater Plutonio (below).

rates were at 88% despite a relatively high level of turnaround activity in 2012.

Our lubricants business continued to deliver robust performance in 2012, despite weak demand.

In petrochemicals, a combination of increased supply and lower demand growth in the market narrowed margins for our business in 2012, although we were able to maintain production volumes at around the same levels as 2011.

During the year we continued to make good progress in repositioning the Downstream business. In August 2012 we announced an agreement to sell our Carson refinery, in California, and related logistics and marketing assets in the region to Tesoro Corporation for an estimated \$2.5 billion. In October 2012 we announced an agreement to sell our Texas City refinery and all associated assets in the south-east US to Marathon Petroleum Corporation. This sale was completed on 1 February 2013 for proceeds of up to \$2.4 billion (see page 72).

Meanwhile, we made significant progress with the upgrade of our Whiting refinery. On completion, this modernization project is expected to allow us to capture additional margin through the processing of a greater proportion of heavy crudes. During the year the new crude oil unit, coker, upgraded sulphur recovery complex and gasoil hydrotreater all advanced

and tax[bc] for 2012 was \$3.1 billion, compared with \$4.1 billion in 2011. The most significant factor affecting performance in 2012 compared with 2011 was the absence of more than two months income following the cessation of equity accounting.

[b] See footnote b on page 34.

[c] Under equity accounting, BP s share of TNK-BP s earnings after interest and tax has been included in the BP group income statement within profit before interest and tax.

Outlook

The company s divestment programme is fundamentally reshaping and repositioning our upstream and downstream portfolios. In the Upstream segment, we now have a portfolio that we believe plays to our distinctive strengths and capabilities in exploration, deep water, giant fields and gas value chains. In the Downstream segment, we expect that the measures we are taking to improve efficiency and margin quality will be largely complete by the end of 2013.

Looking ahead, we continue to expect that we can deliver around 50% growth in operating cash flow by 2014 compared with 2011.[d] We intend to use the proceeds of improved cash flow in a number of ways, including increased investment in upstream development. This will focus on towards their targeted start-up dates in 2013 and the whole project remains on schedule to start up in the second half of 2013.

We also made good progress towards our aim of divesting the LPG bulk and bottled business, completing the exit from three of the nine countries we originally identified and

four high-margin areas: Angola, Azerbaijan, the Gulf of Mexico and the North Sea.

More development, more exploration

The level of planned activity is reflected in the number of rigs we have at work. Across our portfolio, we had 53 rigs in operation at the end of 2012 20 onshore and 33 offshore, including 11 in the deep water. We expect to have around 60 rigs in operation in 2014.

We intend to increase investment in exploration. Our drilling programme is expected to test 15 new plays between 2012 and 2015.

[d] See footnote c on page 21.

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Our key performance indicators

We track our performance against key financial and non-financial indicators.

Our board assesses the group s performance according to a wide range of measures and indicators. The 13 key performance indicators on these pages help us measure performance against our strategic priorities safety, trust and value and our business plans. We keep these metrics under periodic review and test their relevance to our strategy regularly. We believe non-financial measures such as safety and an engaged and diverse workforce have a useful role to play as leading indicators of future performance.

Changes to KPIs

We have changed our employee engagement key performance indicator from a satisfaction measure to one that measures engagement with our strategic priorities of safety, trust and long-term value, as we believe this measure is more closely aligned with our longer-term objectives. Details of our employee engagement are on page 56.

Replacement cost profit (loss) per ordinary share[a] (cents)

Replacement cost profit (loss) reflects the replacement cost of supplies. It is arrived at by excluding from profit inventory holding gains and losses and their associated tax effect. Replacement cost profit for the group is a profitability measure used by management. It is a non-GAAP measure. See page 34 for the equivalent measure on an IFRS basis.

2012 performance Our results were impacted by the cost of the legal settlement agreed with the US government following the Gulf of Mexico oil spill, as well as by lower results in our operating segments.

Operating cash flow ($ billion)

Operating cash flow is net cash flow provided by operating activities, from 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.

2012 performance Lower operating cash flow in 2012 reflected the cash flow impact of lower profits, which was partly mitigated by a lower cash outflow relating to the Gulf of Mexico oil spill.

Gearing (net debt ratio)[a] (%)

Gearing enables investors to see how significant net debt is relative to equity from shareholders. Net debt is equal to gross finance debt, plus associated derivatives, less cash and cash equivalents. Net debt and net debt ratio are non-GAAP measures. See Financial statements Note 35 on page 234 for the nearest equivalent measure on an IFRS basis and for further information.

2012 performance We ended the year with gearing within our desired 10-20% range and we will continue to target this range while uncertainties remain.

Oil spills[b]

Remuneration

To help ensure that the focus of our board and management is aligned with the interests of our shareholders, certain of these measures are reflected in the annual bonus element of executive remuneration.

Overall annual bonuses are based on performance relative to measures and targets linked to the annual group plan.

The measures used to determine 2012 and 2013 remuneration are identified with this symbol.

Remuneration

For details of our policy see pages 127-145.

Not all financial KPIs are recognized GAAP measures, but are provided for investors because they are closely tracked by management to evaluate BP s operating performance and to make financial, strategic and operating decisions.

Reported recordable injury frequency[b]

Reported recordable injury frequency (RIF) measures the number of reported work-related incidents that result in a fatality or injury (apart from minor first aid cases) per 200,000 hours worked.

2012 performance Our workforce RIF, which includes employees and contractors combined, was 0.35, compared with 0.36 in 2011 and 0.61 in 2010. The 2010 group RIF was affected by the Gulf Coast response efforts and we continue to focus on improving personal safety.

Loss of primary containment[a]

Loss of primary containment is the number of unplanned or uncontrolled releases of material, excluding non-hazardous releases, such as water from a tank, vessel, pipe, railcar or other equipment used for containment or transfer.

2012 performance There was a 19% reduction in loss of primary containment compared to 2011, which continues a year on year improvement. Tracking losses of integrity is a way of measuring safety performance and helping drive improvements.

We report the number of spills of hydrocarbons greater than or equal to one barrel (159 litres, 42 US gallons). We include spills that were contained, as well as those that reached land or water.

2012 performance We continue to take measures to strengthen mandatory safety-related standards and processes, including operational risk and integrity management.

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Total shareholder return (%)

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

2012 performance In 2012 the growth in TSR resulted from increases in the dividend, with the improvement for ordinary shares diminished by exchange rate effects.

Reserves replacement ratio (%)

Proved reserves replacement ratio (also known as the production replacement ratio) is the extent to which production is replaced by proved reserves additions. The ratio is expressed in oil-equivalent terms and includes changes resulting from revisions to previous estimates, improved recovery and extensions, and discoveries. The measure reflects both subsidiaries and equity-accounted entities, but excludes acquisitions and disposals.

2012 performance Our reserves replacement ratio was impacted by a lower than usual number of final investment decisions related to major projects, lower than expected reservoir performance, and the curtailing or replanning of certain development activities due to lower natural gas prices and higher costs.

Production (mboe/d)

We report crude oil, natural gas liquids (NGLs) and natural gas produced from subsidiaries and equity-accounted entities. These are converted to barrels of oil equivalent (boe) at 1 barrel of NGL = 1boe and 5,800 standard cubic feet of natural gas = 1boe.

2012 performance BP s total reported production in 2012, including both our Upstream and TNK-BP segments, was 3.6% lower than in 2011, mainly due to the effect of transactions completed in Upstream as part of our $38-billion divestment programme.

Refining availability (%)

Refining availability represents Solomon Associates operational availability, which is defined as the percentage of the year that a unit is available for processing after subtracting the annualized time lost due to turnaround activity and all planned mechanical, process and regulatory maintenance downtime.

2012 performance Refining availability remained at a high level of 94.8%, reflecting strong operations around our global refining portfolio.

Greenhouse gas emissions

(million tonnes of CO_2 equivalent)

Group priorities engagement[c] (%)

Diversity and inclusion[c] (%)

We report greenhouse gas (GHG) emissions on a CO_2-equivalent basis, including CO_2 and methane. This represents all consolidated entities and BP s share of equity-accounted entities, except TNK-BP. In 2010 we did not report on GHG emissions associated with the Deepwater Horizon incident or response (see page 52).

2012 performance The 2.0Mte decrease in direct GHG emissions in 2012 is primarily explained by operational changes due to temporary reductions in activity in some of our businesses and by the sale of upstream assets as part of our divestment programme.

We track how engaged our employees are with our strategic priorities of strengthening safety, earning back trust and building long-term value. The measure is derived from 12 questions about employee perceptions of BP as a company and how it is managed in terms of leadership and standards.

2012 performance Aggregate results for these questions showed a 4% improvement on 2011 to 71%.

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

2012 performance BP has increased the percentage of female leaders in 2012 and remains focused on building a more sustainable pipeline of diverse talent for the future.

[a] Not a recognized GAAP measure.

[b] 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.

[c] Relates to BP employees.

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Our management of risk

Risk management

Our system of risk management identifies and provides the response to risks of group significance through the establishment of standardized requirements and controls.

For information on BP s risk management system see Risk in BP on page 117.

Risk factors

For the risk factors that could have an adverse effect on our business see pages 38-44.

The following is a summary of how we seek to manage the risks we have identified as having a high priority in 2013. There can be no guarantee that our risk management activities will mitigate or prevent these, or other, risks from occurring.

Strategic and commercial risk

We aim to manage risks associated with the general macroeconomic outlook, and changes in prices and markets, by responding to early warnings from our economics and treasury teams and customer-facing businesses. To manage our liquidity, financial capacity and financial exposure risks, we apply our financial framework and we conduct liquidity stress testing and interventions based on scenario planning (see Liquidity and capital resources on pages 90-93).

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. For example, government. We are also focused on completing our agreement to sell our interest in TNK-BP to, and purchase interests in, Rosneft.

Many of our major projects and operations are conducted through joint ventures or associates and through contracting and sub-contracting arrangements where BP may not have full operational control. We seek to manage the risks arising from such joint venture and contractor relationships actively, and this may include monitoring compliance with applicable standards.

In 2011 we set out a 10-point plan to address our near-term strategic priorities. Among other things, the plan aims to target investments and disposals efficiently, renew and reposition our portfolio and deliver our major projects to plan.

As part of managing the risks to delivery of the 10-point plan we conduct regular planning and our investments in Russia could be adversely affected by heightened political and other social and environment risks. As such, we try to actively manage our relationships in Russia, including with the Russian federal

performance-monitoring activity, including the planning of disposals; we focus on the successful delivery of major projects; and we pursue the development of continued technological advances and innovation.

Operators descending coker structure, Castellon oil refinery, Castellon, Spain.

We seek to manage our reputation through actively managing our relationships with key stakeholders and through clear, consistent and coherent communications. We seek to engage with local communities in order to foster improved relationships.

There have been many important developments in 2012 related to the Deepwater Horizon accident, oil spill, and response including the agreement reached with the US government to resolve all federal criminal claims and with the SEC regarding its securities claims. There remains, however, continuing uncertainty regarding the final extent and timing of civil costs and liabilities relating to the incident (with the trial to address many of these issues, which started on 25 February 2013). Further, BP is in ongoing discussions with the EPA to lift the temporary suspension and mandatory debarment. As such, the long-term impact of the incident on our reputation remains uncertain.

In addressing these risks we have been working to review and adapt where necessary our current controls and procedures to assure compliance with the requirements contained within the settlements.

In addition we have been preparing for trial while remaining open to settlement of the remaining civil claims on reasonable terms. We are committed to rebuilding trust with all

We have also appointed an independent adviser to provide oversight and assurance regarding the company s implementation of the Bly Report s recommendation and to report on observed process safety culture.

Crisis and continuity management plans, including in respect of oil spill preparedness and response, have been developed to help us to respond effectively to emergencies to minimize impacts and to avoid potentially severe disruption in our business and operations. See Safety on pages 46-50 for information on the recommendations of BP s internal investigation into the Deepwater Horizon oil spill and the actions we are pursuing to address them.

Security threats require continuous monitoring and control as hostile actions against our staff, our facilities (as in the In Amenas joint venture in Algeria) and our digital infrastructure (cyber security) could cause harm to people and could disrupt our operations. We have procedures that are intended to monitor for threats and vulnerabilities and policies to manage our physical and digital security. We also maintain disaster recovery, crisis and business continuity management plans.

Compliance and control risk

our stakeholders and continue to co-operate with all investigators, monitors and regulators. Further, we are clear that we always seek to comply with local regulations and, in some cases, our required practices will exceed regulations if our assessment of the operating risk indicates it would be beneficial to do so.

Safety and operational risk

The nature of the group s operations exposes us to a wide range of significant health, safety and environmental risks such as incidents associated with the drilling of wells, operation of facilities, transportation of hydrocarbons and product quality. In addressing these risks we seek to apply our operating management system (OMS), including group and engineering technical practices, as applicable.

We seek to conduct maintenance and equipment testing and to apply product quality control and testing procedures. We also provide our staff with training and competency development. To better manage the risks inherent in drilling wells where we are the operator, we conduct activity through a global wells organization that is accountable for systems and processes for designing, constructing and managing wells.

Ethical misconduct or breaches of applicable laws or regulations could be damaging to our reputation, results of operations and shareholder value and could affect our licence to operate. Central to managing these risks is our code of conduct and our values and behaviours (see page 56), the requirements of which apply to all employees, supported by our various group requirements covering issues such as anti-bribery and corruption, anti-money laundering, competition/anti-trust law compliance and trade sanctions. We seek to monitor for new regulations and legislation and plan our response to them. We also operate a range of compliance training and monitoring programmes for our employees, including OpenTalk, our confidential helpline for employees.

In the normal course of business, we are subject to risks around our treasury and trading activities, which could arise from shortcomings or failures in our systems, risk management methodology, internal control processes or employees. In addressing these risks, we have adopted specific operating standards and control processes, including guidelines in relation to trading, and seek to monitor compliance through dedicated compliance organizations. We also seek to maintain a positive and collaborative relationship with regulators and the industry at large.

Cautionary statement

This document contains certain forecasts, projections and forward looking statements that is, statements related to future, not past events with respect to the financial condition, results of operations and businesses of BP and certain of the plans and objectives of BP with respect to these items. These statements may generally, but not always, be identified by the use of words such as will , expects , is expected to , aims , should , may , objective , is likely believes , anticipates , plans , we see or similar expressions. In particular, among other statements, (i) certain stateme in the Chairman s letter (pages 8-9), the Group chief executive s letter (pages 10-11), the Business review (pages 3-99) and Additional disclosures (pages 161-175), including but not limited to statements under the headings Energy outlook , Our strategy , Outlook and Looking Ahead , with regard to expectations regarding BP s agreement with and prospective shareholding in Rosneft, including BP s expectations regarding its representations on the Rosneft board, the composition of the board of directors, expectations regarding our strategy and strategic priorities including our Upstream and Downstream strategies and our longer term objectives, plans to deliver shareholder value, plans to continue to simplify the organization and portfolio, plans to focus on efficient execution and use of capital, plans to prioritize value rather than seeking to grow production volume for its own sake, prospects for the settlement of outstanding claims related to the Gulf of Mexico oil spill, plans to continue to meet commitments in the Gulf Coast region, plans to implement the recommendations of the Bly Report, plans to appoint two independent monitors and an independent auditor, BP s intention to prioritize operating cash flow and replacement cost operating profit over barrels of production, plans to work to focus and improve the business, plans to enhance safety and earn back trust, anticipated increases in regulation and taxation of the energy industry and energy users, projections regarding the ability of renewable energy sources to meet total energy demand, expectations regarding investments in proprietary technology, expectations regarding *LoSal* technology, plans to sell assets and entities, expectations regarding the future level of capital expenditures through the end of the decade, expectations regarding the amount of divestments per year, the expected level of gearing, expectations regarding the 10-point plan , expectations regarding future dividend payments and BP s plans to continue to pursue a progressive dividend policy, BP s outlook on global energy trends to 2030 and beyond, BP s outlook on its ability to meet the growing demand for energy, the intention to make $2-3 billion in disposals per annum on an ongoing basis, BP s plans to grow operating cash flow and margins by 2014 and the expected quantum of growth, plans for the use of expected improved cash flow, plans to grow free cash flow in Downstream, expectations regarding the level and types of investments and divestments, expectations regarding the Shah Deniz consortium, BP s plans for involvement in growth markets, the anticipated timing for completion of the disposition of certain BP assets and entities and estimates of the final proceeds therefrom, future production levels including expectations for an increase in high-margin production, the timing and composition of future projects including expected Final Investment Decisions, start-up, construction, commissioning, completion, timing of production, level of production and margins, expectations for drilling and rig activity in the Gulf of Mexico, the timing of measures taken to improve efficiency and margin quality, expectations for the number of rigs in operation, the timing of the delivery of new tankers and rigs, expectations regarding turnover time and the volume of proved undeveloped reserves held for more than five years, the estimated cost of the settlements with the Plaintiffs Steering Committee in MDL 2179, the expected amount, source and timing of payments under any settlements related to the Gulf of Mexico oil spill, expectations with regard to the terms of any settlements and BP s compliance therewith, the anticipated effect of accounting changes on BP s earnings and cash flow, the timing of the positioning of well cap systems and dispersant application equipment packages, expectations regarding employee training, expectations for an increase in the carbon intensity of operations, expectations regarding environmental research, plans regarding the launch of BP s human rights policy, expectations regarding regulation and taxation of the energy industry and energy users, BP s expectations with regard to employee diversity and inclusion, the timing for completion of and prospects for the High-Performance Computing centre in Houston, prospects for debarment of BP entities and the expected duration and consequences of any such debarment, the timing of the commissioning of the LNG train at Tangguh, plans to retain the petrochemicals manufacturing plants at Texas City, expectations regarding future levels of capital investment, plans regarding Project *20K*, the expected impact of the expiry of the Abu Dhabi onshore concession, plans regarding environmental restoration of the Gulf Coast, future global refinery capacity and utilization, plans and timing for the completion of the upgrade to and start-up of the Whiting refinery, plans regarding upgrades to the Cherry Point refinery, expectations regarding oil price movements in 2013, expectations regarding the gas market in 2013 and the expected drivers thereof, prospects for the persistence in a large gap between US and European gas prices in 2013, BP s plans to license back the *ARCO* brand, prospects for Upstream s contribution to BP s plans to increase operating cash flow by around 50% by 2014, expectations regarding the unit operating cash margins of new upstream projects, BP s strategies with regard to optimizing value across the business, plans regarding BP s PTA project, the timing of a review of BP s assets and estimation processes, plans regarding the implementation of enhancements to BP s risk management system, expectations regarding refining margins, expectations regarding the market for lubricants and petrochemicals, expectations regarding Downstream capital expenditures, expectations regarding the reduction of net debt and the net debt ratio, the expected future level of depreciation, depletion and amortization, the completion of

planned and announced divestments, expectations regarding the announced disposal of TNK-BP to Rosneft and acquisition of an 18.5% shareholding in Rosneft, BP s intentions to use part of the cash proceeds from the planned disposal of TNK-BP to offset any dilution to BP s earnings per share, expectations about BP s future investments and operations in the North Sea, expectations regarding reported production and underlying production in Upstream, expectations regarding Vivergo, the timing of the completion of the Angola LNG plant, the timing for the completion of the Mad Dog spar, and the level of future turnaround activity; (ii) the statements in the Business review (pages 3-99), Corporate governance (pages 101-126), the Directors remuneration report (pages 127-145), and Shareholder information (pages 153-159) with regard to the board s goals and plans stemming from the board s annual evaluation, expectations regarding the timing of events with investors, plans to continue the ongoing process of embedding OMS and to ensure joint venture partners follow principles similar to those of the OMS, plans and timing for the implementation of the Bly report recommendations, plans regarding investments in research, the timing of projects, programs and initiatives, intentions to continue monitoring process safety at TNK-BP, intentions to implement group-wide practices for oil spill preparedness and response and crisis management, plans to spend $700 million on certain refinery-related safety measures, plans to implement enhanced and standardized technical practices across the refining business, the timing of, cost of, source of payment and provision for future remediation and restoration programmes and environmental operating and capital expenditures, plans to halve US refining capacity, plans and expectations with regard to the remuneration, pensions and other benefits of executive directors, expectations regarding the impact of various regulations upon BP s business and expectations regarding greater regulation and increased operating costs in the Gulf of Mexico in the future; (iii) the statements in the Business review (pages 90-93) with regard to future dividend and optional scrip dividend payments, future capital expenditures and capital expenditure commitments, taxation, intentions to maintain a significant liquidity buffer, future working capital and cash flows, gearing and the net debt ratio, BP s intention to maintain a strong cash position, expectations regarding taxes due upon repatriation of cash into the UK, expectations regarding total capital expenditure, expected payments under contractual and commercial commitments and purchase obligations, and including under Liquidity and capital resources Trend information , with regard to production in Upstream, the expected financial impact of refinery turnarounds, expectations regarding petrochemicals margins and the average quarterly charge for Other businesses and corporate, estimated levels of capital expenditure in 2013 and to the end of the decade, estimated amount of divestments, intentions regarding net debt ratio and the expected level of depreciation, depletion and amortization, and the expected level of underlying effective tax rate; and (iv) certain statements in Additional disclosures (pages 161-175) regarding the anticipated timing of trial proceedings, court decisions and potential investigations and civil or criminal actions by US state and/or local governments; are all forward looking in nature.

By their nature, forward-looking statements involve risk and uncertainty because they relate to events and depend on circumstances that will or may occur in the future and are outside the control of BP. Actual results may differ materially from those expressed in such statements, depending on a variety of factors, including the specific factors identified in the discussions accompanying such forward-looking statements; the receipt of relevant third party and/or government approvals; the timing of bringing new fields onstream; the timing of certain disposals; future levels of industry product supply, demand and pricing, including supply growth in North America; OPEC quota restrictions; PSA effects; operational problems; general economic conditions; political stability and economic growth in relevant areas of the world; changes in laws and governmental regulations; regulatory or legal actions including the types of enforcement action pursued and the nature of remedies sought; the actions of prosecutors, regulatory authorities and courts; the actions of the Claims Administrator appointed under the Economic and Property Damages Settlement; the actions of all parties to the Gulf of Mexico oil spill-related litigation at various phases of the litigation; exchange rate fluctuations; development and use of new technology; the success or otherwise of partnering; the actions of competitors; the actions of contractors; natural disasters and adverse weather conditions; changes in public expectations and other changes to business conditions; wars and acts of terrorism or sabotage; and other factors discussed elsewhere in this report including under Risk factors (pages 38-44). In addition to factors set forth elsewhere in this report, those set out above are important factors, although not exhaustive, that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements.

Statements regarding competitive position

Statements referring to BP s competitive position are based on the company s belief and, in some cases, rely on a range of sources, including investment analysts reports, independent market studies and BP s internal assessments of market share based on publicly available information about the financial results and performance of market participants.

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Financial review

Selected financial information[a]

					$ million
	2012	2011	2010	2009	2008
Income statement data					
Sales and other operating revenues	**375,580**	375,517	297,107	239,272	361,143
Underlying replacement cost profit (loss) before interest and tax[b]					
By business					
Upstream	**19,419**	25,225	25,073	19,668	37,318
Downstream	**6,447**	6,013	4,883	3,607	3,318
TNK-BP[c]	**3,127**	4,134	2,617	1,948	2,262
Other businesses and corporate	**(1,997)**	(1,656)	(1,316)	(1,833)	(590)
Consolidation adjustment unrealized profit in inventory	**(576)**	(113)	447	(717)	466
	26,420	33,603	31,704	22,673	42,774
Net favourable (unfavourable) impact of non-operating items and fair value accounting effects[b]					
By business					
Upstream	**3,055**	1,141	3,196	3,184	(1,272)
Downstream	**(3,601)**	(539)	672	(2,864)	858
TNK-BP	**246**				
Other businesses and corporate	**(798)**	(822)	(200)	(489)	(633)
Gulf of Mexico oil spill response[d]	**(4,995)**	3,800	(40,858)		
	(6,093)	3,580	(37,190)	(169)	(1,047)
Replacement cost profit (loss) before interest and tax[b]					
By business					
Upstream	**22,474**	26,366	28,269	22,852	36,046
Downstream	**2,846**	5,474	5,555	743	4,176
TNK-BP[c]	**3,373**	4,134	2,617	1,948	2,262
Other businesses and corporate	**(2,795)**	(2,478)	(1,516)	(2,322)	(1,223)
Gulf of Mexico oil spill response[d]	**(4,995)**	3,800	(40,858)		
Consolidation adjustment unrealized profit in inventory	**(576)**	(113)	447	(717)	466
Replacement cost profit (loss) before interest and taxation[b]	**20,327**	37,183	(5,486)	22,504	41,727
Inventory holding gains (losses)[e]	**(594)**	2,634	1,784	3,922	(6,488)
Profit (loss) before interest and taxation	**19,733**	39,817	(3,702)	26,426	35,239
Finance costs and net finance expense/income relating to pensions and other post-retirement benefits	**(924)**	(983)	(1,123)	(1,302)	(956)
Taxation	**(6,993)**	(12,737)	1,501	(8,365)	(12,617)

Profit (loss) for the year	**11,816**	26,097	(3,324)	16,759	21,666
Profit (loss) for the year attributable to BP shareholders	**11,582**	25,700	(3,719)	16,578	21,157
Inventory holding (gains) losses[e], net of tax	**411**	(1,800)	(1,195)	(2,623)	4,436
Replacement cost profit (loss) for the year attributable to BP shareholders[b]	**11,993**	23,900	(4,914)	13,955	25,593
Non-operating items and fair value accounting effects[b], net of tax	**(5,645)**	2,242	(25,436)	(622)	(650)
Underlying replacement cost profit (loss) for the year attributable to BP shareholders[b]	**17,638**	21,658	20,522	14,577	26,243

[a] This information, insofar as it relates to 2012, has been extracted or derived from the audited consolidated financial statements of the BP group presented on pages 177-262. 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.

[b] Replacement cost (RC) profit or loss reflects the replacement cost of supplies and is arrived at by excluding inventory holding gains and losses from profit or loss. RC profit or loss is the measure of profit or loss for each operating segment that is required to be disclosed under International Financial Reporting Standards (IFRS). RC profit or loss for the group is not a recognized GAAP measure. Underlying RC profit or loss is RC profit or loss after adjusting for non-operating items and fair value accounting effects. Underlying RC profit or loss and fair value accounting effects are not recognized GAAP measures. For further information on RC profit or loss, underlying RC profit or loss, non-operating items and fair value accounting effects, see page 37 and Certain definitions on pages 98-99.

[c] BP ceased equity accounting for its share of TNK-BP earnings from 22 October 2012. See TNK-BP on pages 80-81 for further information.

[d] Under IFRS these costs are presented as a reconciling item between the sum of the results of the reportable segments and the group results.

[e] Inventory holding gains and losses represent the difference between the cost of sales calculated using the average cost to BP of supplies acquired during the year 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. BP s management believes it is helpful to disclose this information. An analysis of inventory holding gains and losses by business is shown in Financial statements Note 6 on page 203 and further information on inventory holding gains and losses is provided on page 98.

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Selected financial information continued

	$ million except per share amounts				
	2012	2011	2010	2009	2008
Per ordinary share cents					
Profit (loss) for the year attributable to BP shareholders					
Basic	**60.86**	135.93	(19.81)	88.49	112.59
Diluted	**60.45**	134.29	(19.81)	87.54	111.56
Replacement cost profit (loss) for the year attributable to BP shareholders	**63.02**	126.41	(26.17)	74.49	136.20
Underlying replacement cost profit for the year attributable to BP shareholders	**92.68**	114.55	109.23	77.81	139.66
Dividends paid per share cents	**33.00**	28.00	14.00	56.00	55.05
pence	**20.852**	17.404	8.679	36.417	29.387
Capital expenditure and acquisitions[a]	**24,342**	31,518	23,016	20,309	30,700
Acquisitions and asset exchanges	**200**	11,283	3,406	308	2,514
Organic capital expenditure[b]	**23,088**	19,139	18,218	20,001	21,697
Balance sheet data (at 31 December)					
Total assets	**300,193**	293,068	272,262	235,968	228,238
Net assets	**119,620**	112,482	95,891	102,113	92,109
Share capital	**5,261**	5,224	5,183	5,179	5,176
BP shareholders equity	**118,414**	111,465	94,987	101,613	91,303
Finance debt due after more than one year	**38,767**	35,169	30,710	25,518	17,464
Net debt to net debt plus equity[c]	**18.7%**	20.5%	21.2%	20.4%	21.4%
Ordinary share data[d]					Shares million
Average number outstanding of 25 cent ordinary shares (undiluted)	**19,028**	18,905	18,786	18,732	18,790
Average number outstanding of 25 cent ordinary shares (diluted)	**19,158**	19,136	18,998	18,936	18,963

[a] Includes asset exchanges. All capital expenditure and acquisitions during the past five years have been financed from cash flow from operations, disposal proceeds and external financing.

[b] Organic capital expenditure excludes acquisitions and asset exchanges, and: in 2012, $1,054 million associated with deepening our US natural gas and North Sea asset bases; in 2011, $1,096 million associated with deepening our US natural gas asset bases; in 2010, $900 million relating to the formation of a partnership with Value Creation Inc. to develop the Terre de Grace oil sands acreage and $492 million for the purchase of additional interests in the Valhall and Hod fields in the North Sea; and, in 2008, $3,667 million in respect of our purchase of all Chesapeake Energy Corporation s interest in the Arkoma Basin Woodford Shale assets and the purchase of a 25% interest in Chesapeake s Fayetteville Shale assets and $2,822 million relating to the formation of an integrated North American oil sands business with Husky Energy Inc.

[c] Net debt and the ratio of net debt to net debt plus equity are not recognized GAAP measures. We believe that these measures provide useful information to investors. Further information on net debt is given in Financial statements Note 35 on page 234.

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

Profit or loss for the year

Profit attributable to BP shareholders for the year ended 31 December 2012 was $11,582 million. After adjusting for $411 million in respect of inventory holding losses and their associated tax effect, replacement cost (RC) profit attributable to BP shareholders in 2012 was $11,993 million. After further adjusting for a net charge of $5,300 million for non-operating items and adverse fair value accounting effects (relative to management s measure of performance) of $345 million, both net of tax, underlying RC profit attributable to BP shareholders in 2012 was $17,638 million. RC profit or loss for the group, underlying RC profit and fair value accounting effects are non-GAAP measures, see footnote b on page 34 for further information.

Non-operating items in 2012, on a pre-tax basis, mainly related to further charges associated with the Gulf of Mexico oil spill (primarily the cost of the agreement with the US government to settle all federal criminal charges) and impairment charges, partially offset by gains on disposals. More information on non-operating items, and fair value accounting effects, can be found on page 37. See Gulf of Mexico oil spill on pages 59-62 and Financial statements Note 2 on page 194 for further information on the impact of the Gulf of Mexico oil spill on BP s financial results.

For the year ended 31 December 2011, profit attributable to BP shareholders was $25,700 million, replacement cost profit attributable to BP shareholders in 2011 was $23,900 million and underlying RC profit attributable to BP shareholders in 2011 was $21,658 million. Inventory holding gains and their associated tax effect were $1,800 million in 2011. There was a net post-tax credit for non-operating items of $2,195 million, which included a $3.7 billion pre-tax credit relating to the Gulf of Mexico oil spill, and fair value accounting effects had a favourable impact, net of tax, of $47 million.

Compared with 2011, underlying replacement cost profit in 2012 was impacted by higher upstream costs (driven primarily by sector inflation), lower production and realizations, the absence of equity-accounted earnings from TNK-BP as of 22 October 2012 (when our investment was

reclassified as an asset held for sale, as required under IFRS), weak petrochemicals margins and a significant reduction in the supply and trading contribution. These factors were partially offset by an improved refining environment, which we were able to capture as a result of strong refinery operations.

For the year ended 31 December 2010, there was a loss attributable to BP shareholders of $3,719 million, which included inventory holding gains, net of tax, of $1,195 million leading to a replacement cost loss attributable to BP shareholders of $4,914 million. After adjusting for a net charge for non-operating items of $25,449 million and net favourable fair value accounting effects of $13 million, both net of tax, underlying profit attributable to BP shareholders in 2010 was $20,522 million. Non-operating items in 2010 included a pre-tax charge relating to the Gulf of Mexico oil spill of $40.9 billion.

Compared with 2010, in 2011 there were higher realizations, higher earnings from equity-accounted entities, a higher refining margin environment and a stronger supply and trading contribution, partly offset by lower production volumes, rig standby costs in the Gulf of Mexico, higher costs related to turnarounds, higher exploration write-offs, and negative impacts of increased relative sweet crude prices in Europe and Australia, primarily caused by the loss of Libya production and the weather-related power outages in the US.

See Upstream on page 63, Downstream on page 72, TNK-BP on page 80 and Other businesses and corporate on page 82 for further information on segment results.

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Finance costs and net finance expense relating to pensions and other post-retirement benefits

Finance costs comprise interest payable less amounts capitalized, and interest accretion on provisions and long-term other payables. Finance costs in 2012 were $1,125 million compared with $1,246 million in 2011 and $1,170 million in 2010.

Net finance income relating to pensions and other post-retirement benefits in 2012 was $201 million compared with $263 million in 2011 and $47 million in 2010. In 2012, compared with 2011, the reduced net income largely reflected lower expected returns on pension assets following reductions in the yield assumptions, mainly for bonds, being applied in 2012 compared to 2011.

In 2013, when we adopt the revised version of IAS 19 Employee Benefits , we will be required to apply the same expected rate of return on plan assets as we use to discount our pension liabilities. We expect this accounting change to adversely impact our annual earnings by approximately $1 billion on a pre-tax basis, with no impact on cash flow.

Taxation

The charge for corporate taxes in 2012 was $6,993 million, compared with a charge of $12,737 million in 2011 and a credit of $1,501 million in 2010. The effective tax rate was 37% in 2012, 33% in 2011 and 31% in 2010. The group earns income in many countries and, on average, pays taxes at rates higher than the UK statutory rate of 24%. The increase in the effective tax rate in 2012 compared with 2011 primarily reflects the impact of the provision for the settlement with the US government, which is not tax deductible. The increase in the effective tax rate in 2011 compared with 2010 primarily reflected a higher level of income earned in jurisdictions with a higher tax rate.

Acquisitions and disposals

In 2012 there were no significant acquisitions.

Total disposal proceeds received during 2012 were $11.4 billion.

In Upstream, total disposal proceeds of $10.7 billion included $5.55 billion for the disposal of BP s interests in the Marlin hub, Horn Mountain, Holstein, Ram Powell and Diana Hoover fields in the Gulf of Mexico. Proceeds of $1.5 billion were received for the sale of the Canadian natural gas liquids (NGL) business to Plains Midstream Canada ULC, a wholly owned subsidiary of Plains All American Pipeline, L.P. and $1.2 billion for the Hugoton basin assets (including the Jayhawk NGL processing plant and associated producing gas fields in Kansas) to an affiliate of LINN Energy, LLC. The sale of BP s interest in the Jonah and Pinedale upstream operations in Wyoming, also to LINN Energy, LLC generated disposal proceeds of $1.025 billion.

In Downstream, disposal proceeds totalled $0.5 billion, including the sale of our interests in purified terephthalic acid production in Malaysia.

There were no significant disposals during 2012 in Other businesses and corporate.

Prior years transactions

In 2011, BP acquired from Reliance Industries Limited (Reliance) a 30% interest in each of 21 oil and gas production-sharing agreements operated by Reliance in India for $7.0 billion. We completed the purchase, for $3.6 billion, of 10 exploration and production blocks in Brazil, which was the final part of a $7-billion transaction with

Devon Energy that had been

announced in March 2010, and our Alternative Energy business acquired the Brazilian sugar and ethanol producer Companhia Nacional de Açúcar e Álcool (CNAA) for $0.7 billion. See Financial statements Note 3 on page 198 for further details of business combinations.

Total disposal proceeds received during 2011, after the repayment of the disposal deposit relating to Pan American Energy LLC (PAE) (see below), were $2.7 billion.

In Upstream, disposal proceeds included $0.6 billion from the sale of our upstream assets in Pakistan to United Energy Pakistan Limited, a subsidiary of United Energy Group (UEG); $0.5 billion from the sale of half of the 3.29% interest in the Azeri-Chirag-Gunashli (ACG) development in the Caspian Sea, which we had acquired from Devon Energy in 2010, to Azerbaijan (ACG) Limited; and $0.5 billion from the sale of our interests in the Wytch Farm, Wareham, Beacon and Kimmeridge fields to Perenco UK Ltd. In addition, further payments of $1.1 billion were received on completion of the sales of our upstream and certain midstream interests in Venezuela and Vietnam and our oil and gas exploration, production and transportation business in Colombia, for which we had received $2.3 billion in 2010 as deposits. In November 2011, BP received from Bridas Corporation (Bridas) a notice of termination of the agreement for their purchase of BP s 60% interest in PAE. As a result, the deposit of $3.5 billion relating to the sale of PAE, which had been received by BP in 2010, was repaid to Bridas.

In Downstream we made disposals totalling $0.7 billion, which included completion of the divestment of non-strategic pipelines and terminals in the US, announced in 2009, for $0.3 billion and the disposal of our fuels marketing businesses in several African countries for $0.2 billion.

Within Other businesses and corporate, we completed the sale of BP s wholly-owned subsidiary, ARCO Aluminum Inc., to a consortium of Japanese companies for $0.7 billion.

In 2010, BP acquired a major portfolio of deepwater exploration acreage and prospects in the US Gulf of Mexico and an additional interest in the BP-operated ACG developments in the Caspian Sea, Azerbaijan, for $2.9 billion, as part of a $7-billion transaction with Devon Energy. Total disposal proceeds during 2010 were $17 billion, which included $7 billion from the sale of US Permian Basin, Western Canadian gas assets, and Western Desert exploration concessions in Egypt to Apache Corporation (and an existing partner that exercised pre-emption rights), and $6.2 billion of deposits received in advance of disposal transactions expected to complete in 2011. Of these deposits received, $3.5 billion was for the sale of our interest in PAE to Bridas; however, this was subsequently repaid to Bridas at the end of 2011 following the termination of the sale agreement.

The deposits received also included $1 billion for the sale of our upstream and midstream interests in Venezuela and Vietnam to TNK-BP, and $1.3 billion for the sale of our oil and gas exploration, production and transportation business in Colombia to a consortium of Ecopetrol and Talisman.

In Downstream we made disposals totalling $1.8 billion in 2010, which included our French retail fuels and convenience business to Delek Europe; the fuels marketing business in Botswana to Puma Energy; certain non-strategic pipelines and terminals in the US, our interests in ethylene and polyethylene production in Malaysia to Petronas; and our interest in a futures exchange.

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Non-operating items

Non-operating items are charges and credits arising in consolidated entities and in TNK-BP that are included in the financial statements and that BP discloses separately because it considers such disclosures to be meaningful and relevant to investors. They are items that management considers not to be part of underlying business operations and are disclosed in order to enable investors better to understand and evaluate the group s reported financial performance. An analysis of non-operating items is shown in the table below.

			$ million
	2012	2011	2010
Upstream			
Impairment and gain (loss) on sale of businesses and fixed assets	**3,638**	2,131	3,812
Environmental and other provisions	**(48)**	(27)	(54)
Restructuring, integration and rationalization costs			(137)
Fair value gain (loss) on embedded derivatives	**347**	191	(309)
Other[a]	**(748)**	(1,165)	(113)
	3,189	1,130	3,199
Downstream			
Impairment and gain (loss) on sale of businesses and fixed assets	**(2,935)**	(334)	877
Environmental and other provisions	**(172)**	(219)	(98)
Restructuring, integration and rationalization costs	**(32)**	(4)	(97)
Fair value gain (loss) on embedded derivatives			
Other	**(35)**	(45)	(52)
	(3,174)	(602)	630
TNK-BP[b]			
Impairment and gain (loss) on sale of businesses and fixed assets	**(55)**		
Environmental and other provisions	**(83)**		
Restructuring, integration and rationalization costs			
Fair value gain (loss) on embedded derivatives			
Other	**384**		
	246		
Other businesses and corporate			
Impairment and gain (loss) on sale of businesses and fixed assets	**(282)**	275	5
Environmental and other provisions	**(261)**	(220)	(103)
Restructuring, integration and rationalization costs	**(15)**	(39)	(81)
Fair value gain (loss) on embedded derivatives[c]		(123)	
Other[d]	**(240)**	(715)	(21)
	(798)	(822)	(200)
Gulf of Mexico oil spill response	**(4,995)**	3,800	(40,858)
Total before interest and taxation	**(5,532)**	3,506	(37,229)
Finance costs[e]	**(19)**	(58)	(77)
Taxation credit (charge)[f]	**251**	(1,253)	11,857
Total after taxation	**(5,300)**	2,195	(25,449)

[a] 2012 included a charge of $370 million relating to onerous gas marketing and trading contracts and $308 million relating to exploration expense associated with our US natural gas assets (2011 $395 million). 2011 included a charge of $700 million associated with the termination of the agreement to sell our 60% interest in Pan American Energy LLC to Bridas Corporation.
[b] Disclosure of non-operating items for TNK-BP began in 2012. Non-operating items for TNK-BP were reported in the group income statement within earnings from associates until 22 October 2012 after interest and tax. See TNK-BP on pages 80-81 for more information on non-operating items.
[c] Relates to an embedded derivative arising from a financing arrangement.
[d] 2012 included charges of $244 million relating to our exit from the solar business (2011 $717 million).
[e] Finance costs relate to the Gulf of Mexico oil spill. See Financial statements Note 2 on page 194 for further details.
[f] For the Gulf of Mexico oil spill and certain impairment losses and disposal gains in 2012, tax is based on US statutory tax rates, except for non-deductible items. For dividends received from TNK-BP in December 2012, there is no tax arising. For other items reported by consolidated subsidiaries, tax is calculated using the group s discrete quarterly effective tax rate (adjusted for the items noted above, equity-accounted earnings from 2012 onwards and the deferred tax adjustments relating to changes to the taxation of UK oil and gas production (2011 $683 million and 2012 $256 million)). Non-operating items arising within the equity-accounted earnings of TNK-BP are reported net of tax.

Non-GAAP information on fair value accounting effects

The impacts of fair value accounting effects, relative to management s internal measure of performance, and a reconciliation to GAAP information is also set out below. Further information on fair value accounting effects is provided on page 98.

			$ million
	2012	2011	2010
Upstream			
Unrecognized gains (losses) brought forward from previous period	**(538)**	(527)	(530)
Unrecognized (gains) losses carried forward	**404**	538	527
Favourable (unfavourable) impact relative to management s measure of performance	**(134)**	11	(3)
Downstream[a]			
Unrecognized gains (losses) brought forward from previous period	**74**	137	179
Unrecognized (gains) losses carried forward	**(501)**	(74)	(137)
Favourable (unfavourable) impact relative to management s measure of performance	**(427)**	63	42
	(561)	74	39
Taxation credit (charge)[b]	**216**	(27)	(26)
	(345)	47	13
By region			
Upstream			
US	**(67)**	15	141
Non-US	**(67)**	(4)	(144)
	(134)	11	(3)
Downstream[a]			
US	**(441)**		19
Non-US	**14**	63	23
	(427)	63	42

[a] Fair value accounting effects arise solely in the fuels business.

[b] Tax is calculated using the group s discrete quarterly effective tax rate (adjusted for the Gulf of Mexico oil spill, certain impairment losses and disposal gains in 2012, equity-accounted earnings from 2012 onwards and the deferred tax adjustments relating to changes to the taxation of UK oil and gas production (2011 $683 million, 2012 $256 million)).

Reconciliation of non-GAAP information

			$ million
	2012	2011	2010
Upstream			
Replacement cost profit before interest and tax adjusted for fair value accounting effects	**22,608**	26,355	28,272
Impact of fair value accounting effects	**(134)**	11	(3)
Replacement cost profit before interest and tax	**22,474**	26,366	28,269
Downstream			
Replacement cost profit before interest and tax adjusted for fair value accounting effects	**3,273**	5,411	5,513
Impact of fair value accounting effects	**(427)**	63	42
Replacement cost profit before interest and tax	**2,846**	5,474	5,555
Total group			
Profit (loss) before interest and tax adjusted for fair value accounting effects	**20,294**	39,743	(3,741)
Impact of fair value accounting effects	**(561)**	74	39
Profit (loss) before interest and tax	**19,733**	39,817	(3,702)

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Risk factors

We urge you to consider carefully the risks described below. The potential impact of the occurrence, or reoccurrence, of any of the risks described below could have a material adverse effect on BP s business, financial position, results of operations, competitive position, cash flows, prospects, liquidity, shareholder returns and/or implementation of its strategic agenda.

The risks are categorized against the following areas: strategic and commercial; compliance and control; and safety and operational. In addition, we have also set out one further risk for your attention those resulting from the 2010 Gulf of Mexico oil spill (the Incident).

The Gulf of Mexico oil spill has had and could continue to have a material adverse impact on BP.

While significant charges have been recognized in the income statement since the Incident occurred in 2010, there is significant uncertainty regarding the extent and timing of the remaining costs and liabilities relating to the Incident, the potential changes in applicable regulations and the operating environment that may result from the Incident, the impact of the Incident on our reputation and the resulting possible impact on our licence to operate including our ability to access new opportunities. The amount of claims that become payable by BP, the amount of fines ultimately levied on BP (including any potential determination of BP s negligence or gross negligence), the outcome of litigation, the terms of any further settlements including the amount and timing of any payments thereunder, and any costs arising from any longer-term environmental consequences of the Incident, will also impact upon the ultimate cost for BP. Although the provisions recognized represent the current best estimates of expenditures required to settle certain present obligations that can be reasonably estimated at the end of the reporting period, there are future expenditures for which it is not possible to measure our obligations reliably and the total amounts paid by BP in relation to all obligations relating to the Incident are subject to significant uncertainty. These uncertainties are likely to continue for a significant period, increase the risks to which the group is exposed and may cause our costs to increase. Thus, the Incident has had, and could continue to have, a material adverse impact on the group s business, competitive position, financial performance, cash flows, prospects, liquidity, shareholder returns and/or implementation of its strategic agenda, particularly in the US. The risks associated with the Incident could also heighten the impact of the other risks to which the group is exposed as further described below.

Strategic and commercial risks

Access and renewal BP s future hydrocarbon production depends on our ability to renew and reposition our portfolio. Increasing competition for access to investment opportunities, the effects of the Gulf of Mexico oil spill on our reputation and cash flows, and more stringent regulation could result in decreased access to opportunities globally.

Successful execution of our group strategy depends on implementing activities to renew and reposition our portfolio. The challenges to renewal of our upstream portfolio are growing due to increasing competition for access to opportunities globally among both national and international oil companies, and heightened political and economic risks in certain countries where significant hydrocarbon basins are located. Lack of material positions could impact our future hydrocarbon production.

Moreover, the Incident has damaged BP s reputation, which may have a long-term impact on the group s ability to access new opportunities, both in the US and elsewhere. Adverse public, political, regulatory and industry sentiment towards BP, and towards oil and gas drilling activities generally, could damage or impair our existing commercial relationships with counterparties, partners and host governments and could impair our access to new investment opportunities, exploration properties, operatorships or other essential commercial arrangements with potential partners and host governments, particularly in the US. In addition, responding to the Incident has placed, and will continue to place, a significant burden on our cash flow over the next several years, which could also impede our ability to invest in new opportunities and deliver long-term growth.

More stringent regulation of the oil and gas industry generally, and of BP s activities specifically, following the Incident, could increase this risk.

Prices and markets BP s financial performance is subject to the fluctuating prices of crude oil and gas, the volatile prices of refined products and the profitability of our refining and petrochemicals operations, as well as the general macroeconomic outlook.

Oil, gas and product prices and margins can be very volatile, and are subject to international supply and demand. Political developments (including conflict situations) and the outcome of meetings of OPEC can particularly affect world supply and oil prices. Previous oil price increases have resulted in increased fiscal take, cost inflation and more onerous terms for access to resources. As a result, increased oil prices may not improve margin performance. In addition to the adverse effect on revenues, margins and profitability from any fall in oil and natural gas prices, a prolonged period of low prices or other indicators would lead to further reviews for impairment of the group s oil and natural gas properties. Such reviews would reflect management s view of long-term oil and natural gas prices and could result in a charge for impairment that could have a significant effect on the group s results of operations in the period in which it occurs. Rapid material or sustained change in oil, gas and product prices can impact the validity of the assumptions on which strategic decisions are based and, as a result, the ensuing actions derived from those decisions may no longer be appropriate. A prolonged period of low oil prices may impact our cash flow, profit and ability to maintain our long-term investment programme with a consequent effect on our growth rate, and may impact shareholder returns, including dividends and share buybacks, or share price.

Refining profitability can be volatile, with both periodic over-supply and supply tightness in various regional markets, coupled with fluctuations in demand. Sectors of the petrochemicals industry are also subject to fluctuations in supply and demand, with a consequent effect on prices and profitability. Periods of global recession could impact the demand for our products, the prices at which they can be sold and affect the viability of the markets in which we operate.

Governments are facing greater pressure on public finances, which may increase their motivation to intervene in the fiscal and regulatory frameworks of the oil and gas industry, including the risk of increased taxation, nationalization and expropriation.

The global financial and economic situation may have a negative impact on third parties with whom we do, or may do, business. In particular, ongoing instability in or a collapse of the eurozone could trigger a new wave of financial crises and push the world back into recession, leading to lower demand and lower oil and gas prices.

Climate change and carbon pricing climate change and carbon pricing policies could result in higher costs and reduction in future revenue and strategic growth opportunities.

Compliance with changes in laws, regulations and obligations relating to climate change could result in substantial capital expenditure, taxes, reduced profitability from changes in operating costs, and revenue generation and strategic growth opportunities being impacted. Our commitment to the transition to a lower-carbon economy may create expectations for our activities, and the level of participation in alternative energies carries reputational, economic and technology risks.

Socio-political the diverse nature of our operations around the world exposes us to a wide range of political developments and consequent changes to the operating environment, regulatory environment and law.

We have operations, and are seeking new opportunities, in countries where political, economic and social transition is taking place. Some countries have experienced, or may experience in the future, political instability, changes to the regulatory environment, changes in taxation, expropriation or nationalization of property, civil strife, strikes, acts of war and insurrections. Any of these conditions occurring could disrupt or terminate our operations, causing our development activities to be curtailed or terminated in these areas, or our production to decline, could limit our ability to pursue new opportunities, could affect the recoverability of our assets and could cause us to incur additional costs. In particular, our investments in the US, Russia, the Middle East region, North Africa, Bolivia, Argentina, Angola, Azerbaijan and other countries could be adversely affected by heightened political and economic environment risks. See pages 6-7 for information on the locations of our major areas of operation and activities.

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We set ourselves high standards of corporate citizenship and aspire to contribute to a better quality of life through the products and services we provide. If it is perceived that we are not respecting or advancing the economic and social progress of the communities in which we operate or that we have not satisfactorily addressed all relevant stakeholder concerns in respect of our operations, our reputation and shareholder value could be damaged and development opportunities may be precluded.

Competition BP s group strategy depends upon continuous innovation and efficiency in a highly competitive market.

The oil, gas and petrochemicals industries are highly competitive. There is strong competition, both within the oil and gas industry and with other industries, in supplying the fuel needs of commerce, industry and the home. Competition puts pressure on the terms of access to new opportunities, licence costs and product prices, affects oil products marketing and requires continuous management focus on reducing unit costs and improving efficiency, while ensuring safety and operational risk is not compromised. The implementation of group strategy requires continued technological advances and innovation including advances in exploration, production, refining, petrochemicals manufacturing technology and advances in technology related to energy usage. Our performance could be impeded if competitors developed or acquired intellectual property rights to technology that we require, if our innovation lagged the industry, or if we fail to adequately protect our company brands and trade marks. Our competitive position in comparison to our peers could be adversely affected if competitors offer superior terms for access rights or licences, if we fail to control our operating costs or manage our margins, or if we fail to sustain, develop and operate efficiently a high quality portfolio of assets.

Joint ventures and other contractual arrangements BP may not have full operational control and may have exposure to counterparty credit risk and disruptions to our operations and strategic objectives due to the nature of some of its business relationships.

Many of our major projects and operations are conducted through joint ventures or associates and through contracting and sub-contracting arrangements. These arrangements often involve complex risk allocation, decision-making processes and indemnification arrangements. In certain cases, we may have less control of such activities than we would have if BP had full operational control. Our partners may have economic or business interests or objectives that are inconsistent with, or opposed to, those of BP and may exercise veto rights to block certain key decisions or actions that BP believes are in its or the joint venture s or associate s best interests, or approve such matters without our consent. Additionally, our joint venture partners or associates or contractual counterparties are primarily responsible for the adequacy of the human or technical competencies and capabilities which they bring to bear on the joint project and, in the event these are found to be lacking, our joint-venture partners or associates may not be able to meet their financial or other obligations to their counterparties or to the relevant project, potentially threatening the viability of such projects. Furthermore, should accidents or incidents occur in operations in which BP participates, whether as operator or otherwise, and where it is held that our sub-contractors or joint-venture partners are legally liable to share any aspects of the cost of responding to such incidents, the financial capacity of these third parties may prove inadequate to fully indemnify BP against the costs we incur on behalf of the joint venture or contractual arrangement. Should a key sub-contractor, such as a lessor of drilling rigs, be no longer able to make these assets available to BP, this could result in serious disruption to our operations. Where BP does not have operational control of a venture, BP may nonetheless still be pursued by regulators or claimants in the event of an incident.

Rosneft transaction BP s failure to complete the agreed transaction with Rosneft, or any future erosion of our relationship with Rosneft, could adversely impact our business, the level of our reserves and our reputation.

On 22 November 2012, BP announced that it had signed definitive and binding agreements in respect of the sale of BP s 50% interest in TNK-BP to Rosneft and BP s investment in Rosneft (the Rosneft transaction). See TNK-BP on pages 80-81. Completion of the Rosneft transaction is subject to certain customary closing conditions, including governmental, regulatory and anti-trust approvals. Failure by BP to complete the Rosneft

transaction as contemplated due to the failure to receive required approvals or otherwise could negatively impact our reputation and result in a loss of stakeholder confidence in BP s ability to meet its identified strategic objectives in Russia. In addition, to the extent we fail to maintain a good commercial relationship with Rosneft in the future, or to the extent that as a minority shareholder in Rosneft we are unable in the future to exercise influence over our investment in Rosneft or other growth opportunities in Russia, our business and strategic objectives in Russia and our ability to recognize our share of Rosneft s reserves as contemplated may be adversely impacted.

Investment efficiency poor investment decisions could negatively impact our business.

Our organic growth is dependent on creating a portfolio of quality options and investing in the best options. Ineffective investment selection and/or subsequent execution could lead to loss of value and higher capital expenditure.

Reserves progression inability to progress upstream resources in a timely manner could adversely affect our long-term replacement of reserves and negatively impact our business.

Successful execution of our group strategy depends critically on sustaining long-term reserves replacement. If upstream resources are not progressed in a timely and efficient manner due to commercial, technical or regulatory reasons or otherwise, we will be unable to sustain long-term replacement of reserves.

Major project delivery our group plan depends upon successful delivery of major projects, and failure to deliver major projects successfully could adversely affect our financial performance.

Successful execution of our group plan depends critically on implementing the activities to deliver the major projects over the plan period. Poor delivery of any major project that underpins production or production growth and/or any other major programme designed to enhance shareholder value, including maintenance turnaround programmes, could adversely affect our financial performance. Successful project delivery requires, among other things, adequate engineering and other capabilities and therefore successful recruitment and development of staff is central to our plans. See People and capability on page 40.

Digital infrastructure is an important part of maintaining our operations, and a breach of our digital security could result in serious damage to business operations, personal injury, damage to assets, harm to the environment, reputational damage, breaches of regulations, litigation, legal liabilities and reparation costs.

The reliability and security of our digital infrastructure are critical to maintaining the availability of our business applications, including the reliable operation of technology in our various business operations and the collection and processing of financial and operational data, as well as the confidentiality of certain third-party information. A breach of our digital security, either due to intentional actions or due to negligence, could cause serious damage to business operations and, in some circumstances, could result in the loss of data or sensitive information, injury to people, damage to assets, harm to the environment, reputational damage, breaches of regulations, litigation, legal liabilities and reparation costs.

Business continuity and disaster recovery the group must be able to recover quickly and effectively from any disruption or incident, as failure to do so could adversely affect our business and operations.

Contingency plans are required to continue or recover operations following a disruption or incident. Inability to restore or replace critical capacity to an agreed level within an agreed timeframe would prolong the impact of any disruption and could severely affect our business and operations.

Crisis management crisis management plans are essential to respond effectively to emergencies and to avoid a potentially severe disruption in our business and operations.

Crisis management plans and capability are essential to deal with emergencies at every level of our operations. If we do not respond, or are perceived not to respond, in an appropriate manner to either an external or internal crisis, our business and operations could be severely disrupted.

People and capability successful recruitment, development and utilization of staff is central to our plans.

Successful recruitment of new staff, employee training, development and continuing enhancement of skills, in particular technical capabilities such as petroleum engineers and scientists, are key to implementing our plans. Inability to develop human capacity and capability, both across the organization and in specific operating locations, could jeopardize performance delivery. The group relies on recruiting and retaining high-quality employees to execute its strategic plans and to operate its business. The reputational damage suffered by the group as a result of the Incident and any consequent adverse impact on our business could affect employee recruitment and retention.

In addition, significant board and management focus continues to be required in responding to matters related to the Incident. Although BP set up the Gulf Coast Restoration Organization to manage the group s long-term response, other key management personnel will need to continue to devote substantial attention to addressing the associated consequences for the group, which may negatively impact our staff s capability to address and respond to other operational matters affecting the group but unrelated to the Incident.

Liquidity, financial capacity and financial, including credit, exposure failure to operate within our financial framework could impact our ability to operate and result in financial loss. Exchange rate fluctuations can impact our underlying costs and revenues.

The group seeks to maintain a financial framework to ensure that it is able to maintain an appropriate level of liquidity and financial capacity. This framework constrains the level of assessed capital at risk for the purposes of positions taken in financial instruments. Failure to accurately forecast or maintain sufficient liquidity and credit to meet these needs (including a failure to understand and respond to potential liabilities) could impact our ability to operate and result in a financial loss. Commercial credit risk is measured and controlled to determine the group s total credit risk. Inability to determine adequately our credit exposure could lead to financial loss. Trade and other receivables, including overdue receivables, may not be recovered whether an impairment provision has been recognized or not. A credit crisis affecting banks and other sectors of the economy could impact the ability of counterparties to meet their financial obligations to the group. It could also affect our ability to raise capital to fund growth, to maintain our long-term investment programme and to meet our obligations, and may impact shareholder returns, including dividends and share buybacks, or share price. Decreases in the funded levels of our pension plans may also increase our pension funding requirements. The group s financial framework may not be sufficient to respond to a substantial and unexpected cash call or funding request, and external events may materially impact the effectiveness of the group s financial framework. In addition, operational challenges could impact the availability of the group s assets, which could adversely affect the group s operating cash flows.

BP s potential liabilities resulting from pending and future claims, lawsuits, settlements and enforcement actions relating to the Gulf of Mexico oil spill, together with the potential cost of implementing remedies sought in the various proceedings, cannot be fully estimated at this time but they have had, and could continue to have, a material adverse impact on the group s financial performance and liquidity. Further potential liabilities may continue to have a material adverse effect on the group s results of operations and financial condition. See Financial statements Note 43 on page 253 and Legal proceedings on pages 162-171. More stringent regulation of the oil and gas industry arising from the Incident, and of BP s activities specifically, could increase this risk.

Crude oil prices are generally set in US dollars, while sales of refined products may be in a variety of currencies. In addition, a high proportion of our major project development costs are denominated in local currencies, which may be subject to volatile fluctuations against the US dollar. Fluctuations in exchange rates can therefore give rise to foreign exchange exposures, with a consequent impact on underlying costs and revenues. See Prices and markets on page 38.

See Financial statements Note 26 on page 220 for more information on financial instruments and financial risk factors.

Insurance BP s insurance strategy means that the group could, from time to time, be exposed to material uninsured losses which could have a material adverse effect on BP s financial condition and results of operations.

In the context of the limited capacity of the insurance market, many significant risks are retained by BP. The group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. This means that the group could be exposed to material uninsured losses, which could have a material adverse effect on its financial condition and results of operations. In particular, these uninsured costs could arise at a time when BP is facing material costs arising out of some other event which could put pressure on BP s liquidity and cash flows. For example, BP has borne and will continue to bear the entire burden of its share of any property damage, well control, pollution clean-up and third-party liability expenses arising out of the Gulf of Mexico oil spill.

Compliance and control risks

Our settlement with the US Department of Justice and the SEC in respect of federal criminal charges and US securities law violations related to the Gulf of Mexico oil spill may expose us to further penalties, liabilities and private litigation, and may impact our operations and adversely affect our ability to quickly and efficiently access US capital markets.

On 15 November 2012, BP reached an agreement with the US government to resolve all federal criminal and securities claims arising out of the Incident and comprising settlements with the US Department of Justice (DoJ) and the SEC. On 29 January 2013, the US District Court for the Eastern District of Louisiana accepted BP s pleas regarding the federal criminal charges, and sentenced BP in accordance with the criminal plea agreement. BP pleaded guilty to 11 felony counts of Misconduct or Neglect of Ships Officers relating to the loss of 11 lives; one misdemeanour count under the Clean Water Act; one misdemeanour count under the Migratory Bird Treaty Act; and one felony count of obstruction of Congress. Pursuant to that sentence, BP will pay $4 billion, including $1.256 billion in criminal fines, in instalments over a period of five years. The court also ordered, as previously agreed with the US government, that BP serve a term of five years probation. Pursuant to the terms of the plea agreement, the court also ordered certain equitable relief, including additional actions, enforceable by the court, to further enhance the safety of drilling operations in the Gulf of Mexico. In addition, BP will undertake several initiatives with academia and regulators to develop new technologies related to deepwater drilling safety. The resolution also provides for the appointment of two monitors, both with terms of four years. A process safety monitor will review, evaluate, and provide recommendations for the improvement of BP s process safety and risk management procedures concerning deepwater drilling in the Gulf of Mexico. An ethics monitor will review and provide recommendations for the improvement of BP s code of conduct and its implementation and enforcement. BP has also agreed to hire an independent third-party auditor who will review and report to the probation officer, the DoJ, and BP regarding BP s implementation of key terms of the proposed settlement, including procedures and systems related to safety and environmental management, operational oversight, and oil spill response training and drills. Under the plea agreement, BP has also agreed to co-operate in ongoing criminal actions and investigations, including prosecutions of four former employees who have been separately charged.

Also on 15 November 2012, BP reached a settlement with the SEC to resolve the SEC s Deepwater Horizon-related claims against the company under Sections 10(b) and 13(a) of the Securities Exchange Act of 1934 and the associated rules. Under the SEC settlement, BP has agreed to a civil penalty of $525 million, payable in three instalments over a period of three years, and has consented to the entry of an injunction prohibiting it from violating certain US securities laws and regulations. The SEC settlement was approved by the US District Court for the Eastern District of Louisiana on 10 December 2012. See Legal proceedings on pages 162-171.

On 28 November 2012, the US Environmental Protection Agency (EPA) notified BP that it had temporarily suspended BP p.l.c., BP Exploration & Production Inc. (BPXP) and a number of other BP subsidiaries from participating in new federal contracts. As a result of the temporary suspension, the BP entities listed in the EPA notice are ineligible to receive any US government contracts either through the award of a new contract, or the extension of the term or renewal of an expiring contract. The suspension does not affect existing contracts the company has with the US government, including those relating to current and ongoing drilling and production operations in the Gulf of Mexico.

The charges to which BPXP pleaded guilty included one misdemeanour count under the Clean Water Act which, by operation of law following the court s acceptance of BP s plea, triggers a statutory debarment, also referred to as mandatory debarment, of the BPXP facility where the Clean Water Act violation occurred.

On 1 February 2013, the EPA issued a notice that BPXP was mandatorily debarred at its Houston headquarters. Mandatory debarment prevents a company from entering into new contracts or new leases with the US government that would be performed at the facility where the Clean Water Act violation occurred. A mandatory debarment does not affect any existing contracts or leases a company has with the US government and will remain in place until such time as the debarment is lifted through an agreement with the EPA.

With respect to the entities named in the temporary suspension, the temporary suspension may be maintained or the EPA may elect to issue a notice of proposed discretionary debarment to some or all of the named entities. Like suspension, a discretionary debarment would preclude BP entities listed in the notice from receiving new federal fuel contracts, as well as new oil and gas leases, although existing contracts and leases will continue. Discretionary debarment typically lasts three to five years and may be imposed for a longer period, unless it is resolved through an administrative agreement.

While BP s discussions with the EPA have been taking place in parallel to the court proceedings on the criminal plea, the company s work toward reaching an administrative agreement with the EPA is a separate process, and it may take some time to resolve issues relating to such an agreement. BP s mandatory debarment applies following sentencing and is not an indication of any change in the status of discussions with the EPA. The process for resolving both mandatory and discretionary debarment is essentially the same as for resolving the temporary suspension. BP continues to work with the EPA in preparing an administrative agreement that will resolve suspension and debarment issues.

The DoJ criminal and SEC settlements impose significant compliance and remedial obligations on BP and its directors, officers and employees. Failure to comply with the terms of these settlements could result in further enforcement action by the DoJ and the SEC, expose BP to severe penalties, financial or otherwise, and subject BP to further private litigation, each of which could impact our operations and have a material adverse effect on the group s business. Prolonged suspension or debarment from entering new federal contracts, or further suspension or debarment proceedings against BP and/or its subsidiaries as a result of violations of the terms of the DoJ or SEC settlements or otherwise, could have a material adverse impact on the group s operations in the US.

As a result of the SEC settlement, as of the filing with the SEC of certain registration statements on Form S-8 on 5 February 2013, and for a period of three years thereafter, we will no longer be qualified as a well known seasoned issuer (WKSI) as defined in Rule 405 of the Securities Act of 1933, as amended (Securities Act), and therefore will not be able to take advantage of the benefits available to a WKSI, including engaging in delayed or continuous offerings of securities using an automatic shelf registration statement. In addition, as of the settlement date and for a period of five years thereafter, we are no longer able to utilize certain registration exemptions provided by the Securities Act in connection with certain securities offerings. In addition, we may be denied certain trading authorizations under the rules of the US Commodities Futures Trading Commission, which may prevent us in the future from entering certain routine swap transactions for an indefinite period of time.

Regulatory BP, and the oil industry in general, face increased regulation in the US and elsewhere that could increase the cost of regulatory compliance and limit our access to new exploration properties.

Due to the Gulf of Mexico oil spill and any remedial provisions contained in or resulting from the DoJ and SEC settlements (see Legal proceedings on pages 162-169), it is likely that there will be more stringent regulation of BP s oil and gas activities in the US and elsewhere, particularly relating to environmental, health and safety controls and oversight of drilling operations, as well as access to new drilling areas. Regulatory or legislative action may

impact the industry as a whole and could be directed specifically towards BP. New regulations and legislation, the terms of BP s settlements with US government authorities and future settlements or litigation outcomes related to the Incident, and/or evolving practices could increase the cost of compliance and may require changes to our drilling operations, exploration, development and decommissioning plans, and could impact our ability to capitalize on our assets and limit our access to new exploration properties or operatorships, particularly in the deepwater Gulf of Mexico. In addition, increases in taxes, royalties and other amounts payable to governments or governmental agencies, or restrictions on availability of tax relief, could also be imposed as a response to the Incident.

In addition, the oil industry in general is subject to regulation and intervention by governments throughout the world in such matters as the award of exploration and production interests, the imposition of specific drilling obligations, environmental, health and safety controls, controls over the development and decommissioning of a field (including restrictions on production) and, possibly, nationalization, expropriation, cancellation or non-renewal of contract rights.

We buy, sell and trade oil and gas products in certain regulated commodity markets. Failure to respond to changes in trading regulations could result in regulatory action and damage to our reputation. The oil industry is also subject to the payment of royalties and taxation, which tend to be high compared with those payable in respect of other commercial activities, and operates in certain tax jurisdictions that have a degree of uncertainty relating to the interpretation of, and changes to, tax law. As a result of new laws and regulations or other factors, we could be required to curtail or cease certain operations, or we could incur additional costs. See pages 51-54 for more information on environmental regulation.

Ethical misconduct and non-compliance ethical misconduct or breaches of applicable laws by our employees could be damaging to our reputation and shareholder value.

Our code of conduct, which applies to all employees, defines our commitment to integrity, compliance with all applicable legal requirements, diversity, high ethical standards and the behaviours and actions we expect of our businesses and people wherever we operate. Our values are intended to guide the way we and our employees behave and do business. Under the terms of the DoJ settlement (see pages 40-41), an ethics monitor will review and provide recommendations for the improvement of our code of conduct and its implementation and enforcement. Incidents of ethical misconduct, non-compliance with the recommendations of the ethics monitor or non-compliance with applicable laws and regulations, including non-compliance with anti-bribery, anti-corruption and other applicable laws could be damaging to our reputation and shareholder value and could subject us to further regulatory action or penalties under the terms of the DoJ settlement. Multiple events of non-compliance could call into question the integrity of our operations. For example, in our trading businesses, there is the risk that a determined individual could operate as a rogue trader , acting outside BP s delegations, controls or code of conduct and in contravention of our values in pursuit of personal objectives that could be to the detriment of BP and its shareholders.

For certain legal proceedings involving the group, see Legal proceedings on pages 162-171. For further information on the risks involved in BP s trading activities, see Treasury and trading activities on page 43.

Liabilities and provisions BP s potential liabilities resulting from pending and future claims, lawsuits, settlements and enforcement actions relating to the Gulf of Mexico oil spill, together with the potential cost and burdens of implementing remedies sought in the various proceedings, cannot be fully estimated at this time but they have had, and are expected to continue to have, a material adverse impact on the group s business.

Under the Oil Pollution Act of 1990 (OPA 90), BP Exploration & Production Inc. and BP Corporation North America are among the parties financially responsible for the clean-up of the Gulf of Mexico oil spill and for certain economic damages as provided for in OPA 90, as well as certain natural resource damages associated with the spill and certain costs determined by federal and state trustees engaged in a joint assessment of such natural resource damages.

BP and certain of its subsidiaries have also been named as defendants in numerous lawsuits in the US arising out of the Incident, including actions for personal injury and wrongful death, purported class actions for commercial or economic injury, actions for breach of contract, violations of statutes, property and other environmental damage, securities law claims and various other claims. See Legal proceedings on pages 162-169.

BP is subject to a number of investigations related to the Incident by numerous federal and State agencies. See Legal proceedings on pages 162-169. The types of enforcement action pursued and the nature of the remedies sought will depend on the discretion of the prosecutors and regulatory authorities and, in some circumstances, their assessment of BP s culpability, if any, following their investigations. Under the Clean Water Act, any finding of gross negligence for purposes of penalties sought against BP would result in significantly higher fines and penalties than the amounts for which we have provided and would also have a material adverse impact on the group s reputation, would affect our ability to recover costs relating to the Incident from other parties responsible under OPA 90 and could affect the fines and penalties payable by BP with respect to the Incident under enforcement actions outside the Clean Water Act context.

On 3 March 2012, BP reached an agreement (comprising two separate settlement agreements) with the Plaintiffs Steering Committee (PSC) in the Multi-District Litigation pending in New Orleans (MDL 2179) to resolve the substantial majority of legitimate private economic and property damages claims and medical benefits claims stemming from the Incident. The settlement agreement in respect of economic and property damages claims was approved by the Court on 21 December 2012, and the settlement agreement in respect of medical benefits claims was approved on 11 January 2013. The PSC settlement is uncapped except for economic loss claims related to the Gulf seafood industry. The cost of the PSC settlement is expected to be paid from the $20-billion Deepwater Horizon Oil Spill Trust fund (Trust). As at 31 December 2011, the estimate of items covered by the settlement with the PSC for Individual and Business claims was $7.8 billion. During 2012, BP increased its estimate of the cost of claims administration by $280 million and also increased the estimate by a further $400 million as described below.

Business economic loss claims received by the Deepwater Horizon Court Supervised Settlement Program (DHCSSP) to date are being paid at a significantly higher average amount than previously assumed by BP in formulating the original estimate of the cost. Further, BP s initial estimate of aggregate liability under the settlement agreements was premised on BP s interpretation of certain protocols established in the economic and property damages settlement agreement. As part of its monitoring of payments made by the court-supervised claims processes operated by the DHCSSP for the economic and property damages settlement, BP identified multiple claim determinations that appeared to result from an interpretation of the settlement agreement by that settlement s claims administrator that BP believes was incorrect. This interpretation produced a higher number and value of awards than the interpretation BP assumed in making the initial estimate. Pursuant to the mechanisms in that settlement agreement, the claims administrator sought clarification from the court on this matter and on 30 January 2013, the court initially upheld the claims administrator s interpretation of the agreement.

In its unaudited fourth quarter and full year 2012 results announcement dated 5 February 2013, BP stated that if the initial trend of higher average payments than assumed by BP in its original estimate of the cost continued, then it was likely that BP s estimate of these claims would be increased significantly. Management s initial assessment of the ruling regarding the interpretation of the settlement agreement led to an increase in the estimated cost of the settlement with the PSC of $400 million, bringing the total estimated cost to $8.5 billion. This estimate was based upon management s initial assessment of the ruling s impact on claims already submitted to and processed by the DHCSSP. At that time, BP was seeking reversal of the court s decision in relation to this matter, management concluded that it was not possible to estimate reliably the impact of the interpretation on any future claims not yet received or processed by the DHCSSP.

On 6 February 2013, the court reconsidered and vacated its ruling of 30 January 2013 and stayed the processing of certain types of bussiness economic loss claims. The court lifted the stay on 28 February 2013. On 5 March 2013, the court affirmed the claims administrator s interpretation of the economic and property damages settlement agreement and rejected BP s position as it relates to business economic loss claims. BP strongly disagrees with the decision of 5 March 2013 and the current implementation of the agreement by the claims administrator. BP intends to pursue all available legal options, including rights of appeal, to challenge this ruling.

Other business economic loss claims have continued to be paid at a higher average amount than previously assumed by BP in determining its initial estimate of the total cost. Management has continued to analyse the claims in the period since 5 February 2013 to

gain a better understanding of whether or not the number and average value of claims received and processed to date are predictive of future claims (and so would allow management to estimate the total cost of the Settlements reliably). Management has concluded based upon this analysis that it is not possible to determine whether the claims experience to date is, or is not, an appropriate basis for determining the total cost. Therefore, given the inherent uncertainty that exists as BP pursues all available legal options to challenge the recent ruling and the higher number of claims received and higher average claims payments than previously assumed by BP, which may or may not continue, management has concluded that no reliable estimate can be made of any business economic loss claims not yet received or processed by the DHCSSP.

Therefore, BP s estimate of the cost of business economic loss claims at 31 December 2012 now includes only the estimated cost of claims already received and processed by the DHCSSP. An amount of $0.8 billion previously provided for future claims not yet received and processed by the DHCSSP has been derecognized, with a corresponding reduction in the reimbursement asset and therefore no net impact on the income statement, as no reliable estimate can be made for this liability. It is therefore disclosed as a contingent liability in Note 43. A provision will be re-established when a reliable estimate can be made of the liability as explained more fully below.

BP s current estimate of the total cost of those elements of the PSC settlement that can be estimated reliably, which excludes any future business economic loss claims not yet received or processed by the DHCSSP, is $7.7 billion.

If BP is successful in its challenge to the Court s ruling, the total estimated cost of the settlement agreement will, nevertheless, be significantly higher than the current estimate of $7.7 billion, because business economic loss claims not yet received or processed are not reflected in the current estimate and the average payments per claim determined so far are higher than anticipated. If BP is not successful in its challenge to the Court s ruling, a further significant increase to the total estimated cost of the settlement will be required. However, there can be no certainty as to how the dispute will ultimately be resolved or determined. To the extent that there are insufficient funds available in the Trust fund, payments under the PSC settlement will be made by BP directly and charged to the income statement.

As previously disclosed, significant uncertainties exist in relation to the amount of claims that are to be paid and will become payable through the claims process. There is significant uncertainty in relation to the amounts that ultimately will be paid in relation to current claims, and the number, type and amounts payable for claims not yet reported. In addition, there is further uncertainty in relation to interpretations of the claims administrator regarding the protocols under the economic and property damages settlement agreement and judicial interpretation of these protocols, and the outcomes of any further litigation including in relation to potential opt-outs from the settlement or otherwise.

While BP has determined its current best estimate of the cost of those aspects of the settlement with the PSC that can be measured reliably, it is possible that the actual cost could be significantly higher than this estimate due to the uncertainties noted above. In addition, the provision will be re-established for remaining business economic loss claims and the estimate will increase as more information becomes available, the interpretation of the protocols is clarified and the claims process matures, enabling BP to estimate reliably the cost of these claims. See Financial statements Note 36 on page 235 and Note 43 on page 253 for further information.

The Gulf of Mexico oil spill has damaged BP s reputation. This, combined with other past events in the US (including the 2005 explosion at the Texas City refinery and the 2006 pipeline leaks in Alaska), may lead to an increase in the number of citations and/or the level of fines imposed in relation to any alleged breaches of safety or environmental regulations.

See Legal proceedings on pages 162-169 and Financial statements Note 2 on page 194.

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 is reliant on the integrity of systems and people. Failure to report data accurately and in compliance with external standards could result in regulatory action, legal liability and damage to our reputation.

As of the date of the SEC settlement, 10 December 2012, and for a period of three years thereafter, we are unable to rely on the safe harbor provisions regarding forward-looking statements provided by the regulations issued under the Securities Act, and the Securities Exchange Act of 1934, as amended. Our inability to rely on these safe harbor provisions may expose us to future litigation and liabilities in connection with forward-looking statements in our public disclosures.

Changes in external factors could affect our results of operations and the adequacy of our provisions.

We remain exposed to changes in the external environment, such as new laws and regulations (whether imposed by international treaty or by national or local governments in the jurisdictions in which we operate), changes in tax or royalty regimes, price controls, government actions to cancel or renegotiate contracts, market volatility or other factors. Such factors could reduce our profitability from operations in certain jurisdictions, limit our opportunities for new access, require us to divest or write-down certain assets or affect the adequacy of our provisions for pensions, tax, environmental and legal liabilities. Potential changes to pension or financial market regulation could also impact funding requirements of the group.

Treasury and trading activities control of these activities depends on our ability to process, manage and monitor a large number of transactions. Failure to do this effectively could lead to business disruption, financial loss, regulatory intervention or damage to our reputation.

In the normal course of business, we are subject to operational risk around our treasury and trading activities. Control of these activities is highly dependent on our ability to process, manage and monitor a large number of complex transactions across many markets and currencies. Shortcomings or failures in our systems, risk management methodology, internal control processes or people could lead to disruption of our business, financial loss, regulatory intervention or damage to our reputation.

Following the Gulf of Mexico oil spill, Moody s Investors Service, Standard and Poor s and Fitch Ratings downgraded the group s long-term credit ratings. Since that time, the group s credit ratings have improved somewhat but are still lower than they were immediately before the Gulf of Mexico oil spill. The impact that a significant operational incident can have on the group s credit ratings, taken together with the reputational consequences of any such incident, the ratings and assessments published by analysts and investors concerns about the group s costs arising from any such incident, ongoing contingencies, liquidity, financial performance and volatile credit spreads, could increase the group s financing costs and limit the group s access to financing. The group s ability to engage in its trading activities could also be impacted due to counterparty concerns about the group s financial and business risk profile in such circumstances. Such counterparties could require that the group provide collateral or other forms of financial security for its obligations, particularly if the group s credit ratings are downgraded. Certain counterparties for the group s non-trading businesses could also require that the group provide collateral for certain of its contractual obligations, particularly if the group s credit ratings were downgraded below investment grade or where a counterparty had concerns about the group s financial and business risk profile following a significant operational incident. In addition, BP may be unable to make a drawdown under certain of its committed borrowing facilities in the event that we are aware that there are pending or threatened legal, arbitration or administrative proceedings which, if determined adversely, might reasonably be expected to have a material adverse effect on our ability to meet the payment obligations under any of these facilities. Credit rating downgrades could trigger a requirement for the company to review its funding arrangements with the BP pension trustees. Extended constraints on the group s ability to obtain financing and to engage in its trading activities on acceptable terms (or at all) would put pressure on the group s liquidity. In addition, this could occur at a time when cash flows from our business operations would be constrained following a significant operational incident, and the group could be required to reduce planned capital expenditures and/or increase asset disposals in order to provide additional liquidity, as the group did following the Gulf of Mexico oil spill.

Safety and operational risks

The risks inherent in our operations include a number of hazards that, although many may have a low probability of occurrence, can have extremely serious consequences if they do occur, such as the Gulf of Mexico oil spill. The occurrence of any such risks could have a consequent material adverse impact on the group s business, competitive position, cash flows, results of operations, financial position, prospects, liquidity, shareholder returns and/or implementation of the group s strategic goals.

Process safety, personal safety and environmental risks the nature of our operations exposes us to a wide range of significant health, safety, security and environmental risks, the occurrence of which could result in regulatory action, legal liability and increased costs and damage to our reputation.

The nature of the group s operations exposes us to a wide range of significant health, safety, security and environmental risks. The scope of these risks is influenced by the geographic range, operational diversity and technical complexity of our activities. In addition, in many of our major projects and operations, risk allocation and management is shared with third parties such as contractors, sub-contractors, joint venture partners and associates. See Strategic and commercial risks Joint ventures and other contractual arrangements on page 39.

There are risks of technical integrity failure as well as risk of natural disasters and other adverse conditions in many of the areas in which we operate, which could lead to loss of containment of hydrocarbons and other hazardous material, as well as the risk of fires, explosions or other incidents.

In addition, inability to provide safe environments for our workforce and the public while at our facilities or premises could lead to injuries or loss of life and could result in regulatory action, legal liability and damage to our reputation.

Our operations are often conducted in difficult or environmentally sensitive locations, in which the consequences of a spill, explosion, fire or other incident could be greater than in other locations. These operations are subject to various environmental and safety laws, regulations and permits and the consequences of failure to comply with these requirements can include remediation obligations, penalties, loss of operating permits and other sanctions. Accordingly, inherent in our operations is the risk that if we fail to abide by environmental and safety and protection standards, such failure could lead to damage to the environment and could result in regulatory action, legal liability, material costs, damage to our reputation or denial of our licence to operate.

BP s group-wide operating management system (OMS) intends to address health, safety, security, environmental and operations risks, and to provide a consistent framework within which the group can analyse the performance of its activities and identify and remediate shortfalls. There can be no assurance that OMS will adequately identify all process safety, personal safety and environmental risk or provide the correct mitigations, or that all operations will be in conformance with OMS at all times.

Security hostile activities against our staff and activities could cause harm to people and disrupt our operations.

Security threats require continuous oversight and control. Acts of terrorism, piracy, sabotage, cyber-attacks and similar activities directed against our operations and offices, pipelines, transportation or computer systems could cause harm to people and could severely disrupt business and operations. Our business activities could also be severely disrupted by, among other things, conflict, civil strife or political unrest in areas where we operate.

Product quality failure to meet product quality standards could lead to harm to people and the environment and loss of customers.

Supplying customers with on-specification products is critical to maintaining our licence to operate and our reputation in the marketplace. Failure to meet product quality standards throughout the value chain could lead to harm to people and the environment and loss of customers.

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Drilling and production these activities require high levels of investment and are subject to natural hazards and other uncertainties. Activities in challenging environments heighten many of the drilling and production risks including those of integrity failures, which could lead to curtailment, delay or cancellation of drilling operations, or inadequate returns from exploration expenditure.

Exploration and production require high levels of investment and are subject to natural hazards and other uncertainties, including those relating to the physical characteristics of an oil or natural gas field. Our exploration and production activities are often conducted in extremely challenging environments, which heighten the risks of technical integrity failure and natural disasters discussed above. The 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. In addition, exploration expenditure may not yield adequate returns, for example in the case of unproductive wells or discoveries that prove uneconomic to develop. The Gulf of Mexico oil spill illustrates the risks we face in our drilling and production activities.

Transportation all modes of transportation of hydrocarbons involve inherent and significant risks.

All modes of transportation of hydrocarbons involve inherent risks. An explosion or fire or loss of containment of hydrocarbons or other hazardous material could occur during transportation by road, rail, sea or pipeline. This is a significant risk due to the potential impact of a release on people and the environment and given the high volumes potentially involved.

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Further note on certain activities

During the period covered by this report, non-US subsidiaries or other non-US entities of BP conducted limited activities in, or with persons from, certain countries identified by the US Department of State as State Sponsors of Terrorism or otherwise subject to US sanctions (Sanctioned Countries). These activities continue to be insignificant to the group s financial condition and results of operations.

In July 2012, US President Obama signed Executive Order 13622 (EO) authorizing the imposition of additional sanctions against persons who engage in certain dealings with Iran, and in August 2012, the US Congress enacted the US Iran Threat Reduction and Syria Human Rights Act of 2012 (ITRA). Further, on 3 January 2013, US President Obama signed into law the National Defense Authorization Act for Fiscal Year 2013, containing a subtitle known as the Iran Freedom and Counter-Proliferation Act of 2012 (IFCPA) that will impose additional sanctions against Iran when its provisions become effective in July 2013. Together, these measures impose additional sanctions against Iran which include new sanctions against persons involved with Iran s energy, shipping and petrochemicals industries, and sanctions against financial institutions that engage in significant transactions with the Iran Central Bank.

Similarly the EU has strengthened its sanctions on Iran. On 23 March 2012 the Council of the European Union extended its existing measures against Iran by promulgating Regulation 267/2012 which included a prohibition on the import, purchase and transport of Iranian-origin crude oil and petroleum products. Further, on 15 October 2012, the EU announced new restrictive measures against Iran and certain Iranian entities, including Naftiran Intertrade Co. Limited, some of which were effective immediately, and some of which were implemented by an amending Regulation (1263/2012) on 22 December 2012, including a prohibition on the import, purchase and transport of Iranian-origin natural gas.

Both the US and the EU have enacted strong sanctions against Syria, including a prohibition on the purchase of Syrian-origin crude and a US prohibition on the provision of services to Syria by US persons. The EU sanctions against Syria include a prohibition on supplying certain equipment used in the production, refining, or liquefaction of petroleum resources as well as restrictions on dealing with the Central Bank of Syria and numerous other Syrian financial institutions.

BP seeks to comply with all applicable laws and regulations of the US, the EU and other countries where BP operates, and monitors its activities with Sanctioned Countries and persons from Sanctioned Countries.

BP has interests in and operates two fields the North Sea Rhum field and the Azerbaijan Shah Deniz field and has interests in a gas marketing entity and a gas pipeline entity which, respectively, market and transport Shah Deniz gas (both entities and related assets are located outside Iran), in which Naftiran Intertrade Co. Limited and NICO SPV Limited (collectively, NICO) or Iranian Oil Company (UK) Limited (IOC UK) have interests. Production was suspended at the North Sea Rhum field (in which IOC UK has a 50% interest) in November 2010 and Rhum remains shut-in. The Shah Deniz field, its gas marketing entity and the gas pipeline entity (in which NICO has a 10% or less non-operating interest) continue in operation. The Shah Deniz joint venture and its gas marketing and pipeline entities were excluded from the main operative provisions of the EU Regulations as well as from the application of the new US sanctions, and fall within the exception for certain natural gas projects under Section 603 of ITRA.

BP has no operations in Iran and it is BP s policy that it shall not purchase or ship crude oil or other products of Iranian origin. Participants in non-BP controlled or operated joint ventures may purchase Iranian-origin crude oil or other components as feedstock for facilities located outside the EU and US. It is also BP s policy that BP shall not sell crude oil or other products into Iran, except that small quantities of lubricants are sold to non-Iranian third parties for resale or use in Iran. Further, until January 2010, BP held an equity interest in an Iranian joint venture that blended and marketed automotive lubricants for sale to domestic consumers in Iran. BP sold its equity interest but continues to sell small quantities of automotive lubricants and components and licence relevant trade marks to the current owner. Transactions with Iranian shipping companies have been terminated. BP currently holds a non-controlling interest in a non-BP operated joint venture

which sells crude oil to an Indian entity in which NICO holds a minority, non-controlling stake. In 2012, BP distributed certain scrip dividends to BP shareholder Naftiran Intertrade Co. Limited in accordance with applicable UK law in effect at the time of such scrip dividend distributions. In accordance with relevant EU sanctions under EU Regulation 945/2012, BP has withheld scrip dividend distributions to Naftiran Intertrade Co. Limited from October 2012.

BP has become aware that a Canadian university had been using graduate students, some of whom were nationals of Iran, on a research programme funded in part by BP. BP has suspended such programme and made an initial voluntary disclosure to the US Treasury Department s Office of Foreign Assets Control (OFAC), and is currently reviewing these activities to determine to what extent, if any, the activities may have violated OFAC Regulations.

In addition, BP has become aware that in 2010, as consideration for certain auditing services, BP effected a transfer of funds to a local Iranian consulting firm which may have been in violation of relevant EU notification requirements. BP is reviewing this funds transfer to determine to what extent, if any, BP may have violated relevant EU regulations.

Following the imposition in 2011 of further US and EU sanctions against Syria, BP terminated all sales of crude oil and petroleum products into Syria, though BP continues to supply aviation fuel to non-governmental Syrian resellers outside of Syria.

BP sells lubricants in Cuba through a 50:50 joint venture and trades in small quantities of lubricants. BP sold small quantities of lubricants to third parties that were resold in Sudan; BP has terminated these sales. In the first quarter of 2013, BP sold a small quantity of lubricants to a third-party drilling company for use in Myanmar.

BP has equity interests in non-operated joint ventures with air fuel sellers, resellers, and fuel delivery services around the world. From time to time, the joint venture operator may sell or deliver fuel to airlines from Sanctioned Countries or flights to Sanctioned Countries without BP s knowledge or consent. BP has registered and paid required fees for patents and trade marks in Sanctioned Countries.

Disclosure pursuant to Section 219 of ITRA

To our knowledge, none of BP s activities, transactions or dealings are required to be disclosed pursuant to ITRA Section 219, with the following possible exceptions:

The Rhum field (Rhum), located in the UK sector of the North Sea, is operated by BP Exploration Operating Company Limited (BPEOC), a non-US subsidiary of BP. Rhum is owned under a 50:50 unincorporated joint venture between BPEOC and Iranian Oil Company (U.K.) Limited (IOC). The Rhum joint venture was originally formed in 1974. During the period of production from Rhum, the Rhum joint venture supplied natural gas and certain associated liquids to the UK. On 16 November 2010, production from Rhum was suspended in response to relevant EU sanctions. Rhum remains shut-in. During the year ended 31 December 2012, BP recorded gross revenues of £7,329.49 related to Rhum due to changes in prices related to hydrocarbon stock. These changes in prices were non-cash transactions that were recorded as revenue in accordance with BP accounting policy. BP had no net profits related to Rhum during the year ended 31 December 2012, recording an overall loss. BP currently intends to continue to hold its ownership stake in the Rhum joint venture, and to meet any applicable obligations in respect of safety and maintenance of the facilities related to the Rhum field.

BP distributed dividends in the form of new ordinary shares in accordance with BP s Scrip Dividend Programme to Naftiran Intertrade Co. Limited in March, June and September 2012 as part of BP s dividend distributions to shareholders during those periods. Such scrip dividends were distributed in accordance with applicable UK law in effect during such periods. BP subsequently declared and distributed a dividend to shareholders in December 2012, but a scrip alternative was not distributed to Naftiran Intertrade Co. Limited in accordance with relevant EU sanctions under EU Regulation 945/2012 which took effect in October 2012. As at 1 March 2013, Naftiran Intertrade Co. Limited is the registered owner of ordinary shares in BP amounting to less than 0.15% of BP s total outstanding ordinary shares. BP intends to withhold or to procure the withholding of distribution of any form of dividends to Naftiran Intertrade Co. Limited until such time as applicable laws or regulations permit such distribution.

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Safety

We operate in a high-hazard industry so safety is our top priority. We continue working to embed safety and operational risk management into the heart of the company.

In 2012 BP reported four workforce fatalities: a road-related fatality in Scotland; a fall from a roof in India; an incident at a compressor station in the US; and a tractor accident in our biofuels business in Brazil. Additionally, the armed attack on our joint venture gas facility in Algeria in January 2013 resulted in four BP fatalities. We deeply regret the loss of these lives.

Managing safety

We are delivering a programme of action to continuously improve safety and risk management across BP. Our approach to safety and risk management is informed by our experience, including what we have learned from the Deepwater Horizon oil spill in 2010 and the Texas City refinery explosion in 2005, operations audits, annual risk reviews, other

incident investigations and from industry practice of sharing experience. Three objectives guide our efforts:

- To promote deep capability and a safe operating culture across all levels of BP.
- To embed OMS as the way BP operates.
- To support self-verification and independent assurance that confirms our conduct of operating.

A dedicated function

We established a new safety and operational risk (S&OR) function in early 2011. Our S&OR function supports the business line in delivering safe, reliable and compliant operations across the group s operated business. S&OR:

- Sets clear requirements.
- Maintains an independent view of operating risk.
- Provides deep technical support to the operating businesses.
- Intervenes and escalates as appropriate to cause corrective action.

In 2012 S&OR was led by Mark Bly, the executive vice president who led BP s investigation into the Deepwater Horizon incident. Mark Bly stepped down from his position as executive vice president of safety and operational risk in February 2013 and has been replaced by Bob Fryar who will continue to report directly to the group chief executive.

S&OR consists of a central team and teams deployed in BP s businesses. All teams report to the group chief executive via the head of S&OR, independently of the business line. S&OR includes some of BP s top engineers and safety specialists, several of whom have experience in other industries where major hazards have to be managed, including the military, nuclear energy and space exploration.

The central team serves as the custodian of group-wide safety and operational risk requirements, and runs S&OR audit and capability programmes, with the support of a substantial dedicated audit team.

Our deployed S&OR staff work with our operating businesses ranging from upstream oil and gas development and production to refineries, petrochemicals plants and retail networks. They help the businesses apply our standards to their operations and help provide assurance to the group as to the management of operational risks, business by business.

Operating businesses remain accountable for delivering safe, reliable and compliant operations with S&OR setting requirements and acting to provide independent advice, scrutiny, challenge and, if needed, intervention.

Governance

BP reviews risks at all levels of the organization, with our S&OR function providing an expert view on safety and operational risks that is independent of the business that remains responsible for management of the risks. While operating line managers are responsible for identifying and managing risks, we place strong emphasis on checks and balances, including both enhanced self-verification by individual BP operations such as drilling rigs or refineries and independent assurance by the S&OR function.

Each business segment or function has a safety and operational risk committee, chaired by the segment or function head, to manage safety and risk in their respective areas of the business. The group operations risk committee (GORC) reviews company safety and risk management across the company.

The board s safety, ethics and environment assurance committee (SEEAC) receives updates from the group chief executive and the head of S&OR on management plans associated with the highest priority risks as part of its update on the GORC s work. GORC also provides the SEEAC with updates on BP s process and personal safety performance, and the monitoring of major incidents and near misses across the group. Where appropriate other senior managers attend to provide briefings on safety, environmental and operational integrity in their areas of responsibility. The SEEAC also receives information from external sources, including Carl Sandlin, who was appointed in 2012 to provide oversight and assurance including regarding the implementation of the recommendations of BP s investigation into the Deepwater Horizon accident. See Corporate governance report on pages 101-126 for further information on the activities of the board s committees, including the SEEAC and the Gulf of Mexico committee.

In May 2012 Duane Wilson s five-year board appointment as independent expert to provide an independent objective assessment of BP s progress in implementing the recommendations of the BP US Refineries Independent Safety Review Panel came to an end. Following the end of his term, the SEEAC appointed him as process safety expert and assigned him to work, in a global capacity, with the Downstream business.

Operating management system

BP s OMS is a group-wide framework designed to provide a basis for managing our operations in a systematic way. OMS integrates BP requirements on health, safety, security, environment, social responsibility and operational reliability, as well as related issues such as maintenance, contractor management and organizational learning, into a common management system. Our OMS evolves over time, for example by amending mandatory practices to reflect implementation experience as well as lessons learned from incident investigations, audits and risk assessments.

Integrated into the OMS are guiding principles and requirements for safe, reliable and compliant operations. Each operating unit has an OMS which describes how it addresses specific operating risks and delivers its operating activities. Business needs, applicable legal and regulatory requirements and group-wide BP requirements are translated into practical plans to reduce risk and deliver strong, sustainable performance.

Conformance and continuous improvement

Our OMS was introduced in 2008. The application of a comprehensive management system such as OMS across a global company is an ongoing process. OMS defines the process for BP operations to apply and conform to required standards and practices on an ongoing basis including defined time periods for doing so as well as to continuously improve their operational performance. All of our operations, with the exception of those recently acquired, are now applying our OMS to govern their BP operations and are working to achieve full conformance to standards and practices required by OMS through the performance improvement cycle. Recently acquired businesses are working to transition to OMS. See page 99 for information about joint ventures.

OMS is a dynamic system. Periodically, after an initial assessment as part of the annual performance improvement cycle, our operations are required to conduct a fresh assessment to develop an updated prioritized plan in respect of any existing gaps or new gaps that may have been identified. These actions form an integral part of each operation s multi-year and annual planning cycle. Where appropriate, actions are aggregated to provide common solutions. S&OR reviews how these assessments are undertaken.

Capability development

BP strives to equip its staff with the skills needed to apply OMS and its associated processes and practices. For example, in addition to a dedicated programme to assess the technical well control competencies of BP s well site leaders, we have been working to identify safety-critical roles and the associated technical and leadership competencies to do them. We are also strengthening capability and competence by consolidating and standardizing our competence management programme. Our approach is being tested in a number of job categories, such as offshore installation managers and well site leaders.

We continue to provide training programmes for our operations personnel at all levels. This training includes our operations academy programmes for senior management, delivered in partnership with the Massachusetts Institute of Technology, US; specialized operational and technical management programmes, for example, courses in engineering and project management at the University of Manchester, UK; and process safety and management training for our front-line leaders, delivered under our operating essentials programme. Since 2008 we have been running operating essentials modules and in 2012 over 6,000 modules were delivered to managers, supervisors and technicians across the BP group. Both non-executive and senior management team members addressed operations academy participants during sessions in 2012. We also offer a substantial programme of eLearning modules.

Crisis management

Crisis management planning is essential to respond effectively to emergencies and to avoid a potentially severe disruption in our business and operations. In 2012 we issued new group-wide OMS practices for

both crisis management and oil-spill preparedness and response, which are replacing the interim practices put in place following the Deepwater Horizon accident. All BP businesses and functions are required to achieve conformance within a defined time period.

See Environmental and social responsibility on pages 51-54 for information on BP s approach to oil spill preparedness and response.

Safer drilling

BP has worked to centralize and standardize our approach to drilling practices and oversight of projects with the establishment of the global wells organization (GWO) and the global projects organization in 2011. The GWO now employs more than 2,000 people, bringing functional wells expertise into a single organization with common global standards. The GWO works with our safety and operational risk function with a view to continuously reducing risk in drilling and so reduce the likelihood of an oil spill or incident occurring. BP has already established requirements and standards for Gulf of Mexico drilling that exceed regulatory requirements.

Following the settlement with the US government of all federal criminal claims related to the Gulf of Mexico, BP has agreed to appoint a process safety monitor in the US for a term of four years. The monitor will review, evaluate and provide recommendations for the improvement of BP s process safety and risk management procedures concerning deepwater drilling in the Gulf of Mexico. Additionally, an independent third-party auditor will review and report on BP s implementation of key terms of the agreement, including procedures and systems related to safety and environmental management, operational oversight, and oil spill response training and drills. For more information on this agreement with the US government, see Legal proceedings on pages 162-169.

Building capability

BP is committed to establishing a global wells institute and has invested in state-of-the art simulator facilities to support practical learning and testing. The institute aims to build and sustain enhanced capability within the GWO by developing the skills to deliver safe and compliant wells that will align with our broader people processes, such as performance development plans and performance appraisals, contractor strategy and ways of working.

Competence testing is an important part of assuring safe operations. In a competence testing programme in the GWO, 532 well site leaders have been assessed on a risk-prioritized basis. Remediation activities have been carried out where areas for improvement have been identified.

We are also engaged in targeted recruitment to support critical work areas. One of these has been the cementing of wells a key issue as identified in the investigation reports into the Deepwater Horizon accident. For this reason, we are enhancing oversight of cementing services. We have recruited additional expertise into the company and now have 21 cementing specialists.

The Bly Report implementing the recommendations

The Bly Report concluded that no single cause was responsible for the accident. The investigation instead found that a complex, inter-linked series of mechanical failures, human judgements, engineering design, operational implementation and team interfaces, involving several companies including BP, contributed to the accident.

The Bly Report made 26 recommendations that were specific to drilling. We accepted all of the recommendations and are working to implement them across our drilling operations worldwide. The recommendations include measures to improve contractor management, as well as to strengthen design and assurance on blowout preventers (BOPs), well control, pressure-testing for well integrity, emergency systems, cement testing, rig audit, verification and personnel competence.

Implementing the 26 recommendations across the group requires detailed work and many activities from creating new practices and guidance, training and testing identified staff, changing requirements and expectations of our contractors, and establishing verification processes.

A project of this scale takes time. Implementing these recommendations across all BP-operated drilling activity across the world is an enormous undertaking involving a programme team of around 85 people, consisting of a central team based in Houston and others embedded in BP s businesses. We are working to assure that all actions are delivered to a

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high standard across all of our well operations, and are independently verified by our S&OR audit or internal audit function.

We have estimated and communicated delivery timelines for each of the recommendations and will continue to provide periodic updates of our progress. These timelines are based on existing facts and circumstances and can shift due to complexity, resource availability and evolving regulatory requirements.

At the end of 2012, 14 of the Bly Report recommendations had been completed. We continue to make progress on all of the remaining recommendations largely in line with our planned schedule. Progress is tracked quarterly by executive management. We also regularly update investors. See *bp.com/internalinvestigation* for the full report and periodic updates on progress.

Independent advice

In June 2012 the BP board appointed Carl Sandlin to provide SEEAC with an objective and independent assessment of BP s global progress in implementing the 26 Bly Report recommendations and on process safety. Carl Sandlin will also on occasion be asked to provide his views to the board on other matters related to, but not specifically within the scope of the Bly Report recommendations, for example, his views on organizational effectiveness or culture of the GWO and process safety observations in the upstream. He has direct access to the chair of SEEAC and will report to the committee in person at least twice a year. See *BP Sustainability Review 2012* for more information on Carl Sandlin s activities.

Delivering enhanced processes and practices

Eight interim actions were issued to our operating regions immediately following the publication of the Bly Report. Seven of those actions have now been incorporated into engineering technical practices or other documents being developed as part of the work towards completing the 26 recommendations. The final interim action is scheduled to be incorporated into a new practice in early 2013.

During 2012, as we continued to work towards delivering the recommendations, we developed or refreshed key operating practices and engineering standards on:

- Cementing or zonal isolation: we have issued new mandatory requirements and nine associated guides covering cementing activities. As of December 2012, 711 technical professionals in BP have now undergone training on the revised practices. We have also strengthened the technical approval process for some cementing operations. Systematic input into the well design workflow now requires both the regional and global BP specialist to agree on the basis of design for complex zonal isolation activities.

- Integrating process safety concepts into management of wells: we have produced a technical practice specifying minimum requirements for well barrier management managing the movement of fluids and gas within the well throughout the life cycle of the well. Implementation of this practice has commenced with two-day workshops training 624 people as of December 2012.

Well casing design: we have updated our design manual for well casing and inner tubing to include new requirements for pressure tests and revised technical practices. A one-day training workshop on this revised practice has been developed for BP professionals and 247 people have been trained as of December 2012.

BOP stacks: we have issued a revised technical practice on well control, defining and documenting our requirements for subsea BOP configurations. We require two sets of blind shear rams and a casing shear ram for all subsea BOPs used on dynamically positioned rigs in deep water. This exceeds regulatory requirements. We also require that third-party verification is carried out on the testing and maintenance of subsea BOPs in accordance with industry recommended practice, and that remotely operated vehicles capable of operating these BOPs are available in an emergency.

Rig intake and start-up operating procedure: we have continued the rig audit process enhanced in 2011. We have also conducted detailed hazard and operability reviews for key fluid handling systems on all offshore rigs in the BP fleet. All drilling rigs joining the BP fleet are subject to an independent S&OR audit and readiness to operate is verified with a detailed go/no-go process assured by S&OR. This includes a checklist that, among other things, assists in assessing that
the rig conforms to BP practices and industry standards, that it has the necessary technical specification, and that the actions required for start-up are completed. All rigs are also subject to subsequent periodic rig audits.

BP is in the process of issuing the above guides and implementing the above practices across all our operating regions. Practices are implemented through training workshops and accompanying training materials, gap assessments, and requirements for reaching conformance. We continue to progress the remaining recommendations of the Bly Report.

External investigations

There have also been a number of external investigations into the Gulf of Mexico oil spill, including those of the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (*oilspillcommission.gov)* and the joint investigation team of the Bureau of Ocean Energy Management, Regulation and Enforcement and the US Coast Guard *(boemre.gov/ooc/press/2011/press0914.htm)*. Additionally, the US National Academy of Engineering undertook an independent study. All of these reports were consistent with the general conclusion that the accident resulted from multiple causes and was due to the actions of multiple parties. We are committed to understanding the causes, impacts and implications of the Deepwater Horizon incident and to learn and act on lessons from it. As part of this commitment, BP is reviewing the recommendations from government and industry reports.

Sharing lessons learned

We are committed to sharing what we have learned globally to advance the capabilities and practices that enhance safety in our company and the deepwater industry and help to prevent an accident of this magnitude from happening again. We have conducted more than 200 briefings in nearly 30 countries over the past two years to share lessons learned. Other examples of our collaboration include:

Participating in the International Association of Oil & Gas Producers   Well Expert Committee that is working to prevent well control incidents by improving well engineering design and well operations management.

Providing equipment and expertise developed during the Deepwater Horizon accident response to the Marine Well Containment Company to help industry meet regulatory requirements for drilling in the Gulf of Mexico.

Participating in the Subsea Well Response Project to enhance the industry s global well capping capabilities resulting in a collaboration with Oil Spill Response Limited to build four well cap systems and two dispersant application equipment packages due to be positioned in Europe, Africa, Asia and South America in 2013.

Filing patent applications in the US and elsewhere to cover about 30 technical innovations related to well capping and containment work, with the aim of ensuring the capping and containment technology we have developed will be open for access and further development for the benefit of the industry.

Implementing a technology licence agreement with Petróleos Mexicanos (PEMEX) that will share BP capping system technology and know-how with the national oil company of Mexico.

Participating in the 19 sub-committees of the IPIECA/International Oil and Gas Producers Association, Joint Industry Project on Oil Spill Response, focused on developing recommendations for effective and fit-for-purpose oil spill response preparedness and capability.

Establishing the Center for Offshore Safety with the American Petroleum Institute with a mission to promote the highest level of safety in the deepwater Gulf of Mexico.

Safety in the Downstream business

In our hydrocarbon facilities across the Downstream business we focus on the safe storage, handling and processing of hydrocarbons via systematic management of associated operating risks. In seeking to manage these risks, BP takes measures to:

Prevent loss of hydrocarbon containment through well-designed, maintained and operated equipment.

Reduce the likelihood of any hydrocarbon releases and the possibility of ignition that may occur by controlling ignition sources.

Provide safe locations, emergency procedures and other mitigation measures in the event of a release, fire or explosion.

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Senior downstream leaders, led by the segment chief executive, participate in the segment operations risk committee, which provides leadership and expectations on the management of operations. Quarterly, this committee also reviews safety and operations performance indicators. All of our businesses use a set of common leading and lagging safety metrics that are intended to monitor performance and help identify opportunities for improvement.

BP continues to implement the BP US Refineries Independent Safety Review Panel recommendations as part of ongoing process safety management.

Risk management

Hazard identification and risk management are key components of our OMS and are fundamental to the success of safely managing hydrocarbons. Over the past two years, our Downstream business has implemented a risk management programme under OMS that focuses on identification, assessment, response and action to manage safety and operational risk combined with monitoring and review of identified and newly emerging risks.

Management plans for the Downstream businesses high-consequence, low-probability risks are reviewed annually by the segment chief executive and the chief operating officers.

Some examples of specific risk reduction work across our refining and petrochemicals portfolio in 2012 include:

- Installation of additional safety instrumentation and equipment to reduce the likelihood of identified risks occurring.

- Continuing work to improve the safety of site occupied buildings. We have a major programme under way to install safety shelters for personnel; to move people further away from hydrocarbon-containing equipment; and to reduce the number of vehicles onsite. For example, during 2012 a building-hardening programme was completed at our Toledo refinery, and at our Bulwer refinery we constructed new offices to move employees away from higher risk processing areas. The business also continues to train and drill personnel to respond to emergencies.

- Work to reduce explosion and toxic risks through inventory reduction by, for example, reducing ethylene and propylene refrigerants in our petrochemical plants and by eliminating or reducing the use of ammonia across the refining portfolio.

Where similar risks have been identified across multiple facilities, new guidance for gasoline storage, tanker loading and buildings were developed and issued to drive consistent risk mitigation efforts across the segment.

Capability development

Each facility has experienced and trained operational staff and a system for assessing their competency. We are developing a consistent competency framework that standardizes this assessment process for safety-critical roles supported by and in conjunction with S&OR direction and expertise.

To support the competency development plan for operations personnel, our refineries and chemical manufacturing plants are in the process of installing high fidelity process simulators for selected process units. These will be used to train operators via simulations to respond to low-probability, high-consequence scenarios, similar to methods used with airline pilots.

Measurement, evaluation and corrective action

The oversight of the management of hydrocarbons across our operations is supported by our S&OR function. S&OR personnel work with our operating businesses to provide independent perspectives on the quality of our operations and the management of risks.

A quarterly assurance process enables S&OR to provide an ongoing independent view of OMS conformance by the sites. Each site is assessed on its OMS self-verification processes, the strength of existing risk mitigations and progress on risk reduction plans. Periodic S&OR audits against OMS requirements also provide valuable insights and result in actions to close any identified findings.

Lessons learned from incidents and near-misses are important for identifying ways to improve safety practices. In 2012 we issued a number of briefings and alerts on lessons learned from incidents and near-misses and we require our sites to provide assurance that similar risks have been assessed and appropriate corrective actions undertaken.

New process safety expert for our Downstream business

Duane Wilson s five-year board appointment as independent expert to provide an independent objective assessment of BP s progress in implementing the recommendations of the BP US Refineries Independent Safety Review Panel came to an end in May 2012. Recognizing the extensive experience he has acquired during his years as independent expert and following the end of his term, SEEAC appointed him as process safety expert and assigned him to work, in a global capacity, with the Downstream business.

In this new role, he is providing an independent perspective on the progress that BP s fuels and petrochemicals businesses are making globally toward becoming industry leaders in process safety performance. Specifically, Duane Wilson is focusing and reporting to the SEEAC on three topics:

- Downstream s prioritization of the agenda to become an industry leader in process safety.
- Downstream s progress in embedding BP s OMS including process safety risk assessment processes, process safety culture and interpretation of trends in process safety performance.
- The effectiveness of the Downstream safety and operational risk function s agenda.

Duane Wilson continues to have frequent and direct access not only to the board, but also to BP employees from the most senior executives down to the shop floor. He visits facilities, conducts interviews and reviews relevant documents, such as audit and incident reports, to fulfil his duties. Additionally, he is an ex officio member of the Downstream segment operations risk committee and regularly attends its meetings with the senior executives of the business. His contract is for a two-year term ending in May 2014, and may be renewed for up to an additional two years on mutual agreement.

Safety performance

Workforce fatalities

In 2012 BP reported four workforce fatalities: a road related fatality in Scotland; a fall from a roof in India; an incident at a compressor station in the US; and a tractor accident in our biofuels business in Brazil. Additionally, the armed attack on our joint venture gas facility in Algeria in January 2013 resulted in four BP fatalities. We deeply regret the loss of these lives.

Oil spills and other loss of primary containment

We monitor the integrity of our assets used to produce, process and transport oil and other hydrocarbons with the aim of preventing the loss of material from its primary containment.

Accordingly, we track loss of primary containment as a metric, which includes unplanned or uncontrolled releases from a tank, vessel, pipe, rail car or equipment used for containment or transfer of materials within our operational boundary, excluding non-hazardous releases such as water.

The US government and third parties have announced various estimates of the flow rate or total volume of oil spilled from the Deepwater Horizon incident. The multi-district litigation pending in New Orleans will address the amount of oil spilled. See Financial statements Note 36 on page 235 for information about the volume used to determine the estimated liabilities.

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Loss of primary containment and oil spills (excluding Deepwater Horizon oil spill in respect of 2010 volume)

	2012	2011	2010
Loss of primary containment number of all incidents[a]	**292**	361	418
Loss of primary containment number of oil spills[b]	**204**	228	261
Number of oil spills to land and water	**102**	102	142
Volume of oil spilled (thousand litres)	**801**	556	1,719
Volume of oil unrecovered (thousand litres)	**320**	281	758

[a] Does not include either small or non-hazardous releases.
[b] Number of spills greater than or equal to one barrel (159 litres, 42 US gallons).

Process safety

We monitor the number of process safety events occurring across our operations using the American Petroleum Institute (API) RP-754 standard. Introduced in 2010 it sets out process safety indicators, organized into different tiers and is used as the basis for our internal and external process safety reporting. API tier 1 process safety events are the loss of primary containment from a process of greatest consequence causing harm to a member of the workforce or costly damage to equipment, or exceeding defined quantities. API tier 2 process safety events are loss of primary containment, from a process, of lesser consequence. Forty-three tier 1 process safety events were reported in BP in 2012, compared with 74 in 2011. This is our first year reporting API tier 2 safety events externally.

Personal safety

BP reports publicly on its personal safety performance according to standard industry metrics.

Personal safety performance

	2012	2011	2010
Recordable injury frequency (group) incidents per 200,000 hours worked	**0.35**	0.36	0.61
Days away from work case frequency[a] (group) incidents per 200,000 hours worked	**0.076**	0.090	0.193

[a] Incidents that resulted in an injury where a person is unable to work for a day (shift) or more.

Working with partners and contractors

BP, like our industry peers, rarely works in isolation we need to work with suppliers, contractors and partners to carry out our operations. In 2012, 55% of the 402 million hours worked by BP were carried out by contractors.

Our ability to be a safe and responsible operator depends in part on the conduct of our suppliers, contractors and partners. We address this in a variety of ways, from training and dialogue to requiring adherence to operational standards through legally binding agreements.

Our OMS is a group-wide framework designed to provide business-specific requirements and practices, including for working with contractors and our operations are obliged to plan and execute actions to reach conformance with OMS on contractor management. OMS is also designed to drive continuous improvement, including how BP businesses continue to work towards full conformance with the elements relevant to working with contractors.

In 2012 we prepared guidance for conformance with OMS, where it relates to working with contractors, in order to support the accountable line organizations. We intend to field test this in 2013.

We expect our contractors to comply with legal requirements and to operate consistently with the principles of our code of conduct when they work on our behalf. The objective is to provide assurance that goods, equipment and services provided by third parties meet contractual and BP requirements and that there is a consistent, shared understanding of responsibilities.

Following the Deepwater Horizon incident, we undertook an in-depth review of contractor management practices, with the aim of documenting and learning from the latest proven practices throughout BP and across a number of sectors and industries that use contractors in potentially high-consequence activities. The review confirmed to us the value of building long-term relationships with a limited number of contractors, supported by shared structures and common processes.

Initially our work has focused on contracts in our upstream supply chain involving potentially high-consequence activities. In 2012 we built on this work to identify contracts involving potentially higher-consequence activities across the group and bringing a consistent level of oversight to the management of these contracts as a priority. In our global projects organization, we have put in place global agreements with seven suppliers for plant inspection and surveillance services, covering the work previously undertaken by more than 60 suppliers.

The review also highlighted the importance of clearly defined responsibilities and decision rights at every stage of each process including training, monitoring and auditing as well as rigorous qualification of suppliers, including their demonstration of the competency of key personnel. In 2012 we focused, including through our OMS, on practical assistance to operational line management to build competence in this area.

In 2013, we plan to continue our work on the management of contractors through our OMS framework and actions related to additional supplier audits, competence testing and other programmes.

Our partners in joint ventures

We seek to work with companies that share our commitment to ethical, safe and sustainable working practices. However, we do not control how our co-venturers and their employees approach these issues.

Typically, our level of influence or control over a joint venture is linked to the size of our financial stake compared with other participants. In some joint ventures we act as the operator. Our OMS provides that where we are the operator, and where legal and contractual arrangements allow, OMS applies to the operations of that joint venture.

In other cases, one of our joint venture partners may be the designated operator, or the operator may be an incorporated joint venture company owned by BP and other companies. In those cases our OMS does not apply as the management system to be used by the operator, but is available to our businesses as a reference point for their engagement with operators and co-venturers. Where BP does not have overall control of a joint venture, we will do everything we reasonably can to make sure joint ventures follow similar principles.

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Environmental and social responsibility

We strive to minimize our impact on the environment and communities, to respect human rights and to conserve cultural heritage.

Managing our environmental and social risks and impacts

At a group level, we review our management of material issues such as GHG emissions, water, sensitive and protected areas and human rights annually. We seek to identify emerging risks and assess methods to reduce them across the company.

Our OMS helps our operations around the world to assess and manage their environmental and social impacts. This includes conducting an annual OMS assessment to identify risks and impacts, and then putting in place action plans to manage them.

The principles and standards of OMS are supported by our environmental and social practices. These set out how our major projects identify and manage environmental and social impacts. They also apply to projects that involve new access, projects that could affect an international protected area and some BP acquisition negotiations.

In the early planning stages, these projects complete a screening process. Results are used to identify the most significant environmental and social impacts associated with the project, with a requirement to identify mitigation measures and implement these in project design, construction and operations. From April 2010 to the end of 2012, 88 projects had completed the screening process, and used outputs of the process to implement measures to reduce impact.

During screening, we identify any international protected areas that could be affected by the project, using the UNEP World Conservation Monitoring Centre s World Database on Protected Areas. Our international protected areas classification includes areas designated as protected by the International Union for the Conservation of Nature (categories I-IV),

Ramsar and World Heritage sites, as well as areas proposed for international protected status.

Where screening indicates that a proposed BP project could affect an international protected area a high-level risk assessment is carried out, including identification of potential avoidance and mitigation measures. Our safety and operational risk function provides an independent review of the risk assessment, and before any physical activity begins, permission is sought from senior management. In 2012 no new projects sought permission for entry into an international protected area.

Our operations are expected to work to continually reduce their impacts and risks. All our major operating sites, with the exception of recently acquired operations, are required to be certified to the environmental management system standard ISO 14001, and publish an externally verified environmental statement. In 2012 our Gelsenkirchen refinery in Germany was not recertified due to conflicts in scheduling a verification audit. They completed a verification audit in late 2012 and were recertified in January 2013.

More information about our approach to environmental and social issues can be found in *BP Sustainability Review 2012* and at *bp.com/sustainability*.

Oil spill preparedness and response

We have used lessons from our Deepwater Horizon oil spill response to further enhance our internal approaches to preparedness and response planning. In July 2012 new group requirements for oil spill preparedness and response planning, and for crisis management were issued, with timeframes established for required conformance by the businesses. To facilitate understanding of these new requirements, workshops have been conducted with more than 600 staff from 45 countries, ranging from senior leaders to on-site oil spill response teams.

Understanding and mitigating the risks

Identifying and assessing the potential oil spill risks and potential impacts helps us to develop appropriate oil spill response and crisis management plans. These plans are backed up by the tools and people required to mount an effective response to an incident and mitigate potential impacts.

We further developed our oil spill modelling systems and capabilities in 2012. Improving existing modelling tools, conducting staff training in our regions and enhancing the environmental and socio-economic data required in the models have all helped to better define different oil spill scenarios and to plan for responding to them. Modelling for two deepwater drilling operations, Salamat and North Uist, indicated that international protected areas could potentially be affected from the worst case oil spill scenario. As a result, additional mitigations were put in place to try to reduce this risk.

Understanding the environmental and socio-economic sensitivities can help inform response planning. Across our operating regions, we are developing enhanced, high resolution sensitivity maps aided by the use of technologies such as remote sensing satellites. In 2012 we used high resolution satellite imagery to enhance sensitivity maps of coastlines in Brazil and Africa.

The use of oil spill dispersants as a response tool for major oil spills in the deep-sea environment continued to be a focus area in 2012. We continue to gain a greater understanding of dispersants and their use through scientific research programmes, conducted individually: for example, characterizing the oil-degrading bacterial communities in our operating regions and collectively, through joint industry programmes such as IPIECA-OGP and the API.

Collaboration on lessons learned

We seek to work collaboratively with government regulators in planning for oil spill response, sharing lessons learned and our technical approaches, with the aim of improving any potential future response. In the past two years we conducted workshops on issues such as dispersant use and in-situ burn response to regulators in Australia, Brazil, China, Egypt, Indonesia, Norway and the UK.

We are advancing our capability to respond to potential incidents and are working with our industry to further enhance access to equipment and technologies around the world. BP s global deepwater well capping and tooling package is stored in Houston and can be deployed in a matter of days to anywhere in the world in the event of a deepwater well blowout.

The equipment is designed to operate in water depths of up to 10,000 feet. It includes a remotely operated vehicles intervention system, a subsea dispersant injection system and subsea debris removal equipment and a deepwater well cap.

See Safety on pages 46-50 for further information on BP s approach to oil spill prevention and for performance data on loss of primary containment.

Gulf of Mexico our long-term commitments

See Gulf of Mexico oil spill on pages 59-62 for further information on BP s response to the incident and environmental and economic restoration efforts.

Climate change

Climate change represents a significant challenge for society and the energy industry, including BP. In response to the challenges and opportunities, BP is continuing to take a number of practical steps, including investing in lower-carbon energy products such as biofuels and wind, and ventures focused on sustainable energy solutions. We seek to manage our own GHG emissions through our OMS, by requiring our operations to incorporate energy use considerations in their business plans and to assess, prioritize and implement technologies and systems to improve energy usage.

As part of our OMS and project screening process, we consider and identify risks and potential impacts of a changing climate on our facilities and operations.

Greenhouse gas emissions

Our direct GHG emissions[a] were 59.8 million tonnes (Mte) in 2012, compared with 61.8Mte in 2011, a decrease of 2.0Mte versus 2011. The net effect of acquisitions and divestments is a decrease of 0.7Mte, primarily the result of the sale of upstream assets as part of our divestment programme. Operational changes led to a decrease of 0.7Mte, principally due to temporary reductions in activity at some of our upstream sites and one of our major US refineries and lower mileage by our shipping vessels. Improvements made by our businesses to calculate their emissions more accurately resulted in a net decrease of 0.4Mte. We achieved 0.2Mte of sustainable emissions reductions in 2012.

[a] We report GHG emissions on a CO_2 -equivalent basis, including CO_2 and methane. This represents all consolidated entities and BP s share of equity-accounted entities except TNK-BP.

Over the long term it is likely that the carbon intensity of our upstream operations will continue to trend upwards as we move further into technically challenging and potentially more energy-intensive areas. The carbon intensity will likely remain relatively flat or even decrease in certain refining operations because of improved energy efficiency even with the trend towards processing heavier crudes.

Greenhouse gas regulation

In the future, we expect that additional regulation of GHG emissions aimed at addressing climate change will have an increasing impact on our businesses, operating costs and strategic planning, but may also offer opportunities for the development of lower-carbon technologies and businesses.

To help address potential future regulation, we factor a carbon cost into our investment appraisals and engineering designs for new projects where appropriate. We do this in order to assess, and protect the value of, our new investments under future scenarios in which the cost of carbon emissions is higher than it is today. We require larger projects, and those for which emissions costs would be a material part of the project, to apply a standard carbon cost to the projected GHG emissions over the life of the project. The standard cost is based on our estimate of the carbon price that might realistically be expected in particular parts of the world. In industrialized countries, this standard cost assumption is currently $40 per tonne of CO_2 equivalent. We use this cost as a basis for assessing the economic value of the investment and as one consideration in optimizing the way the project is engineered with respect to emissions.

See Regulation of the group s business Greenhouse gas regulation on pages 96-97.

Climate change adaptation

We are taking steps to prepare for the potential physical impacts of climate change on our existing and future operations. We are working closely with Imperial College in the UK to develop specialized climate models that help us better understand and predict possible impacts resulting from the changing climate.

Projects implementing our environmental and social practices are required to assess the potential impacts to the project from the changing climate and manage any identified significant potential impacts. Where climate change impacts are identified as a risk for a project, our engineers seek to address them in the project design like any other physical and ecological hazard. We periodically review and adjust existing design criteria and engineering technology practices. For example, a regional climate model was used in 2012 to inform decisions on the depth of cover required for river crossings for the South Caucasus Pipeline and to review any risks associated with landslides.

We regularly update and improve our climate impact modelling tools and make them available to both new projects and existing operations. An internal guide, available to both existing operations and projects, has been in place since 2010. It sets out guidance on how to assess potential risks and impacts from a changing climate to enable mitigation steps to be incorporated into project planning, design and operations.

Water

BP recognizes the importance of managing water effectively and efficiently in areas of water stress or scarcity, the need to minimize water quality impacts from our discharges, and the need to protect water resources at our operations.

We are continuing to pilot and develop standardized tools to more deeply understand the nature of the risks and opportunities associated with water management at a strategic and local level. This includes an assessment of water scarcity, the impact of changing effluent discharge standards, and the long-term social and environmental pressures on water resources within the local area. We also commissioned Harvard University in the US to conduct research in 2012 on the allocation and use of water in Jordan, the United Arab Emirates, Iraq and Oman. This will be followed through in 2013 and 2014 with more detailed research in three or four of these countries. This will equip BP with peer-reviewed science as a basis for planning water needs for oil and gas developments in the Middle East.

Unconventional gas and hydraulic fracturing

Natural gas resources, including unconventional gas, have an increasingly important role in meeting the world s growing energy needs. New technologies are making it possible to extract unconventional gas resources safely, responsibly and economically. BP has unconventional gas operations in the US, Algeria, Indonesia and Oman.

Hydraulic fracturing is the process of pumping water, mixed with a small proportion of sand and chemicals, underground at a high enough pressure to split and keep open the rock and release natural gas that would otherwise not be accessible. Some stakeholders have expressed concerns about the potential environmental and community impacts of this process.

BP recognizes these concerns and seeks to apply responsible well design, construction and operation to mitigate the risk that natural gas and hydraulic fracturing fluids enter underground aquifers, including drinking water sources. We are trialling a number of water-saving innovations to minimize the amount of fresh water used in our drilling and hydraulic fracturing operations.

Water and sand constitute on average 99.5% of the injection fluid. This is mixed with chemicals to create the fracturing fluid that is pumped underground at high pressure to fracture the rock with the sand propping the fractures open. The chemicals used in this process help to reduce friction and control bacterial growth in the well. Some of them are classified as hazardous materials, as are the constituents of many everyday products when in concentrated form. Each chemical used in the fracturing process is listed in the material safety data sheets at each site, which detail safe dosage limits. We submit data on chemicals used at our hydraulically fractured wells in the US at *fracfocus.org*.

At our operating sites, we aim to minimize air pollutant and GHG emissions by, for example, seeking to use natural gas or electricity instead

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of more carbon-intensive conventional fuel sources to power operations at sites where these energy sources are readily available and affordable. We introduced green completion technology in our North American gas operations in 2001 to recover natural gas for sale and minimize the amount of natural gas either flared or vented from our wells.

To help manage potential impacts on the community, such as increased traffic, noise, dust and light, we seek to design and locate our equipment and manage our work patterns in ways that reduce impact to relevant communities. We also listen to suggestions or complaints from nearby local communities and try to address their concerns.

More information about our approach to unconventional gas and hydraulic fracturing may be found at *bp.com/unconventionalgas.*

Canada s oil sands

Canada s oil sands are believed to hold one of the world s largest supplies of oil, third in size to the resources in Saudi Arabia and Venezuela.

BP is involved in three oil sands properties, all of which are located in the province of Alberta. Development of the Sunrise project, our joint venture operated by Husky Energy, is under way, with production from Phase 1 expected to start in 2014. The other two proposed projects Pike, which will be operated by Devon Energy, and Terre de Grace, which will be BP-operated are still in the early stages of development.

Our decision to invest in Canadian oil sands projects takes into consideration GHG emissions, impacts on land, water use and local communities, and commercial viability. In the case of joint ventures in which we are not the operator, we monitor the progress of these projects and the mitigation of risk. In the Terre de Grace project where we are the operator, we are responsible for managing these potential impacts and the mitigation of risk.

More information on BP s investments in Canada s oil sands can be found at *bp.com/oilsands*.

Environmental expenditure

			$ million
	2012	2011	2010
Environmental expenditure relating to the Gulf of Mexico oil spill			
Spill response	**118**	671	13,628
Additions to environmental remediation provision	**801**	1,167	929
Other environmental expenditure			
Operating expenditure	**742**	704	716
Capital expenditure	**1,207**	819	911
Clean-ups	**46**	53	55
Additions to environmental remediation provision	**549**	510	361
Additions to decommissioning provision	**3,756**	4,596	1,800

Environmental expenditure relating to the Gulf of Mexico oil spill

BP continues to incur significant costs related to the 2010 Gulf of Mexico oil spill. The spill response cost incurred during 2012 is $118 million (2011 $671 million), and $345 million (2011 $336 million) remains as a provision at

31 December 2012.

The environmental remediation provision includes amounts for BP s commitment to fund the Gulf of Mexico Research Initiative, estimated natural resource damage (NRD) assessment costs and early NRD restoration projects under the $1-billion framework agreement. The provision for NRD assessment costs was increased during the year. Further amounts for spill response costs were provided during the year, primarily to reflect increased costs for patrolling and maintenance and shoreline treatment projects. The majority of the active clean-up of the shorelines was completed in 2011.

See Financial statements Note 2 on page 194, Note 36 on page 235 and Note 43 on page 253 for further information relating to the Gulf of Mexico oil spill.

Other environmental expenditure

Operating and capital expenditure on the prevention, control, abatement or elimination of air, water and solid waste pollution is often not incurred as a separately identifiable transaction. Instead, it forms part of a larger transaction that includes, for example, normal 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 $742 million in 2012 was at a similar level to 2010 and 2011.

Capital expenditure in 2012 was higher than in 2011 principally due to the high level of construction activity at our Whiting refinery in relation to new units as part of the Whiting refinery modernization project which is due to be completed in the second half of 2013. Similar levels of operating and capital expenditures are expected in the foreseeable future.

In addition to operating and capital expenditures, we also establish provisions for future environmental remediation. 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 increased in 2012 largely due to scope reassessments of the remediation plans of a number of our sites in the US and Canada. The charge for environmental remediation provisions in 2012 included $19 million in respect of provisions for new sites (2011 $12 million and 2010 $54 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.

The level of increase in the decommissioning provision varies with the number of new fields coming onstream in a particular year and the outcome of the periodic reviews. The significant increases in 2010 and 2011 were driven by changes in estimation and detailed reviews of expected future costs. The majority of these increases related to our sites in Trinidad, the Gulf of Mexico and the North Sea.

The Gulf of Mexico was impacted by the Bureau of Ocean Energy Management, Regulation and Enforcement s (BOEMRE) Notice to Lessees (NTL) 2010-G05, issued in October 2010, which requires that idle infrastructure on active leases is decommissioned earlier than previously was required and establishes guidelines to determine the future utility of idle infrastructure on active leases.

In 2012 additions to the decommissioning provision were less than in 2011, although still significant, and were again driven by detailed reviews of expected future costs. The majority of the additions related to our sites in the North Sea, Alaska, the Gulf of Mexico and Angola.

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 36 on page 235.

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Respecting human rights

In 2012 we developed a human rights policy in consultation with businesses and functions, and we expect to launch it in 2013. The policy builds on commitments in our code of conduct regarding communities, workforces and the supply chain and we expect to report annually on its implementation. See page 56 for further information about our code of conduct.

We understand our responsibility to respect the human rights of the communities and workforces with whom we interact. BP supports the Universal Declaration of Human Rights, which lays out the rights to which all human beings are entitled. Our policy sets out our commitment to respect all internationally recognized human rights, including those set out in the International Bill of Human Rights and the International Labour Organization s Declaration on Fundamental Principles and Rights at Work.

We are a signatory to two voluntary agreements with implications for specific aspects of human rights: the UN Global Compact, which includes principles on protecting internationally proclaimed human rights, and the Voluntary Principles on Security and Human Rights, which define good practice for security operations in the extractive industry.

In 2011 we used external consultants to carry out a comparison between our current policies and practices and the expectations in the Guiding Principles. In 2012 we used the findings to create an action plan designed to achieve closer alignment with the Guiding Principles over a number of years. Planned actions include:

- Developing and implementing human rights training prioritizing specific businesses and functions.
- Developing guidance on integrating human rights into impact assessments and community grievance processes.
- Embedding human rights requirements into our procurement and supply chain management processes.

A steering committee has provided oversight for the development of the planned actions.

We are participating in the work of oil and gas industry organization IPIECA s human rights taskforce, and are contributing our experience to develop practical guidance for the industry on integrating human rights into impact assessments and community grievance processes.

More information about our approach to human rights may be found at *bp.com/humanrights*.

Revenue transparency and business ethics

As a member of the Extractive Industries Transparency Initiative (EITI), we work with governments, non-governmental organizations and international agencies to improve transparency on revenue disclosures. In several countries that are in the process of becoming EITI compliant, BP is supporting the process. For example, BP is an active member of the Trinidad & Tobago EITI steering committee. In countries that have achieved EITI compliance, including Azerbaijan and Norway, BP submits an annual report on payments to their governments.

We have taken part in consultations in relation to new or proposed revenue transparency reporting requirements in the US and Europe for companies in the extractive industries. BP will comply with the relevant laws and regulations in force.

We are working to respond effectively to the standards arising from the UK Bribery Act as well as other anti-corruption legislation such as the Foreign Corrupt Practices Act and certain regulations promulgated under the Dodd-Frank Wall Street Reform and Consumer Protection Act in the US.

Bribery and corruption are serious risks in the oil and gas industry. Our code of conduct requires that our employees or others working on behalf of BP do not engage in bribery or corruption in any form in both the public and private sectors. We operate a group-wide anti-bribery and corruption standard, which applies to all BP employees and contractors. The standard requires annual bribery and corruption risk assessments; due diligence on all parties with whom BP does business; appropriate anti-bribery and corruption clauses in contracts; and the training of personnel in anti-bribery and corruption measures.

Enterprise and community development

We run a range of programmes to build the skills of businesses in places where we work and to develop the local supply chain. The programmes can benefit local companies by empowering them to reach the standards needed to supply BP and other organizations. For example, we provide training and share standards in areas such as health and safety. At the same time BP benefits from the local sourcing of goods and services.

BP s social investments, the contributions we make to social and community programmes in locations where we operate, support development activities that aim for a meaningful and sustainable impact. We look for social investment opportunities that are relevant to local needs, aligned with BP s business, and offer partnerships with local organizations. The programmes we support include building business skills and developing enterprise, supporting education and other community needs and sharing technical expertise with local and national host governments. In a few locations we also support small community infrastructure programmes that help people improve their access to basic resources such as drinking water and public health services. We work with local authorities, community groups and specialists to deliver these community programmes.

Our direct spending on community programmes in 2012 was $90.6 million, which included contributions of $31.7 million in the US, $16.3 million in the UK (including $6.9 million to UK charities, of which $4.8 million for arts and culture, and $2.1 million for education), $2.3 million in other European countries and $40.3 million in the rest of the world, including disaster relief. These reported amounts exclude social bonuses paid by BP to governments as part of licence acquisition costs and that have been capitalized as intangible assets on the group balance sheet. In such cases the group has no direct oversight of the expenditure. Contributions relating to economic recovery following the Deepwater Horizon oil spill are also excluded, see page 60 for details of these contributions.

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Employees

To be sustainable as a business, BP needs employees who have the right skills for their roles and who understand the values and expected behaviour that guide everything we do as a group.

Number of employees at 31 December[a]	US	Non-US	Total
2012			
Upstream	**9,500**	**14,500**	**24,000**
Downstream[b]	**11,900**	**39,400**	**51,300**
Other businesses and corporate	**1,900**	**8,400**	**10,300**
Gulf Coast Restoration Organization	**100**		**100**
	23,400	**62,300**	**85,700**
2011			
Upstream	8,900	13,300	22,200
Downstream[b]	12,000	39,000	51,000
Other businesses and corporate	1,900	8,200	10,100
Gulf Coast Restoration Organization	100		100
	22,900	60,500	83,400
2010			
Upstream	7,900	13,200	21,100
Downstream[b]	12,400	39,900	52,300
Other businesses and corporate	1,700	4,500	6,200
Gulf Coast Restoration Organization	100		100
	22,100	57,600	79,700

[a] Reported to the nearest 100.
[b] Includes 14,700 (2011 14,600 and 2010 15,200) service station staff, all of whom are non-US.

We had approximately 85,700 employees at 31 December 2012, compared with approximately 83,400 at the same time in 2011. During 2012 our headcount has increased by about 3%. This is a result of a focused effort to re-shape the business and strengthen capability.

Our values

Our values of safety, respect, excellence, courage and one team align explicitly with BP s code of conduct and translate into the responsible actions necessary for the work we do every day. Our values represent the qualities and actions we wish to see in BP, they guide the way we do business and the decisions we make.

We work with our employees to raise their awareness of our values and to help them embed the values in all activities. In 2012 we worked on embedding BP s values into many of our group-wide systems and processes, including our recruitment, promotion and development assessments. See *bp.com/values* for more information.

People policies

The group people committee, chaired by the group chief executive, has overall responsibility for key policy decisions relating to employees. In 2012 subjects discussed included longer-term people priorities; quarterly reviews of progress in our diversity and inclusion programme; the rolling out and embedding of our revised performance review procedures; and the continuing development of our learning programmes.

We have a good understanding of our future demand for people and where they will come from. Building our employees capability is a priority, as is rewarding them in a way that aligns with our goals. We focus on ensuring the safety of our employees, engaging with them, and increasing the diversity of our workforce so that it reflects the societies in which we operate.

Attracting and retaining our people

The increasing demand for energy products and the complexity of our projects means that attracting and retaining skilled and talented people is vital to the delivery of our strategy and plans.

In support of this, the group chief executive and each member of the executive team hold regular review meetings to ensure that appropriate plans to build capability are in place and that a rigorous and consistent succession process is followed for all group leadership roles.

To supplement our existing internal capability, we also target experienced and skilled professionals in the external market and are continuing to increase our intake of graduates to create a strong internal talent pipeline for the future. We have tailored training programmes for graduates and post-graduates to develop BP s future leaders.

Our graduate development programme currently has around 1,600 participants. To address increasing demands for skilled people outside the US and UK, more than 40% of 2013 s graduate recruitment is targeted at universities in growing markets. We invest in universities worldwide to further develop the quality of our potential recruits.

We conduct external assessments for all new hires into BP at senior levels and for internal promotions to senior level and group leader level roles. These assessments help ensure rigour and objectivity in our hiring and talent processes. They give an in-depth analysis of leadership behaviour, intellectual capacity and the required experience and skills for the role in question.

Building enduring capability

We provide development opportunities for all our employees, including external and on-the-job training, international assignments, mentoring, team development days, workshops, seminars and online learning. We encourage all employees to take at least five training days a year.

We continue to work to embed appropriate leadership behaviours throughout our organization. By 2012 our group-wide suite of management development programmes, managing essentials, had been attended by employees from 74 countries, in four regions and in 10 different languages.

We provide world-class education opportunities for our people, partnering with 19 academies and institutes that deliver technical learning and development.

Meeting the expectations of our people

We have reviewed our reward strategy, including how the group incentivizes business performance, with the aim of encouraging excellence in safety, compliance and operational risk management. In annual performance reviews all staff are required to set priorities for themselves in these three areas.

We encourage employee share ownership. For example, through our ShareMatch plan run in around 50 countries, we match BP shares purchased by our employees. We have also consolidated our equity plans into one single company-wide plan, and extended this to more junior members of staff. The plan is linked to the company s performance, with the same measure for everyone.

We aim to treat employees affected by divestments, mergers, acquisitions and joint ventures fairly and with respect, through open and regular communication. When divestments do occur, BP seeks the same or comparable pay and benefits for employees transferring to other companies.

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Diversity and inclusion

We are a global company and aim for a workforce that is representative of the societies in which we operate. For our employees to be properly motivated and to perform to their full potential, and for the business to thrive, our people need to be treated with respect and dignity, and without discrimination.

Through living our values we create an inclusive working environment where everyone can make a difference and give their best. Our work on diversity and inclusion is overseen by the group people committee who reviews performance on a quarterly basis. The committee agrees strategic direction and group standards which are then implemented through business-specific diversity and inclusion plans. In 2012 we launched a framework to set out our ambition and drive further progress across the group. It includes statements of wide-ranging improvements we hope to achieve by 2016.

By 2020, more than half our operations are expected to be in non-OECD countries and we see this as an opportunity to develop a new generation of experts and skilled employees. At the end of 2012, 17% of our group leaders were female and 22% came from countries other than the UK and the US. When we started tracking the composition of our group leadership in 2000, these percentages were 9% and 14% respectively. We supported the UK government-commissioned Lord Davies review in 2011, which made recommendations on increasing gender diversity on the boards of listed companies. See page 113 governance report.

We are also incorporating detailed diversity and inclusion analysis into talent reviews, with processes to identify actions where any issues are found. We continue to increase the number of local leaders and employees in our operations so that they reflect the communities in which we operate and this is monitored at a local, business or national level.

We aim to ensure equal opportunity in recruitment, career development, promotion, training and reward for all employees, including those with disabilities. Where existing employees become disabled, our policy is to provide continuing employment and training wherever practicable.

Employee engagement

Executive team members hold regular town-hall style meetings and webcasts to communicate with our employees around the world.

Team meetings and one-to-one meetings are complemented by formal processes through works councils in parts of Europe. These communications, along with training programmes, are designed to contribute to employee development and motivation by raising awareness of financial, economic, ethical, social and environmental factors affecting our performance. The group seeks to maintain constructive relationships with labour unions.

We conduct an annual survey of our employees with more than 55,000 employees in around 70 countries for 2012 to monitor employee engagement and identify areas where we can improve this. The 2012 results show levels of engagement are up across all levels and business areas.

Business leadership teams review the results of the survey and agree actions to address the identified issues. Safety scores remain strong although there is more work for us to do in continuing to embed our OMS as the way BP operates so people fully understand what it means for them.

We also measure how engaged our employees are with our strategic priorities of safety, trust and value. The group priorities engagement measure is derived from 12 questions about employee perceptions of BP as a company and how it is managed in terms of leadership and standards. Aggregate results for these questions showed a 4% improvement on 2011 to 71%.

Alongside engagement, a new indicator of employee and workplace satisfaction was introduced in 2012, replacing the previous employee satisfaction index (ESI). This new measure is more comprehensive than the previous index and looks at management behaviour, job satisfaction, development and reward. The aggregate score for employee and workplace satisfaction in 2012 was 71%. For comparison, the ESI, based on a narrower set of measures, rose by 4% to 66%.

The BP code of conduct

The BP code of conduct sets the standard that all BP employees are required to work to. It is based on our values and it clarifies the ethics and compliance expectations for everyone who works at BP.

The code defines what BP expects of its people in key areas such as safety, workplace behaviour, bribery and corruption and financial integrity. The code is based on four foundations: what we do, what we stand for, what we value and speaking up.

Employees, contractors or other third parties who have questions or concerns that laws, regulations or the code of conduct may be breached, can get help through OpenTalk, a helpline that is operated by an independent company. The number of cases raised through OpenTalk in 2012 was 1,295, compared with 796 in 2011. In the US, former district court Judge Stanley Sporkin acts as an ombudsperson. Employees and contractors can contact him confidentially to report any suspected breach of compliance, ethics or the code of conduct, including safety concerns.

We take steps to identify and correct areas of non-compliance and take disciplinary action where appropriate. In 2012, 424 dismissals were reported by BP s businesses for non-adherence to the code of conduct or unethical behaviour compared with 529 in 2011. This excludes dismissals of staff employed at our retail service station sites, for incidents such as thefts of small amounts of money. A new reporting process to capture information on dismissals is presently being put in place for 2013.

Following the settlement with the US government of all federal criminal claims related to the Gulf of Mexico, BP has agreed to appoint an ethics monitor in the US for a term of four years to review and provide recommendations for the improvement of BP s code of conduct and its implementation and enforcement.

BP continues to apply a policy that the group will not participate directly in party political activity or make any political contributions, whether in cash or in kind. We review employees rights to political activity in each country where we operate. For example, in the US, BP facilitates staff participation in the political process by providing staff support to ensure BP employee political action committee contributions are publicly disclosed and comply with the law.

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Technology

BP develops and deploys technology to find and produce more hydrocarbons, improve conversion efficiency and build new lower-carbon businesses.

Technology investment

2012 highlights:

- We spent $674 million on research and development (R&D) in 2012, supporting business priorities across our portfolio.
- We successfully progressed a suite of technologies aimed at improving safety and operational risk management. Highlights include: demonstration of our real-time blowout preventer (BOP) monitoring tool offshore Brazil; digital radiography to assess the integrity of subsea systems in the North Sea; and deployment of Permasense® corrosion probes to monitor the wall thickness of equipment in refineries in real time.
- We announced plans to deploy *LoSal* enhanced oil recovery technology at our Clair Ridge development in the UK North Sea, which we believe will lead to significantly increased amounts of recoverable oil (see Salt reduction promises healthy returns on page 17).
- We awarded first contracts for Project *20K*, a multi-year initiative to develop next-generation systems and tools to unlock high pressure oil and gas resources in deep water.
- We began construction of a new High-Performance Computing (HPC) centre in Houston, designed to ensure BP remains at the forefront of subsurface imaging technology.
- We licensed our latest-generation purified terephthalic acid (PTA) and paraxylene (PX) technologies to non-affiliated third-parties for the first time, and sold our third licence for *Veba combi-cracking (VCC)* technology.
- In lubricants, we launched new *Castrol* products: *EDGE with Titanium* to deliver enhanced protection under extreme conditions; and *Magnatec Hybrid* to tackle the challenges of engines working with hybrid and stop/start powertrains.

We are investing $100 million over 10 years to set up the International Centre for Advanced Materials (ICAM) to fund research into fundamental understanding and use of advanced materials, from self-healing coatings to membranes, across the energy industry.

How we manage technology

We define technology in BP as the practical application of science to manage risks, capture business value and inform strategy development. This includes the research, development, demonstration and acquisition of new technical capabilities and support for the deployment of BP s know-how.

Our investments are focused on safe operations and areas of competitive advantage: access to resources, process efficiency, product formulation and lower-carbon opportunities.

In 2012 we invested $674 million in R&D (2011 $636 million). (See Financial statements Note 13 on page 210.)

The group technology function provides input to BP s strategy, oversees our major technology programmes, supports technology development and deployment across the company, builds science capability and conducts long-term research.

The technology advisory council, comprised of eminent business and academic technology leaders, provides the board and executive management with an independent view of BP s capabilities judged against the highest industrial and scientific standards.

BP has more than 2,000 scientists and technologists across the group, with seven major technology centres in the US, the UK and Germany.

We also access external expertise through various forms of partnership and collaboration, from joint research agreements to venturing. We have a strategic approach to university relationships across our portfolio for the purposes of research, recruitment, policy insights and education.

Long-term research programmes

International Centre for Advanced Materials (ICAM)

In 2012 BP announced the establishment of ICAM, a $100-million 10-year research partnership to fund research aimed at advancing the fundamental understanding and use of advanced materials from self-healing coatings to membranes, across a variety of energy and industrial applications. The University of Manchester will be the hub for a network of world-class academic institutions, with the University of Cambridge, Imperial College London and the University of Illinois at Urbana-Champaign already participating.

Energy Sustainability Challenge (ESC)

BP is partnering with leading research universities to establish trusted peer-reviewed data on the relationships between natural resource usage and energy. The ESC is a multi-disciplinary research programme, aimed at building a better understanding of natural resource constraints on energy production and consumption including land, water and mineral resources.

Initial findings of the ESC suggest that energy-related natural resource constraints can be managed, but doing so will not be easy, and will require wise policy decisions and technology choices. The next phase of the research will focus on a number of specific natural resource challenges for our businesses and operations across the world.

More information on the ESC can be found at *bp.com/energysustainabilitychallenge*.

The Energy Biosciences Institute (EBI)

The EBI is BP s largest external R&D collaboration, with up to $500-million funding over 10 years for a multi-disciplinary research effort with the University of California Berkeley, the Lawrence Berkeley National Laboratory, and the University of Illinois at Urbana-Champaign. Its goal is to perform groundbreaking research aimed at the development of next-generation biofuels, as well as other bioscience applications to the energy sector. Now in its fifth year, the EBI is generating multiple innovations, particularly in the field of cellulosic conversion.

Massachusetts Institute of Technology Energy Initiative (MITEI)

In 2012 BP renewed its commitment to the MITEI through an agreement to provide another $25 million for continued energy research over the next five years, bringing the company s total programme funding to $50 million. The MITEI conducts multi-disciplinary research aimed at tackling complex energy challenges such as increasing energy supply, improving efficiency, and addressing environmental impacts of

energy consumption. To date, the initiative has sponsored hundreds of energy projects ranging from unconventional sources of hydrocarbons to renewables and nuclear fusion.

Energy Technologies Institute (ETI)

BP is a founding member of the UK s Energy Technologies Institute a public/private partnership established in 2008 to accelerate lower-carbon technology development. By the end of 2012 the ETI had commissioned more than $281 million of work covering 41 projects across a wide range of technologies.

Upstream

Our upstream technologies support BP s business strategy by:

- Focusing on safety and operational risks.
- Helping to obtain new access.
- Increasing recovery and reserves.
- Improving production efficiency.

Our strengths in exploration, deep water, giant fields and gas are underpinned by dedicated flagship technology programmes. These undertake proprietary scientific research to develop industry-leading technologies such as imaging, enhanced recovery and real-time data capabilities. (See Upstream technology flagships on page 18.)

In 2012:

- We began construction of a new HPC centre in Houston, our laboratory for processing and analysing seismic images. BP s investment in the new 110,000 square foot (10,209 square metres) facility will help drive seismic imaging beyond the methods we know today, extending BP s scientific and technical capability. The facility is due for completion in mid-2013.
- The BP Well Advisor suite of technologies aims to bring wells online more efficiently and enhance safety through providing real-time information for decision making. A major programme is under way to develop and deploy BP Well Advisor tools, from casing running, already installed in Azerbaijan, to BOP monitoring in Brazil, cementing in the North Sea and pressure testing in the Gulf of Mexico. These integrated systems provide consoles for the rig crew and onshore engineers to monitor operations in real-time, during well construction and over the life of the well. BP has selected Kongsberg as vendor for the consoles, which will provide a standard interface for drilling teams across the world. In 2012 we continued industry-first field trials of our BOP diagnostic tool on the Ensco

DS4 rig offshore Brazil. This technology has been shared with the industry and with the US Bureau of Safety and Environmental Enforcement.

In February 2012 we announced the launch of Project *20K*, a multi-year initiative to develop next-generation systems and tools to help recover high-pressure, high-temperature deepwater oil and gas resources. We intend to develop technologies over the next decade in four key areas: well intervention and containment; well design and completions; drilling rigs, riser and BOP equipment; and subsea production systems. In November 2012 we awarded the first contracts for Project *20K* to KBR and FMC Technologies. KBR will develop programme execution and management plans, including capital cost and schedule estimates, risk assessments and technical designs. FMC Technologies will participate in a technology development agreement in which it will work jointly with BP to design and develop 20,000 pounds per square inch rated subsea production equipment, including a subsea production tree and a subsea high integrity pressure protection system.

BP announced a plan to deploy its *LoSal* enhanced oil recovery (EOR) technology at the Clair Ridge development in the UK North Sea. This will be the first large-scale offshore deployment of this BP enhanced oil recovery application. The $7.6-billion development at Clair Ridge includes around $120 million for the desalination facilities to create low salinity water. BP estimates that this breakthrough technology (part of BP s suite of *Designer Water* EOR technologies) will increase production by around 42 million barrels of additional oil, compared with conventional waterflooding methods. BP has also confirmed that Mad Dog phase 2 project in the Gulf of Mexico will be the next offshore deployment of *LoSal*.

In collaboration with GE and Oceaneering, we completed BP s first full-field trial of shallow water subsea digital radiography technology (DRT) in the Madoes field in the UK North Sea. This technology employs imaging technology similar to that used in the medical field, adapted for use in marine environments for improved inspection of subsea flow lines up to 2,000 feet below the surface. BP also collaborated with JME, Oceaneering and GE in developing an alternative technology for use in the inspection of subsea flow lines located in deep water.

Downstream

Our Downstream technology focus is both operational and customer facing:

- Developing and applying technology to monitor operational integrity.
- Improving process efficiency in our refineries and petrochemicals plants.
- Optimizing conversion of unconventional feedstocks, including renewables, to liquid transport fuels and chemicals.
- Creating high-performance, energy-efficient, cleaner fuels and lubricants for customers.

Petrochemicals

Our proprietary processing technologies and operational experience continue to reduce the manufacturing costs and environmental impact of our plants, helping to maintain competitive advantage in PTA, PX and acetic acid. For the first time, we have licensed our latest generation aromatics technology to non-affiliated third parties; firstly PTA technology to JBF Petrochemicals, and secondly PX technology to Reliance through our exclusive licensor, CB&I Lummus, both in India.

Lubricants

We completed a number of product developments and launches. *Castrol EDGE with Titanium* is proven to reduce metal to metal contact and delivering enhanced protection under extreme conditions and *Castrol Magnatec Hybrid* tackles the challenges of engines working with hybrid and stop/start powertrains. We also launched an oil co-engineered with Ford during the development of its newly-released EcoBoost engine. This oil delivers a benefit of around 1% to fuel economy. In the commercial transport sector, we launched an updated *Castrol CRB* product, which offers enhanced protection and durability for truck engines. The launch of our new Performance Biolubes product range added bio-based lubricants for use in metalworking operations, improving productivity, safety and environmental impact.

Fuels

We demonstrated our biofuels proprietary technology and collaboration by providing three specially formulated advanced biofuels (containing bio-derived components including cellulosic ethanol, diesel from sugar and biobutanol). These, blended with *BP Ultimate*, fuelled some of the vehicles in the official London 2012 Olympic and Paralympic Games fleet. We also continue to work proactively with governments and regulatory bodies in all countries where we operate to develop practical and effective solutions to meet local and regional biofuel mandates.

Conversion technologies

Veba Combi Cracking (VCC) upgrades heavy oil or coal into high-value transport fuel by adding hydrogen and a proprietary ingredient that prevents unwanted carbon deposits fouling equipment, making the process more reliable. BP has a collaboration agreement on VCC with KBR, who are promoting, marketing and licensing the technology to third parties. In 2012, the third VCC licence with the largest capacity was secured to implement the technology at the Nizhnekamsk refinery in Russia.

BP has developed a proprietary Fischer-Tropsch (FT) technology and a route to upgrade products from the FT process to transport fuel and chemical feedstocks such as diesel, kerosene and naphtha. Having proved this technology under commercial conditions, we and our collaborator Davy Process Technology are actively pursuing commercialization including licensing the technology to third parties. Technology licensing combined with recent successful demonstrations of improvements to both process and catalyst are underpinning the longer-term competitiveness of our technology.

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Refining technologies

We have made improvements in integrity management by deploying Permasense® wireless corrosion sensors in selected areas of all BP-operated refineries worldwide to monitor and enable better decisions about corrosion management. We developed this technology in collaboration with Imperial College, London.

Biofuels

In addition to our biofuel production business in Brazil, we continue to invest in and operate a world-class biofuels research facility in San Diego, California, and a demonstration plant in Jennings, Louisiana, to further develop our next-generation cellulosic biofuel technology and license it for commercial use.

BP s joint venture with DuPont, Butamax Advanced Biofuels LLC, is working to develop and market the advanced biofuel, biobutanol. A technology demonstration plant has been constructed in Hull, UK to accelerate the commercialization of biobutanol technology.

BP is also working in partnership with DSM to advance the development of a step-change technology for conversion of sugars into renewable diesel.

Technology venturing

Our portfolio of technology venturing investments aims to put us at the forefront of innovation. Our emerging business and ventures unit brings together BP s venturing and carbon markets expertise with carbon capture and storage capability. Through this unit, we have invested about $175 million in 33 investments, spanning the following areas:

- Bioenergy.
- Energy efficiency and storage.
- Carbon management.
- Renewable power.
- Emerging oil and gas technologies.

Our recent investments include:

Oxane Materials, a company that is commercializing advanced materials, such as ceramic proppants to improve production and reduce the environmental impact of hydraulic fracturing.

Skyonic, whose SkyMine® technology is a novel application of carbon capture principles that can be retrofitted onto power plants and other industrial sites that emit high volumes of CO_2.

Heliex Power, whose rotary screw expander technology can recover waste heat from a variety of sources commonly found in industry and use it to generate electricity.

Liquid Light, a company developing new ways of converting CO_2 into high-performance chemicals and fuels.

More information on BP and technology can be found at *bp.com/ technology*.

Gulf of Mexico oil spill

We remain committed to meeting our responsibilities to the US federal, state and local governments and communities of the Gulf Coast following the Deepwater Horizon accident.

Key events included:

Continuing the clean-up of the Gulf shoreline under the direction of the Federal On-Scene Coordinator and working to progress the clean-up of shorelines to the point where removal actions are deemed complete.

Supporting economic recovery by resolving legitimate claims and providing support to two of the region s most important industries tourism and seafood.

Reaching settlement agreements to resolve the substantial majority of legitimate private economic loss and medical claims final approval was granted by the court on 21 December 2012 for the economic loss settlement agreement and on 11 January 2013 for the medical settlement agreement.

Completing the funding of the $20-billion Deepwater Horizon Oil Spill Trust, which was established to pay individual and business claims, final judgments in litigation and litigation settlements, state and local response costs and claims, and natural resource damages and related costs.

Working in co-operation with state and federal trustees to collect data needed to assess potential injuries to natural resources resulting from the accident and to progress early restoration activities.

Supporting independent research through the Gulf of Mexico Research Initiative to better understand and mitigate the potential impacts of future oil spills.

Reaching an agreement with the US government in November 2012 (which was subsequently approved by the court in January 2013) to pay $4 billion to resolve all federal criminal claims arising out of the Gulf of Mexico incident. BP also reached a settlement with the SEC to resolve the SEC s Deepwater Horizon-related civil claims against BP. Following these agreements, BP Exploration & Production Inc. (BPXP) received notice from the US Environmental Protection Agency (EPA) of a mandatory debarment from contracting with the US federal government, as well as notice of a temporary suspension, in respect of certain BP group companies. See Agreement with the US government on page 61 for further information.

On 25 February 2013, the first phase of a Trial of Liability, Limitation, Exoneration and Fault Allocation commenced in the federal multi-district litigation proceeding in New Orleans (MDL 2179). This phase will address issues arising out of the conduct of various parties allegedly relevant to the loss of well control at the Macondo well, the ensuing fire and explosion on the Deepwater Horizon on 20 April 2010, the sinking of the vessel on 22 April 2010 and the initiation of the release of oil from the Deepwater Horizon or the Macondo well during those time periods, including whether BP or any other party was grossly negligent. See page 164 for further information.

We have made significant progress in completing the response to the accident and supporting economic and environmental recovery efforts in affected areas.

Completing the response

BP, working under the direction of the US Coast Guard s Federal On-Scene Coordinator (FOSC), continued to complete the Deepwater Horizon operational response activities in 2012.

Residual clean-up of the Gulf of Mexico shoreline

Throughout the year, BP continued to work to progress the clean-up of shorelines to the point where removal actions are deemed complete as established by the Shoreline Clean-up Completion Plan, which was approved by the FOSC in November 2011. The plan established the clean-up requirements for the range of shoreline types in the area of

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response and describes the rigorous process for determining that operational removal activity is complete.

By the end of 2012, the FOSC had deemed removal actions complete on 4,029 miles (6,484kms) of shoreline out of the 4,376 miles (7,043kms) that were in the area of response. Approximately 108 miles were pending final monitoring or inspection and a determination that removal actions are complete. The remaining 239 miles are in the monitoring and maintenance phase, which will continue until the FOSC determines that operational removal activity is complete.

According to a study by the Operational Science Advisory Team (OSAT), composed of scientists representing federal agencies and BP, the residual oil that remains is heavily weathered, contains only a small fraction of the compounds of concern and is below the EPA s benchmarks for the protection of human health.

The US Coast Guard has indicated that if oil is later discovered in a shoreline segment where removal actions have been deemed complete, they will follow long-standing response protocols established under the law and contact whoever it believes is the responsible party or parties.

Hurricane Isaac

In late August 2012, Hurricane Isaac made landfall on the Gulf Coast, uncovering residual oil in some areas in Louisiana. The remaining residual oil had been buried when tropical storms in 2010 and 2011 deposited several feet of sand along some of the Gulf Coast shoreline. After the material was buried, in many instances, net environmental benefit analysis had indicated that deep cleaning at these sites could do more harm than good. But once Isaac removed this sand overburden in some places, clean-up crews have been able to clean the residual material without the same degree of potential environmental impact.

Other shorelines in the area of response were less affected by Hurricane Isaac. A few areas saw a short-term increase in the number of tar balls in the initial aftermath, but conditions returned to pre-Isaac levels after a few days once clean-up operations were resumed in these locations.

Response efforts guided by science

Scientific studies conducted at the direction of the FOSC continued to guide response actions and help define what is known scientifically about the fate of the oil and the potential impacts to human health, aquatic life, wildlife and the environment. This included OSAT studies and net environmental benefit analyses conducted in 2010 and 2011.

At the request of BP, the FOSC formed another OSAT in 2012 to investigate discrete areas of buried oil accumulations (tar mats) near the shoreline. The team was directed to integrate a number of data sets to evaluate the potential for buried oil in discrete locations across the area of response and determine if additional mitigating actions may be taken to excavate the residual material with minimal environmental impact.

Economic recovery

BP continued to support economic recovery efforts in local communities through a variety of actions and programmes in 2012. By 31 December 2012, BP had spent nearly $10 billion on economic recovery, including claims, advances, settlements and other payments, such as state tourism grants and funding for state-led seafood testing and marketing. In addition, $1.8 billion has been paid to the seafood compensation fund, which has not yet been paid to final claimants.

Plaintiffs Steering Committee settlements

In April 2012, BP reached settlements with the Plaintiffs Steering Committee (PSC) to resolve the substantial majority of legitimate economic loss and medical claims stemming from the accident. In May 2012, the court preliminarily approved the settlements. The PSC acts on behalf of individual and business plaintiffs in the multi-district litigation proceedings pending in New Orleans.

Typically in class action settlements, claims are not paid until after the court has granted final approval to the settlement and all appeals have been exhausted. Here, BP took the unusual step of agreeing to process and pay claims under the economic and property damages agreement prior to any such court approval. Accordingly, a court-supervised transitional claims programme took over the processing and payment of economic loss claims from the Gulf Coast Claims Facility on 8 March 2012.

On 4 June 2012, the transitional process was closed, and the Deepwater Horizon Court Supervised Settlement Program (DHCSSP) began processing and paying claims from settlement class members under the economic and property damages agreement.

In November 2012, the court held a fairness hearing with respect to the settlements and subsequently granted final approval of the economic and property damages agreement on 21 December 2012 and of the medical benefits class action settlement agreement on 11 January 2013.

Under the economic and property damages agreement, there are agreed compensation protocols for the payment of class members economic and property damages. In addition, many economic and property damages settlement class members will also receive payments based on negotiated risk transfer premiums, which are multipliers designed to compensate claimants for potential future losses relating to the accident, along with other potential damages.

Under the medical benefits class action settlement agreement, payments will be made based on a matrix for certain specified physical conditions. The agreement also provides for a 21-year Periodic Medical Consultation Program for qualifying class members. Class members claiming later-manifested physical conditions may pursue their claims in the future through a mediation or litigation process, but waive the right to seek punitive damages.

In addition, under the medical benefits class action settlement agreement, BP has agreed to provide $105 million to the Gulf Region Health Outreach Program to improve the availability, scope and quality of healthcare in Gulf communities. The focus will be on strengthening local capacity to deliver primary care, behavioural and mental health services, and environmental medicine. This healthcare outreach programme is intended to benefit both class members and others in those communities. BP provided approximately $20 million in 2012 to launch the assessment and evaluation phase of the health outreach programme across the four Gulf States.

Business economic loss claims received by the DHCSSP to date are being paid at a higher average amount than previously assumed by BP in formulating the original estimate of the cost of the PSC settlement, resulting from an interpretation of the settlement agreement by the claims administrator that BP believes was incorrect. As more fully described in Legal proceedings on pages 162-169, this matter has been considered by the court and on 5 March 2013, the court affirmed the claims administrator s interpretation of the settlement agreement and rejected BP s position as it relates to business economic loss claims. BP strongly disagrees with the ruling of 5 March 2013 and the current implementation of the agreement by the claims administrator. BP intends to pursue all available legal options, including rights of appeal, to challenge this ruling. Given the inherent uncertainty that exists as BP pursues all available legal options to challenge the recent ruling, and the higher number of claims received and higher average claims payments than previously assumed by BP, which may or may not continue, management has concluded that no reliable estimate can be made of the cost of any business economic loss claims not yet received or processed by the DHCSSP. As a consequence, an amount of $0.8 billion previously provided for such claims has been derecognized. A provision will be re-established when a reliable estimate can be made of the liability. For further information see Financial statements Note 36 on page 235, Note 43 on pages 253 and Risk factors on pages 38-44.

BP s current estimate of the total cost of those elements of the PSC settlement that can be estimated reliably, which excludes any future business economic loss claims not yet received or processed by the DHCSSP, is $7.7 billion. If BP is successful in its challenge to the Court s ruling, the total estimated cost of the settlement agreement will, nevertheless, be significantly higher than the current estimate of $7.7 billion, because business economic loss claims not yet received or processed are not reflected in the current estimate and the average payments per claim determined so far are higher than anticipated. If BP is not successful in its challenge to the Court s ruling, a further significant increase to the total estimated cost of the settlement will be required. However, there can be no certainty as to how the dispute will ultimately be resolved or determined. To the extent that there are insufficient funds available in the Trust fund, payments under the PSC settlement will be made by BP directly, and charged to the income statement.

Significant uncertainties exist in relation to the amount of claims that are to be paid and will become payable through the claims process. There is significant uncertainty in relation to the amounts that ultimately will be paid in relation to current claims, and the number, type and amounts payable for claims not yet reported. In addition, there is further uncertainty in relation to interpretations of the claims administrator regarding the protocols under the settlement agreement and judicial interpretation of these protocols, and the outcomes of any further litigation including in relation to potential opt-outs from the settlement or otherwise. The PSC settlement is uncapped except for economic loss claims related to the Gulf seafood industry. See Risk factors on pages 41-42, Financial statements Note 2 on page 194, Note 36 on page 235 and Note 43 on page 253 for further information.

Claims under the Oil Pollution Act of 1990

On 4 June 2012, the BP claims programme also began accepting claims under the Oil Pollution Act of 1990 (OPA 90). The programme is open to claimants that wish to file economic and property damages claims and fall into one of three categories: individuals and businesses that are not class members; individuals and businesses that are class members, but exercise their legal right to opt out of the class settlement; and individuals and businesses that are class members but wish to pursue claims that are expressly reserved to them pursuant to the PSC settlement, to the extent such claims may fall within OPA 90.

Claims payments

By the end of 2012, BP had paid a total of $8.2 billion to individual and business claimants, including payments from the DHCSSP, the Gulf Coast Claims Facility, the BP claims programmes and the court-supervised transitional claims programme. In 2012, $1.9 billion was paid to individuals and businesses through the various programmes.

BP is also responsible for directly managing claims and funding requests for losses or expenses incurred by states, parishes, counties, federally recognized Indian tribes and other government entities. These government claims primarily cover costs associated with response and removal activities, increased public services and loss of revenues due to the accident.

Government entities have received approximately $1.4 billion in payments for claims, advances, and settlements.

Supporting recovery of the tourism and seafood industries

To support tourism in the affected states, BP has committed $179 million by the end of 2013 to Alabama, Florida, Louisiana and Mississippi for regional and national tourism promotion campaigns. To date, tourism organizations have received $173 million and are using the BP funds in part to expand their advertising and marketing efforts to reach potential visitors. State and regional tourism organizations reported strong visitor numbers across the affected states in 2012.

In addition to resolving legitimate claims made by those in the fishing and seafood processing industries, by the end of 2012 BP had paid or committed to pay $82 million to Alabama, Florida, Louisiana and Mississippi for state-led seafood testing and marketing programmes.

A further $57 million is being given to non-profit groups and government entities to promote the tourism and seafood industries as part of the PSC settlement.

Although research and monitoring continues, a number of experts believe the Gulf of Mexico seafood industry is making a strong recovery. Government testing results have led state and federal officials to declare that Gulf seafood is safe to consume. Government landings and abundance data show that Gulf seafood generally is within pre-spill landings and population trends in most areas in the northern Gulf. According to a September 2012 report from the

National Oceanic and Atmospheric Administration (NOAA), 2011 commercial seafood landings in the Gulf reached their highest levels since 1999, although the results varied by state and by species.

Agreement with the US government

On 15 November 2012, BP Exploration & Production Inc. (BPXP) reached an agreement with the US government to resolve all federal criminal claims arising out of the Deepwater Horizon accident, spill, and response. On 29 January 2013, the US District Court for the Eastern District of Louisiana accepted BPXP s pleas and sentenced BPXP in accordance with the criminal plea agreement. Under the terms of the criminal plea agreement, BPXP pleaded guilty to 11 felony counts of Misconduct or Neglect of Ships Officers relating to the loss of 11 lives; one misdemeanour count under the Clean Water Act; one misdemeanour count under the Migratory Bird Treaty Act; and one felony count of obstruction of Congress. As part of the resolution of federal criminal claims, BPXP will pay $4 billion, including $1.256 billion in criminal fines, in instalments over a period of five years. Under the terms of the criminal plea agreement, a total of $2.394 billion will be paid to the National Fish & Wildlife Foundation (NFWF) over a period of five years. In addition, $350 million will be paid to the National Academy of Sciences (NAS) over a

period of five years. The court also ordered, as previously agreed with the US government, that BPXP serve a term of five years probation.

Also on 15 November 2012, BP reached a settlement with the US Securities and Exchange Commission (SEC), resolving the SEC s Deepwater Horizon-related civil claims against the company under Sections 10(b) and 13(a) of the Securities Exchange Act of 1934 and the associated rules. BP has agreed to a civil penalty of $525 million, payable in three instalments over a period of three years, and has consented to the entry of an injunction prohibiting it from violating certain US securities laws and regulations. The SEC s claims are premised on oil flow rate estimates contained in three reports provided by BP to the SEC during a period from 29 April 2010 to 4 May 2010, within the first 14 days after the accident. The settlement was approved by the US District Court for the Eastern District of Louisiana on 10 December 2012, and BP made its first payment of $175 million on 11 December 2012.

Under US law, companies convicted of certain criminal acts are subject to debarment from contracting with the federal government. The charges to which BPXP pleaded guilty included one misdemeanour count under the Clean Water Act which, by operation of law following the court s acceptance of BPXP s plea, triggers a statutory debarment, also referred to as mandatory debarment, of the BPXP facility where the Clean Water Act violation occurred.

On 1 February 2013, the EPA issued a notice that BPXP was mandatorily debarred at its Houston headquarters. Mandatory debarment prevents BPXP from entering into new contracts or new leases with the US government. A mandatory debarment does not affect any existing contracts or leases a company has with the US government and will remain in place until such time as the debarment is lifted through an agreement with the EPA.

On 28 November 2012, the EPA notified BP that it had temporarily suspended BP p.l.c., BPXP and a number of other BP subsidiaries from participating in new federal contracts. As a result of the temporary suspension, the BP entities listed in the notice are ineligible to receive any US government contracts either through the award of a new contract, or the extension of the term of, or renewal of, an expiring contract. The suspension does not affect existing contracts the company has with the US government, including those relating to current and ongoing drilling and production operations in the Gulf of Mexico.

With respect to the entities named in the temporary suspension, the temporary suspension may be maintained or the EPA may elect to issue a notice of proposed discretionary debarment to some or all of the named entities. Like suspension, a discretionary debarment would preclude BP entities listed in the notice from receiving new federal fuel contracts, as well as new oil and gas leases, although existing contracts and leases will continue. Discretionary debarment typically lasts three to five years, and may be imposed for a longer period, unless it is resolved through an administrative agreement.

While BP s discussions with the EPA have been taking place in parallel to the court proceedings on the criminal plea, the company s work towards reaching an administrative agreement with the EPA is a separate process, and it may take some time to resolve issues relating to such an agreement. BPXP s mandatory debarment applies following sentencing and is not an indication of any change in the status of discussions with the EPA. The process for resolving both mandatory and discretionary debarment is essentially the same as for resolving the temporary suspension. BP continues to work with the EPA in preparing an administrative agreement that will resolve suspension and debarment issues.

For further details, see Legal proceedings on pages 162-169.

Environmental restoration

We continued to support and participate in the Natural Resource Damages Assessment (NRDA) process and made progress in 2012 in a number of key areas as part of the ongoing effort to assess and address injury to natural resources in the Gulf of Mexico.

Natural resource damages assessment

Since May 2010, more than 200 initial and amended work plans have been developed to study resources and habitat by state and federal trustees and BP, and by the end of 2012 BP had paid $973 million to support the assessment process, including co-operative and independent

studies. The study data will inform an assessment of injury to the Gulf Coast natural resources and the development of a restoration plan to mitigate the identified injuries. Detailed analysis and interpretation continue on the data that have been collected.

Scientists are studying a range of species, including marine mammals, birds, fish and plants to understand how wildlife populations may have been affected by the accident. Teams of experts are also studying habitats such as wetlands and beaches, with the goal of returning these resources to their baseline condition the condition they would be in if the Deepwater Horizon accident had not occurred. In addition, experts are looking at how recreational uses of natural resources may have been affected so that lost opportunities to enjoy those activities can be addressed through restoration.

Early restoration projects

In 2012, work began on the initial set of early restoration projects identified through an agreement BP signed with state and federal trustees in April 2011. The trustees also approved two new early restoration projects in December 2012, which are designed to improve nesting habitat for birds and loggerhead sea turtles on a number of Gulf Coast beaches.

Under the early restoration framework agreement, BP agreed to fund up to $1 billion in early restoration projects to accelerate efforts to restore natural resources injured as a result of the Deepwater Horizon accident. The framework requires BP and the trustees to agree on the potential projects, funding and the natural resources benefits the projects are expected to provide. The trustees will then implement the projects.

The agreement between BP and the trustees makes it possible for restoration to begin at an earlier stage of the NRDA process than usual. Natural Resource Damages (NRD) restoration projects are typically funded only after the NRD assessment is complete and a final settlement has been reached or a final court judgment has been entered. This process often takes many years, and restoration is often delayed during that time. The early restoration framework agreement allows the parties to expedite projects to restore, replace or acquire the equivalent of injured natural resources in the Gulf soon after an injury is identified, reducing the time needed to achieve restoration of those resources.

BP committed to fund the estimated $60 million cost of the eight initial early restoration projects that were approved by the trustees in April 2012 following public review and comment. The eight projects will collectively restore and enhance wildlife, habitats, the ecosystem services provided by those habitats, and provide additional access for fishing, boating and related recreational uses. Funding will come from the $20-billion Trust.

Following a 30-day public comment period, the trustees approved on 21 December 2012 the two new projects to improve habitat for nesting birds and sea turtles that will cost an additional estimated $9 million. The trustees and BP are working to identify additional projects for public review and comment. More information about the status of early restoration can be found on the NOAA website.

Sharing the information

In 2012 BP produced a second progress report on the NRDA effort and made presentations at scientific conferences to describe studies that are under way. The trustees have already made some of the data sets from these studies available online while others are still being finalized. BP seeks to share data and information collected from the co-operative NRDA studies with stakeholders and members of the public once these have been approved for release by the trustees.

Supporting the Gulf of Mexico Research Initiative

BP has committed $500 million over 10 years to fund independent scientific research through the Gulf of Mexico Research Initiative. The goal of the research initiative is to improve society s ability to understand, respond to and mitigate the potential impacts of oil spills to marine and coastal ecosystems.

Through a competitive review process, the initiative approved funding in August 2012 for 19 grants that will provide approximately $20 million to researchers over the next three years. Including funding awarded in 2010 and 2011, the total funding awarded by the end of 2012 was $184 million. Grant recipients are investigating the fate of oil releases; the ecological

and human health aspects of spills; and the development of new tools and technology for future spill response, mitigation and restoration.

Financial update

The group income statement for 2012 includes a pre-tax charge of $5.0 billion in relation to the Gulf of Mexico oil spill. The charge for the year reflects the agreement with the US government, adjustments to provisions and the ongoing costs of the Gulf Coast Restoration Organization. As at 31 December 2012, the total cumulative charge recognized to date for the accident amounts to $42.2 billion.

The cumulative income statement charge does not include amounts for obligations that BP considers are not possible, at this time, to measure reliably. The total amounts that will ultimately be paid by BP in relation to all the obligations relating to the accident are subject to significant uncertainty and the ultimate exposure and cost to BP will be dependent on many factors, as discussed under Contingent liabilities in Note 43 on page 253, including in relation to any new information or future developments. These could have a material impact on our consolidated financial position, results of operations and cash flows. The risks associated with the accident could also heighten the impact of the other risks to which the group is exposed, as further described under Risk factors on pages 38-44.

For details regarding the impacts and uncertainties relating to the Gulf of Mexico oil spill refer to Financial statements Note 2 on page 194, Note 36 on page 235 and Note 43 on page 253. See also Proceedings and investigations relating to the Gulf of Mexico oil spill on pages 59-62.

Trust update

BP, in agreement with the US government, set up the $20-billion Deepwater Horizon Oil Spill Trust (the Trust) to provide confidence that funds would be available to satisfy individual and business claims, final judgments in litigation and litigation settlements, state and local response costs and claims, and natural resource damages and related costs.

BP contributed a total of $4.9 billion to the Trust in 2012. The Trust has now been fully funded. Payments made during 2012 were $2.8 billion for individual and business claims, medical settlement programme payments, NRD assessment and early restoration, state and local government claims, DHCSSP expenses and other resolved items. These payments were made from the Trust and qualified settlement funds (QSFs) established for paying the costs of the settlement agreements with the PSC and funded by the Trust. An additional $1.8 billion was paid from the Trust into the $2.3-billion seafood compensation fund, extinguishing BP s liability, which had not yet been paid to claimants. As at 31 December 2012, the cumulative amount paid from the Trust and QSFs since inception was $9.5 billion, and the remaining cash balance was $10.5 billion, including $1.8 billion remaining in the seafood compensation fund.

As at 31 December 2012, the cumulative charges for provisions to be paid from the Trust and the associated reimbursement asset recognized amounted to $17.8 billion. The increased charges in 2012 reflect higher provision estimates for claims paid prior to establishing the DHCSSP, claims and administration costs of the DHCSSP and NRD assessment costs. A further $2.2 billion could be provided in subsequent periods for items covered by the Trust, with no net impact on the income statement. The amount of cumulative charges for provisions described above will increase as more information becomes available, the interpretation of the protocols established in the economic and property damages settlement agreement is clarified and the claims process matures, enabling BP to estimate reliably the cost of claims which currently cannot be estimated reliably and are therefore not provided for. See Plaintiffs Steering Committee settlements on page 60 and Financial statements Note 36 on page 235 for further information.

Legal proceedings and investigations

On 25 February 2013, the first phase of a Trial of Liability, Limitation, Exoneration and Fault Allocation commenced in the federal multi-district litigation proceeding in New Orleans. For further information on this and other legal proceedings, see pages 162-169.

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Upstream

In 2012 we continued to actively manage and simplify our portfolio, strengthening our incumbent positions to provide a platform for growth in the future.

What we do

We are focused on accessing and extracting oil and gas through all stages of the life cycle and we deliver these activities through three separate divisions:

Exploration responsible for renewing our resource base through access, exploration and appraisal.

Developments ensures the safe, reliable and compliant execution of wells (drilling and completions) and major projects and comprises the global wells organization and the global projects organization.

Production ensures safe, reliable and compliant operations, including upstream production assets, midstream transportation and processing activities, and the development of our resource base.

These activities are optimized and integrated with support from global functions with specialist areas of expertise and the group s strategy and integration organization, which comprises finance, procurement and supply chain, human resources, technology and information technology.

Our Upstream segment includes upstream and midstream activities, and gas marketing and trading activities in 28 countries with production from 19 countries, see pages 6-7.

Our strategy

In Upstream, our highest priority is to ensure safe, reliable and compliant operations worldwide. Our strategy is to invest to grow long-term value by continuing to build a portfolio of material, enduring positions in the world s key hydrocarbon basins. Our strategy is enabled by:

- A continued focus on safety and the systematic management of risk.
- Playing to our strengths exploration, giant fields, deepwater and gas value chains.
- A simplified portfolio with strengthened incumbent positions and reduced operating complexity.
- An execution model that drives improvement in efficiency and reliability through both operations and investment.

A bias to oil while maintaining a balance of gas markets and resource types.

Strong relationships built on mutual advantage, deep knowledge of the basins in which we operate, and technology.

We intend to gradually increase investment with a focus on exploration, a key source of value creation, and evolve the nature of our relationships, particularly with national oil companies.

Outlook

In 2013 we expect reported production to be lower than 2012, mainly due to the impact of divestments which we estimate at around 150mboe/d. After adjusting for the impacts of divestments and entitlement effects in our PSAs, we expect underlying production to grow.

We expect four major projects to come onstream towards the end of 2013, with a further six in 2014.

We expect to make the final investment decision (FID) on five projects in 2013.

Capital investment in 2013 will increase, reflecting the progression of our major projects and the increases in exploration and access activity.

We remain on track to deliver Upstream s contribution to the group s plan to generate an increase of around 50% in operating cash flow by 2014 compared with 2011.[b]

[a] Underlying replacement cost profit before interest and tax is not a recognized GAAP measure. See footnote b on page 34 for further information. The equivalent measure on an IFRS basis is replacement cost profit before interest and tax.

[b] See footnote c on page 21.

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With effect from 1 January 2012, the Exploration and Production segment was split to form two new operating segments, Upstream and TNK-BP, reflecting the way in which we were managing our investment in TNK-BP. Comparative data has been restated to reflect this change. For information on our subsequent agreement to sell our interest in TNK-BP to Rosneft, see pages 80-81.

Market commentary

The growth in world oil consumption remained weak in 2012, with continued growth in China and other non-OECD countries offsetting yet another decline in OECD countries. With oil markets balancing supply losses against weak consumption and high OPEC production, average crude oil prices in 2012 were similar to the previous year. Natural gas prices continued to show divergence amongst markets globally in 2012.

	2012	2011	2010
Average oil marker prices[a]			$ per barrel
West Texas Intermediate	**94.13**	95.04	79.45
Brent	**111.67**	111.26	79.50
Average natural gas marker prices	$ per million British thermal units		
Average Henry Hub gas price[b]	**2.79**	4.04	4.39
			pence per therm
Average UK National Balancing Point gas price[a]	**59.74**	56.33	42.45

[a] All traded days average.
[b] Henry Hub First of Month Index.

Crude oil prices

Crude oil prices, as demonstrated by the industry benchmark of dated Brent for the year, averaged $111.67 per barrel in 2012, similar to the 2011 average of $111.26 per barrel. This represented the highest annual average ever (in nominal terms).

Brent remains an integral marker to the production portfolio with a significant proportion of production being priced directly or indirectly from this. Certain regions use other local markers, which are derived using differentials, premiums or a lagged impact from the Brent crude oil price.

Prices rose early in 2012 due to concerns about risks to supply stemming from the stand-off over Iran s nuclear programme, with prices reaching a peak of $128 per barrel in March. Thereafter, weaker economic growth, high OPEC production and rising OECD commercial inventories pushed oil prices to a low of $89 per barrel in June, before better economic news, a substantial reduction in Iranian production, and renewed concerns about risks to supply drove a recovery in prices.

Against this backdrop of a weak economy and high oil prices, global oil consumption remained weak, rising by roughly 1 million barrels per day for the year (1.1%)[a]. Growth in 2012 was once again led by non-OECD countries including China. OECD consumption fell for the sixth time in the past seven years. Non-OPEC production rose slightly, with strong US growth offset by declines elsewhere. OPEC crude oil production remained robust despite a large decline in Iranian output due to US and EU sanctions. As a result, OECD commercial oil inventories rose above average in late 2012.

By comparison, global oil consumption in 2011 grew by roughly 0.6 million barrels per day (0.7%)[b]. OPEC production met the growth in consumption despite the disruption of Libyan production due to large increases in Saudi Arabia and other Middle-Eastern producers, but the loss of production drove oil prices sharply higher.

We expect oil price movements in 2013 to continue to be driven by the pace of global economic growth and its resulting implications for oil consumption, by the supply growth in North America, and OPEC production decisions. The path of Iranian production in the face of ongoing US and EU sanctions remains a key uncertainty.

Natural gas prices

Natural gas prices continued to diverge globally in 2012. The average US Henry Hub First of Month Index fell 31% to average $2.79/mmBtu in 2012, while European spot prices increased. In Upstream, with the exception of our North American gas business, a significant amount of our

[a] From *Oil Market Report 18 January 2013©,* OECD/IEA 2013, page 4.
[b] *BP Statistical Review of World Energy June 2012.*

gas production is based on long-term contracts with fixed prices, meaning that market fluctuations have less of an impact on our revenues.

The US gas market in 2012 was dominated by an unusually warm winter at the start of the year, causing a collapse of heating demand. Spot prices fell to 10-year lows, promoting an unprecedented coal-to-gas switch in power generation, and a slowdown in gas drilling activity. Together with an unusually warm summer, boosting electricity demand for air-conditioning, these short-run market responses led to a modest recovery in US prices, which was stalled by a return to an unusually warm December towards the end of 2012.

In Europe, spot gas prices at the UK National Balancing Point increased by 6% to an average of 59.74 pence per therm for 2012. This increase came despite weak demand in European gas markets, due to the economic turmoil in Europe and gas being uncompetitive in power generation relative to coal. European spot prices were supported by the tight global LNG market as strong demand and high spot prices in Asia, driven by Japan s need for LNG to replace lost nuclear power and cover demand during an unusually cold December in 2012, continued to attract LNG away from Europe. LNG deliveries to Europe in 2012 were 23% lower than in 2011.

In 2011, compared with 2010, the strength of shale gas production growth had led the average Henry Hub First of Month Index to weaken, falling by 8% to $4.04/mmBtu. In the UK, National Balancing Point prices averaged 56.33 pence per therm, 33% above prices in 2010.

In 2013, we expect gas markets to continue to be driven by the economy, weather, domestic production, limited increases in LNG supplies and continuation of the uncertainty surrounding nuclear power generation in Japan. Futures markets indicate that the large gap between US and European gas prices is expected to persist through 2013.

2012 performance

Safety performance

In Upstream, delivering safe, reliable and compliant operations remains our highest priority. The group safety and operational risk (S&OR) function supports the business line in delivering safe, reliable and compliant operations across the group s operated businesses. S&OR staff are deployed at the operating level throughout the Upstream segment to support the systematic and disciplined application of those standards. This creates an independent reporting line, working alongside line management while having the power to intervene, supported by a systematic framework provided by BP s operating management system (OMS). All upstream operated businesses are applying OMS to govern BP operations and continue to work to achieve conformance to standards and practices required by OMS through the performance improvement cycle process. We continue to work to enhance local systems and processes at all our sites. See Safety on pages 46-50 for more information on OMS.

Safety performance is monitored by a suite of input and output metrics that focus on personal and process safety including operational integrity, occupational health and legal compliance.

In 2012 there was one workforce fatality in Upstream. In 2011, there were no workforce fatalities.

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The recordable injury frequency (RIF), which measures the number of recordable injuries to the BP workforce per 200,000 hours worked, was 0.32. This is higher than 2011 when it was 0.30 and equal to 2010 when it was also 0.32. The 2012 DAFWCF, a subset of the RIF that measures the number of cases where an employee misses one or more days from work per 200,000 hours worked, was 0.053. This is lower than 2011 when it was 0.060 and 2010 when it was 0.063.

In 2012 the number of reported loss of primary containment (LOPC) incidents in Upstream was 151, down from 152 in 2011. The number of reported oil spills equal to or larger than 1 barrel during 2012 was 87, up from 71 in 2011.

Financial and operating performance

			$ million
	2012	2011	2010
Sales and other operating revenues[a]	**71,940**	75,475	66,266
Replacement cost profit before interest and tax	**22,474**	26,366	28,269
Net (favourable) unfavourable impact of non-operating items and fair value accounting effects[b]	**(3,055)**	(1,141)	(3,196)
Underlying replacement cost profit before interest and tax[c]	**19,419**	25,225	25,073
Capital expenditure and acquisitions	**17,859**	25,535	17,753
BP average realizations[d]			$ per barrel
Crude oil	**108.94**	107.91	77.54
Natural gas liquids	**42.75**	51.18	42.78
Liquids[e]	**102.10**	101.29	73.41
			$ per thousand cubic feet
Natural gas	**4.75**	4.69	3.97
US natural gas	**2.32**	3.34	3.88
			$ per thousand barrels of oil equivalent
Total hydrocarbons[f]	**61.86**	62.31	47.90
Production (net of royalties)[g]			
Liquids[e]			thousand barrels per day
Subsidiaries	**896**	992	1,228
Equity-accounted entities	**284**	294	289
Total of subsidiaries and equity-accounted entities	**1,179**	1,285	1,517
Natural gas			million cubic feet per day
Subsidiaries	**6,193**	6,393	7,332
Equity-accounted entities	**416**	415	429
Total of subsidiaries and equity-accounted entities	**6,609**	6,807	7,761
Total hydrocarbons[f]			thousand barrels of oil equivalent per day
Subsidiaries	**1,963**	2,094	2,492
Equity-accounted entities	**355**	366	363
Total of subsidiaries and equity-accounted entities	**2,319**	2,460	2,855

[a] Includes sales between businesses.
[b]

Fair value accounting effects represent the (favourable) unfavourable impact relative to management s measure of performance (see page 37 for further details).

[c] Underlying replacement cost profit is not a recognized GAAP measure. See footnote b on page 34 for information on underlying replacement cost profit.

[d] Realizations are based on sales of consolidated subsidiaries only, which excludes equity-accounted entities.

[e] Liquids comprise crude oil, condensate and natural gas liquids (NGLs).

[f] Expressed in thousands of barrels of oil equivalent per day (mboe/d). Natural gas is converted to oil equivalent at 5.8 billion cubic feet = 1 million barrels.

[g] Includes BP s share of production of equity-accounted entities in the Upstream segment. Because of rounding, some totals may not agree exactly with the sum of their component parts.

			$ million
	2012	2011	2010
Estimated net proved reserves			
(net of royalties)			
Liquids[h]			million barrels
Subsidiaries[i]	**4,477**	5,154	5,558
Equity-accounted entities[j]	**838**	929	1,221
Equity-accounted entities (bitumen)[j]	**195**	178	179
Total of subsidiaries and equity-accounted entities	**5,510**	6,261	6,958
Natural gas			billion cubic feet
Subsidiaries[k]	**33,264**	36,380	37,809
Equity-accounted entities[j]	**2,549**	2,397	2,532
Total of subsidiaries and equity-accounted entities	**35,813**	38,777	40,341
Total hydrocarbons			million barrels of oil equivalent
Subsidiaries	**10,213**	11,426	12,077
Equity-accounted entities	**1,472**	1,520	1,837
Total of subsidiaries and equity-accounted entities	**11,685**	12,946	13,914

[h] Liquids comprise crude oil, condensate, NGLs and bitumen.

[i] Includes 14 million barrels (20 million barrels at 31 December 2011 and 22 million barrels at 31 December 2010) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[j] During 2012, upstream operations in Abu Dhabi, Argentina and Bolivia, as well as some of our operations in Angola, Canada, Indonesia and Trinidad, were conducted through equity-accounted entities.

[k] Includes 2,890 billion cubic feet of natural gas (2,759 billion cubic feet at 31 December 2011 and 2,921 billion cubic feet at 31 December 2010) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

Sales and other operating revenues for 2012 were $72 billion, compared with $75 billion in 2011 and $66 billion in 2010. The decrease in 2012, compared with 2011, primarily reflected lower production and persistently low Henry Hub gas prices. The increase in 2011, compared with 2010, primarily reflected higher oil and gas realizations, partly offset by lower production.

The replacement cost profit before interest and tax for 2012 was $22,474 million, compared with $26,366 million for the previous year. This included net non-operating gains of $3,189 million, primarily a result of gains on disposals being partly offset by impairment charges. (See page 37 for further information on non-operating items.) In addition, fair value accounting effects had an unfavourable impact of $134 million relative to management s measure of performance. (See page 37 for further information on fair value accounting effects.)

After adjusting for non-operating items and fair value accounting effects, the underlying replacement cost profit in 2012 was $19,419 million, compared with $25,225 million in 2011. The 23% decrease was due to higher costs (primarily higher depreciation, depletion and amortization, as well as ongoing sector inflation), lower production and lower realizations.

Total capital expenditure including acquisitions and asset exchanges in 2012 was $17.9 billion (2011 $25.5 billion and 2010 $17.8 billion). (See page 66 for further information on acquisitions.)

Provisions for decommissioning increased from $17.2 billion at the end of 2011 to $17.3 billion at the end of 2012. The increase reflects updated estimates of the cost of future decommissioning and additions for new assets, largely offset by transfers to assets held for sale and divestments. Decommissioning costs are initially capitalized within fixed assets and are subsequently depreciated as part of the asset.

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Prior years comparative financial information

The replacement cost profit before interest and tax for the year ended 31 December 2011 of $26,366 million included net non-operating gains of $1,130 million, primarily a result of gains on disposals being partly offset by impairments, a charge associated with the termination of our agreement to sell our 60% interest in Pan American Energy LLC (PAE) to Bridas Corporation and other non-operating items. In addition, fair value accounting effects had a favourable impact of $11 million relative to management s measure of performance.

The replacement cost profit before interest and tax for the year ended 31 December 2010 of $28,269 million included net non-operating gains of $3,199 million, comprised primarily of gains on disposals that completed during the year partly offset by impairment charges and fair value losses on embedded derivatives. In addition, fair value accounting effects had an unfavourable impact of $3 million relative to management s measure of performance.

After adjusting for non-operating items and fair value accounting effects, the underlying replacement cost profit in 2011 compared with 2010 was marginally increased, reflecting higher realizations partially offset by lower production volumes (including in higher margin areas).

Acquisitions and disposals

During 2012 we undertook a number of disposals. In total, disposal transactions generated $10.7 billion in proceeds during 2012. With regards to proved reserves, 441mmboe net were disposed of, all within our subsidiaries. There were no significant acquisitions in 2012.

Disposals

On 28 February 2012 BP announced it had agreed terms with LINN Energy to sell BP s Hugoton basin assets (including the Jayhawk NGL plant). Under the agreement LINN Energy agreed to pay BP $1.2 billion in cash. The sale completed on 30 March 2012.

On 27 March 2012 BP announced that it had agreed to sell its interests in all of its operated gas fields in the southern North Sea, including associated pipeline infrastructure and the Dimlington terminal (including the integrated Easington terminal) to Perenco UK Ltd for $400 million. The sale completed in October 2012.

On 2 April 2012 the sale of the Canadian natural gas liquid business to Plains Midstream Canada ULC, a wholly owned subsidiary of Plains All American Pipeline L.P., announced in 2011, was completed.

On 25 June 2012 BP announced that it had agreed to sell its interests in the Jonah and Pinedale upstream operation in Wyoming to LINN Energy for $1.025 billion. The sale completed on 31 July 2012.

On 26 June 2012 BP announced that it had agreed to sell its non-operated interests in the Alba and Britannia fields in the UK North Sea to Mitsui & Co Ltd for $280 million. The sale completed in December 2012.

On 10 August 2012 BP announced that it had agreed to sell its Sunray and Hemphill gas processing plants in Texas, together with their associated gas gathering system, to Eagle Rock Energy Partners for $228 million. The sale completed on 1 October 2012.

On 10 September 2012 BP announced that it had agreed to sell its interests in a number of non-strategic assets in the Gulf of Mexico to Plains Exploration and Production Company for $5.55 billion. The sale includes interests in three BP-operated assets: the Marlin hub, comprised of the Marlin, Dorado and King fields (BP 100%); Horn Mountain (BP 100%) and Holstein (BP 50%). The deal also includes BP s stake in two non-operated assets: Ram Powell (BP 31%) and Diana Hoover (BP 33.33%). The sale completed on 30 November 2012.

On 13 September 2012 BP announced that it had agreed to sell its 18.36% non-operated interest in the Draugen field in the Norwegian Sea to AS Norske Shell for $240 million in cash. The sale completed in November 2012.

On 28 November 2012 BP announced that it had agreed to sell a package of its central North Sea assets to TAQA Bratani Ltd for up to $1.3 billion (comprising $1.058 billion consideration plus future payments which, dependent on oil price and production, are expected to exceed $250 million after tax). This package comprised the non-operated Braes and Braemar assets, and the operated Harding, Maclure and Devenick assets. The transaction is subject to third-party and regulatory approvals.

On 17 December 2012 BP announced that it had agreed to sell its 50% non-operated interest in the Sean field in the UK North Sea to SSE PLC for $288 million in cash. The transaction is subject to third-party and regulatory approvals.

On 19 December 2012 BP announced that it had agreed the sale of its 34.3% interest in the Yacheng gas field in the South China Sea to Kuwait Foreign Petroleum Exploration Company (KUFPEC) for $308 million in cash. The transaction is subject to regulatory, CNOOC and third-party approvals.

BP s 33.3% ownership in the Phu My 3 power business in Vietnam was originally part of the divestment programme of the integrated gas business to TNK-BP. However, the Phu My 3 part of the divestment failed to conclude prior to the expiry of the sale and purchase agreement, and hence was reclassified from being held for sale into routine business. BP is open to other future divestment options and is currently evaluating its position in the business over the medium term.

Exploration

We continually seek access to resources and in 2012 this included Brazil, where we farmed in to four deepwater concessions covering 2,100km^2 on the Equatorial Margin; Canada, where we were the successful bidder on four leases, covering almost 14,000km^2 offshore Nova Scotia, for which award is expected to be completed in early 2013; Egypt, where we farmed in to two blocks covering 1,400km^2; deepwater Gulf of Mexico, where we were assigned 51 leases covering 1,200km^2; Namibia, where we farmed in to five deepwater blocks covering 22,900km^2; Uruguay, where we signed three production sharing agreements (PSAs) for deepwater exploration blocks covering almost 26,000km^2; and the onshore US, where we signed an agreement to lease 300km^2 in the Utica/Point Pleasant shale formation in Ohio.

Our exploration and appraisal programme is currently active in Algeria, Angola, Australia, Azerbaijan, Brazil, Canada, Egypt, the deepwater Gulf of Mexico, Jordan, Namibia, Trinidad, the UK North Sea, Oman and onshore US.

The group explores for oil and natural gas under a wide range of licensing, joint venture and other contractual agreements. We may do this alone or, more frequently, with partners. BP acts as operator for many of these ventures.

In 2012 our exploration and appraisal costs, excluding lease acquisitions, were $4,317 million, compared with $2,398 million in 2011 and $2,706 million in 2010. 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 58% of 2012 exploration and appraisal costs were directed towards appraisal activity. In 2012, we participated in 177 gross (46.2 net) exploration and appraisal wells in eight countries.

Total exploration expense in 2012 of $1,475 million (2011 $1,520 million and 2010 $843 million) included the write-off of expenses related to unsuccessful drilling activities in the UK North Sea ($97 million), Namibia ($64 million) and others ($72 million). It also included $97 million related to decommissioning of idle infrastructure, as required by the Bureau of Ocean Energy Management Regulation and Enforcement s Notice of Lessees 2010 G05 issued in October 2010.

Reserves

Reserves booking from new discoveries will depend on the results of ongoing technical and commercial evaluations, including appraisal drilling.

The Upstream segment s total hydrocarbon reserves, on an oil equivalent basis including equity-accounted entities comprised 11,685mmboe (10,213mmboe for subsidiaries and 1,472mmboe for equity-accounted entities) at 31 December 2012, a decrease of 10% (decrease of 11% for subsidiaries and decrease of 3% for equity-accounted entities) compared with the 31 December 2011 reserves of 12,946mmboe (11,426mmboe for subsidiaries and 1,520mmboe for equity-accounted entities).

The proved reserves replacement ratio is the extent to which production is replaced by proved reserves additions. This ratio is expressed in oil equivalent terms and includes changes resulting from revisions to previous estimates, improved recovery and extensions and discoveries. For 2012 the proved reserves replacement ratio for the Upstream segment, excluding acquisitions and disposals, was 6% for subsidiaries and equity-accounted entities, 5% for subsidiaries alone and 65% for

Major projects portfolio

equity-accounted entities alone. For more information on proved reserves replacement for the group, see pages 85-86.

Developments

In 2012 five major projects came onstream: Devenick in the North Sea; Skarv in the Norwegian Sea; Clochas Mavacola and the Plutão field, part of the Plutão, Saturno; Venus and Marte (PSVM) project in Angola; and Galapagos in the Gulf of Mexico. In November 2012 we announced the Savonette gas discovery offshore Trinidad.

We took final investment decisions on three projects: Juniper, Kizomba Satellites phase 2 and Point Thomson.

The map above shows our major development areas, which include Angola, Australia, Azerbaijan, Canada, Egypt, the deepwater Gulf of Mexico, North Africa and the UK North Sea. Development expenditure of subsidiaries incurred in 2012, excluding midstream activities, was $12.0 billion, compared with $10.2 billion in 2011 and $9.7 billion in 2010.

Production

Our oil and natural gas production assets are located onshore and offshore and 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. The principal areas of production are Angola, Argentina, Azerbaijan, Egypt, Trinidad, the UAE, the UK and the US.

Our total hydrocarbon production during 2012 averaged 2,319 thousand barrels of oil equivalent per day (mboe/d). This comprised 1,963mboe/d for subsidiaries and 355mboe/d for equity-accounted entities, a decrease of 6% (decreases of 10% for liquids and 3% for gas) and a decrease of 3% (decrease of 3% for liquids and no change for gas) respectively compared with 2011. For subsidiaries, 34% of our production was in the US, 19% in Trinidad and 8% in the UK.

In aggregate, after adjusting for the impact of price movements on our entitlement to production in our PSAs and the effect of acquisitions and disposals, underlying production was broadly flat compared with 2011. This primarily reflects major project start-ups and improved operating performance in Angola, partly offset by natural field decline and the impact of turnaround and maintenance activities.

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.

Regional summary

The following discussion reviews operations in our upstream business by geographical area, and lists associated significant events. 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 reserves and production.

Europe

In Europe, BP is active in the UK North Sea and the Norwegian Sea. Key aspects of our activities in the North Sea include a focus on in-field drilling and selected new field developments. We are the largest producer of hydrocarbons in the UK.

On 16 November 2010, production from the Rhum gas field in the central North Sea was suspended following the imposition of EU sanctions on Iran. Rhum is owned by BP (50%) and the Iranian Oil Company (50%) under a joint operating agreement dating back to the early 1970s. Rhum remains shut-in. See Further note on certain activities on page 45 for further information.

In October 2012 BP announced the start-up of the Devenick gas project in the central North Sea. It was subsequently announced in November

2012 that BP s interests in Devenick would form part of the package of central North Sea assets to be sold to TAQA Bratani Ltd along with the Braes and Braemar assets and the Harding and Maclure assets.

In December 2012 BP announced that it had acquired Total s equity in the Mungo and Monan Fields for a cost of $155 million. The acquisition takes BP s ownership of Mungo and Monan from 69% to 82%.

In December 2012 gas production from the Skarv field in the Norwegian Sea commenced. The new Skarv floating production storage and offloading vessel (FPSO) is expected to produce for 25 years and to be a key hub for BP in Norway, with production capabilities of 85,000 barrels per day of oil and 670 million standard cubic feet per day (mmcf/d) of gas. The vessel is built for adverse weather and is the most northerly operated FPSO in BP s portfolio.

In January 2013 production from the new facilities at the Valhall field in the southern part of the Norwegian North Sea commenced. Production from Valhall is expected to build up to around 65,000 barrels of oil equivalent per day in the second half of 2013.

North America

Our upstream activities in North America take place in four main areas: deepwater Gulf of Mexico, Lower 48 states, Alaska and Canada. For further information on the activities of BP s Gulf Coast Restoration Organization established following the Deepwater Horizon oil spill, see pages 59-62. BP is one of the largest producers of hydrocarbons and the largest acreage holder in the deepwater Gulf of Mexico, operating four production hubs.

In 2012 BP started up an additional two rigs in the Gulf of Mexico and by the end of the year had seven rigs operational. An eighth rig is in place on the Mad Dog platform and is expected to start up in 2013.

BP was assigned 51 blocks in the deepwater Gulf of Mexico, 40 blocks from the 2012 central lease sale that took place in June 2012 and 11 blocks from the western lease sale which occurred in December 2011.

In June 2012 BP announced the start-up of the Galapagos development in the deepwater Gulf of Mexico. The development includes the subsea tie-back to the BP operated Na Kika facility of three deepwater fields Isabela, Santiago and Santa Cruz.

For information on the temporary suspension and mandatory debarment notices issued by the US Environmental Protection Agency (EPA) see Legal proceedings on page 163.

The US onshore business operates in the Lower 48 states producing natural gas, NGLs and condensate across nine states, including production from tight gas, coalbed methane (CBM) and shale gas assets. For further information on the use of hydraulic fracturing in our shale gas assets see pages 52-53.

During 2012 the US lower 48 onshore gas business recognized impairment losses of $1,458 million primarily in the Woodford and Fayetteville shales reflecting reduced fair market values in the prevailing low price environment.

In March 2012 BP announced it had signed an agreement to lease approximately 300 km^2 in northeast Ohio for future oil and gas production in the Utica/Point Pleasant shale formation. The agreement was signed with the Associated Landowners of the Ohio Valley (ALOV), a group representing area mineral owners.

In Alaska, we operate 13 North Slope oilfields (including Prudhoe Bay, Endicott, Northstar and Milne Point) and four North Slope pipelines, and own significant interests in six other producing fields.

On 30 March 2012 BP, other Alaska North Slope producers, and the State of Alaska announced the settlement of a long-running legal dispute about the future development of the Point Thomson field. BP holds a 32% interest in the Point Thomson field and ExxonMobil is the operator. Under the terms of the settlement agreement, the working interest owners committed to an initial gas and condensate cycling project, with production start-up scheduled for May 2016. A significant portion of the cost of this initial project will be pre-investment for a full scale Point Thomson gas development project with production either to be sold in world markets via a major North Slope gas export project; or to be transported and injected into the main Prudhoe Bay reservoirs to increase oil recovery in the near term, and later reproduced and sold.

Also on 30 March BP, ExxonMobil and ConocoPhillips jointly announced that they are working together on a plan aimed at commercializing the extensive natural gas resources on the North Slope of Alaska. The three companies, along with TransCanada, are assessing a potential LNG development project.

In June 2012 BP took the decision to suspend the Liberty project in Alaska. The Liberty oil field is located approximately six miles offshore in the Beaufort Sea. In November 2010 BP made the decision to suspend on-site physical construction of the Liberty rig to conduct an extensive engineering review and evaluation of the rig design, materials, and key systems. In the course of this review it was determined that the rig would require significant changes and investment in order to meet BP standards, and that these were not viable. The decision to suspend the Liberty project resulted in an impairment of the construction-in-progress value totalling $1 billion in the second quarter of 2012. On 20 November BP filed a request for a five-year lease extension to pursue alternative development plans. On 31 December 2012 the US Bureau of Safety and Environmental Enforcement (BSEE) approved a two-year extension for the Liberty leases until 31 December 2014 to allow BP time to prepare and submit a new Liberty development plan. BSEE also advised that they will grant a further extension as necessary to accommodate the regulatory review, preparation, and issuance of the final Record of Decision by the agencies on the proposed development project.

In November 2012 the last remaining claims related to the March and April 2006 leaks from the Prudhoe Bay Oil Transit Lines were resolved. On 31 March 2009 the State of Alaska filed a complaint seeking civil penalties and damages relating to these leaks. In December 2011, BP and the State of Alaska entered into a Dispute Resolution Agreement that provided for a $10-million payment attributable to the state s environmental and attorneys fee claims, and binding arbitration of the state s claims for royalty income damages, if any, arising out of the 2006 oil spills and related production shut-ins and pipeline replacements. The arbitration panel issued its final award on 31 October 2012, which required BP to pay the state $245.7 million. After reimbursement from the other Prudhoe Bay owners, BP s net working interest share of the arbitration award and the other claims was $64.8 million and $2.6 million respectively. Payments to the state were made on 13 and 14 November 2012.

In Canada, BP is currently focused on oil sands development, and intends to use in situ steam-assisted gravity drainage (SAGD) technology. This 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 leases through the Sunrise Oil Sands and Terre de Grace partnerships and the Pike Oil Sands joint venture. In addition, we have significant exploration interests in the Canadian Beaufort Sea. In 2012 we were the successful bidder on four leases covering almost

14,000km^2 offshore Nova Scotia, for which award is expected to be completed in early 2013.

South America

In South America, BP has upstream activities in Brazil, Argentina, Bolivia, Chile, Uruguay and Trinidad & Tobago.

In Brazil, BP has interests in 14 exploration and production blocks: seven in the Campos basin, two in the Ceará basin, two in the Barreirinhas basin, one in the Camamu-Almada basin, and two onshore in the Parnaiba basin.

In March 2012 BP announced that the Brazilian National Petroleum Agency (ANP) approved its farm in to four deepwater exploration and production concessions operated by Petróleo Brasileiro S.A. (Petrobras) in Brazil. BP has a 40% interest in each of the blocks, located in the Barreirinhas and Ceará basins, and together the blocks cover a total area of 2,113km^2.

In Argentina, Bolivia and Chile, BP conducts activity through PAE, an equity-accounted joint venture with Bridas Corporation in which BP has a 60% interest.

On 24 January 2012 the Republic of Bolivia issued a press statement declaring its intent to nationalize PAE s interests in the Caipipendi Operations Contract. Nevertheless, no formal decision was issued or announced by the government, and no nationalization process has occurred.

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In 2012 production was impacted by the construction union (Los Dragones) strike in the Cerro Dragon field which commenced on 21 June. At the end of October an agreement was reached with the construction union and in November with the oil labour workers union at a national and provincial level. Operations have now resumed.

In Uruguay, BP confirmed in October 2012 that it had signed PSAs for three offshore deepwater exploration blocks. The contracts cover blocks 11 and 12 in the Pelotas basin and block 6 in the Punta del Este basin and together cover an area of almost 26,000km^2. The PSAs provide that BP will hold a 100% interest in the blocks and the Uruguayan state oil company, ANCAP, will have a right to participate in up to 30% of any discoveries. BP intends to carry out 2D and 3D seismic acquisition on the blocks during the initial three-year exploration phase of the contracts. This work is expected to begin in 2013.

In Trinidad & Tobago, BP almost doubled its exploration and production licences acreage during 2012, and now holds licences covering 1,806,000 acres offshore of the east coast. Facilities include 13 offshore platforms and one onshore processing facility. Production is comprised of oil, gas and NGLs. In May, BP announced that it had signed two PSAs with the government of Trinidad & Tobago for the two deepwater exploration and production blocks awarded in 2011. BP has a 100% interest in both these blocks.

Africa

BP s upstream activities in Africa are located in Angola, Algeria, Libya, Egypt and Namibia.

BP is present in nine major deepwater licences offshore Angola and is operator in four of these. In addition, BP holds a 13.6% interest in the Angola LNG project.

The Clochas and Mavacola fields (BP 26.7%), operated by Esso Angola, started production in May 2012 and are steadily ramping up. Production reached 65,000 barrels of oil per day by the end of 2012.

In December 2012 production from the PSVM development area in Block 31, offshore Angola, started. Initial production, coming from the Plutão field, averages 60,000 barrels of oil per day. PSVM is expected to build towards plateau rates of 150,000 barrels per day of oil over the coming year.

In Algeria, BP is a partner with Sonatrach and Statoil in the In Salah (BP 33.15%) and In Amenas (BP 45.89%) projects, which supply gas to the domestic and European markets. In addition, BP is in a joint venture with Sonatrach in the Bourarhet Sud block, located to the south west of In Amenas. The Bourarhet licence has been extended until September 2014 and appraisal is ongoing. BP s total assets in Algeria at 31 December 2012 were $2,372 million ($335 million current and $2,037 million non-current).

On 16 January 2013, a terrorist attack occurred at the In Amenas joint venture site. Following the incident, BP had a staged reduction of non-essential workers out of Algeria as a precautionary and temporary measure. Limited production from Train 1 restarted on 22 February. We are working with our joint-venture partners to assess the broader impact of the incident. BP remains committed to operating in Algeria where it has high-quality assets.

In Libya, BP is in partnership with the Libyan Investment Authority (LIA) to explore acreage in the onshore Ghadames and offshore Sirt basins, covered under the exploration and production-sharing agreement (EPSA) ratified in December 2007 (BP 85%). BP s total assets in Libya at 31 December 2012 were $452 million ($101 million current and $351 million non-current).

On 29 May 2012 BP announced that it had lifted force majeure in respect of its Libyan EPSA with the National Oil Corporation (NOC) with effect from 15 May 2012. Force majeure had been in place since 21 February 2011 following the outbreak of civil unrest in Libya. Since lifting force majeure we have completed the rehabilitation and re-staffing of our Tripoli office, and resumed planning and preparation work towards our onshore and offshore exploration drilling programmes.

In Egypt, BP and its partners currently produce 10% of Egypt s oil production and more than 30% of its gas production. BP s total assets in Egypt at 31 December 2012 were $7,818 million, of which $2,982 million were current (see Financial statements Note 26 on page 224) and $4,836 million were non-current.

During 2012 Egypt elected President Morsi and executive power was passed from the interim military ruling council to the new government. There has been a significant reduction in Central Bank foreign currency reserves and the political and economic outlook remains uncertain. Our production and operations continue and we are monitoring and working with the government to manage the situation.

In June 2012 first gas from the Seth development in Egypt was announced. The Seth field is located 60km offshore in the Ras El Bar concession in the east Nile Delta, close to the existing producing Ha py and Denise fields.

In August 2012 BP announced the Taurt North and Seth South gas discoveries in the North El Burg offshore concession (BP 50% and operator), in the Nile Delta. These are the fourth and fifth discoveries made by BP in the concession following Satis-1 and Satis-3 Oligocene deep discoveries and Salmon-1 shallow Pleistocene discovery.

In Namibia, BP is a non-operating partner in five deepwater blocks, which are currently in the exploration phase. All five blocks were accessed in 2012.

Asia

In Asia, BP has activities in Western Indonesia, China, Azerbaijan, Oman, Jordan, Abu Dhabi, India and Iraq.

In Indonesia, BP has a joint interest in Virginia Indonesia Company LLC (VICO), the operator of the Sanga-Sanga PSA (BP 38%) supplying gas to Indonesia s largest LNG export facility, the Bontang LNG plant in Kalimantan. BP also participates in the Sanga-Sanga CBM PSA (BP 38%), as well as four other CBM PSAs Tanjung IV and Kapuas I, II and III in the Barito basin of Central Kalimantan. BP holds a 44% interest in the Pertamina-operated Tanjung IV PSA, and a 45% operating interest in each of the Kapuas I, II and III PSAs. After conducting site visits and further evaluation BP has decided to exit the Kapuas I, II and III CBM PSAs and will transfer its working interest to its partner in each PSA, subject to approval.

In China, BP s upstream activities in the country include production from the China National Offshore Oil Corporation (CNOOC) operated Yacheng offshore gas field (BP 34.3%) as well as deepwater exploration in the South China Sea s Block 42/05 (BP 40.82%) and Block 43/11 (BP 40.82%). In December 2012 BP announced the sale of its interest in Yacheng gas field to Kuwait Foreign Petroleum Exploration Company (see Disposals on page 66).

In Azerbaijan, BP is the largest foreign investor and operates two PSAs, Azeri-Chirag-Gunashli (ACG) and Shah Deniz, and also holds other exploration leases. BP is expecting to progress the sanctioned Chirag Oil project by starting up the West Chirag production and drilling platform in late 2013.

In 2012 further EU and US regulations concerning restrictive measures against Iran were issued. These further measures clarified that they do not apply to Naftiran Intertrade Co. Ltd (NICO), a Shah Deniz project participant, and as such NICO and Shah Deniz continue to operate in full compliance with EU and US law. For further information see Further note on certain activities on page 45.

In June 2012 the Shah Deniz consortium announced it was considering two export routes for gas sales to Europe. The Nabucco West project was selected as the single pipeline option for the potential export of Shah Deniz Stage 2 gas to Central Europe. The Trans-Adriatic Pipeline (TAP) was selected as the potential route for export of Stage 2 gas to Italy. The Shah Deniz consortium will continue to work with the owners of both pipeline options and potential gas purchasers to agree transit and marketing terms before selecting the final option and concluding the related gas sales agreements ahead of the Shah Deniz final investment decision planned for mid-2013. Development of the South East Europe Pipeline (SEEP) project will cease.

In September 2012 BP was offered 12% equity in the Trans-Anatolian gas pipeline (TANAP) by SOCAR, which acts as a project operator and its majority shareholder. In late December 2012 BP (together with Total and Statoil) agreed with SOCAR the main principles for its participation in the TANAP project, the key terms for the TANAP GTA for Shah Deniz Stage 2 gas, as well as a framework for technical co-operation on the project. By the end of 2012 significant progress was also achieved in resolving other outstanding commercial issues with SOCAR including

the Shah Deniz Stage 2 gas marketing entity and the South Caucasus Pipeline (SCP) expansion.
BP is currently conducting exploration and appraisal programmes in Jordan and Oman.

In Abu Dhabi, we have equity interests of 9.5% and 14.67% in onshore and offshore concessions respectively. The Abu Dhabi onshore concession expires in January 2014 with a consequent production impact of approximately 140mb/d.

In India, BP has a 30% interest in nine oil and gas PSAs operated by Reliance Industries Limited (RIL), a 50% interest in one operated PSA, and is a partner with RIL in a 50:50 joint venture for the sourcing and marketing of gas in India.

In 2011, BP acquired from RIL a 30% interest in 21 oil and gas PSAs in India operated by RIL. As part of continued evaluation to high grade the portfolio and focus our efforts, 12 of the blocks acquired were relinquished in 2012.

During 2012 progress continued toward the anticipated ramp-up of drilling and project activity in 2013. Activities to arrest the decline in production on Block KG D6 fields were approved by the relevant authorities and execution planning has commenced. The government also approved the submitted Field Development Plan (FDP) of Satellite I discoveries, declaration of commerciality of R-Series discoveries and appraisal plan of the Cauvery basin block discovery. Site survey and engineering studies have been undertaken to progress already discovered resources in the KG D6 and NEC 25 blocks. The final investment decisions on these projects are subject to completion of appraisal and engineering work, obtaining regulatory approvals and determining gas pricing. Exploration drilling is scheduled to commence in early 2013.

In Iraq, BP holds a 38% working interest and is the lead contractor in the Rumaila technical service contract. Rumaila is one of the world s largest oilfields and was discovered by BP, as part of a consortium, in 1953 and comprises five producing reservoirs.

Australasia

In Australasia, we are active in Australia and Eastern Indonesia.

In Australia, BP is one of seven partners 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 principal supplier to the domestic market in Western Australia and one of the largest LNG export projects in Asia with five LNG trains[a] in operation. BP also holds a 5.375% interest in the Jansz-lo field and 12.5% interests in the Geryon, Orthrus and Maenad fields which are part of the Greater Gorgon project. In May 2012 the 3D seismic survey of the four deepwater offshore exploration blocks in the Ceduna Sub Basin (BP 100%) awarded in 2011 was completed. The survey covered approximately 12,500km^2. Following interpretation of the seismic survey, BP will drill four deepwater wells in this frontier exploration basin, located within the Great Australian Bight off the coast of southern Australia.

In Eastern Indonesia, BP has a 100% interest in the North Arafura PSA, located on the coast of the Arafura Sea, 480 kilometres south east of our Tangguh LNG plant (BP 37.16% and operator). In addition, BP owns a 32% interest in the Chevron-operated West Papua I and Ill PSAs, located 120 kilometres to the south of the Tangguh LNG plant (see

Liquefied natural gas on pages 70-71). BP also has 100% interests in two deepwater PSAs; West Aru I and II. The PSAs are located 500 kilometres south west of the North Arafura PSA and 200 kilometres west of the Aru island group.

[a] An LNG train is a processing facility used to liquefy and purify natural gas in the formation of LNG.

Midstream 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) extraction business.

Oil and natural gas transportation

BP has direct or indirect interests in certain crude oil and natural gas transportation systems. The following narrative details the significant events that occurred during 2012 by geographical area.

BP s onshore US crude oil and product pipelines and related transportation assets are included in the Downstream segment (see page 77).

Europe

In the UK sector of the North Sea, BP operates the Forties Pipeline System (FPS) (BP 100%), an integrated oil and NGLs transportation and processing system that handles production from more than 80 fields in the central North Sea. The system has a capacity of more than 1 million barrels per day, with average throughput in 2012 of 390mboe/d. During 2012 FPS processed its 8 billionth barrel, having transported and processed more than one third of the total UK North Sea oil produced to date. BP also operates and has a 36% interest in the Central Area Transmission System (CATS), a 400-kilometre natural gas pipeline system in the central UK sector of the North Sea. The pipeline has a transportation capacity of 293mboe/d to a natural gas terminal at Teesside in north-east England. Average throughput in 2012 was 54mboe/d. CATS offers natural gas transportation and processing services. In addition, BP operates the Sullom Voe oil and gas terminal in Shetland. The Dimlington and Easington terminals in Humberside form part of the southern gas assets, the sale of which was completed in November 2012 (see Disposals on page 66).

North America

BP owns a 46.9% interest in the Trans-Alaska Pipeline System (TAPS). The TAPS transports crude oil from Prudhoe Bay on the Alaska North Slope to the port of Valdez in south-east Alaska.

In April 2012 the two minority owners of TAPS, Koch (3.08%) and Unocal (1.37%) gave notice to BP, ExxonMobil (20.4%) and ConocoPhillips (28.2%) of their intentions to withdraw as an owner of TAPS. The effect of these notifications and the resultant ownership interest and abandonment obligations are still under discussion and regulatory review.

In September 2012 BP, ExxonMobil and ConocoPhillips entered into two settlement agreements among themselves on the pooling of costs on TAPS and the agreements are under review by the Federal Energy Regulatory Commission.

Asia

BP, as operator, holds a 30.1% interest in and manages the Baku-Tbilisi-Ceyhan (BTC) oil pipeline. The 1,768-kilometre pipeline transports oil from the BP-operated ACG oilfield in the Caspian Sea, along with other third-party oil, to the eastern Mediterranean port of Ceyhan and has a capacity of 1.2 million barrels per day. Average throughput in 2012 was 673mboe/d. BP is technical operator of, and holds a 25.5% interest in, the 693-kilometre South Caucasus Pipeline, which takes gas from Azerbaijan through Georgia to the Turkish border and has a capacity of 134mboe/d with average throughput in 2012 of 67.8mboe/d. In addition, BP operates the Western Export Route Pipeline between Azerbaijan and the Black Sea coast of Georgia (as operator of Azerbaijan International Operating Company).

Liquefied natural gas

Our LNG activities are located in Abu Dhabi, Angola, Australia, China, Indonesia and Trinidad. In both the Atlantic and Asian regions, BP is marketing LNG using BP LNG shipping and contractual rights to access import terminal capacity in the liquid markets of the US (via Cove Point and Elba Island), the UK (via the Isle of Grain) and Italy (Rovigo), and is supplying Asian customers in Japan, South Korea and Taiwan.

In Abu Dhabi, we have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company, which in 2012 supplied 5.6 million tonnes of LNG (289 billion cubic feet equivalent regasified).

In Angola, BP has a 13.6% share in the Angola LNG project, which is expected to receive approximately 1 billion cubic feet of associated gas per day from offshore producing blocks and to produce 5.2 million tonnes per annum of LNG (gross), as well as related gas liquids products. The Angola LNG plant is in the process of being commissioned and is expected to start production in 2013.

In Australia, BP is one of seven partners in the NWS venture. The joint venture operation covers offshore production platforms, trunklines, onshore gas and LNG processing plants and LNG carriers. BP s net share of the capacity of NWS LNG trains 1-5 is 2.7 million tonnes per annum of LNG. BP is also one of five partners in the Browse LNG venture (operated by Woodside) and holds a 17% interest. A proposed greenfield LNG development for Browse hydrocarbons is being considered by the Browse joint venture and is currently in the early design stage. The proposed development remains subject to regulatory, joint-venture and internal BP approvals.

In China, BP has a 30% equity stake in the 7 million tonnes per annum capacity Guangdong LNG regasification and pipeline project in south-east China, making it the only foreign partner in China s LNG import business. The terminal is also supplied under a long-term contract with Australia s NWS project described above.

In Indonesia, BP is involved in two of the three LNG centres in the country. BP participates in Indonesia s LNG exports through its holdings in the Sanga-Sanga PSA (BP 38%). Sanga-Sanga currently delivers around 16% of the total gas feed to Bontang, one of the world s largest LNG plants. The Bontang plant has a capacity of 22 million tonnes per annum of LNG and produced more than 11 million tonnes of LNG in 2012. Also in Indonesia, BP has its first operated LNG plant, Tangguh (BP 37.16%), in Papua Barat. The asset comprises 14 producing wells, two offshore platforms, two pipelines and an LNG plant with two production trains with a total capacity of 7.6 million tonnes per annum. Tangguh supplies LNG to customers in China, South Korea, Mexico and Japan through a combination of long-, medium- and short-term contracts.

In December 2012 BP and partners received government approval for the Tangguh expansion project plan of development for a third LNG train at Tangguh, which would increase capacity by 3.8 million tonnes per annum. The new train is expected to be scheduled for commissioning in late 2018.

In Trinidad, BPs net share of the capacity of Atlantic LNG trains 1, 2, 3 and 4 is 6 million tonnes of LNG per year. All of the LNG from Atlantic train 1 and most of the LNG from trains 2 and 3 is sold to third parties in the US and Spain under long-term contracts. All of BP s LNG entitlement from Atlantic LNG train 4 and some of its entitlement from trains 2 and 3 is marketed via BP s LNG marketing and trading business to a variety of markets including the Dominican Republic, India, Japan, South Korea, Spain, the UK and the US.

Gas marketing and trading activities

Marketing and trading of natural gas, power and NGLs provide routes into liquid markets for BP s produced gas, and generate margins and fees associated with the provision of physical products and derivatives to third parties and income from asset optimization and trading.

Gas and power marketing and trading activity is undertaken primarily in the US, Canada and Europe to market both BP production and third-party natural gas, to support group LNG activities and manage market price risk, as well as to create incremental trading opportunities through the use of commodity derivative contracts. Additionally, this activity generates fee income and enhances margins from sources such as the management of price risk on behalf of third-party customers. These markets are large, liquid and volatile. Market conditions have become more challenging over the past few years due to the availability of shale gas in North America and an excess of supply on long-term contracts from producers coupled with recession-led demand reduction in Europe. The business (including support functions) operates primarily from offices in Houston and London and employs around 1,200 people.

In connection with its trading activities, the group uses a range of commodity derivative contracts, storage and transport contracts. These include commodity derivatives such as futures, swaps and options to manage price risk and forward contracts used to buy and sell gas and power in the marketplace. Using these contracts, in combination with rights to access storage and transportation capacity, allows the group to access advantageous pricing differences between locations, time periods and arbitrage between markets. Natural gas futures and options are traded through exchanges, while over-the-counter (OTC) options and swaps are used for both gas and power transactions through bilateral and/or centrally cleared arrangements. Futures and options are primarily used to trade the key index prices, such as Henry Hub, while swaps can be tailored to price with reference to specific delivery locations where gas

and power can be bought and sold. OTC forward contracts have evolved in both the US and UK markets, enabling gas and power to be sold forward in a variety of locations and future periods. These contracts are used both to sell production into the wholesale markets and as trading instruments to buy and sell gas and power in future periods. Storage and transportation contracts allow the group to store and transport gas, and transmit power between these locations. The group has developed a risk governance framework that seeks to manage and oversee the financial risks associated with this trading activity, which is described in Note 26 to the Financial statements on page 220. The group s trading activities in natural gas are managed by the integrated supply and trading function.

The range of contracts that the group enters into is described in Certain definitions commodity trading contracts, on page 98.

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Downstream

2012 was a year of sustained safety and operational improvements and significant strategic progress in repositioning Downstream, with further progress in our Whiting refinery modernization project (WRMP) and agreement reached on major divestments in the US.

What we do

Our Downstream segment is the product- and service-led arm of BP, focused on fuels, lubricants and petrochemicals. We have significant operations in Europe, North America and Asia, and we also manufacture and market our products across Australasia, southern Africa and Central and South America. The Downstream segment operates hydrocarbon value chains covering three main businesses: fuels, lubricants and petrochemicals.

Fuels The fuels business is made up of regionally based integrated fuels value chains (FVCs), which include refineries, a number of fuels marketing businesses, a global aviation fuels marketing business, and global oil supply and trading activities. These businesses sell refined petroleum products including gasoline, diesel, aviation fuel and LPG.

Lubricants Our lubricants business manufactures and markets lubricants and related products and services. It is a global business adding value through brand, technology and relationships.

Petrochemicals Our petrochemicals business produces petrochemicals products at manufacturing locations around the world leveraging proprietary BP technology. These products are then used by others to make vital consumer products such as paints, plastic bottles and fibres for clothing.

Our strategy

In Downstream we are focused on a consistent set of priorities executed in a systematic and disciplined way.

These priorities start with safety and include excellent execution, portfolio quality and integration and growing margin share through exposure to growth.

Our segment strategy is about winning sustainably in the markets in which we choose to participate. This means seeking to outperform the best competitor in a region and doing it safely.

Our aim is to invest to strengthen our established positions while maintaining overall capital employed. Over time we will seek to shift participation and capital employed from established to growth markets.

We strive to do this within a stable financial framework delivering attractive returns and growth in earnings and cash flow.

Global lubricants demand continued to be weak in 2012 as a result of economic slowdown, despite growth in excess of 2% in the emerging markets of Brazil, Russia, India and China.

Petrochemicals margins for our products suffered steep declines driven by capacity additions in Asia, coupled with lower growth in demand.

Outlook

In 2013 we expect refining margins to decline slightly from the relatively high average levels seen in 2012 as further refining capacity comes onstream and demand continues to be weak in many markets.

We expect the financial impact of refinery turnarounds in 2013 to be lower than in 2012.

Demand for lubricants in 2013 is expected to be similar to 2012.

We expect the petrochemicals market to remain difficult in 2013 as further new Chinese PTA capacity enters the market.

We expect our segment capital expenditure to be slightly lower in 2013 than in 2012 as we enter the final phase of WRMP.

[a] Underlying replacement cost profit before interest and tax is not a recognized GAAP measure. See footnote b on page 34 for further information. The equivalent measure on an IFRS basis is replacement cost profit before interest and tax.

With effect from 1 January 2012, we reported the Refining and Marketing segment as Downstream, with no changes in the composition of the segment.

Market commentary

The weakness in the global economy continued in 2012 (see page 12), creating a challenging demand environment for our downstream businesses.

In 2012 we saw a significant improvement in refining margins, which were, on average, over $3 per barrel higher than in 2011, driven mainly by supply-side issues experienced by the industry throughout 2012.

We track the margin environment by way of a global refining marker margin. 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 by way of a simplified indicator that reflects the margins achieved on gasoline and diesel only. The refining marker margin (RMM) is calculated at a regional level using region-specific marker crudes and product grades that are then weighted by our refining capacity in the region to an aggregate BP average RMM. 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. Many of our competitors adopt a similar approach as it enables simplified benchmarking on a like-for-like basis. The RMM does not include estimates of fuel costs or other variable costs.

$ per barrel

	Crude marker	**2012**	2011	2010
Refining marker margin (RMM)				
US West Coast	Alaska North Slope (ANS)	**17.4**	13.6	13.1
US Gulf Coast	Mars	**16.1**	11.9	10.2
US Midwest	Light Louisiana Sweet (LLS)	**10.3**	7.5	6.0
Northwest Europe	Brent	**16.1**	11.9	10.4
Mediterranean	Azeri Light	**12.7**	9.0	8.8
Singapore	Dubai/Tapis blend	**15.3**	14.6	10.7
BP average RMM		**15.0**	11.6	10.0

The RMMs for 2012 were higher than 2011 in all the regions that we operate in. The global BP RMM averaged $15.0/bbl compared with the 2011 RMM of $11.6/bbl. Higher margins were mainly attributable to the refining capacity gap left by refinery closures on the US east coast and in Europe, removing nearly 1.8 million barrels per day of refined products from the market at the peak of the closures. Refining margins tend to follow a seasonal pattern in which they usually peak in the second quarter and then decline through the rest of the year. In 2012, however, the peak occurred in the third quarter as a result of unplanned refinery unit outages and closures combined with hurricane activity in the US Gulf Coast and low product inventories. Industry-wide utilization rates were around the same level as 2011, but significantly lower than the five-year average, mostly driven by the previously mentioned refinery closures.

These restrictions on supply were partially offset by lower demand for petroleum products in the OECD. This demand reduction was driven by low economic growth, increased blending of biofuels and increased car fleet efficiencies. In addition there have been changes in consumer behaviour such as a long-term decline in demand for gasoline and growth in diesel demand in Europe. Nonetheless, higher refining margins were available in the year due to growth in non-OECD countries demand for oil products, which attracted gasoline and diesel exports from the regions in which BP operates.

Our refineries, particularly Toledo and Whiting in the US, benefited from a location advantage as they were able to access discounted crudes. Throughout 2012, US midcontinent crudes priced off the West Texas Intermediate (WTI) marker, remained cheaper than waterborne crudes of a similar quality, such as European Brent and Gulf Coast LLS, due to increased production from shale oil, combined with bottleneck logistical capacity constraints in transporting these crudes to the coast. Heavy Canadian crudes continued to flow into the US as producers ramped up

production and consequently these grades of crude were less expensive than last year when compared with lighter crudes.

Globally, the impact of Libyan sweet crude returning to the market after the end of the civil war of 2011 was compounded by the advances in shale oil production in the US, which reduced the demand-pull of these crude types from abroad. This made sweet crudes globally less expensive compared with previous years. OPEC production was also higher than 2011 and reached around 31.5 million barrels per day, on average. This helped to offset the loss of Iranian oil following an embargo by the US and Europe and markets generally remained well supplied throughout the year. Upward pressure on prices, mainly attributable to geopolitical issues such as unrest in the Middle East (particularly Iran and Syria) and concerns over the stability of the eurozone were generally offset by a tepid global economic outlook.

In February 2013 BP updated the RMM methodology and regions to reflect the changes to our US portfolio after the refinery divestments and trends in regional crude markets since the RMM was established. For example, a new Australia region, using Brent crude, replaced the Singapore RMM, which was based previously on a Dubai/Tapis crude blend. This change has been made to better reflect the types of crude that Australian refiners process. In addition, we changed the marker crude for the US Midwest region from Gulf Coast LLS to WTI to reflect the increased availability of the lower-cost crudes in the US midcontinent mentioned previously.

The effect of this update is that the 2012 BP average RMM will be restated in the *BP Annual Report and Form 20-F 2013* from $15.0 per barrel (as reported here) to $18.2 per barrel.

The global lubricants market continued to be challenging in 2012 as a result of economic slowdown and low demand growth. The automotive sector has been squeezed by pressure on real incomes, which has resulted in demand for new passenger vehicles in the EU falling 8.2% in 2012. Industrial demand has also been under pressure from weak manufacturing production. Lubricants base oil prices were, however, lower than in 2011, which helped alleviate some of the downward pressure on margins.

Compared with 2011, there was a sharply deteriorating business environment for the focused group of petrochemicals products that BP produces. Substantial capacity additions in Asia in combination with global demand slowdown meant a deterioration of both purified terephthalic acid (PTA) and paraxylene (PX) margins with PTA margins at very low levels. The petrochemicals margin environment has tended to be cyclical in the past, with times of high margins during periods of demand increases and economic growth leading to investment in new capacity to meet this demand, followed by periods of lower margins as this new capacity comes onstream. 2012 has represented a downward cycle and although by the end of 2012 there were some signs of recovery, we expect the market to remain difficult in 2013 as further Chinese capacity additions enter the market.

By contrast, competitors who have significant production of ethylene, olefins, and derivatives in the US have seen advantage through the low cost of natural gas. This has resulted in many ethylene crackers being converted from heavy feeds (liquids priced with crude oil) to light feeds (gas, priced against US natural gas) resulting in strong margins for these players.

2012 performance

Safety performance

Safe, reliable and compliant operations remain the top priority within Downstream. This is underpinned by the systematic implementation of BP s operating management system (OMS) by all entities. (See Safety on pages 46-50 for further information on safety and OMS.)

In 2012 the Downstream segment continued the journey to enhance local systems and processes at our sites in response to OMS. For example, in 2012, a programme designed to improve the capability of the workforce to identify and mitigate risks within their local OMS was rolled out. This brings specialist coaches and entity teams together to improve safety and performance by systematically closing gaps between local work processes and OMS standards and then embeds these improvements

through front-line engagement and training. We have also focused on improving the capability to reduce risk through OMS through the learning from incidents process. Drawn from incident investigations and the risk process, targeted high-value learning and learning alert communications show front-line teams what went wrong or could go wrong, and the actions to take to prevent similar incidents from happening at their site.

Safety performance is monitored by a suite of input and output metrics, which focus on personal and process safety. Regrettably, there were two workforce fatalities in 2012. In India, a contractor fell through a roof sheet while installing a fall prevention line and, in Scotland, a contractor vehicle collided with a third-party vehicle resulting in fatal injuries to the contract driver. These tragic events have been fully investigated.

Two of the key measures used to track process safety are the process safety incident index (PSII), a weighted index that reflects both the number and severity of events per 200,000 hours worked and loss of primary containment (LOPC), a measure of unplanned or uncontrolled releases of material from primary containment. The PSII has improved by 40% since it was established in 2008. In 2012 it was 0.26 compared with 0.36 in 2011. There was also a 40% reduction in the number of LOPC, from 2011 to 2012, falling from 195 in 2011 to 117 in 2012. In addition, the number of oil spills greater than one barrel reduced from 145 in 2011 to 96, however the volume of these spills for 2012 was higher at 0.6 million litres compared with 0.4 million litres in 2011.

We measure our personal safety performance through recordable injury frequency (RIF) and days away from work case frequency (DAFWCF) as well as the severe vehicle accident rate (SVAR). In 2012 our RIF (measured by the number of recordable injuries to the BP workforce per 200,000 hours worked) was 0.33, better than the 2011 rate of 0.37. The 2012 DAFWCF, a subset of the RIF that measures the number of cases where an employee misses one or more days from work per 200,000 hours worked) was 0.09, compared with 0.11 in 2011.

Driving safety has continued to be an area of focus in 2012 with the formation of a driving safety team to facilitate how we manage the risks associated with driving in an effective and consistent manner. Despite this, the severe vehicle accident rate[a] increased in 2012 to a rate of 0.16 compared with 0.11 in 2011.

[a] The severe vehicle accident rate (SVAR) is the number of vehicle incidents that result in death, injury, a spill, a vehicle rollover, or serious or disabling vehicle damage per one million kilometres travelled.

Financial and operating performance

			$ million
	2012	2011	2010
Replacement cost profit before interest and tax[a]			
Fuels	**1,385**	3,003	2,628
Lubricants	**1,276**	1,350	1,357
Petrochemicals	**185**	1,121	1,570
	2,846	5,474	5,555
Net (favourable) unfavourable impact of non-operating items and fair value accounting effects[b]			
Fuels	**3,611**	640	(381)

Lubricants	**9**	(100)	47
Petrochemicals	**(19)**	(1)	(338)
	3,601	539	(672)
Underlying replacement cost profit before interest and tax[ac]			
Fuels	**4,996**	3,643	2,247
Lubricants	**1,285**	1,250	1,404
Petrochemicals	**166**	1,120	1,232
	6,447	6,013	4,883
Sales and other operating revenues[d]	**346,491**	344,116	266,751
Capital expenditure and acquisitions	**5,048**	4,130	4,029
			thousand barrels per day
Total refinery throughputs[e]	**2,354**	2,352	2,426
			%
Refining availability[f]	**94.8**	94.8	95.0
			thousand tonnes
Total petrochemicals production[g]	**14,727**	14,866	15,594

[a] Income from petrochemicals produced at our Gelsenkirchen and Mülheim sites is reported within the fuels business. Segment-level overhead expenses are included within the fuels business.

[b] Fair value accounting effects represent the (favourable) unfavourable impact relative to management s measure of performance (see page 37 for further details). For Downstream, these arise solely in the fuels business.

[c] Underlying replacement cost profit is not a recognized GAAP measure. See footnote b on page 34 for information on underlying replacement cost profit.

[d] Includes sales between businesses.

[e] Refinery throughputs reflect crude oil and other feedstock volumes.

[f] Refining availability represents Solomon Associates operational availability, which is defined as the percentage of the year that a unit is available for processing after subtracting the annualized time lost due to turnaround activity and all planned mechanical, process and regulatory maintenance downtime.

[g] Petrochemicals production includes 1,625kte of petrochemicals produced at our Gelsenkirchen and Mülheim sites in Germany for which the income is reported in our fuels business.

Replacement cost profit before interest and tax for the year ended 31 December 2012 was $2,846 million, compared with $5,474 million for the previous year. The full-year results included a net loss for non-operating items of $3,174 million, compared with a net loss of $602 million in 2011. The non-operating items in 2012 mainly related to impairments. (See page 37 for further information on non-operating items.) In addition, fair value accounting effects had an unfavourable impact of $427 million, compared with a favourable impact of $63 million in 2011. (See page 37 for further information on fair value accounting effects.)

After adjusting for non-operating items and fair value accounting effects, Downstream reported record underlying replacement cost profit before interest and tax in 2012 of $6,447 million.

The fuels business delivered an underlying replacement cost profit before interest and tax of $4,996 million for the year; compared with $3,643 million in 2011. This reflects strong operations that enabled us to capture the favourable refining environment, partly offset by a reduction in the supply and trading contribution for the year compared with 2011. The following table summarizes the volume, by region, of crude oil and feedstock processed by BP for its own account and for third parties. Utilization data is also summarized.

			thousand barrels per day
Refinery throughputs[a]	**2012**	2011	2010
US	**1,310**	1,277	1,350
Europe	**751**	771	775
Rest of World	**293**	304	301
Total	**2,354**	2,352	2,426
Refinery capacity utilization			
Crude distillation capacity at 31 December[b]	**2,681**	2,679	2,667
Refinery utilization[c]	**88%**	88%	91%
US	**89%**	87%	93%
Europe	**89%**	91%	91%
Rest of World	**80%**	84%	84%

[a] Refinery throughputs reflect crude oil and other feedstock volumes.

[b] Crude distillation capacity is gross rated capacity, which is defined as the highest average sustained unit rate for a consecutive 30-day period.

[c] Refinery utilization is throughput (thousands of barrels/day) divided by crude distillation capacity, expressed as a percentage.

Overall refinery throughputs were at a similar level to 2011, notwithstanding the planned outage of the largest of the crude units at our Whiting refinery in the fourth quarter.

The lubricants business delivered an underlying replacement cost profit before interest and tax of $1,285 million for the year, compared with $1,250 million in 2011, reflecting continued robust performance despite challenging levels of demand. This is the fifth consecutive year in which the lubricants business has delivered more than $1 billion of underlying replacement cost profit.

The petrochemical business delivered an underlying replacement cost profit before interest and tax of $166 million for the year, compared with $1,120 million in 2011, reflecting weakness in margins for BP s mix of products compared with last year resulting from recent capacity additions in Asia and lower demand growth than in 2011. Our petrochemicals production was lower than 2011 at 14,727 thousand tonnes compared with 14,866 in 2011 as a result of decisions to reduce production for commercial reasons.

2012 was the highest ever underlying replacement cost profit delivery in the Downstream segment reflecting the fourth consecutive year of underlying replacement cost profit growth. In March 2010 we outlined an opportunity to deliver an additional $2 billion of performance improvement by 2012 relative to a 2009 base-line.[a] However, despite better operational reliability and high utilization rates that allowed us to capture more of the available margin, and improvements in our cost efficiency, we were unable to fully deliver this level of improvement principally due to a significant reduction in the supply and trading contribution in 2012 compared with a particularly strong performance in 2009.

[a] This performance improvement measure was based on comparing Downstream s underlying replacement cost profit before interest and tax for 2009 with that of 2012, after adjusting for the impact of changes in the refining margin and petrochemicals environment (including energy costs), foreign exchange impacts and price-lag effects for crude

and product purchases. This adjusted measure of underlying replacement cost profit before interest and tax is non-GAAP. We believe the measure is useful to investors because it is one that is viewed and tracked by management as an important indicator of segment performance.

Sales and other operating revenues in 2012 were $346 billion, a similar level to the $344 billion in 2011, and higher than the $267 billion in 2010. This increase reflects higher prices almost offset by lower volumes and foreign exchange losses.

			$ million
	2012	2011	2010
Sale of crude oil through spot and term contracts	**56,383**	57,055	44,290
Marketing, spot and term sales of refined products	**275,920**	273,940	209,221
Other sales and operating revenues	**14,188**	13,121	13,240
Sales and other operating revenues[a]	**346,491**	344,116	266,751

[a] Includes sales between businesses.

The following table sets out oil sales volumes by type for the past three years. Marketing sales volumes were 3,213mb/d, slightly lower than 2011, principally reflecting reduced demand in some OECD markets and simplification of our portfolio.

			thousand barrels per day
Refined product volumes	**2012**	2011	2010
Marketing sales[a]	**3,213**	3,311	3,445
Trading/supply sales[b]	**2,444**	2,465	2,482
Total refined product sales	**5,657**	5,776	5,927
Crude oil[c]	**1,518**	1,532	1,658
Total oil sales	**7,175**	7,308	7,585

[a] Marketing sales include sales to service stations, end-consumers, bulk buyers and jobbers (i.e. third parties who own networks of a number of service stations and small resellers).

[b] Trading/supply sales are 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. Seventy-three thousand barrels per day relate to revenues reported by Upstream.

Prior years comparative financial information

Replacement cost profit before interest and tax for the year ended 31 December 2011 was $5,474 million, compared with $5,555 million for the previous year. The 2011 results included a net loss for non-operating items of $602 million, compared with a net gain of $630 million in 2010. The non-operating items in 2011 mainly related to impairment charges relating to our disposal programme, partially offset by gains on disposal (see page 37 for further information on non-operating items). In addition, fair value accounting effects had a favourable impact of $63 million, compared with a favourable impact of $42 million in 2010 (see page 37 for further information on fair value accounting effects).

In the fuels business, we were able to capture the benefits available in 2011 from BP s location advantage in accessing WTI-based crude grades. Compared with 2010, the result also benefited from a higher refining margin environment and a stronger supply and trading contribution. These benefits were partly offset by a significantly higher level of turnarounds in 2011 than 2010 and negative impacts from increased relative sweet crude prices in Europe and Australia and the weather-related power outages in the second quarter.

Performance in our lubricants business in 2011 was impacted by significant base oil price increases and weaker demand. These impacts were partly offset by supply-chain efficiencies and our ability to recover the increased cost of goods in the market.

In our petrochemicals business, compared with 2010, the 2011 result was negatively impacted by weakening market conditions as the year progressed as additional Asian capacity came onstream during the year at a time of weaker demand. This was somewhat offset by the strength in aromatics margins and volumes in the first half of the year.

The replacement cost profit before interest and tax for the year ended 31 December 2010 of $5,555 million included a net gain for non-operating items of $630 million, mainly relating to gains on disposal, partly offset by restructuring charges. In addition, fair value accounting effects had a favourable impact of $42 million relative to management s measure of performance. The primary additional factors contributing to the increase in replacement cost profit before interest and tax compared with 2009 were improved operational performance in the fuels value chains (FVCs), continued strong operational performance in lubricants and petrochemicals, and further cost efficiencies, as well as a more favourable refining environment. Against very good operational delivery, the results were impacted by a significantly lower contribution from supply and trading compared with 2009.

Our businesses

Fuels

The fuels businesses is made up of seven regionally based FVCs, a number of regionally focused fuels marketing businesses, a global aviation fuels marketing business and our global oil supply and trading activities. These fuels businesses sell refined petroleum products including gasoline, diesel, aviation fuel and LPG.

Fuels value chains

The FVCs seek to optimize the activities of our assets across the supply chain: crude delivery to the refineries; manufacture of high-quality fuels;

distribution through pipeline and terminal infrastructure; and marketing and sales to our customers on a regional basis. This integration, together with a focus on excellent execution and cost management as well as a strong brand, market presence and customer base, are key to our financial performance.

The FVC strategy focuses on large-scale, feedstock-advantaged, highly upgraded, dual-fuel-capable, well-located refineries integrated into advantaged logistics and marketing. Consequently, in the US, we are in the process of completing refinery sales that will roughly halve our US refining capacity through the sale of our Texas City refinery (which completed on 1 February 2013) and our Carson refinery and related marketing and logistics assets (see refinery table below). The Texas City refinery[a] was not strongly integrated into BP s marketing assets and has limited access to logistics and tankage flexibility. The Carson refinery is gasoline biased and would need investment in logistics and/or configuration to upgrade capability. This portfolio re-shaping will shift the balance of our US refining portfolio to northern tier refineries able to access advantaged, US mid-continent and Canadian crudes and utilize a significantly greater proportion of heavy crudes.

In our remaining FVCs, we believe we have a portfolio of well-located refineries, integrated with strong marketing positions offering the potential for improvement and growth.

[a] We will retain the petrochemicals manufacturing plants at Texas City.

Refining

At 31 December 2012, we owned or had a share in 16 refineries producing refined petroleum products that we supply to retail and commercial customers. On 1 February 2013 we completed the sale of the Texas City refinery and a portion of our retail and logistics network in the south-east US to Marathon Petroleum Corporation for up to $2.4 billion. In

addition, we have announced the sale of our South West FVC including the Carson refinery in California, *ARCO* network and related logistics assets in the region to Tesoro Corporation for $2.5 billion and we expect to close this sale by the middle of 2013 subject to regulatory and other approvals.

Strategic investments in our refineries are focused on securing the safety and reliability of our assets while improving the relative unit margins to capture capability versus the competition. The most important of these strategic investments under way is the Whiting refinery modernization project (WRMP), which we expect will allow the capture of additional margin through the processing of a greater proportion of heavy crudes.

This project made significant progress in 2012 as we entered the heaviest field construction phase. The new crude oil unit, coker, upgraded sulphur recovery complex and gasoil hydrotreater all advanced towards their targeted start-up dates in 2013. The largest of the refinery s crude units, which processed sweet crude, was taken out of service in early November. This outage will allow construction of a replacement crude distillation unit, and will facilitate demolition of the existing unit, thereby enabling the expected start-up of the WRMP project in the second half of 2013. BP is temporarily redeploying refining and technical resources from around the world to assist with the start-up of the new units.

We continue to invest in developing capability to produce cleaner fuels to meet the requirements of our customers and their communities. For example, we are currently investing in a new hydrotreater unit and hydrogen plant at our Cherry Point refinery. This project is designed to allow the refinery to produce fuels that meet ultra-low sulphur diesel (ULSD) standards for rail and marine diesel customers. In addition, the new hydrogen plant is designed to improve operation of naphtha reforming units at the refinery. The project has progressed steadily

The following tables summarize the BP group s interests in refineries and average daily crude distillation capacities as at 31 December 2012.

thousand barrels per day

	Refinery	Fuels value chain	Group interest[b] %	Crude distillation capacities[a] Total	BP share
US					
California	Carson[c]	US South West	100.0	266	266
Washington	Cherry Point	US North West	100.0	234	234
Indiana	Whiting	US East of Rockies	100.0	413	413
Ohio	Toledo	US East of Rockies	50.0	160	80
Texas	Texas City[c]		100.0	475	475
Total US				1,548	1,468
Europe					
Germany	Bayernoil[d]	Rhine	22.5	217	49
	Gelsenkirchen	Rhine	50.0	265	132
	Karlsruhe[d]	Rhine	12.0	322	39
	Lingen	Rhine	100.0	95	95
	Schwedt[d]	Rhine	18.8	239	45
Netherlands	Rotterdam	Rhine	100.0	377	377
Spain	Castellón	Iberia	100.0	110	110
Total Europe				1,625	847
Rest of World					
Australia	Bulwer	Australia New Zealand	100.0	102	102
	Kwinana	Australia New Zealand	100.0	146	146
New Zealand	Whangarei[d]	Australia New Zealand	23.7	118	28
South Africa	Durban[d]	Southern Africa	50.0	180	90
Total Rest of World				546	366
Total				3,719	2,681
Capacity relating to assets held for sale					(741)
Total capacity post-divestment					1,940

[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] Refinery classified as assets held for sale at 31 December 2012.
[d] Indicates refineries not operated by BP.

through 2012 and we expect to complete construction and commissioning by the middle of 2013.

In addition, we completed construction and started up a new, higher efficiency naphtha reformer at our joint venture Toledo refinery in March 2013.

In addition to refined petroleum products, we also blend and market biofuels in our FVCs. In 2012 we blended over 7 billion litres of biofuels into finished product in our FVCs, mainly in Europe and the US. Biogasoline (bioethanol) and biodiesel (hydrogenated vegetable oils and fatty acid methyl esters) continue to grow in volume, primarily in Europe and the US, as regulatory requirements demand heavier blending levels. Our response is to continue to develop blend capabilities and to work with regulators, biofuels supply chains and other stakeholders to improve the sustainability of the biofuels we blend and supply.

Developing new refining technology is also an important part of our strategy. Our refining and logistics technology team is focused on optimizing crude oil selection, utilization and refinery processing capability. They develop and deploy technology and apply knowledge and expertise to support BP s refining and logistics assets. They drive excellence in operational and commercial performance (see Technology pages 57-59).

The London 2012 Olympic and Paralympic Games showcased BP s expertise and technology leadership in biofuels through the development of three advanced biofuel formulations (lignocellulosic ethanol, diesel from sugar and biobutanol from sugar). These new formulations blended with *BP Ultimate,* fuelled the London 2012 Olympic fleet. We continue to work proactively with governments and regulatory bodies in all the countries in which we operate to develop practical and effective solutions to meet local and regional biofuel mandates.

Logistics and marketing

Downstream of our refineries, we operate an advantaged infrastructure and logistics network (which includes pipelines, storage terminals and road or rail tankers), and seek to drive excellence in operational and transactional processes, and deliver compelling customer offers in the various markets in which we operate.

We supply fuel and related convenience services to retail consumers through company-owned and franchised retail sites, as well as other channels, including wholesalers and jobbers. We supply commercial customers within the transport and industrial sectors. We also focus on creating sustainable, differentiated high performance, energy efficient, cleaner and competitive fuels through our fuels technology group. We continue to support our partners and customers in delivering greater energy efficiency and reduced CO_2 emissions in both established and emerging markets and we are working on new fuels that deliver improved fuel economy and compatibility with the latest engine technology and with biofuel components.

Our retail network is largely concentrated in Europe and the US, but also has established operations in Australasia and southern Africa. We have developed networks in China in two separate joint ventures, one with PetroChina and the other with China Petroleum and Chemical Corporation (Sinopec). These two joint ventures operate over 700 dual-branded sites in China. We have also licensed the *BP* brand for use on retail sites to Hellenic Petroleum, which operates around 1,000 BP-branded retail sites in Greece, and to Delek, which operates around 400 BP-branded retail sites in France.

The following table shows the number of BP-branded retail sites by region. Some of these retail sites include a convenience store, which offers consumers a range of food, drink and other consumables and services in a convenient and innovative manner. The convenience offer includes brands such as *Wild Bean Café* and *Petit Bistro* and includes partnerships with leading retailers such as Marks & Spencer in the UK.

	Number of retail sites operated under a BP brand		
Retail sites[a b]	**2012**	2011	2010
US	**10,100**	11,300	11,300
Europe	**8,300**	8,200	8,400
Rest of World	**2,300**	2,300	2,400
Total	**20,700**	21,800	22,100

[a] The number of retail sites includes sites not operated by BP but instead operated by dealers, jobbers, franchisees or brand licensees that operate 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.*

[b] Excludes our interest in equity-accounted entities that are dual-branded.

As at 31 December 2012, BP s worldwide retail network consisted of some 20,700 sites across the US, Europe, Australia, New Zealand and southern Africa. This is a reduction of about 1,100 since 2011, primarily due to a reduction in the US where we are focusing on higher throughput sites. These retail sites are primarily branded *BP, ARCO* and *Aral.* We expect the number of branded retail sites to fall by around 800 in 2013 in the US south west, as we dispose of the *ARCO* brand as part of the sale of the US South West FVC to Tesoro Corporation. BP intends to license back the *ARCO* brand post divestment for use in the North West FVC. BP will, however, retain ownership of the *ampm* convenience store brand after the disposal and franchise it to Tesoro Corporation for use in the south-west US.

Supply and trading

BP s integrated supply and trading function is responsible for delivering value across the overall crude and oil products supply chain. This structure enables the optimization of BP s FVCs to maintain a single interface with the oil trading markets and to operate with a single set of trading compliance processes, systems and controls. The oil trading business (including support functions) has trading offices in Europe, the US and Asia and employs around 1,800 people. This enables the function to maintain a presence in the more actively traded regions of the global oil markets in order to gain an overall understanding of the supply and demand forces across this market. It has a two-fold strategic purpose in our business.

First, it seeks to identify the best markets and prices for our crude oil, source optimal feedstocks for our refineries, and provide competitive supply for our marketing businesses. In addition, where refinery production is surplus to marketing requirements or can be sourced more competitively, it is sold into the market. Wherever possible, the group will look to optimize value across the supply chain. For example, BP will often sell its own crude and purchase alternative crudes from third parties for its refineries where this will provide incremental margin.

Second, the function seeks to create and capture incremental trading opportunities. It enters into the full range of exchange-traded commodity derivatives, over-the-counter (OTC) contracts and spot and term contracts (described in Certain definitions commodity trading contracts on page 98). In order to facilitate the generation of trading margin from arbitrage, blending and storage opportunities, it also owns and contracts for storage and transport capacity. The group has developed a risk governance framework which seeks to manage and oversee the financial risks associated with this trading activity, see Financial statements Note 26 on page 220.

The group s trading activities in oil are managed by the integrated supply and trading function. In order to carry out the unique delegations from the BP group, the integrated supply and trading function operates and enforces a robust system of internal control. The internal control systems operated by the regional business leads are augmented by internal support functions that provide independent oversight, including product control, risk, trade completion, and accounting and reporting. They are further supported by regional and group ethics and compliance and group internal audit.

Aviation

Our global aviation business, Air BP, is one of the world s largest and best-known aviation fuels suppliers, serving many major commercial airlines as well as the general aviation and military sectors. We have marketing sales in excess of 460,000 barrels per day. Air BP s strategic aim is to grow its position in the core locations of Europe, the US, Australasia and the Middle East, while focusing its portfolio towards airports that offer long-term competitive advantage. In line with this strategy, in the second quarter of 2012, we completed the acquisition of Shell and Cosan Industria e Commercio s interests in significant aviation fuels assets at seven Brazilian airports, which is an important growth market.

LPG

We are in the process of exiting our global LPG marketing business, which sells bulk and bottled LPG products, in order to simplify our marketing operations. We will retain focus on LPG where it is deeply integrated into our wholesale and autogas sectors in order to optimize refinery and retail operations. As at 31 December 2012, the sales of the LPG business in three countries out of nine had been completed and a further three announced and the integration of the wholesale and autogas sectors into the FVCs is complete.

Lubricants

Our lubricants business manufactures and markets lubricants and related products and services to the automotive, industrial, marine, aviation and energy markets across the world. Distinctive brands, cutting-edge technology and sustaining customer relationships are the cornerstone of our approach. Our key brands are *Castrol, BP* and *Aral. Castrol* is a recognized brand worldwide and we believe it provides us with a significant competitive advantage. In technology, we apply our expertise to create quality lubricants and high performance fluids for customers in on-road, off-road, air, sea and industrial applications globally.

We divide our lubricants business up into five customer sectors: automotive, marine, industrial, aviation and energy:

- The automotive sector, which accounts for more than two-thirds of our lubricants sales, serves the needs of land-based vehicles including cars, trucks, motorcycles, buses, tractors, earth movers and other vehicles. We supply lubricants and other related products and services to intermediate customers such as retailers and workshops. These, in turn, serve end consumers such as car, truck and motorcycle owners.

- The marine sector serves users of river and sea-going vessels. BP s marine lubricants business is one of the largest global suppliers of lubricants to the marine industry, with a global presence in over 800 ports.

- Our industrial sector serves customers who run or maintain plant and equipment and it is a leading supplier to those sectors of the market involved in the manufacturing of automobiles, trucks, machinery components and steel.

- Our aviation sector serves aircraft operators and maintenance industries. In the aviation industry, we estimate that we are the lubricants supplier for around 40% of the jet engines of the world s commercial airlines.

- Our energy sector serves the oil and gas and power industries. In the oil and gas industry we supply some of world s largest production and drilling companies.

We look to market and sell our products across the world. We sell products direct to our customers in around 45 countries and use approved local distributors for other geographies. Approximately 40% of our employees are located in non-OECD markets and around 20% are located in China and India alone. We are particularly strong in Europe and key Asia Pacific markets including India. In 2012 approximately 50% of the lubricants business replacement cost profit before interest and tax was generated from non-OECD markets.

We have chosen not to participate at scale in base oil or additives manufacturing. We are, however, one of the largest purchasers of base oil in the market.

We participate in blending in locations where scale and competitive advantage can be sustained, or where customer service or security of supply are of critical importance and otherwise difficult to secure. We have a network of 25 wholly owned and operated blending plants worldwide and joint ownership in five others operated by third parties.

Our participation in the value chain is focused on areas of competitive differentiation and strength. These fall into three main areas: the development of formulations and the application of cutting-edge technology; developing product brands and communicating the benefits that our products provide to our customers; and building and extending

our relationships with customers so that our products and services are delivered in a manner that best meets their needs.

In lubricants technology we apply our expertise to create quality lubricants and high performance fluids for on-road, off-road, air, sea and industrial applications globally. We continue to support our partners and customers in delivering high-performance lubricants that deliver greater energy efficiency and reduced CO_2 emissions in both established and emerging markets.

During 2012 we launched a Performance Biolubes product line, adding a range of bio-based metalworking fluids and lubricants for use in cutting, grinding, forming and maintenance lubrication. This new technology underpins the *Castrol* brand s commitment to developing environmentally responsible product offers. In addition, we introduced 80BN (the BN refers to the base number), a new product for the marine market that uses advanced technology to optimize the performance of lubricants in slow-steaming marine engines and further strengthens our credentials in technology leadership. In 2012 we also introduced a co-branded product with Ford to support their new range of environmentally friendly engines.

Our focus is on developing premium products, and we often work alongside original equipment manufacturers in doing this. The new *Castrol EDGE* professional range was launched to the franchised workshop market in Europe and Africa in 2012.

Our lubricants businesses continued to grow the proportion of total sales resulting from premium product sales; in 2012 the percentage of premium sales was 39% compared with 37% in 2011 and 34% in 2010.

Petrochemicals

Our global petrochemicals business has operations in the US, Europe and Asia. The business buys a range of feedstocks for input into our manufacturing units, the majority of which have been built and operate utilizing our proprietary technology. We manufacture and market four main product lines:

- Purified terephthalic acid (PTA).

- Paraxylene (PX).

Acetic acid.

Olefins and derivatives (O&D).

We also produce a number of other speciality petrochemicals products.

Our strategy is to leverage our industry-leading technology in the markets in which we choose to participate, to grow the business and to deliver industry-leading returns. New investments are targeted principally in the higher-growth Asian markets. We both own and operate assets, and have also invested in a number of joint ventures in Asia, where our partners are leading companies within their domestic market.

PTA is a raw material used in the manufacture of polyesters used in fibres, textiles and film, and polyethylene terephthalate (PET) bottles. PTA production requires PX as a feedstock, which we produce in the US and Europe and buy in Asia. PTA is then reacted with glycol to produce polyester chips or fibres, which are in turn used to produce PET bottles, polyester fibres and various speciality products, including protective screens for computers and TVs. PX production is primarily from the mixed xylene stream produced in a reformer within a refinery.

Acetic acid is a versatile intermediate chemical used in a variety of products such as paints, adhesives and solvents, as well as in the production of PTA. In producing acetic acid, we purchase methanol and either make or buy carbon monoxide (CO). CO can be produced from a variety of hydrocarbon feedstocks, including natural gas, naphtha, fuel oil and coal.

Our O&D business is based in China and is focused on serving the Chinese market. The SECCO joint venture is between BP, Sinopec and its subsidiary, Shanghai Petrochemical Company. BP also co-owns one other naphtha cracker site outside Asia, which is integrated with our Gelsenkirchen refinery in Germany and this has an associated solvents plant at Mülheim, Germany.

At 31 December 2012, the petrochemicals business ran 15 manufacturing sites including our joint ventures (as shown in the following table), and we have two petrochemicals plants (Gelsenkirchen and Mülheim), which are managed by the fuels business as they utilize feedstock from our

Gelsenkirchen refinery. In October 2012 we sold our interest in BP Chemicals (Malaysia) Sdn Bhd (BPCM), which manufactures PTA with a production capacity of 610,000 tonnes per annum, to Reliance Global Holdings Pte. Ltd. for $230 million.

Our portfolio is underpinned with proprietary technology and leading cost positions allowing BP assets to remain competitive against the newest world-scale units being built in China. These capacity additions and technology advances have resulted in a sharp fall in margins resulting in losses for the older, less efficient producers.

Our technology team develops, deploys and optimizes advantaged chemicals technology to advance the competitiveness of the installed asset base and deliver competitively advantaged projects to access growth. We plan to continue to deploy our advantaged technology in new asset platforms to access the demand centres of Asia and advantaged feedstock sources.

In 2012 we progressed our 1.25-million tonnes per annum PTA project in Zhuhai, China. Below ground preparation work is now complete. We also furthered our growth strategy in Asia by signing a memorandum of understanding with SK Global Chemical Co., Ltd (SKGC) and Sinopec

Sichuan Vinylon Works (SVW), to explore the development of an integrated 1,4-butanediol (BDO) and acetic acid project in Chongqing. The proposed 200,000-tonnes per annum BDO plant will be built by SKGC and SVW while the 600,000-tonnes per annum acetic acid plant will be built by our existing acetic acid joint venture in Chongqing. The units in the integrated project are planned to be inter-dependent: the BDO plant will supply acetylene off-gas to the acetic acid plant, which, in return, will supply hydrogen to the BDO plant. This integrated approach is expected to enhance the competitiveness of the complex.

We continue to make progress on our joint study with IndianOil Corp (IOC) to invest in a 1-million tonnes per annum acetic acid plant in Gujarat, India, and have recently completed a refinery integration study to optimize the integration benefits of the proposed project with IOC s refinery.

In 2012, we created a new revenue stream in petrochemicals through third-party licensing of our proprietary PX and PTA technology with two licences being sold in 2012 for use in large-scale plants in India. We also secured a 15-year methanol off-take agreement with Lake Charles s Petcoke Gasification project in Louisiana, US, which will place us well to access advantaged feedstock supply to our acetic acid business.

Petrochemicals production capacity[a b]

Geographical area	Site	Product	Group interest %	BP share of capacity thousand tonnes per annum[c]
US				
	Cooper River	Purified terephthalic acid (PTA)	100.0	1,300
	Decatur[d]	PTA	100.0	1,000
		Paraxylene (PX)	100.0	1,100
	Texas City	Acetic acid	100.0[e]	600[e]

		PX	100.0	1,300
		Metaxylene	100.0	100
				5,400
Europe				
UK	Hull[d]	Acetic acid	100.0	500
		Acetic anhydride	100.0	200
Belgium	Geel	PTA	100.0	1,300
		PX	100.0	700
Germany	Gelsenkirchen[f]	Olefins and derivatives	50.0 to 61.0	1,800[bg]
	Mülheim[f]	Solvents	50.0	100[b]
				4,600
Rest of World				
China	Caojing	Olefins and derivatives	50.0	3,300[b]
	Chongqing	Acetic acid	51.0	200[b]
		Esters	51.0	100[b]
	Nanjing	Acetic acid	50.0	300[b]
	Zhuhai	PTA	85.0	1,800[h]
Indonesia	Merak	PTA	50.0	300[b]
South Korea	Ulsan	Acetic acid	51.0	300[b]
		Vinyl acetate monomer	34.0	100[b]
Malaysia	Kertih	Acetic acid	70.0	400[b]
Taiwan	Kaohsiung	PTA	61.4	900[b]
	Taichung	PTA	61.4	500[b]
	Mai Liao	Acetic acid	50.0	200[b]
				8,400
Total BP share of capacity at 31 December 2012				18,400

[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] Includes BP share of equity-accounted entities, as indicated.

[c] Capacities are shown to the nearest hundred thousand tonnes per annum.

[d] These sites have capacity under 100,000 tonnes per annum for a speciality product (e.g. naphthalene dicarboxylate and ethylidene diacetate).

[e] Group interest is quoted at 100%, reflecting the capacity entitlement, which is marketed by BP. This capacity is not part of the refinery divestment.

[f] 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.

[g] Group interest varies by product.

[h] BP Zhuhai Chemical Company Ltd is a subsidiary of BP, the capacity of which is shown above at 100%.

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TNK-BP

Since 2003, BP has owned 50% of TNK-BP, an integrated oil company. The other 50% is owned by the consortium of Alfa Access Renova (AAR). TNK-BP s major assets are held by OAO TNK-BP Holding. Other assets of TNK-BP include OAO Slavneft, an equity-accounted joint venture with Gazpromneft in Russia, and TNK Overseas Ltd, which holds its major non-Russian interests. TNK-BP employs about 50,000 staff. Globally, TNK-BP is the tenth largest non-fully state-owned oil company as measured by both SEC proved reserves and hydrocarbon production. It has upstream interests in Russia, Brazil, Venezuela and Vietnam, which produced approximately 2 million barrels of oil equivalent per day (gross TNK-BP) in both 2012 and 2011. TNK-BP also has downstream interests in five refineries in Russia and one in Ukraine, with total throughput of approximately 656mb/d in 2012 compared with 711mb/d in 2011. It has over 1,500 branded retail stations in Russia and Ukraine.

From 1 January 2012, BP s investment in TNK-BP has been reported as a separate operating segment, reflecting the way in which the investment has been managed.

Following the announcement of the agreement described below, BP s investment in TNK-BP met the criteria to be classified as an asset held for sale. Consequently, BP ceased accounting for its interest in TNK-BP using the equity method from 22 October 2012. BP will continue to report its share of TNK-BP s production and reserves until the transaction completes.

Definitive agreements with Rosneft

Having agreed heads of terms on 22 October 2012, BP announced on 22 November that it, Rosneft and Rosneftegaz the Russian state-owned parent company of Rosneft had signed definitive and binding sale and purchase agreements (SPAs) for the sale of BP s 50% interest in TNK-BP to Rosneft, and for BP s further investment in Rosneft. The transaction will consist of three tranches:

- BP will sell its 50% shareholding in TNK-BP to Rosneft for cash consideration of $25.4 billion (which includes a dividend of $0.7 billion received from TNK-BP in December 2012) and Rosneft shares representing a 3.04% stake in Rosneft (TNK-BP SPA).

- BP will use $4.8 billion of the cash consideration to acquire a further 5.66% stake in Rosneft from the Russian government at a price of $8 per share (representing a premium of 12% to the Rosneft share closing price on the bid date of 18 October 2012).

- BP will use $8.3 billion of the cash consideration to acquire a further 9.8% stake in Rosneft from a Rosneft subsidiary at a price of $8 per share.

The SPAs were signed after the Russian government approved BP s purchase of the 5.66% stake in Rosneft. On completion, the net result of the overall transaction is that BP will receive $12.3 billion in cash (including $0.7 billion of TNK-BP dividends received by BP in December 2012) and will acquire an 18.5% shareholding in Rosneft. Combined with BP s existing 1.25% shareholding, this will result in BP owning 19.75% of Rosneft. It is expected that the TNK-BP sale and the further investment in Rosneft will complete on the same day. At this level of ownership, BP expects to be able to account for its share of Rosneft s earnings, production and reserves on an equity basis. In due course BP expects to have two seats on Rosneft s nine-person main board.

Completion is subject to certain customary closing conditions, including governmental, regulatory and anti-trust approvals, and is anticipated to occur during the first half of 2013. Under the terms of the SPAs, BP has agreed not to dispose of any of the Rosneft shares acquired in the transaction for at least 360 days following completion. In addition, the TNK-BP SPA contains remedial provisions that take effect if certain events occur.

Financial and operating performance

			$ million
	2012	2011	2010
Profit before interest and tax[a]	**3,370**	4,185	2,617
Inventory holding (gains) losses	**3**	(51)	
Replacement cost profit before interest and tax	**3,373**	4,134	2,617
Net charge (credit) for non-operating items[b]	**(246)**		
Underlying replacement cost profit before interest and tax[c]	**3,127**	4,134	2,617

[a] The TNK-BP segment includes equity-accounted earnings from associates, in which all amounts shown relate to BP s 50% share in TNK-BP, as follows:

Profit before interest and tax	**4,405**	5,992	3,866
Finance costs	**(84)**	(132)	(128)
Taxation	**(979)**	(1,333)	(913)
Minority interest	**(356)**	(342)	(208)
Net income	**2,986**	4,185	2,617
Inventory holding (gains) losses, net of tax	**3**	(51)	
Net income on a replacement cost basis	**2,989**	4,134	2,617
Net charge (credit) for non-operating items,[b] net of tax	**138**		
Net income on an underlying replacement cost basis[c]	**3,127**	4,134	2,617

[b] Disclosure of non-operating items for TNK-BP began in 2012.

[c] Underlying replacement cost profit is not a recognized GAAP measure. See footnote b on page 34 for information on underlying replacement cost profit.

	2012	2011	2010
Production (net of royalties)(BP share)[d]			
Crude oil (thousand barrels per day)	**876**	871	856
Natural gas (million cubic feet per day)	**784**	710	640
Total hydrocarbons[e] (thousand barrels of oil equivalent per day)	**1,012**	994	967
Estimated net proved reserves[d] (net of royalties)(BP share)			
Crude oil (million barrels)[f]	**4,540**	4,305	3,750
Natural gas (billion cubic feet)[g]	**4,492**	2,881	2,359
Total hydrocarbons[f g] (million barrels of oil equivalent)	**5,315**	4,802	4,157
Average oil marker prices			$ per barrel
Urals (Northwest Europe CIF)	**110.19**	109.08	78.26

Russian domestic oil	**53.98**	49.57	36.96

[d] BP continues to report its share of TNK-BP s production and reserves until the transaction to sell its 50% share to Rosneft closes.

[e] Expressed in thousands of barrels of oil equivalent per day (mboe/d). Natural gas is converted to oil equivalent at 5.8 billion cubic feet = 1 million barrels.

[f] Includes 328 million barrels (310 million barrels at 31 December 2011 and 254 million barrels at 31 December 2010) in respect of the 7.35% minority interest in TNK-BP (7.37% at 31 December 2011 and 7.03% at 31 December 2010).

[g] Includes 270 billion cubic feet (174 billion cubic feet at 31 December 2011 and 137 billion cubic feet at 31 December 2010) in respect of the 6.17% minority interest in TNK-BP (6.27% at 31 December 2011 and 5.89% at 31 December 2010).

Replacement cost profit before interest and tax[h] for the TNK-BP segment was $3,373 million, compared with $4,134 million in 2011. These amounts include BP s equity-accounted share of TNK-BP s earnings. In 2012, equity-accounted earnings are included from 1 January to 21 October, after which our investment was classified as an asset held for sale and therefore equity accounting ceased.

[h] Under equity accounting, BP s share of TNK-BP s earnings after interest and tax has been included in the BP group income statement within profit before interest and tax.

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The 2012 result also included a net non-operating gain of $246 million, primarily dividend income from TNK-BP of $709 million, partly offset by a charge of $325 million to settle disputes with AAR. With the cessation of equity accounting, under IFRS dividends from our investment in TNK-BP are recognized as revenue in the period in which they become receivable. In addition, within equity-accounted earnings, there was an impairment loss associated with the temporary shutdown of the Lisichansk refinery in the Ukraine (due to deteriorating economic conditions) and environmental provisions, partly offset by gains on disposals. Prior to 2012, non-operating items for the TNK-BP segment were not identified or disclosed.

After adjusting for non-operating items, the underlying replacement cost profit before interest and tax[a b] for the TNK-BP segment was $3,127 million, compared with $4,134 million in 2011. The primary factors impacting the 2012 result, compared with 2011, were the absence of more than two months of equity-accounted earnings, lower realizations and the impact of the tax reference price lag on Russian export duties in falling price environments, partly offset by positive foreign exchange effects.

BP received $1,399 million in cash dividends from its investment in TNK-BP in 2012, as compared with $3,747 million during 2011. This included $709 million received after reaching agreement with Rosneft for the sale of BP s shareholding in TNK-BP.

[a] Underlying replacement cost profit is not a recognized GAAP measure. See footnote b on page 34 for information on underlying replacement cost profit.

[b] See footnote h on page 80.

Production and reserves

BP s share of TNK-BP production for the full year of 2012 was 1,012mboe/d, 2% higher than in 2011. After adjusting for the effect of the acquisition of BP s upstream interests in Vietnam and Venezuela, production increased only slightly compared with 2011, with the ramp-up of new developments offsetting declines from mature fields and the impact of divestments.

The TNK-BP segment s total hydrocarbon reserves, on an oil equivalent basis, was 5,315mmboe at 31 December 2012, an increase of 11% (increase of 5% for crude oil and increase of 56% for natural gas), compared with the 31 December 2011 reserves of 4,802mmboe.

The proved reserves replacement ratio is the extent to which production is replaced by proved reserves additions. For 2012, the proved reserves replacement ratio excluding acquisitions and disposals was 242% (2011 245%, 2010 165%). For more information on proved reserves replacement for the group, see pages 85-86.

Key business events

On 11 March, TNK-BP announced the acquisition of two companies that operate the jet fuel storage and re-fuelling services at the Koltsovo International Airport in Ekaterinburg. The airport is the fifth largest in the Russian Federation in terms of number of passengers.

On 21 May, TNK-BP announced the appointment of Evert Henkes to the board of TNK-BP Ltd as a BP-nominated independent director. He became the tenth member of the board of TNK-BP Ltd and the second of the board s three independent directors. This appointment followed the resignations of Gerhard Schroeder and James Leng.

On 28 May, TNK-BP announced that Mikhail Fridman had resigned from the position of chief executive officer of the TNK-BP group. He also resigned from the position of chairman of the management board of TNK-BP Management, a Russian subsidiary of TNK-BP, which manages the company s assets in Russia and Ukraine, including the publicly traded company, TNK-BP Holding. Both resignations took effect at the end of June 2012.

On 20 August, TNK-BP announced that it had sold OJSC Novosibirskneftegaz and OJSC Severnoeneftegaz as part of the company s strategy to optimize the asset portfolio and improve per barrel efficiency.

On 9 October, TNK-BP announced that the group s subsidiary, TNK Vietnam, had produced the first gas from the Lan Do field in Block 06.1, offshore of Ba Ria Vung Tau province. Two sub-sea wells were tied back to the Lan Tay platform, through 28 kilometres of flow line and umbilical, enabling TNK Vietnam to produce gas from the existing infrastructure.

The Lan Do field is expected to bring 2 billion cubic metres (70 billion cubic feet) of gas to market annually.

On 13 November, BP and AAR announced they had reached an agreement to settle all outstanding disputes between them, including the arbitrations brought by each against the other. The agreement included a waiver of the new opportunities provision in the TNK-BP shareholder agreement, allowing each party to explore new opportunities and partnerships in Russia and Ukraine. BP paid AAR $325 million as part of the settlement. See Legal proceedings on pages 169-171 for further information.

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Other businesses and corporate

Other businesses and corporate comprises the Alternative Energy business, Shipping, Treasury (which includes interest income on the group s cash and cash equivalents), and corporate activities worldwide.

The replacement cost loss before interest and tax for the year ended 31 December 2012 was $2,795 million, compared with $2,478 million for the previous year. 2012 included a net charge for non-operating items of $798 million. (See page 37 for further information on non-operating items.)

After adjusting for non-operating items, the underlying replacement cost loss before interest and tax for the year ended 31 December 2012 was $1,997 million compared with $1,656 million in 2011. The 2012 result was impacted by the loss of income from the sale of the aluminium business in 2011, adverse foreign exchange effects and higher corporate and functional costs.

The replacement cost loss before interest and tax for the year ended 31 December 2011 included a net charge for non-operating items of $822 million.

The replacement cost loss before interest and tax for the year ended 31 December 2010 included a net charge for non-operating items of $200 million.

The primary additional factors reflected in 2011 s result compared with that of 2010 were weaker business performance and higher corporate costs, offset by more favourable foreign exchange effects and cost efficiencies.

			$ million
	2012	2011	2010
Sales and other operating revenues[a]	**1,985**	2,957	3,328
Replacement cost (loss) before interest and tax	**(2,795)**	(2,478)	(1,516)
Net (favourable) unfavourable impact of non-operating items	**798**	822	200
Underlying replacement cost profit (loss) before interest and tax[b]	**(1,997)**	(1,656)	(1,316)
Capital expenditure and acquisitions	**1,435**	1,853	1,234

[a] Includes sales between businesses.
[b] Underlying replacement cost profit (loss) is not a recognized GAAP measure. See footnote b on page 34 for information on underlying replacement cost profit.

Alternative Energy

Alternative Energy comprises BP s lower-carbon businesses and future growth options outside oil and gas. These are biofuels, wind and a range of other longer-term technology investments.

Market commentary

A more diverse mix of energy will be required to meet long-term future demand. BP s own estimates suggest that global primary energy demand will increase by around 1.6% per annum between 2010 and 2030. Supported by government policies, renewables global share of power generation is expected to be 11% by 2030. Through 2030, biofuels are expected to account for 13% of transport energy demand growth[a].

[a] *BP Energy Outlook 2030.*

2012 performance

Alternative Energy continues to deliver on its mission to invest in and develop new, material sources of lower-carbon energy that are in alignment with BP s core capabilities.

In 2012 our wind business brought three new wind farms into operation, bringing its total to 16 operating farms in nine US states. Across our wind facilities, BP s net share of wind generation for 2012 was 3,587GWh (5,739GWh gross), compared with 2,394GWh (4,309GWh gross) a year ago. Additional projects continue to be evaluated.

Globally, BP has continued to increase its biofuels production. In Hull, UK, we have commissioned the joint venture Vivergo ethanol facility with a production capacity of 420 million litres per year. In Brazil, BP is progressing expansion of its ethanol production at its existing three sugar

cane ethanol mills. In conjunction with joint venture partner DuPont, BP is undertaking leading edge research into the production of biobutanol under the company name Butamax.

Across our biofuels business, BP s net share of ethanol-equivalent production for 2012 was 404 million litres compared with 314 million litres (410 million litres gross)[b] a year ago. The majority of this production is from BP s sugar cane mills in Brazil.

In the US, BP has made the strategic decision to focus its biofuels business on the research, development, and commercialization of cellulosic ethanol technology at its facilities in San Diego, California, and Jennings, Louisiana.

Alternative Energy has now invested approximately $7.6 billion[c], investing at a faster pace than its 2005 commitment of $8 billion over 10 years.

[b] BP acquired the remaining 50% of Tropical Bioenergia on 22 November 2011.

[c] The majority of costs were initially capitalized, although some were expensed under IFRS.

Biofuels

BP believes that it has a key technological role to play in enabling the transport sector to respond to the dual challenges of energy security and climate change. We have embarked on a focused programme of biofuels development based on the most efficient transformation of sustainable and low-cost sugars into a range of fuel molecules. Our strategy is to focus on the conversion of cost-advantaged feedstocks that are materially scalable and that can be competitive in an $80 crude oil environment without subsidies.

To this end, BP now operates three sugar cane mills in Brazil producing bioethanol, sugar and exporting power to the grid. We continue to evaluate options to increase production at these facilities. Likewise, through the joint venture Vivergo, we are operating the largest bioethanol facility in the UK, and one of the largest in Europe. At 420 million litres per year, the Vivergo facility represents around a third of the UK s 2012-13 requirements under the Renewable Transport Fuels Obligation (RTFO). In addition, once Vivergo is at full production, it is set to become the largest source of animal feed in the UK.

BP continues to invest throughout the entire biofuels value chain, from sustainable feedstocks that minimize pressure on food supplies through to the development of the advantaged fuel molecule biobutanol, which has a higher energy content than ethanol and delivers improved fuel economy. See Technology on pages 57-59 for further information.

Wind

In wind power, BP has focused its business onshore in the US. BP has an interest in 16 wind farms located in nine US states: California (1), Colorado (2), Hawaii (1), Idaho (1), Indiana (3), Kansas (2), Pennsylvania (1), South Dakota (1) and Texas (4).

During 2012, together with our partners, we completed construction of wind farms in Kansas, Pennsylvania and Hawaii. We have created nearly 4,300 construction jobs and more than 200 jobs operating wind farms since creation of our wind business.

BP increased its net wind generation capacity in the US to 1,558MW[d] during 2012, an increase of over 50% compared with the end of the prior year.

[d] BP also has 32MW of wind capacity in the Netherlands, operated by Downstream.

Solar

The exit of our solar business as announced in December 2011 has been substantially completed.

Emerging business and ventures

Our emerging business and ventures unit brings together BP s venturing and carbon markets expertise with our carbon capture and storage capability. Through this unit, we have invested more than $175 million across 33 separate investments spanning the following areas: bioenergy, energy efficiency and storage, carbon management, renewable power and, more recently, in emerging oil and gas technologies. These investments provide BP with insight and access to cutting-edge technologies that can help make the company more efficient, productive, sustainable and profitable. See Technology on pages 57-59 for further information.

Our carbon capture and storage expertise is helping our businesses understand and manage their CO_2 emissions, and to monitor CO_2 storage

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opportunities, such as the In Salah gas field where we have injected almost 4 million tonnes of CO_2 since 2004. Presently, CO_2 injection at the storage site is suspended while the In Salah Gas joint venture partners (BP, Sonatrach and Statoil) evaluate the large body of data acquired during the first phase of operation.

Shipping

We transport our products across oceans, around coastlines and along waterways, using a combination of BP-operated, time-chartered and spot-chartered vessels. All vessels conducting BP activities are subject to our health, safety, security and environmental requirements. The primary purpose of our shipping and chartering activities is the transportation of our hydrocarbon products. In addition, we may use surplus capacity to transport third-party products.

International fleet

At the end of 2012, we had 52 international vessels (37 medium-size crude and product carriers, three very large crude carriers, one North Sea shuttle tanker, eight LNG carriers and three LPG carriers). All these ships are double-hulled. Of the eight LNG carriers, BP manages one on behalf of a joint venture in which it is a participant.

In December 2012 BP announced it had signed a contract with STX Offshore and Shipbuilding to build 13 new tankers in Korea. The first of these will be delivered in late 2014.

Regional and specialist vessels

In Alaska, we retain a fleet of four double-hulled vessels. Outside the US, we had 14 specialist vessels (two double-hulled lubricants oil barges and four offshore support vessels each one complete with two autonomous rescue and recovery crafts).

Time-charter vessels

At the end of 2012 BP had 111 hydrocarbon-carrying vessels above 600 deadweight tonnes on time-charter, all of which are double-hulled. The quality and safety performance of these vessels is assured through BP s Time Charter Assurance Programme.

Spot-charter vessels

BP spot-charters vessels, typically for single voyages. These vessels are always assessed against BP s marine assurance requirements prior to each use.

Other vessels

BP uses various craft such as tugs, crew boats and seismic vessels in support of the group s business. We also use sub-600 deadweight tonne barges to carry hydrocarbons on inland waterways.

Maritime security issues

At a strategic level, BP avoids known areas of pirate attack or armed robbery; where this is not possible for operational reasons and we consider it safe to do so, we will continue to transit vessels through these areas, subject to the adoption of heightened security measures.

2012 has seen continuing pirate activity in the Gulf of Aden, the Indian Ocean (up to approximately 200 miles west of the Indian coast) and the Arabian Sea. It should however be noted that pirate activity has reduced considerably compared with previous years. This decrease in activity is due principally to more robust intervention by the various navies operating in this region and to greater adoption of protective measures by vessels transiting these waters.

At present, we follow available military and government agency advice and are participating in protective group transits through the Gulf of Aden Internationally Recommended Transit Corridor. BP uses the protective measures recommended in the international shipping industry guide *BMP 4 Best Management Practices for Protection against Somalia Based Piracy,* jointly published by industry bodies, including Oil Companies International Marine Forum and supported by military operations in the region.

We continue to monitor other areas where cargo piracy is known to occur, for example West Africa and the South China Sea.

Treasury

Treasury manages the financing of the group centrally, ensuring liquidity sufficient to meet group requirements and manages key financial risks including interest rate, foreign exchange, pension and financial institution credit risk. From locations in the UK, the US and the Asia Pacific region, Treasury provides the interface between BP and the international financial markets and supports the financing of BP s projects around the world. Treasury trades foreign exchange and interest rate products in the financial markets, hedging group exposures and generating incremental value through optimizing and managing cash flows. Trading activities are underpinned by the compliance, control and risk management infrastructure common to all BP trading activities. For further information, see Financial statements Note 26 on page 220.

Insurance

The group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. Losses are borne as they arise, rather than being spread over time through insurance premiums with attendant transaction costs. This approach was reviewed following the Deepwater Horizon oil spill but the group concluded that it will continue with its current approach of not generally purchasing insurance cover.

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Oil and gas disclosures for the group

Resource progression

BP manages its hydrocarbon resources in three major categories: prospect inventory, contingent resources and proved 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 proved reserves 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. 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 contingent.

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 proved reserves 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 2012, BP had material volumes of proved undeveloped reserves held for more than five years in Trinidad, as well as non-material volumes in Angola, Australia, Azerbaijan, Russia, the UK and the US, that are part of ongoing development activities for which BP has a historical track record of completing comparable projects in these countries.

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 on average about 20% of our proved undeveloped reserves (excluding disposals) to proved developed reserves. This equates to a turnover time of about five years. We expect the turnover time to remain at or below five years and anticipate the volume of proved undeveloped reserves held for more than five years to remain about the same.

In 2012 we progressed 1,279mmboe of proved undeveloped reserves (780mmboe for our subsidiaries alone) to proved developed reserves through ongoing investment in our upstream development activities. Total development expenditure in Upstream, excluding midstream activities, was $15,247 million in 2012 ($11,964 million for subsidiaries and $3,283 million for equity-accounted entities). The major areas with progressed volumes in 2012 were Angola, Azerbaijan, Iraq, Norway, Russia, Trinidad and the US. Revisions of previous estimates for proved undeveloped reserves are due to the impact of year-end price (net reduction of 33%) and changes relating to field performance or well results (67%). The following tables describe the changes to our proved undeveloped reserves position through the year for our subsidiaries and equity-accounted assets and for our subsidiaries alone.

Subsidiaries and equity-accounted assets	volumes in mmboe
Proved undeveloped reserves at 1 January 2012	7,919
Revisions of previous estimates	(95)
Improved recovery	586
Discoveries and extensions	462
Purchases	49
Sales	(116)
Total in year proved undeveloped reserves changes	8,805
Progressed to proved developed reserves	(1,279)
Proved undeveloped reserves at 31 December 2012	7,526

Subsidiaries only	volumes in mmboe
Proved undeveloped reserves at 1 January 2012	5,378
Revisions of previous estimates	(700)
Improved recovery	496
Discoveries and extensions	169
Purchases	49
Sales	(108)
Total in year proved undeveloped reserves changes	5,284
Progressed to proved developed reserves	(780)
Proved undeveloped reserves at 31 December 2012	4,504

BP bases its proved reserves estimates on the requirement of reasonable certainty with rigorous technical and commercial assessments based on conventional industry practice. 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 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:

1. Well data used to assess the local characteristics and conditions of reservoirs and fluids.

2. Field scale seismic data to allow the interpolation and extrapolation of these characteristics outside the immediate area of the local well control.

3. 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.

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Internal audit, whose role is to consider whether the group s system of internal control is adequately designed and operating effectively to respond appropriately to the risks that are significant to BP.

Approval hierarchy, whereby proved reserves changes above certain threshold volumes require central authorization and periodic reviews. The frequency of review is determined according to field size and ensures that more than 80% of the BP proved reserves base undergoes central review every two years, and more than 90% is reviewed centrally every four years. In addition, BP commenced a review of certain of its assets and estimation processes. This review process will continue through 2013.

BP s vice president of segment reserves is the petroleum engineer primarily responsible for overseeing the preparation of the reserves estimate. He has nearly 30 years of diversified industry experience with the past eight 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, a sitting member of the American Association of Petroleum Geologists Committee on Resource Evaluation and chair of the bureau of the United Nations Economic Commission for Europe Expert Group on Resource Classification.

For the executive directors and senior management, no specific portion of compensation bonuses 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.

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 (jointly controlled entities 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

Eighty-two per cent of our total proved reserves of subsidiaries at 31 December 2012 were held through unincorporated joint ventures (75% in 2011), and 31% of the proved reserves were held through such unincorporated joint ventures where we were not the operator (33% in 2011).

Estimated net proved reserves of liquids at 31 December 2012[a b c]

			million barrels
	Developed	Undeveloped	Total
UK	242	431	673
Rest of Europe	170	79	249
US	1,443	989	2,432[d]
Rest of North America			
South America	22	32	54[e]
Africa	312	255	567
Rest of Asia	268	137	405
Australasia	52	45	97
Subsidiaries	2,509	1,968	4,477[f]
Equity-accounted entities	3,041	2,532	5,573[g h]
Total	5,550	4,500	10,050

Estimated net proved reserves of natural gas at 31 December 2012[a b]

			billion cubic feet
	Developed	Undeveloped	Total
UK	1,038	666	1,704
Rest of Europe	340	141	481
US	8,245	2,986	11,231
Rest of North America	4		4
South America	3,588	6,250	9,838[i]
Africa	1,139	1,923	3,062
Rest of Asia	926	413	1,339
Australasia	3,282	2,323	5,605
Subsidiaries	18,562	14,702	33,264[f]
Equity-accounted entities	4,196	2,845	7,041[g h]
Total	22,758	17,547	40,305

Net proved reserves on an oil equivalent basis

			million barrels of oil equivalent
	Developed	Undeveloped	Total
Subsidiaries	5,709	4,504	10,213[f]
Equity-accounted entities	3,765	3,022	6,787[g]
Total	9,474	7,526	17,000

[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 minority interests in consolidated operations. We disclose our share of reserves held in jointly controlled entities 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 2012 marker prices used were Brent $111.13/bbl (2011 $110.96/bbl and 2010 $79.02/bbl) and Henry Hub $2.75/mmBtu (2011 $4.12/mmBtu and 2010 $4.37/mmBtu).

[c] Liquids include crude oil, condensate, natural gas liquids and bitumen.

[d] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 76 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] Includes 14 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[f] Includes assets held for sale of 39 million barrels of liquids and 590 billion cubic feet of natural gas (140 million barrels of oil equivalent).

[g] Includes assets held for sale of 4,540 million barrels of liquids and 4,492 billion cubic feet of natural gas (5,315 million barrels of oil equivalent) associated with TNK-BP.

[h] Includes 328 million barrels of liquids and 270 billion cubic feet of natural gas in respect of the 7.35% and 6.17% minority interests respectively in TNK-BP.

[i] Includes 2,890 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

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Proved reserves replacement

Total hydrocarbon proved reserves, on an oil equivalent basis including equity-accounted entities, comprised 17,000mmboe (10,213mmboe for subsidiaries and 6,787mmboe for equity-accounted entities) at 31 December 2012, a decrease of 4% (decrease of 11% for subsidiaries and increase of 7% for equity-accounted entities) compared with the 31 December 2011 reserves of 17,748mmboe (11,426mmboe for subsidiaries and 6,322mmboe for equity-accounted entities). Natural gas represented about 41% (56% for subsidiaries and 18% for equity-accounted entities) of these reserves. The change includes a net decrease from acquisitions and disposals of 455mmboe (440mmboe net decrease for subsidiaries and 15mmboe net decrease for equity-accounted entities). Additions from acquisitions occurred principally in the US following a 2011 acquisition. Divestments occurred in Norway, Russia, Trinidad, the UK and the US.

Proved reserves contain volumes in assets held for sale of 39 million barrels of liquids and 590 billion cubic feet of natural gas (140 million barrels of oil equivalent) in our subsidiaries and 4,540 million barrels of liquids and 4,492 billion cubic feet of natural gas (5,315 million barrels of oil equivalent) associated with TNK-BP.

The proved reserves replacement ratio is the extent to which production is replaced by proved reserves additions. This ratio is expressed in oil equivalent terms and includes changes resulting from revisions to previous estimates, improved recovery, and extensions and discoveries. For 2012, the proved reserves replacement ratio excluding acquisitions and disposals was 77% (103% in 2011 and 106% in 2010) for subsidiaries and equity-accounted entities, -5% for subsidiaries alone and 195% for equity-accounted entities alone.

In 2012, net additions to the group s proved reserves (excluding production and sales and purchases of reserves-in-place) amounted to 953mmboe (-35mmboe for subsidiaries and 988mmboe 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 2012 principally resulted from the application of conventional technologies. The principal proved reserves additions in our subsidiaries were in Angola, Azerbaijan, India and Trinidad. We had material proved reserves reductions in Norway and the US due to price changes, changes in activity and performance updates. The principal reserves additions in our equity-accounted entities were in Angola, Argentina and Russia.

Twelve per cent of our proved reserves are associated with PSAs. The countries in which we operated under PSAs in 2012 were Algeria, Angola, Azerbaijan, Egypt, India, Indonesia, Oman, Vietnam and a non-material volume in Trinidad. In addition, the technical service contract (TSC) governing our investment in the Rumaila field in Iraq functions as a PSA.

The Abu Dhabi onshore concession expires in January 2014 with a consequent reduction in production of approximately 140mb/d. 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 263.

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BP s net production by major field liquids

Subsidiaries	Field or area	2012	2011	2010
		thousand barrels per day BP net share of production[a]		
UK[b]	ETAP[c]	**11**	22	28
	Foinaven (BP-operated)	**14**	26	24
	Other[d]	**61**	65	85
Total UK		**86**	113	137
Norway[b]	Various	**23**	32	40
Total Rest of Europe		**23**	32	40
Total Europe		**109**	145	177
Alaska	Prudhoe Bay (BP-operated)	**77**	78	81
	Kuparuk	**36**	39	42
	Milne Point (BP-operated)	**15**	19	23
	Other	**11**	17	20
Total Alaska		**139**	153	166
Lower 48 onshore[b]	Various	**60**	69	90
Gulf of Mexico deepwater[b]	Thunder Horse (BP-operated)	**49**	77	120
	Atlantis (BP-operated)	**23**	34	49
	Mad Dog (BP-operated)	**9**	8	30
	Mars	**15**	19	23
	Na Kika (BP-operated)	**21**	14	25
	Horn Mountain (BP-operated)	**6**	8	14
	King (BP-operated)	**14**	15	21
	Other	**54**	56	56
Total Gulf of Mexico deepwater		**191**	231	338
Total US		**390**	453	594
Canada[b]	Various (BP-operated)	**1**	2	7
Total Rest of North America		**1**	2	7
Total North America		**391**	455	601
Colombia[b]	Various (BP-operated)		1	18
Trinidad & Tobago	Various (BP-operated)	**21**	31	36
Brazil[b]	Polvo (BP-operated)	**7**	7	
Total South America		**28**	39	54
Angola	Greater Plutonio (BP-operated)	**59**	51	73
	Kizomba C Dev	**9**	21	31

	Dalia	**11**	12	20
	Girassol FPSO	**11**	12	18
	Pazflor	**29**	5	
	Other	**30**	22	28
Total Angola		**149**	123	170
Egypt[b]	Gupco	**32**	34	47
	Other	**9**	11	12
Total Egypt		**41**	45	59
Algeria[b]	Various	**12**	22	17
Total Africa		**202**	190	246
Azerbaijan[b]	Azeri-Chirag-Gunashli (BP-operated)	**82**	86	94
	Other	**10**	8	9
Total Azerbaijan		**92**	94	103
Western Indonesia[b]	Various	**1**	2	2
Iraq	Rumaila	**39**	31	
Other	Various	**7**	11	14
Total Rest of Asia[b]		**139**	138	119
Total Asia		**139**	138	119
Australia	Various	**24**	23	30
Other	Various	**3**	2	2
Total Australasia		**27**	25	32
Total subsidiaries[e]		**896**	992	1,229
Equity-accounted entities (BP share)				
Russia TNK-BP[b]	Various	**863**	865	856
Total Russia		**863**	865	856
Abu Dhabi[f]	Various	**216**	209	190
Other	Various	**1**	1	1
Total Rest of Asia[b]		**217**	210	191
Total Asia		**1,080**	1,075	1,047
Argentina	Various	**65**	74	75
Venezuela[b]	Various	**14**	16	23
Bolivia[b]	Various	**1**		
Total South America		**80**	90	98
Total equity-accounted entities[g]		**1,160**	1,165	1,145
Total subsidiaries and equity-accounted entities		**2,056**	2,157	2,374

[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 2012, BP divested its interests in the US Gulf of Mexico Marlin, Dorado, King, Horn Mountain, Holstein, Ram Powell and Diana Hoover assets, a portion of our interest in US Gulf of Mexico Mad Dog asset, its interests in the US onshore Jonah and Pinedale upstream operation in Wyoming, and associated gas gathering system, its interests in the Canadian natural gas liquid business, its interests in the Alba and Britannia fields in the UK North Sea, its interests in the Draugen field in the Norwegian Sea, and TNK-BP disposed of its interests in OJSC Novosibirskneftegaz, with interests in Novosibirsk region, Omsk region, and Irkutsk region, and its interests in OJSC Severnoeneftegaz, with interests in Novosibirsk region. BP also increased its interest in the US onshore Eagle Ford Shale in south Texas, its interests in certain UK North Sea assets, and in certain US Alaska assets. In 2011, BP sold its holdings in Venezuela and Vietnam to TNK-BP. It also made acquisitions in India through a joint venture with Reliance, Brazil and additional volumes in the US Gulf of Mexico and UK North Sea. BP divested its holdings

in Pompano along with other interests in the US Gulf of Mexico, Tuscaloosa and interests in South Texas in the US onshore, a portion of our interest in the Azeri-Chirag-Gunashli development in Azerbaijan, Wytch Farm in the UK, our interests in the REB field in Algeria, and the remainder of our interests in Colombia and Pakistan. In 2010, BP divested its Permian Basin assets in Texas and south-east New Mexico, the East Badr El-Din and Western Desert concession in Egypt, its Canada gas assets and reduced its interest in the King field in the Gulf of Mexico. It also acquired an increased holding in the Azeri-Chirag-Gunashli development in Azerbaijan and the Valhall and Hod fields in the Norwegian North Sea. Four other producing fields in the Gulf of Mexico that were acquired during 2010 were subsequently disposed of in early 2011.

[c] Volumes relate to six BP-operated fields within ETAP. BP has no interests in the remaining three ETAP fields, which are operated by Shell.

[d] 2012 includes 17mb/d of production in assets held for sale.

[e] Includes 13.5 net mboe/d of NGLs from processing plants in which BP has an interest (2011 28mboe/d and 2010 29mboe/d).

[f] The BP group holds interests, through associates, in onshore and offshore concessions in Abu Dhabi, expiring in 2014 and 2018 respectively.

[g] 2012 includes 877mb/d of production in assets held for sale associated with TNK-BP. See TNK-BP on pages 80-81 for further information.

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BP s net production by major field natural gas

million cubic feet per day

Subsidiaries	Field or area	BP net share of production[a] 2012	2011	2010
UK[b]	Bruce/Rhum (BP-operated)	**15**	20	100
	Other[c]	**399**	335	372
Total UK		**414**	355	472
Norway[b]	Various	**8**	13	15
Total Rest of Europe		**8**	13	15
Total Europe		**422**	368	487
Lower 48 onshore[b]	San Juan (BP-operated)	**561**	603	629
	Jonah (BP-operated)	**69**	145	185
	Anadarko	**142**	141	137
	Arkoma Central	**118**	136	164
	Wamsutter (BP-operated)	**141**	122	126
	Arkoma East	**112**	115	112
	Arkoma West	**98**	109	128
	Other	**258**	274	394
Total Lower 48 onshore	Total	**1,499**	1,645	1,875
Gulf of Mexico deepwater[b]	Various	**134**	176	263
Alaska	Various	**18**	22	46
Total US		**1,651**	1,843	2,184
Canada[b]	Various	**13**	14	202
Total Rest of North America		**13**	14	202
Total North America		**1,664**	1,857	2,386
Trinidad & Tobago	Mango (BP-operated)	**181**	308	544
	Cashima/NEQB (BP-operated)	**305**	570	679
	Kapok (BP-operated)	**360**	464	541
	Cannonball (BP-operated)	**56**	99	156
	Amherstia (BP-operated)	**324**	296	252
	Serrette (BP-operated)	**367**	35	
	Savonette (BP-operated)	**320**	327	203
	Other (BP-operated)	**184**	94	98
Total Trinidad		**2,097**	2,193	2,473
Colombia[b]	Various		4	71

Total South America		**2,097**	2,197	2,544
Egypt[b]	Temsah	**34**	74	90
	Ha py (BP-operated)	**88**	99	73
	Taurt (BP-operated)	**67**	61	75
	Other	**281**	210	192
Total Egypt		**470**	444	430
Algeria	Various	**120**	114	126
Total Africa		**590**	558	556
Pakistan[b]	Various (BP-operated)		73	150
Azerbaijan[b]	Various (BP-operated)	**158**	140	132
Western Indonesia[b]	Sanga-Sanga	**59**	59	69
	Other			1
Total Western Indonesia		**59**	59	70
India[b]	D1D3	**253**	121	
	Other	**60**	25	
Total India		**313**	146	
Vietnam[b]	Various (BP-operated)		69	77
China	Yacheng	**54**	70	95
Oman		**14**	20	
Sharjah	Various (BP-operated)	**35**	41	50
Total Rest of Asia		**633**	618	574
Total Asia		**633**	618	574
Australia	Perseus/Athena	**141**	170	165
	Goodwyn	**73**	72	118
	Angel	**110**	126	133
	Other	**111**	87	46
Total Australia		**435**	455	462
Eastern Indonesia	Tangguh (BP-operated)	**352**	340	323
Total Australasia		**787**	795	785
Total subsidiaries[d]		**6,193**	6,393	7,332
Equity-accounted entities (BP share)				
Russia TNK-BP[b]	Various	**734**	699	640
Western Indonesia	Various	**26**	26	30
Vietnam[b]		**46**	8	
Total Rest of Asia		**72**	34	30
Total Asia		**806**	733	670
Argentina	Various	**355**	371	379
Bolivia[b]	Various	**34**	14	11
Venezuela[b]	Various	**5**	7	9
Total South America		**394**	392	399
Total equity-accounted entities[d e]		**1,200**	1,125	1,069
Total subsidiaries and equity-accounted entities		**7,393**	7,518	8,401

[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 2012, BP divested its interests in the US Hugoton basin including the Jayhawk NGL plant, its interests in US Gulf of Mexico Marlin, Dorado, King, Horn Mountain, Holstein, Ram Powell and Diana Hoover assets, a portion of our interest in US Gulf of Mexico Mad Dog asset, its interests in the US onshore Jonah and Pinedale upstream

operation in Wyoming, its interests in the Sunray and Hemphill gas processing plants in Texas, and associated gas gathering system, its interests in the UK North Sea southern gas fields including associated pipeline infrastructure and the Dimlington terminal (including the integrated Easington terminal), and its interests in the Alba and Britannia fields in the UK North Sea. BP also increased its interest in the US onshore Eagle Ford Shale in South Texas, and its interests in certain UK North Sea assets. In 2011, BP sold its holdings in Venezuela and Vietnam to TNK-BP. It also made acquisitions in India through a joint venture with Reliance, in the Eagle Ford shale in North America and additional volumes in the US Gulf of Mexico. BP divested its holdings in Pompano along with other interests in the US Gulf of Mexico, Tuscaloosa and interests in south Texas in the US onshore, Wytch Farm in the UK, minor volumes in Canada and the remainder of our interests in Colombia and Pakistan. In 2010, BP divested its Permian Basin assets in Texas and south-east New Mexico, the East Badr El-Din concession in Egypt, its Canada gas assets and reduced its interest in the King field in the Gulf of Mexico. It also acquired an increased holding in the Valhall and Hod fields in the Norwegian North Sea. Four other producing fields in the Gulf of Mexico that were acquired during 2010 were subsequently disposed of in early 2011.

[c] 2012 includes 40mmcf/d of production in assets held for sale.

[d] 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.

[e] 2012 includes 785mmcf/d of production in assets held for sale associated with TNK-BP. See TNK-BP on pages 80-81 for further information.

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The following tables provide additional data and disclosures in relation to our oil and gas operations.

Average sales price per unit of production

$ per unit of production[a]

	Europe		North America		South America	Africa	Asia		Australasia	Total group average
	UK	Rest of Europe	US	Rest of North America[b]			Russia	Rest of Asia		
Average sales price[c]										
Subsidiaries										
2012										
Liquids[d]	**109.64**	**106.93**	**96.35**		**84.53**	**106.39**		**109.69**	**103.12**	**102.10**
Gas	**8.62**	**9.43**	**2.32**		**3.53**	**6.05**		**5.08**	**10.08**	**4.75**
2011										
Liquids[d e]	106.89	107.83	96.34		86.60	104.37		111.10	101.22	101.29
Gas	7.91	13.15	3.34		3.60	5.24		4.73	9.13	4.69
2010										
Liquids[d]	76.33	81.09	70.79	48.26	71.01	74.87		78.80	75.81	73.41
Gas	5.44	7.16	3.88	4.20	2.80	4.11		4.05	7.01	3.97
Equity-accounted entities[f]										
2012										
Liquids[d]					**79.08**		**83.85**	**10.15**		**69.41**
Gas					**2.35**		**2.35**	**5.08**		**2.52**
2011										
Liquids[d]					73.51		84.39	8.11		71.35
Gas					2.31		2.23	12.21		2.40
2010										
Liquids[d]					61.60		60.39	6.72		52.81
Gas					1.97		1.91	7.83		2.04

[a] Units of production are barrels for liquids and thousands of cubic feet for gas.

[b] Producing assets now largely divested.

[c] Realizations include transfers between businesses.

[d] Crude oil and natural gas liquids.

[e] A minor amendment has been made to 2011 realizations for UK and Europe.

[f] 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.

Average production cost per unit of production

$ per unit of production[a]

	Europe		North America		South America	Africa	Asia		Australasia	Total group average
	UK	Rest of Europe	US	Rest of North America[b]			Russia	Rest of Asia		
The average production cost per unit of production[a]										
Subsidiaries										
2012	**22.77**	**39.10**	**15.60**		**5.69**	**11.89**		**11.85**	**3.23**	**12.50**
2011	21.59	18.23	12.09		3.20	10.82		8.65	3.05	10.08
2010	12.79	9.76	8.10	15.78	2.48	7.52		4.59	2.03	6.77
Equity-accounted entities										
2012					**11.33**		**5.72**	**2.88**		**5.76**
2011					9.04		5.68	2.70		5.58
2010					6.32		5.04	2.61		4.83

[a] Units of production are barrels for liquids and thousands of cubic feet for gas. Amounts do not include ad valorem and severance taxes.
[b] Producing assets now largely divested.

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Liquidity and capital resources

Since the Gulf of Mexico oil spill in 2010 and the significant costs relating to the response activities and the initial uncertainty regarding the ultimate magnitude of its liabilities and timing of cash outflows, the group s situation has continued to stabilize. This has been reflected in the group s liquidity and capital resources position, which has continued to be strengthened as well as put on a stable footing, underpinned by a prudent financial framework.

The group s long-term credit ratings are A (positive outlook) from Standard & Poor s, strengthened from A (stable outlook) in July 2012, and A2 (stable outlook) from Moody s Investor Services.

BP renegotiated its committed bank facilities during early 2011, putting in place $6.8 billion of facilities with 23 international banking counterparties for a term of three years. In addition the group has continued to strengthen its access to commercial bank letters of credit (LC) and at the end of 2012 has in place committed LC facilities of $6.9 billion and secured LC arrangements of $2.2 billion, to supplement its uncommitted and unsecured LC lines.

The disposal programme for $38 billion has been essentially completed a year ahead of schedule, including $15 billion during 2012. Cash receipts of $11.4 billion were received in 2012, following $2.7 billion of receipts in 2011 and $17.0 billion in 2010.

In addition, we will benefit from further financial flexibility when we complete the sale of BP s 50% share in TNK-BP to Rosneft, as announced early in the fourth quarter of 2012, in return for cash and shares. Having already received $709 million in December as a dividend from TNK-BP, we expect to receive a further net $11.6 billion cash on completion, which is anticipated in the first half of 2013. At that time our shareholding in Rosneft will increase from 1.25% to 19.75%.

During 2012 BP completed the payments into the Deepwater Horizon Oil Spill Trust that have totalled $20 billion.

BP accessed US, European and Australian capital markets throughout the year with bond issuances amounting to $11 billion in 2012.

During 2012 BP repaid the remaining balance of $2.3 billion on the $4.5 billion of borrowings raised in 2010 that were backed by future crude oil sales from BP s interests in specific offshore Angola and Azerbaijan fields.

Financial framework

BP continues to refine its financial framework to support the pursuit of value growth for shareholders, while maintaining a secure financial base. BP intends to increase operating cash flow[a] by around 50% in 2014 compared with 2011[b], and thereafter maintain focus on growing sustainable free cash flows[c]. The improvement in operating cash flow to 2014 will be delivered partly from the removal of quarterly trust fund payments of $1.25 billion after completion in 2012, and partly through high-margin projects coming onstream. The growth in operating cash flow will be utilized to increase both organic reinvestment and shareholder distributions.

The financial framework remains prudent and we expect to operate within a gearing[d] range of 10-20%, and to be robust to cash break-even levels in an oil price environment between $80 and $100 per barrel. BP expects to continue to maintain a significant liquidity buffer while uncertainties remain.

[a] Operating cash flow is net cash provided by (used in) operating activities, as presented in the group cash flow statement on page 185.

[b] Adjusted to remove TNK-BP dividends from 2011 and 2014 operating cash flow; 2014 includes BP s estimate of Rosneft dividend; 2014 includes the impact of payments in respect of the settlement of all federal criminal and securities claims with the US government; BP s assumption for 2014 is $100/bbl oil, $5/mmBtu Henry Hub gas. The projection does not reflect any cash flows relating to other liabilities, contingent liabilities, settlements or contingent assets arising from the Gulf of Mexico oil spill, which may or may not arise at that time. See Financial statements Note 43 on page 253 for further information on contingent liabilities.

[c] Free cash flow is operating cash flow less net cash used in investing activities, as presented in the group cash flow statement on page 185.

[d] Gearing refers to the ratio of the group s net debt to net debt plus equity and is a non-GAAP measure. See Financial statements Note 35 on page 234 for information on gross debt, which is the nearest equivalent measure to net debt on an IFRS basis.

Dividends and other distributions to shareholders

BP aims to have a progressive dividend policy through the focus on increasing sustainable free cash flows. In addition, BP has committed to offset any dilution to earnings per share from the Rosneft transaction through either share buybacks or share consolidation.

Since BP resumed dividend payments following the suspension of dividend payments for the first three quarters of 2010 relating the Gulf of Mexico oil spill and the commitments to the Trust Fund, the dividend has been steadily increased. A quarterly dividend of 7 cents per share was paid in 2011, and increased to 8 cents per share from the first quarter 2012 to the third quarter 2012, and increased again to 9 cents per share for payment in the fourth quarter 2012.

On 5 February 2013, BP announced a dividend of 9 cents per share in respect of the fourth quarter 2012.

The total dividend paid to BP shareholders in cash in 2012 was $5.3 billion with shareholders also having the option to receive a scrip dividend, compared with $4.1 billion cash dividend paid in 2011. The dividend is determined in US dollars, the economic currency of BP.

During 2012 and 2011, the company did not repurchase any of its own shares. Details of purchases to satisfy requirements of certain employee share-based payment plans are set out on page 158.

Financing the group s activities

The group s principal commodity, oil, is 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 overall 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, such as in relation to the euro, regarding its borrowings. Also see Risk factors on pages 38-44 for further information on risks associated with the general macroeconomic outlook, including the stability of the eurozone and Financial statements Note 26 on page 220.

The group s finance debt at 31 December 2012 amounted to $48.8 billion (2011 $44.2 billion). Of the total finance debt, $10.0 billion is classified as short term at the end of 2012 (2011 $9.0 billion). The short-term balance includes $6.2 billion for amounts repayable within the next 12 months relating to long-term borrowings (2011 $4.9 billion). Commercial paper markets in the US and Europe are a further source of short-term liquidity for the group to provide timing flexibility. At 31 December 2012, outstanding commercial paper amounted to $3.0 billion (2011 $3.6 billion). Also included within short-term debt at the end of 2012 was $0.6 billion relating to deposits received for announced disposal transactions still pending legal completion post the balance sheet date (2011 $30 million).

We have in place a European Debt Issuance Programme (DIP) under which the group may raise up to $20 billion of debt for maturities of one month or longer. At 31 December 2012, the amount drawn down against the DIP was $14.0 billion (2011 $11.6 billion). The group also had in place an unlimited US shelf registration statement throughout 2012 and until 5 February 2013, under which it could raise debt with maturities of one month or longer. Following the approval in December 2012 of the SEC settlement in respect of Deepwater Horizon-related claims, the unlimited US shelf registration statement was converted to a shelf registration statement with a limit of $30 billion from 5 February 2013, with no amounts drawn down since conversion. In addition, the group has an Australian Note Issue Programme of $5 billion Australian dollars, and as at 31 December 2012 the amount drawn down was $0.5 billion Australian dollars (2011 nil).

None of the capital market bond issuances since the Gulf of Mexico oil spill contains any additional financial covenants compared with the group s capital markets issuances prior to the incident.

The maturity profile and fixed/floating rate characteristics of the group s debt are described in Financial statements Note 34 on page 233.

Net debt was $27.5 billion at the end of 2012, a reduction of $1.5 billion from the 2011 year-end position of $29.0 billion. The ratio of net debt to net debt plus equity was 18.7% at the end of 2012 (2011 20.5%). Net debt and the ratio of net debt to net debt plus equity are non-GAAP measures. We believe that 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. See Financial statements Note 35 on page 234 for gross debt, which is the nearest equivalent measure on an IFRS basis, and for further information on net debt.

Included in net debt are cash and cash equivalents of $19.5 billion at 31 December 2012 (2011 $14.1 billion). BP manages its cash position to ensure the group has adequate cover to respond to potential short-term market illiquidity, and expects to maintain a strong cash position. Cash balances are pooled centrally where permissible, and deployed globally as required. Cash surpluses are deposited with creditworthy banks and money market funds with short maturities to ensure availability. The group holds $2 billion of cash outside the UK and it is not expected that any significant tax will arise on repatriation. Further information on the management of liquidity risk and credit risk is provided in Financial statements Note 26 on page 220, and on the cash position in Financial statements Note 30 on page 226.

The group also has access to significant sources of liquidity in the form of committed bank facilities. At 31 December 2012, the group had available undrawn committed standby borrowing facilities of $6.8 billion (2011 $6.9 billion) available to draw and repay by mid-March 2014.

BP believes that, taking into account the amounts of undrawn borrowing facilities and increased levels of cash and cash equivalents, and the ongoing ability to generate cash, including further disposal proceeds, the group has sufficient working capital for foreseeable requirements.

Uncertainty remains regarding the amount and timing of future expenditures relating to the Gulf of Mexico oil spill and the implications for future activities. See Risk factors on pages 38-44, and Financial statements Note 2 on page 194, Note 36 on page 235 and Note 43 on page 253 for further information.

Off-balance sheet arrangements

At 31 December 2012, the group s share of third-party finance debt of equity-accounted entities was $6,900 million (2011 $7,003 million). 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 at 31 December 2012 are $237 million (2011 $415 million) in respect of liabilities of jointly controlled entities and associates and $713 million (2011 $1,430 million) in respect of liabilities of other third parties. Of these amounts, $166 million (2011 $220 million) of the jointly controlled entities and associates guarantees relate to borrowings and for other third-party guarantees, $543 million (2011 $1,267 million) relates to guarantees of borrowings. Details of operating lease commitments, which are not recognized on the balance sheet, are shown in the table below and in Note 14 on page 211.

Contractual commitments

The following table summarizes the group s principal contractual obligations at 31 December 2012, 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 and finance leases is given in Financial statements Note 34 on page 233 and more information on operating leases is given in Financial statements Note 14 on page 211.

							$ million
							Payments due by period
Expected payments by period under contractual obligations and commercial commitments	Total	2013	2014	2015	2016	2017	2018 and thereafter
Balance sheet obligations							
Borrowings[a]	51,676	10,232	6,607	6,482	6,481	6,135	15,739
Finance lease future minimum lease payments	604	59	54	54	53	50	334
Decommissioning liabilities[b]	20,200	767	528	442	525	647	17,291
Environmental liabilities[b]	4,029	1,524	1,093	224	215	222	751
Pensions and other post-retirement benefits[c]	26,532	1,908	1,894	1,931	1,923	1,918	16,958
Total balance sheet obligations	103,041	14,490	10,176	9,133	9,197	8,972	51,073
Off-balance sheet obligations							
Operating lease future minimum lease payments[d]	18,459	4,531	3,494	2,666	2,007	1,566	4,195
Unconditional purchase obligations[e]	190,771	109,244	17,355	11,994	8,713	7,987	35,478
Total off-balance sheet obligations	209,230	113,775	20,849	14,660	10,720	9,553	39,673
Total	312,271	128,265	31,025	23,793	19,917	18,525	90,746

[a] Expected payments include interest payments on borrowings totalling $3,894 million ($863 million in 2013, $728 million in 2014, $607 million in 2015, $485 million in 2016, $365 million in 2017 and $846 million thereafter), and exclude disposal deposits of $632 million included in current finance debt on the balance sheet.

[b] The amounts are undiscounted. Environmental liabilities include those relating to the Gulf of Mexico oil spill, including liabilities for spill response costs.

[c] 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.

[d] 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 jointly controlled asset, the amounts shown in the table represent the net future minimum lease payments, after deducting amounts reimbursed, or to be reimbursed, by joint venture partners. Where BP is not the operator of a jointly controlled asset 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.

[e] Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. 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 2013 include purchase commitments existing at 31 December 2012 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 26 on page 220.

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

$ million

Unconditional purchase obligations	Total	2013	2014	2015	2016	2017	Payments due by period 2018 and thereafter
Crude oil and oil products	117,858	80,381	7,269	5,437	3,699	3,736	17,336
Natural gas	40,614	21,708	5,800	3,311	2,394	1,714	5,687
Chemicals and other refinery feedstocks	9,054	2,196	1,470	1,235	1,013	978	2,162
Power	2,769	1,830	549	194	91	86	19
Utilities	889	183	172	114	95	74	251
Transportation	13,450	1,523	1,196	1,014	910	991	7,816
Use of facilities and services	6,137	1,423	899	689	511	408	2,207
Total	190,771	109,244	17,355	11,994	8,713	7,987	35,478

The group expects its total capital expenditure, excluding acquisitions and asset exchanges, to be around $25 billion in 2013. The following table summarizes the group s capital expenditure commitments for property, plant and equipment at 31 December 2012 and the proportion of that expenditure for which contracts have been placed. Capital expenditure is considered to be committed when the project has received the appropriate level of internal management approval. For jointly controlled assets, the net BP share is included in the amounts shown. Where operating lease costs are incurred in connection with a capital project, some or all of the cost may be capitalized as part of the capital cost of the project. Such costs are included in the amounts shown.

$ million

Capital expenditure commitments	Total	2013	2014	2015	2016	2017	2018 and thereafter
Committed on major projects	33,775	16,973	6,273	4,578	2,840	1,443	1,668
Amounts for which contracts have been placed	14,068	8,552	2,479	1,666	812	385	174

In addition, at 31 December 2012, the group had committed to capital expenditure relating to investments in equity-accounted entities amounting to $465 million. Contracts were in place for $275 million of this total. The group has also signed definitive and binding sale and purchase agreements for the sale of BP s 50% interest in TNK-BP and for BP s further investment in Rosneft as described on page 80.

Cash flow

The following table summarizes the group s cash flows.

$ million

	2012	2011	2010
Net cash provided by operating activities	**20,397**	22,154	13,616
Net cash (used in) investing activities	**(12,962)**	(26,633)	(3,960)
Net cash provided by (used in) financing activities	**(2,018)**	482	840
Currency translation differences relating to cash and cash equivalents	**64**	(492)	(279)
Increase (decrease) in cash and cash equivalents	**5,481**	(4,489)	10,217
Cash and cash equivalents at beginning of year	**14,067**	18,556	8,339
Cash and cash equivalents at end of year	**19,548**	14,067	18,556

Net cash provided by operating activities for the year ended 31 December 2012 was $20,397 million compared with $22,154 million for 2011. The cash outflow in respect of the Gulf of Mexico oil spill reduced from $6,813 million in 2011 to $2,382 million in 2012. Excluding the impacts of the Gulf of Mexico oil spill, net cash provided by operating activities was $22,779 million for 2012, compared with $28,967 million for 2011, a decrease of $6,188 million. Profit before taxation decreased by $11,269 million, of which $4,798 million related to the non-cash impacts of higher depreciation, impairments and gains and losses on disposal and lower equity-accounted earnings of jointly controlled entities and associates. A reduction in working capital requirements of $3,500 million was largely offset by lower dividends received from jointly controlled entities and associates, principally TNK-BP.

Net cash provided by operating activities for the year ended 31 December 2011 was $22,154 million compared with $13,616 million for 2010, the increase primarily reflecting a reduction in the cash outflow in respect of the Gulf of Mexico oil spill from $16,019 million in 2010 to $6,813 million in 2011. Excluding the impacts of the Gulf of Mexico oil spill, net cash provided by operating activities was $28,967 million for 2011, compared with $29,635 million for 2010, a decrease of $668 million. Profit before taxation decreased by $1,018 million, working capital requirements increased by $1,509 million and income taxes paid increased by

$1,879 million. These impacts were partially offset by a decrease of $2,622 million in the net impairment, gains and losses on sale of businesses and fixed assets, and an increase in dividends received from jointly controlled entities and associates of $2,104 million.

Net cash used in investing activities was $12,962 million in 2012, compared with $26,633 million and $3,960 million in 2011 and 2010 respectively. The decrease in cash used in 2012 reflected an absence of significant expenditure on business combinations compared with 2011 when we spent $10,909 million, mainly for the Reliance and Devon acquisitions, as well as an increase in disposal proceeds of $8,714 million. This was partially offset by an increase in capital expenditure excluding acquisitions of $5,905 million. The increase in cash used in 2011 reflected a decrease of $14,222 million in disposal proceeds, including the impact of the repayment in 2011 of a $3,530-million disposal deposit received in 2010, following the termination of the Pan American Energy LLC sale agreement, and an increase of $8,441 million in acquisitions, net of cash acquired, of which $7.0 billion was for the Reliance transaction.

Net cash used in financing activities was $2,018 million in 2012 compared with net cash provided by financing activities in 2011 and 2010 of $482 million and $840 million respectively. The increase in net cash used in 2012 primarily reflected a net decrease in short-term debt of $2,901 million and an increase in dividends paid of $1,222 million, partly offset by an increase in net proceeds from long-term financing of $1,412 million. The decrease in net cash provided in 2011 primarily reflected a decrease in net proceeds from long-term financing of $4,734 million, and an increase in dividends paid of $1,445 million partly offset by a net increase in short-term debt of $5,846 million.

The group has had significant levels of capital investment for many years. Cash flow in respect of capital investment, excluding acquisitions, was $24.7 billion in 2012, $18.8 billion in 2011 and $18.9 billion in 2010. Sources of funding are completely fungible, but the majority of the group s funding requirements for new investment come from cash generated by existing operations. The group s level of net debt, that is debt less cash and cash equivalents, was $27.5 billion at the end of 2012, $29.0 billion at the end of 2011 and $25.9 billion at the end of 2010.

During the period 2010 to 2012, our total sources of cash amounted to $88 billion, and our total uses of cash amounted to $88 billion. The increase in cash and cash equivalents held of $12 billion was financed by

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an increase in finance debt of $12 billion over the three-year period. During this period, the price of Brent crude oil has averaged $100.81 per barrel.

The following table summarizes the three-year sources and uses of cash.

	$ billion
Sources of cash:	
Net cash provided by operating activities	56
Disposals	32
	88
Uses of cash:	
Capital expenditure	62
Acquisitions	13
Net repurchase of shares	
Dividends paid to BP shareholders	12
Dividends paid to minority interests	1
	88
Net use of cash	
Increase in finance debt	12
Increase in cash and cash equivalents	12

Disposal proceeds received during the three-year period exceeded cash used for acquisitions, as a result in particular of our ongoing disposal programme started in 2010. Net investment (capital expenditure and acquisitions less disposal proceeds) during this period averaged $15 billion per year. Dividends paid to BP shareholders totalled $12 billion during the three-year period, with no ordinary share dividends being paid in respect of the first three quarters of 2010. In the past three years, $4 billion has been contributed to funded pension plans. This is reflected in net cash provided by operating activities in the table above.

Trend information

For information on external market trends, see Energy outlook on pages 12-14, Upstream on pages 63-71 and Downstream on pages 72-79.

We expect production in our Upstream segment to be lower in 2013 than 2012, mainly due to the impact of divestments, which we estimate at around 150mboe/d.

In Downstream, the financial impact of refinery turnarounds for 2013 is expected to be lower than in 2012. We expect the petrochemicals margins to remain under pressure during 2013.

In 2013, we expect the average quarterly charge, excluding non-operating items, for Other businesses and corporate to remain at around $500 million, although this will remain volatile between individual quarters.

We expect capital expenditure, excluding acquisitions and asset exchanges, to be around $24-25 billion as we invest to grow in the Upstream. From 2014 through to the end of the decade, we expect a range for organic capital expenditure of between $24 billion and $27 billion per annum.

Having essentially reached our $38-billion target of disposals since 2010, we expect to divest on average of $2-3 billion per annum on an ongoing basis.

We intend to target our net debt ratio within the 10-20% range while uncertainties remain. Net debt is a non-GAAP measure.

Depreciation, depletion and amortization in 2013 is expected to be around $0.5-1.0 billion higher than in 2012.

For 2013, the underlying effective tax rate (ETR) (which excludes non-operating items and fair value accounting effects) is expected to be in the range of 36-38% compared with 30% in 2012. The increase in the forecast rate is mainly due to a lower level of equity-accounted income in 2013, which is reported net of tax in the income statement.

Forward-looking statements

The discussion above contains forward-looking statements, particularly those regarding production in Upstream, the expected financial impact of refinery turnarounds, expectations regarding petrochemicals margins and the average quarterly charge for Other businesses and corporate, estimated levels of capital expenditure in 2013 and to the end of the decade, estimated amount of divestments, intentions regarding net debt ratio and the expected level of depreciation, depletion and amortization, and the expected level of underlying ETR. These forward-looking statements are based on assumptions that management believes to be reasonable in the light of the group s operational and financial experience. However, no assurance can be given that the forward-looking statements will be realized. You should not rely on past performance as an indicator of future performance. You are urged to read the cautionary statement on page 32 and Risk factors on pages 38-44, 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. The company provides no commitment to update the forward-looking statements or to publish financial projections for forward-looking statements in the future.

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, alternative energy and shipping activities, are conducted in many different 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.

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. These 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 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 certain 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.

Frequently, BP conducts its exploration and production activities in joint ventures or co-ownership arrangements with other international oil companies, state-owned or controlled companies and/or private companies. These joint ventures may be incorporated or unincorporated ventures, 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 venture or co-ownership. Conventionally, all costs, benefits, rights, obligations, liabilities and risks incurred in carrying out joint-venture or co-ownership operations under a lease or licence are shared among the joint-venture or co-owning parties according to these agreed ownership interests. Ownership of joint-venture or co-owned property and hydrocarbons to which the joint venture 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 venture parties or co-owners themselves, each joint venture party or co-owner will generally be liable to meet these in proportion to its ownership interest (see Financial statements Note 2 on page 194 in relation to the Gulf of Mexico oil spill). In many upstream operations, a party (known as the operator) will be appointed (pursuant to a joint operating agreement (JOA)) to carry out day-to-day operations on behalf of the joint venture or co-ownership. The operator is typically one of the joint venture 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 ventures and co-ownerships in a number of countries where we have 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 venture or the co-owning operator s organization. The relevant contract will specify the work to be done and the remuneration to be paid and typically will set out how major risks will be allocated between the joint venture or co-ownership and the service provider. Generally, the joint venture or co-owner and the contractor would respectively allocate responsibility for and provide reciprocal indemnities to each other for harm caused to 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 reservoir 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 is required to pay income tax on income generated from production activities (whether under a licence or PSAs). 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.

Environmental regulation

BP operates in more than 80 countries and is subject to a wide variety of environmental regulations concerning its products, operations and activities. Current and proposed fuel and product specifications, emission controls, climate change programmes and regulation of unconventional 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. 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. Provisions for environmental restoration and remediation are made when a clean-up is probable and the amount of BP s legal obligation can be reliably estimated. The cost of future environmental remediation obligations is often inherently difficult to estimate.

Uncertainties can include the extent of contamination, the appropriate corrective actions, technological feasibility and BP s share of liability. See Financial statements Note 36 on page 235 for the amounts provided in respect of environmental remediation and decommissioning.

A number of pending or anticipated governmental proceedings against BP and certain subsidiaries under environmental laws could result in monetary or other sanctions. We 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 such 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 on the group, such as stricter environmental laws or enforcement policies, or future events at our facilities, 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 53.

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 exploration and production, refining and marketing, transportation and shipping operations. Significant legislation and

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regulation in the US and the EU affecting our businesses and profitability includes the following:

United States

The Clean Air Act (CAA) regulates air emissions, permitting, fuel specifications and other aspects of our production, distribution and marketing activities. Stricter limits on sulphur and benzene in fuels will affect us in future, as will actions on greenhouse gas (GHG) emissions and other air pollutants. Additionally, states may have separate, stricter air emission laws in addition to the CAA.

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 renewable fuel mandates and imposing GHG emissions thresholds for certain renewable fuels. States such as California also impose additional fuel carbon standards.

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 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 the site. BP has incurred, or expects to incur, liability under the 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 the CERCLA, the Oil Pollution Act of 1990 (OPA 90) (discussed below) and other federal and state laws. CERCLA also requires hazardous substance release notification.

The Toxic Substances Control Act regulates BP s import, export and sale of new chemical products.

The Occupational Safety and Health Act imposes workplace safety and health requirements on BP operations along with significant process safety management obligations.

The Emergency Planning and Community Right-to-Know Act requires emergency planning and hazardous substance release notification as well as public disclosure of our chemical usage and emissions.

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 Marine Transportation Security Act (MTSA), the DOT Hazardous Materials (HAZMAT) and the Chemical Facility Anti-Terrorism Standard (CFATS) regulations impose security compliance regulations on around 50 BP facilities. These regulations require security vulnerability assessments, security risk mitigation plans and security upgrades, increasing our cost of operations.

OPA 90 is implemented through regulations issued by the US Environmental Protection Agency (EPA), the US Coast Guard, the DOT, the Occupational Safety and Health Administration and various states. Alaska and the west coast states currently have the most demanding state requirements although regulation in the Gulf of Mexico has increased following the 2010 Deepwater Horizon incident. There is an expectation that OPA 90 and its regulations will become more stringent in the future. The impact will likely be more rigorous preparedness requirements (the ability to respond over a longer period to larger spills), including the demonstration of that preparedness. There are expected to be additional costs associated with this increased regulation. In 2013, we expect more unannounced exercises and potential penalties for any failure to demonstrate required preparedness even without any OPA 90 amendments.

As a consequence of the Deepwater Horizon incident BP has become subject to claims under OPA 90 and other laws and have established a $20-billion trust fund for legitimate state and local government response claims, final judgments and settlement claims, legitimate state and local response costs, natural resource damages and related costs and

legitimate individual and business claims. We are also subject to Natural Resource Damages claims and numerous civil lawsuits by individuals, corporations and governmental entities. The ultimate costs for these claims cannot be determined at this time. We also expect the industry in general, and BP in particular, to become subject to greater regulation and increased operating costs in the Gulf of Mexico in the future. For further disclosures relating to the consequences of the 2010 Deepwater Horizon oil spill, see Legal proceedings on pages 162-169.

BP is in settlement discussions with EPA to resolve alleged CAA violations at the Toledo, Carson and Cherry Point refineries.

European Union

BP s operations in the EU are subject to a number of current and proposed regulatory requirements that affect or could affect our operations and profitability. These include:

The 2008 EU Climate and Energy Package, including the EU Emissions Trading System (EUETS) Directive and the Renewable Energy Directive (see Greenhouse gas regulation on page 52). In 2013, the European Commission is expected to propose a new Climate and Energy Package for the period up to 2030.

Under the third trading period Phase III which started on 1 January 2013, the EUETS has been expanded to include the petrochemical sector, free allocation is via sector benchmarking, and auctioning is the default method for allocating allowances to some sectors including electricity generation and production, though sectors at risk of carbon leakage are partially compensated with free allocation.

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 EED programme. Such measures include mandatory industrial energy efficiency surveys, and providing data on new and replacement of large plants. Such a programme may result in requirements to implement additional energy saving measures at BP s sites and/or higher power prices for BP s operations.

The EU Industrial Emissions Directive (IED) (revising and replacing the Integrated Pollution Prevention and Control Directive (IPPC)) and several other industrial directives including the Large Combustion Plant Directive (LCPD) should be transposed into national law by the EU Member states by 7 January 2013. The IED provides the framework for setting permits for major industrial sites. Relative to IPPC and LCPD, the IED imposes tighter emission standards for some large combustion plants and is more prescriptive regarding the setting of emission of limit values based on use of Best Available Techniques (BAT) in permits for other discharges to air and water. The emission limit values are informed by the sector specific and cross-sector BAT Reference documents (BREFs), which are reviewed periodically. The outcome of the review of several BREFs relevant to our major sites is expected in 2013. The IED transposition and output from the BREF revisions may result in requirements for further emission reductions at our EU sites. The LCPD imposes air quality standards requiring retrofit of flue gas desulphurization equipment, particularly for coal-fired power stations, that may force some of them to close. This is expected to impact the relative demand for natural gas and electricity prices.

The European Commission Thematic Strategy on Air Pollution and the related work on revisions to the Gothenburg Protocol and National Emissions Ceiling Directive (NECD) will establish national ceilings for emissions of a variety of air pollutants in order to achieve EU-wide health and environmental improvement targets. This may result in requirements for further emission reductions at BP s EU sites.

The implementation of the Water Framework Directive and the Environmental Quality Directive are likely to require BP to take further steps to manage water discharges from its refineries and chemical plants in the EU.

The EU Regulation on ozone depleting substances (ODS), which implements the Montreal Protocol (Protocol) on ODS was most recently revised in 2009. It requires BP to reduce the use of ODS and phase out use of certain ODS substances. BP continues to replace ODS in refrigerants and/or equipment, in the EU and elsewhere, in accordance with the Protocol and related legislation. Methyl bromide (an ODS) is a minor by-product in the production of purified terephthalic acid in our petrochemicals operations. The progressive phase-out of methyl bromide uses may result in future pressure to reduce our emissions of

methyl bromide. In addition, the European Commission recently proposed a revised regulation to phase out the use of fluorinated gases, including hydrofluorocarbons (HFCs). While targeting all HFCs, there is specific emphasis on those with a high global-warming potential. If adopted, this may have an impact on some of BP s operations.

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.

The EU Registration, Evaluation and Authorization of Chemicals (REACH) Regulation requires registration of chemical substances, manufactured in, or imported into, the EU in quantities greater than 1 tonne per annum per legal entity, together with the submission of relevant hazard and risk data. REACH affects our refining, petrochemicals, exploration and production, biofuels, lubricants and other manufacturing or trading/import operations. Having completed registration of all the substances that we were required to submit by the regulatory deadline of 1 December 2010, we are now preparing registration dossiers for substances manufactured or imported in amounts in the range 100-1,000 tonnes per annum/legal entity that are due to be submitted before 1 June 2013. Some substances registered previously in 2010, including substances that we use that are supplied to us by third parties, are now subject to thorough evaluation and/or potential authorization/restriction procedures by the European Chemicals Agency and EU Member state authorities. Legislation similar to REACH is in place in Turkey, which requires the registration of manufactured and imported chemicals.

In addition, Europe has adopted the UN Global Harmonization System for hazard classification and labelling of chemicals and products through the Classification Labelling and Packaging (CLP) Regulation. This requires BP to assess the hazards of all of our chemicals and products against new criteria and will, over time, result in significant changes to warning labels and material safety data sheets. All our European Material Safety Data Sheets will need to be updated to include both REACH and CLP information. We have already completed updates for all chemical substances we manufacture and market in the EU by the compliance deadline in 2011, and have implemented a process to maintain compliance in our European operations. We have also notified the European Chemicals Agency of hazard classifications for our manufactured and imported chemicals, for inclusion in a publicly available inventory of hazardous chemicals. CLP will also apply to mixtures (e.g. lubricants) by 2015. Activities covered by both CLP and REACH are subject to possible enforcement activity by national regulatory authorities.

In the UK, significant health and safety legislation affecting BP includes the Health and Safety at Work Act and regulations and the Control of Major Accident Hazards Regulations.

The EU Commission has proposed the adoption of a regulation on safety of offshore oil and gas prospection, exploration and production activities. While the proposal at this stage is likely to be adopted in the form of a directive rather than a regulation, it aims 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. Although the legislative process is not complete, as proposed, the legislation would not be entirely aligned with the regime currently operating in the UK and could also, if adopted, have the effect of extending liability for clean-up and compensation of environmental damage to marine waters.

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:

In US waters, OPA 90 imposes liability and spill prevention and planning requirements governing, among others, tankers, barges and offshore facilities. It also mandates a levy on imported and domestically produced oil to fund the oil spill response. 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, including the International
Convention on Civil Liability for Oil Pollution, the MARPOL Convention, 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, a new protocol, 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 (the HNS Convention). This protocol will enter into force when at least 12 states have agreed to be bound by it (four of the states must have at least 2 million gross tonnes of shipping) and contributing parties in the consenting states have received at least 40 million tonnes of contributing cargoes in the preceding year. As at 3 January 2013, 14 states had signed or acceded to the Convention subject to ratification but it had not yet entered into force.

In April 2008, the International Maritime Organization approved amendments to Annex VI of The International Convention for the Prevention of Pollution from Ships (MARPOL) to reduce the sulphur content in marine fuels. With effect from 1 January 2012 the global limit of sulphur content in marine fuels was reduced and now shall not exceed 3.50%. This global limit will be further reduced to 0.5% in 2020, provided there is enough fuel available. Annex VI also provides for stricter sulphur emission restrictions on ships in SOx Emission Control Areas (SECAs). EU ports and inland waterways and the North Sea and Baltic Sea have been covered by SECAs since 2010 imposing a sulphur content limit of 0.1%. These restrictions require the use of compliant heavy fuel oil (HFO) or distillate, or the installation of abatement technologies on ships. These restrictions are expected to place additional costs on refineries producing marine fuel, including costs to dispose of sulphur, as well as increased GHG emissions and energy costs for additional refining.

To meet its financial responsibility requirements, BP Shipping maintains marine liability pollution insurance to a maximum limit of $1 billion for each occurrence through mutual insurance associations (P&I Clubs) but there can be no assurance that a spill will necessarily be adequately covered by insurance or that liabilities will not exceed insurance recoveries.

Greenhouse gas regulation

Increasing concerns about climate change have led to a number of international climate agreements and negotiations are ongoing.

At the UN summit in Cancun in December 2010, the parties to the UN Framework Convention on Climate Change (UNFCCC) reached formal agreement on a balanced package of measures to 2020. The Cancun Agreement recognizes that deep cuts in global GHG emissions are required to hold the increase in global temperature to below 2°C. Signatories formally committed to carbon reduction targets or actions by 2020. Around 114 countries, including all the major economies and many developing countries, have made such commitments supplemented currently by an additional 27 parties that have agreed to be listed as agreeing to the accord. Supporting those efforts, principles were agreed for monitoring, verifying and reporting emissions reductions; establishment of a green fund to help developing countries limit and adapt to climate change; and measures to protect forests and transfer low-carbon technology to poorer nations. In November 2011, parties to the UNFCCC conference in Durban (COP17) agreed several measures. One was a roadmap for negotiating a legal framework by 2015 for action on climate change involving all countries by 2020, to close the ambition gap between existing GHG reduction pledges and what is required to achieve the goal of limiting global temperature rise to 2°C. Another was a second commitment period for the Kyoto Protocol, to begin immediately after the first period. An amendment was subsequently adopted at the 2012 conference of parties (COP18) in Doha establishing a second commitment period to run until the end of 2020. However, it will not include the US, Canada, Japan and Russia, thus covers only about 15% of global emissions.

Aspects of these international concerns and agreements are reflected in national and regional measures seeking to limit GHG emissions. Additional, more stringent, measures can be expected in the future. These measures can increase BP s production costs for certain products, increase demand for competing energy alternatives or products with

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lower-carbon intensity and affect the sales and specifications of many of BP s products. Current measures and developments potentially affecting BP s businesses include the following:

The European Union (EU) has agreed an overall GHG reduction target of 20% by 2020. To meet this, a Climate and Energy Package of regulatory measures has been adopted including: national reduction targets for emissions not covered by the EUETS; binding national renewable energy targets to double renewable energy in the EU including at least a 10% share of final energy in transport; a legal framework to promote carbon capture and storage (CCS); and a revised EUETS Phase 3. EUETS revisions include a GHG reduction of 21% from 2005 levels, a significant increase in allowance auctioning, an expanded scope (sectors and gases), no free allocations for electricity production but free allocations for energy-intense and trade-exposed industrial sectors. Finally, EU energy efficiency policy is currently addressed via national energy efficiency action plans and the Energy Efficiency Directive adopted in 2012.

Article 7a of the revised EU Fuel Quality Directive requires fuel suppliers to reduce the life cycle GHG emissions per unit of fuel and energy supplied in certain transport markets.

Australia has committed to reduce its GHG emissions by at least 5% below 2000 levels by 2020. In support of this, a Clean Energy legislative package of 19 bills was passed in November 2011, which includes imposing a carbon price on the top 500 emitting entities meeting the thresholds in the bill. The carbon price took effect on 1 July 2012 with a fixed price of $23 Australian dollars (indexed to forecast inflation) until 1 July 2015, an international linked price (trading) with floor and ceiling prices from 1 July 2015 through to 1 July 2018, and a market-based price (trading) forward. A certain portion of allowances will be distributed to emission intensive trade exposed businesses for no cost; this transitional support decreases with time. The majority of our Australia business emissions will be subject to the pricing scheme and will require additional expenditures for compliance.

New Zealand has agreed to cut GHG emissions by 10-20% below 1990 levels by 2020, subject to a comprehensive global agreement for emissions reductions coming into force. New Zealand s emission trading scheme (NZ ETS) commenced on 1 July 2010 for transport fuels, industrial processes and stationary energy. New Zealand also employs a portfolio of mandatory and voluntary complementary measures aimed at GHG reductions. New Zealand has announced its intention to make its next commitments for GHG reduction under the UN Framework Convention rather than the Kyoto treaty.

In the US, with the potential for passing comprehensive climate legislation remaining very unlikely, the US Environmental Protection Agency (EPA) continues to pursue regulatory measures to address GHGs under the Clean Air Act (CAA).

In late 2009, the EPA released a GHG endangerment finding to establish its authority to regulate GHG emissions under the CAA.

Subsequent to this, the EPA finalized regulations imposing light duty vehicle emissions standards for GHGs.

The EPA finalized the initial GHG mandatory reporting rule (GHGMRR) in 2009 and continues to make amendments to the rule. Reports under the GHGMRR are due annually. The majority of BP s US businesses are affected by the GHGMRR and submitted their GHG emissions reports to the EPA under the GHGMRR on or before the required deadlines. In addition to direct emissions from affected facilities, producers and importers/exporters of petroleum products, certain natural gas liquids and GHGs are required to report product volumes and notional GHG emissions as if these products were fully combusted. The EPA is expected to publically release direct and product emission early in 2013 with certain confidential business information protections.

The EPA finalized permitting requirements for new or modified large GHG emission sources in 2010, with these regulations taking effect in January 2011, the second phase taking effect on 1 July 2011 and the third phase finalized on 29 June 2012.

In a legal settlement with environmental advocacy groups the EPA committed to propose regulations under their New Source Performance Standards (NSPS) for GHG emissions from refineries by December 2011 and to finalize these by November 2012. These deadlines were not met and it is not known when or if EPA will propose regulations for refineries under their NSPS provisions.

Legal challenges to the EPA s efforts to regulate GHG emissions through the CAA continue along with active political debate with the final content and scope of GHG regulation in the US remaining uncertain.

A number of additional state and regional initiatives in the US will affect our operations. Of particular significance, California is seeking to reduce GHG emissions to 1990 levels by 2020 and to reduce the carbon intensity of transport fuel sold in the state, California implemented a low-carbon fuel standard in 2010. Although legal challenges continue, the preliminary injunction stopping implementation was lifted and implementation of the programme continues. The California cap and trade programme started in January 2012 with the first auctions of carbon allowances held in November 2012 and obligations commencing in 2013.

Canada has established an action plan to reduce emissions to 17% below 2005 levels by 2020 and the national government continues to seek a co-ordinated approach with the US on environmental and energy objectives. Additionally, Canada s highest emitting province, Alberta, has been running a market mechanism to reduce GHG since 2007. Controversy, partially driven by perceived GHG intensity regarding Canadian oil sand produced crude, continues with some jurisdictions contemplating policies to restrict or penalize its use.

China has committed to reducing carbon intensity of GDP 40-45% below 2005 levels by 2020 and increasing the share of non-fossil fuels in total energy consumption from 7.5% in 2005 to 15% by 2020. The country s 12th (2011-2015) Development Programme has set the target to reduce carbon intensity by 17% within five years, and this national target has been deconstructed into provincial ones for local actions. Meanwhile, two provinces and five cities are developing pilot schemes for emissions trading. As part of the country s energy saving programme, the government also requires any operating entity with annual energy consumption of 10 thousand tonnes of coal equivalent (7ktoe/a) to have an energy saving target for the next five years. A number of BP joint venture companies in China will be required to participate in these initiatives.

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Certain definitions

Unless the context indicates otherwise, the following terms have the meaning shown below:

Replacement cost profit

Replacement cost (RC) profit or loss reflects the replacement cost of supplies and is arrived at by excluding inventory holding gains and losses from profit or loss. 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, both RC profit or loss before interest and tax and underlying RC profit or loss before interest and tax are provided regularly to the chief operating decision maker. In such cases IFRS requires that the measure of profit disclosed for each operating segment is the measure that is closest to IFRS, which for BP is RC profit or loss before interest and tax. RC profit or loss for the group is not a recognized GAAP measure. The nearest equivalent GAAP measure is profit or loss for the year attributable to BP shareholders. BP believes that replacement cost profit before interest and taxation for the group is a useful measure for investors because it is a profitability measure used by management. A reconciliation is provided between the total of the operating segments measures of profit or loss and the group profit or loss before taxation, as required under IFRS. See Financial statements Note 6 on page 203.

Inventory holding gains and losses

Inventory holding gains and losses represent the difference between the cost of sales calculated using the average cost to BP of supplies acquired during the period 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 historic 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 if an average cost of supplies was used for the period. For this purpose, the average cost of supplies during the period is principally calculated on a monthly basis by dividing the total cost of inventory acquired in the period by the number of barrels acquired. 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.

Management believes this information is useful to illustrate to investors the fact that crude oil and product prices can vary significantly from period to period and that the impact on our reported result under IFRS can be significant. Inventory holding gains and losses vary from period to period due principally to changes in oil prices as well as changes to underlying inventory levels. In order for investors to understand the operating performance of the group excluding the impact of oil price changes on the replacement of inventories, and to make comparisons of operating performance between reporting periods, BP s management believes it is helpful to disclose this information.

Underlying replacement cost profit

Underlying RC profit or loss is RC profit or loss after adjusting for non-operating items and fair value accounting effects. Underlying RC profit or loss and fair value accounting effects are not recognized GAAP measures. On page 37 we provide additional information on the non-operating items and fair value accounting effects that are used to arrive at underlying RC profit or loss in order to enable a full understanding of the events and their financial impact.

BP believes that underlying RC profit or loss before interest and taxation is a useful measure for investors because it is a measure closely tracked by management to evaluate BP s operating performance and to make financial, strategic and operating decisions and because it may help investors to understand and evaluate, in the same manner as management, the underlying trends in BP s operational performance on a

comparable basis, year on year, by adjusting for the effects of these non-operating items and fair value accounting effects. The nearest equivalent measure on an IFRS basis for the group is profit or loss for the year attributable to BP shareholders. The nearest equivalent measure on an IFRS basis for segments is RC profit or loss before interest and taxation.

Non-GAAP information on fair value accounting effects

BP uses derivative instruments to manage the economic exposure relating to inventories above normal operating requirements of crude oil, natural gas and petroleum products. Under IFRS, these inventories are recorded at historic cost. The related derivative instruments, however, are required to be recorded at fair value with gains and losses recognized in income because hedge accounting is either not permitted or not followed, principally due to the impracticality of effectiveness testing requirements. Therefore, measurement differences in relation to recognition of gains and losses occur. Gains and losses on these inventories are not recognized until the commodity is sold in a subsequent accounting period. Gains and losses on the related derivative commodity contracts are recognized in the income statement from the time the derivative commodity contract is entered into on a fair value basis using forward prices consistent with the contract maturity.

BP enters into commodity contracts to meet certain business requirements, such as the purchase of crude for a refinery or the sale of BP s gas production. Under IFRS these contracts are treated as derivatives and are required to be fair valued when they are managed as part of a larger portfolio of similar transactions. Gains and losses arising are recognized in the income statement from the time the derivative commodity contract is entered into.

IFRS requires that inventory held for trading be recorded at its fair value using period end spot prices whereas any related derivative commodity instruments are required to be recorded at values based on forward prices consistent with the contract maturity. Depending on market conditions, these forward prices can be either higher or lower than spot prices resulting in measurement differences.

BP enters into contracts for pipelines and storage capacity, oil and gas processing and liquefied natural gas (LNG) that, under IFRS, are recorded on an accruals basis. These contracts are risk-managed using a variety of derivative instruments, which are fair valued under IFRS. This results in measurement differences in relation to recognition of gains and losses.

The way that BP manages the economic exposures described above, and measures performance internally, differs from the way these activities are measured under IFRS. BP calculates this difference for consolidated entities by comparing the IFRS result with management s internal measure of performance. Under management s internal measure of performance the inventory, capacity, oil and gas processing and LNG contracts in question are valued based on fair value using relevant forward prices prevailing at the end of the period and the commodity contracts for business requirements are accounted for on an accruals basis. We believe that disclosing management s estimate of this difference provides useful information for investors because it enables investors to see the economic effect of these activities as a whole. The impacts of fair value accounting effects, relative to management s internal measure of performance and a reconciliation to GAAP information is shown on page 37.

Commodity trading contracts

BP s Upstream and Downstream segments both participate in regional and global commodity trading markets in order to manage, transact and hedge the crude oil, refined products and natural gas that the group either produces or consumes in its manufacturing operations. These physical trading activities, together with associated incremental trading opportunities, are discussed further in Upstream on page 71 and in Downstream on page 77. The range of contracts the group enters into in its commodity trading operations is as follows.

Exchange-traded commodity derivatives

These contracts are typically in the form of futures and options traded on a recognized exchange, such as Nymex, SGX and ICE. Such contracts are traded in standard specifications for the main marker crude oils, such as Brent and West Texas Intermediate, the main product grades, such as gasoline and gasoil, and for natural gas and power. Gains and losses, otherwise referred to as variation margins, are settled on a daily basis with the relevant exchange. These contracts are used for the trading and risk management of crude oil, refined products, natural gas and power. Realized and unrealized gains and losses on exchange-traded commodity derivatives are included in sales and other operating revenues for accounting purposes.

Over-the-counter contracts

These contracts are typically in the form of forwards, swaps and options. Some of these contracts are traded bilaterally between counterparties; others may be cleared by a central clearing counterparty. These contracts can be used both for trading and risk management activities. Realized and unrealized gains and losses on over-the-counter (OTC) contracts are included in sales and other operating revenues for accounting purposes.

The main grades of crude oil bought and sold forward using standard contracts are West Texas Intermediate and a standard North Sea crude blend (Brent, Forties and Oseberg or BFO). Although the contracts specify physical delivery terms for each crude blend, a significant number are not settled physically. The contracts typically contain standard delivery, pricing and settlement terms. Additionally, the BFO contract specifies a standard volume and tolerance given that the physically settled transactions are delivered by cargo.

Gas and power OTC markets are highly developed in North America and the UK, where the commodities can be bought and sold for delivery in future periods. These contracts are negotiated between two parties to purchase and sell gas and power at a specified price, with delivery and settlement at a future date. Typically, these contracts specify delivery terms for the underlying commodity. Certain of these transactions are not settled physically, which can be achieved by transacting offsetting sale or purchase contracts for the same location and delivery period that are offset during the scheduling of delivery or dispatch. The contracts contain standard terms such as delivery point, pricing mechanism, settlement terms and specification of the commodity. Typically, volume and price are the main variable terms.

Swaps are often contractual obligations to exchange cash flows between two parties: a typical swap transaction usually references a floating price and a fixed price with the net difference of the cash flows being settled. Options give the holder the right, but not the obligation, to buy or sell crude, oil products, natural gas or power at a specified price on or before a specific future date. Amounts under these derivative financial instruments are settled at expiry. Typically, netting agreements are used to limit credit exposure and support liquidity.

Spot and term contracts

Spot contracts are contracts to purchase or sell a commodity at the market price prevailing on or around the delivery date when title to the inventory is taken. Term contracts are contracts to purchase or sell a commodity at regular intervals over an agreed term. Though spot and term contracts may have a standard form, there is no offsetting mechanism in place. These transactions result in physical delivery with operational and price risk. Spot and term contracts typically relate to purchases of crude for a refinery, purchases of products for marketing, purchases of third-party natural gas, sales of the group s oil production, sales of the group s oil products and sales of the group s gas production to third parties. For accounting purposes, spot and term sales are included in sales and other operating revenues, when title passes. Similarly, spot and term purchases are included in purchases for accounting purposes.

Associate

An entity, including an unincorporated entity such as a partnership, over which the group has significant influence and that is neither a subsidiary nor a joint venture. Significant influence is the power to participate in the financial and operating policy decisions of an entity but is not control or joint control over those policies.

Joint control

Joint control is the contractually agreed sharing of control over an economic activity, and exists only when the strategic financial and operating decisions relating to the activity require the unanimous consent of the parties sharing control (the venturers).

Joint venture

A contractual arrangement whereby two or more parties undertake an economic activity that is subject to joint control.

Jointly controlled asset

A joint venture where the venturers jointly control, and often have a direct ownership interest in the assets of the venture. The assets are used to obtain benefits for the venturers. Each venturer may take a share of the output from the assets and each bears an agreed share of the expenses incurred.

Jointly controlled entity

A joint venture that involves the establishment of a corporation, partnership or other entity in which each venturer has an interest. A contractual arrangement between the venturers establishes joint control over the economic activity of the entity.

Subsidiary

An entity that is controlled by the BP group. Control is the power to govern the financial and operating policies of an entity so as to obtain the benefits from its activities.

PSA

A production-sharing agreement (PSA) is an arrangement through which an oil company bears the risks and costs of exploration, development and production. In return, if exploration is successful, the oil company receives entitlement to variable physical volumes of hydrocarbons, representing recovery of the costs incurred and a stipulated share of the production remaining after such cost recovery.

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Governance overview

In my letter to shareholders at the front of this report, I stated that the BP board is well balanced, with a broad range of skills and deep experience in our industry. The governance report which follows describes the work of this board and its committees over the past year. Here I give my own view of the journey that the BP board has taken from April 2010 to the present day.

Board evolution

In this period, the board has seen substantial change amongst both the executive and non-executive directors. Eight out of the eleven non-executives have served four years or less. The intense work undertaken from 2010 has unified and strengthened the board. The team has stuck resolutely to its tasks, and has worked together effectively to address a number of tough challenges.

Board goals

The board has three goals for BP: to operate safely, to earn people s trust, and to create sustainable value for shareholders. The pursuit of these goals has been the foundation of our work and will continue to be so for years to come.

For some time the board has governed within a clear set of robust principles and believes that good governance involves the clarity of roles and responsibilities and the utilization of distinct skills and processes. This has enabled us to carry out the fundamental tasks of strategy development and performance monitoring and oversight, while also responding to the challenges which arose from the Gulf of Mexico accident and wider business events.

We evaluate our performance and effectiveness as a board each year. But we continue to review and improve what we are doing, and how we are doing it, as we move forward. It is important that the board evolves so it can best support the company as it changes. Our work during the year to support the fundamental reorganization of the company is one example of this approach in action.

Inevitably, much of our work is focused on determining the company s approach to risk. Over the past three years we have reviewed our governance and management of risk, and we have monitored and assessed the group s evolution of its systems. One of the key tasks of the board is to review particular group-level risks; this review forms the basis of the board s annual forward agenda.

Board committees

The Gulf of Mexico committee, formed in August 2010, has done much of the heavy lifting in terms of the board s oversight of the Gulf response and litigation. The work of this committee has been intense but invaluable in drawing together the many strands of activity in the US. This has enabled the board to focus on its other roles, including strategy and oversight of the group s operations.

When the board decided to pursue the sale of BP s interest in TNK-BP, it was clear that this would be a complex and concentrated process. Based on the successful experience with the Gulf of Mexico committee, we formed an ad hoc committee to advise and have oversight of the work of executive management during the transaction. Antony

Burgmans, our longest serving non-executive director, chaired this committee. The committee has proved its value in terms of monitoring and consultation. The transaction is due to complete in the first half of 2013.

Board meetings and board skills

Our governance processes are designed to ensure that the board can carry out all of its tasks effectively. Pressing matters have inevitably taken an increased proportion of the board s time over the past three years. We have met much more often than we would normally. Events have meant that our meetings have sometimes had to take place at short notice. The attendance at these meetings is a reflection of the very strong commitment of the directors to your company. The response of all the directors has been excellent.

I believe the board is benefiting significantly from the balance of skills and experience that I mentioned earlier. Here is an outline of the main areas of expertise of our current board:

Director	Key skills and experience
Paul Anderson	Oil and gas industry experience
Admiral Frank Bowman	Safety, technology and risk management
Antony Burgmans	Food and consumer goods; leading a global business
Cynthia Carroll	Oil, gas and extractive industry experience; leading a global business
Carl-Henric Svanberg	Manufacturing and telecoms; leading a global business
George David	Technology and manufacturing
Ian Davis	Strategy, advisory and consulting
Brendan Nelson	Audit, financial services and trading
Phuthuma Nhleko	Civil engineering, telecoms and banking
Andrew Shilston	Oil and gas industry experience; finance
Professor Dame Ann Dowling	Engineering, technology and education

Board support

BP is a global company and there are many challenges for the board to address. One of the features of our system of governance is the independent advice and support that the board receives from our company secretarial team. Each committee has a dedicated secretary, and this has assisted greatly in the organization of work.

During the year BP has benefited from the insight and expertise of our international advisory board a group of distinguished individuals with deep knowledge of geopolitical issues and whose counsel has been invaluable.

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Looking forward

2012 was a year of progress for BP. Some uncertainties remain, but there is a clear direction towards 2014 and beyond. We have a strong team around the board table. We understand the challenges we face. And we are clear that the company must continue to make good progress on achieving its three goals, not least sustainable value for our shareholders. Finally, I would like to take this opportunity to thank my fellow board members for all that they have done in the year.

Carl-Henric Svanberg

Chairman

- In 2009, BP formed an international advisory board (IAB) whose purpose is to advise the chairman, group chief executive and the board on geopolitical and strategic issues relating to the company.
- This group has an advisory role and meets twice a year although its members are on hand to provide advice and counsel to the company when needed.
- The IAB is chaired by BP s previous chairman, Peter Sutherland.
- Its membership in 2012 included Kofi Annan, Lord Patten of Barnes, Josh Bolten, President Romano Prodi, Dr Ernesto Zedillo and Dr Javier Solana.
- The chairman and chief executive attend meetings of the IAB.
- Issues discussed during the year included events in the Middle East, the eurozone crisis, Russia and the US presidential election.

BP governance framework

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Board of directors

As at 6 March 2013

1	Carl-Henric Svanberg	2	Bob Dudley	3	Iain Conn	4	Dr Brian Gilvary
5	Dr Byron Grote	6	Paul Anderson	7	Admiral Frank Bowman KBE	8	Antony Burgmans
9	Cynthia Carroll	10	George David	11	Ian Davis	12	Professor Dame Ann Dowling
13	Brendan Nelson	14	Phuthuma Nhleko	15	Andrew Shilston		

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Board of directors

Carl-Henric Svanberg

Current position

Carl-Henric Svanberg is BP s chairman. He was appointed a non-executive director of BP on 1 September 2009 and became chairman on 1 January 2010.

Board and committee activities

He chairs the chairman s and the nomination committees and attends the Gulf of Mexico and the remuneration committees.

Outside interests

Carl-Henric Svanberg is chairman of AB Volvo.

Career

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 31 December 2009, when he left to join BP, 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 on 4 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.

Relevant experience and skills

Carl-Henric Svanberg s career in international business, latterly as chief executive officer of Ericsson, is particularly relevant to BP globally. During the year, in addition to leading the board, he has contributed to the work of the Gulf of Mexico and the remuneration committees and has chaired the nomination committee. He has focused on succession within the executive team and amongst the non-executive directors. He has developed a well-balanced board that has contributed to BP s strategy and delivery of shareholder value.

Bob Dudley

Current position and group responsibilities

Bob Dudley is BP s group chief executive. He was appointed an executive director of BP on 6 April 2009.

Outside interests

Bob Dudley has no external appointments.

Career

He 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 23 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 became group chief executive on 1 October 2010.

Relevant experience and skills

Bob Dudley has spent his entire career in the oil and gas industry. His broad range of roles with Amoco and BP have given him substantial global experience. This has been supplemented by his time as chief executive officer of TNK-BP. He has performed strongly as BP s chief executive officer since his appointment in 2010.

Paul Anderson

Current position

Paul Anderson was appointed a non-executive director of BP on 1 February 2010.

Board and committee activities

He is chairman of the safety, ethics and environment assurance committee (SEEAC) and is a member of the chairman s, the Gulf of Mexico and the nomination committees.

Outside interests

Paul Anderson is a non-executive director of BAE Systems PLC.

Career

He 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 on 31 January 2010. Previously he served as a non-executive director on a number of boards in the US and Australia and as chief executive officer of Pan Energy Corp.

Relevant experience and skills

Paul Anderson took the chair of the SEEAC in December 2012. As chair he has continued the committee s focus on safety matters both in meetings and through visits to the company s operations. His broad experience of the global oil and gas industry and of the US business environment has benefited both the board, the SEEAC and the Gulf of Mexico committee. He has actively supported the work of the BP Massachusetts Institute of Technology (MIT) academy. This global perspective has also enabled him to guide the work of the ad-hoc Russia committee.

Admiral Frank Bowman

Current position

Frank Bowman was appointed a non-executive director of BP on 8 November 2010.

Board and committee activities

He is a member of the SEEAC and the chairman s and the Gulf of Mexico committees.

Outside interests

Frank Bowman is president of Strategic Decisions, LLC and a director of Morgan Stanley Mutual Funds, the American Shipbuilding Suppliers Association, and the Naval and Nuclear Technologies, LLP.

Career

He joined the United States Navy in 1966. During his naval service, he commanded the nuclear submarine *USS City of Corpus Christi* and the *USS Holland.* He served as a flag officer; as the Navy s chief of personnel; on the joint staff as director of Political-Military Affairs; and as director of the naval nuclear propulsion programme in the Department of the Navy and the Department of Energy for over eight years.

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 was appointed Honorary Knight Commander of the British Empire in 2005 by Queen Elizabeth II. He was also elected to the US National Academy of Engineering in 2009.

Relevant experience and skills

Frank Bowman has a deep knowledge of engineering coupled with exceptional experience in safety arising from his time with the US Navy and, later, the Nuclear Energy Institute. His service on the BP Independent Safety Review Panel gave him direct experience of BP s safety aims and requirements, particularly in the area of refining. He makes a significant contribution to the work of the SEEAC and the Gulf of Mexico committee. He has actively supported the work of the BP MIT academy.

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Antony Burgmans KBE

Current position

Antony Burgmans was appointed a non-executive director of BP on 5 February 2004.

Board and committee activities

He is chairman of the remuneration committee and is a member of the SEEAC and the chairman s and the nomination committees.

Outside interests

Antony Burgmans is a member of the supervisory boards of Akzo Nobel N.V., AEGON N.V. and SHV Holdings N.V., and chairman of the supervisory board of TNT Express.

Career

He joined Unilever in 1972, holding a succession of marketing and sales posts, including, from 1988 until 1991, the chairmanship of PT Unilever Indonesia.

In 1991, he was appointed to the board of Unilever, becoming business group president, ice cream and frozen foods, Europe in 1994, and chairman of Unilever s Europe committee, co-ordinating its European activities. In 1998, he became vice chairman of Unilever NV and in 1999, chairman of Unilever NV and vice chairman of Unilever PLC. In 2005, he became non-executive chairman of Unilever NV and Unilever PLC until his retirement in 2007.

Relevant experience and skills

Antony Burgmans executive career was in international production, distribution and marketing. Over the years he has made a significant contribution to the work of the board, adding insight to the areas of reputation, brand and culture. His global perspective has particular value as chairman of the remuneration committee and also contributes to his work on the SEEAC. During the year he has led on internal board matters in support of the senior independent director. His tenure and independent approach, demonstrated over many years in his work on SEEAC and the nomination and remuneration committees, led the board to ask him to chair the ad-hoc committee of the board dealing with issues relating to the sale of BP s share in TNK-BP. His clarity of thought and his approach in evaluating the events of the last few years has led the board to conclude that he is still independent even though he has now served just over nine years as a director. His continued independence, together with his experience of the BP board and the need for an orderly board succession, means that the board has asked him to remain as a member of the BP board for a further period of three years.

Cynthia Carroll

Current position

Cynthia Carroll was appointed a non-executive director of BP on 6 June 2007.

Board and committee activities

She is a member of the SEEAC and the chairman s and the nomination committees.

Outside interests

Cynthia Carroll is currently chief executive of Anglo American plc, the global mining group, chairman of Anglo Platinum Limited and chairman of De Beers s.a. She will relinquish these roles on 3 April 2013 and will step down as a director of Anglo American, Anglo Platinum and De Beers at Anglo American s AGM in April 2013.

Career

She started her career with Amoco as a petroleum geologist in oil exploration. In 1989, she joined Alcan Inc, where she spent 18 years before joining Anglo American in January 2007. Starting in the business development group of the Rolled Products Division in Alcan, she became president and chief executive officer of the Primary Metal Group, responsible for operations in more than 20 countries. She has been chief executive of Anglo American plc since March 2007.

Relevant experience and skills

Cynthia Carroll s leadership of global businesses, particularly in the extractive industry sector has enabled her to make a strong contribution to the work of the BP board and the SEEAC. Her geo-political experience has been valuable during the course of the year as has her work on the nomination committee.

Iain Conn

Current position

Iain Conn is BP s chief executive, Refining and Marketing. He was appointed an executive director of BP on 1 July 2004.

Group responsibilities

In addition to his position as chief executive, Refining and Marketing, he has regional responsibility for Europe, Southern Africa and Asia. He also has responsibility for the BP brand and related matters.

Outside interests

Iain Conn is a non-executive director and the senior independent director of Rolls-Royce Holdings plc. He is chairman of the Advisory Board of Imperial College Business School and a member of the Council of Imperial College.

Career

He joined BP Oil International in 1986, working in a variety of roles in oil trading, commercial refining and exploration before becoming, on the merger between BP and Amoco in 1999, vice president of BP Amoco Exploration s mid-continent business unit.

At the end of 2000, he returned to London as group vice president and a member of the Refining and Marketing segment s executive committee, taking over responsibility in 2001 for BP s marketing operations in Europe. In 2002 he was appointed chief executive of BP Petrochemicals. Following his appointment to the board in 2004, he served for three years as group executive officer, strategic resources, in which he had responsibility for a number of group functions and regions. He was appointed chief executive, Refining and Marketing on 1 June 2007.

Relevant experience and skills

Iain Conn s career has given him extensive knowledge of a broad range of BP s businesses, particularly in the area of refining and marketing, which he has led since 2007. In this last period he has successfully remodelled BP s downstream business. He has deep knowledge of safety, manufacturing, energy markets and technology.

George David

Current position

George David was appointed a non-executive director of BP on 11 February 2008.

Board and committee activities

He is a member of the chairman s, the audit, the Gulf of Mexico and the remuneration committees.

Outside interests

George David is vice-chairman of the Peterson Institute for International Economics.

Career

He began his career with The Boston Consulting Group before joining the Otis Elevator Company in 1975. He held various roles in Otis and later in United Technologies Corporation (UTC), following Otis s merger with UTC in 1976. In 1992, he became UTC s chief operating officer. He served as UTC s chief executive officer from 1994 until 2008 and as chairman from 1997 until his retirement in 2009.

Relevant experience and skills

George David has substantial global business and financial experience through his long career with UTC, a business with significant reliance on safety and technology. He chairs BP s technology advisory council and has brought insights from that task to the board.

His considerable knowledge of the US business environment benefits considerably the work of the Gulf of Mexico committee of which he is a member and his extensive financial and commercial knowledge contributes to the work of the audit and the remuneration committees.

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Ian Davis

Current position

Ian Davis was appointed a non-executive director of BP on 2 April 2010.

Board and committee activities

He is chairman of the Gulf of Mexico committee and is a member of the chairman s, the nomination and the remuneration committees.

Outside interests

Ian Davis is an independent non-executive director of Johnson & Johnson, Inc. and a senior adviser to Apax Partners LLP. He is also a non-executive member of the UK s Cabinet Office. He joined the Board of Rolls Royce Plc on 1 March 2013 and will become chairman on 2 May 2013.

Career

He spent his early career at Bowater, moving to McKinsey & Company in 1979. He was managing partner of McKinsey s practice in the UK and Ireland from 1996 to 2003. In 2003, he was appointed as chairman and worldwide managing director of McKinsey, serving in this capacity until 2009. During his career with McKinsey, he served as a consultant to a range of global organizations across the private, public and not-for-profit sectors. He retired as senior partner of McKinsey & Company on 30 July 2010.

Relevant experience and skills

Ian Davis brings significant financial and strategic experience to the board. He has had a lengthy career working with and advising global organizations and companies in the oil and gas industry. This experience has been recognized by the board in his appointments as a member of a broad range of committees and as chairman of the Gulf of Mexico committee.

As chairman of the Gulf of Mexico committee he has made a significant contribution in guiding the board s response to the various legal issues which have arisen following the Deepwater Horizon accident. During the year he stood down from the audit committee to allow him to focus his time with the Gulf of Mexico committee; he has remained a member of the remuneration committee.

Professor Dame Ann Dowling

Current position

Professor Dame Ann Dowling was appointed a non-executive director of BP on 3 February 2012.

Board and committee activities

She is a member of the SEEAC and the chairman s and the remuneration committees.

Outside interests

Dame Ann Dowling is Professor of Mechanical Engineering and Head of the Department of Engineering at the University of Cambridge. She is chair of the Physical Sciences, Engineering and Mathematics Panel in the Research Excellence Framework the UK Government s review of research in universities.

Career

She was appointed a Professor of Mechanical Engineering in the Department of Engineering at the University of Cambridge in 1993 (the Department of Engineering is one of the leading centres for engineering research worldwide). Between 1999 and 2000 she was the Jerome C Hunsaker Visiting Professor at MIT subsequently becoming a Moore distinguished scholar at Caltech in 2001. When she returned to the University of Cambridge, she became head of the Division of Energy, Fluid Mechanics and Turbomachinery in the Department of Engineering, becoming UK lead of the Silent Aircraft Initiative in 2003, a collaboration between researchers at Cambridge and MIT. She became head of the Department of Engineering at the University of Cambridge in 2009. She was appointed director of the University Gas Turbine Partnership with Rolls-Royce in 2001 and chairman in 2009.

Between 2003 and 2008 she chaired the Rolls-Royce Propulsion and Power Systems Advisory Board. She chaired the Royal Society/Royal Academy of Engineering study on nanotechnology. She is a Fellow of the Royal Society and the Royal Academy of Engineering and is a foreign associate of the US National Academy of Engineering and of the French Academy of Sciences.

Relevant experience and skills

Dame Ann Dowling has a strong academic and engineering background.

Having initially joined the SEEAC, she is now also a member of the remuneration committee. Her contributions on both of these committees is valued as is her work with the BP technology advisory council, which she joined during the year.

Dr Brian Gilvary

Current position

Dr Brian Gilvary is BP s chief financial officer. He was appointed an executive director on 1 January 2012.

Group responsibilities

He has responsibility for BP s finance, planning, mergers and acquisitions, treasury and information technology activities.

Outside interests

Dr Brian Gilvary has no external appointments.

Career

He joined BP in 1986, after obtaining a PhD in mathematics from the University of Manchester. Following a variety of roles in the Upstream, Downstream and trading with jobs spanning across Europe and the US, he became the Downstream s chief financial officer and commercial director from 2002 to 2005.

In 2003 he was appointed a director of TNK-BP, retiring from the board in 2005 and re-joining in 2010. From 2005 to 2010 he was chief executive of integrated supply and trading, BP s commodity trading arm. In 2010 he was appointed deputy group chief financial officer with responsibility for the finance function before being appointed chief financial officer on 1 January 2012.

Relevant experience and skills

Dr Brian Gilvary has 27 years of experience within BP, gaining a strong knowledge of finance and trading, and a deep understanding of BP s assets and businesses, including its interests in Russia through his time on the board of TNK-BP.

Dr Byron Grote

Current position

Dr Byron Grote is BP s executive vice president, corporate business activities. He was appointed an executive director of BP on 3 August 2000.

He will retire from the BP board at the conclusion of the 2013 AGM.

Group responsibilities

On 1 January 2012, he became executive vice president, corporate business activities. He has accountability for BP s integrated supply and trading operations and shipping businesses, Alternative Energy business, and its technology and remediation activities.

Outside interests

Dr Byron Grote is a non-executive director of Unilever NV and Unilever PLC.

Career

He joined The Standard Oil Company of Ohio in 1979. Following a variety of roles, he became group treasurer and chief executive officer of BP finance in 1992. In 1994, he took up the position of regional chief executive in Latin America, returning to London in 1995 to become deputy chief executive officer of BP exploration. He became group chief of staff in 1997 and, following the merger of BP and Amoco, in 1999 he was appointed executive vice president, exploration and production. Following his appointment to the board in 2000, he served for two years as chief executive of BP chemicals. He was chief financial officer from 2002 until the end of 2011.

Relevant experience and skills

Dr Byron Grote has served on the board for 12 years. Throughout his tenure at BP, Byron has played a key role at critical moments of the company s history, most notably in the integrations of Amoco and Arco, and more recently in guiding BP through the financial challenges following the incidents in April 2010.

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Brendan Nelson

Current position

Brendan Nelson was appointed a non-executive director of BP on 8 November 2010.

Board and committee activities

He is chairman of the audit committee and is a member of the chairman s and nomination committees.

Outside interests

Brendan Nelson is a non-executive director of The Royal Bank of Scotland Group plc where he is chairman of the group audit committee. He is a director of the Financial Skills Partnership and is deputy president of the Institute of Chartered Accountants of Scotland.

Career

He 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 2000 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 six years as a member of the Financial Services Practitioner Panel.

Relevant experience and skills

Brendan Nelson has had a long career in finance and auditing, particularly in the areas of financial services and trading, which qualifies him to chair the audit committee and to act as its financial expert.

This is complemented by his broader business experience. During the year he has led the work of the audit committee in continuing to strengthen the company s financial framework and has monitored the group s relationship with the external auditors. In 2012 he joined the nomination committee.

Phuthuma Nhleko

Current position

Phuthuma Nhleko was appointed a non-executive director of BP on 1 February 2011.

Board and committee activities

He is a member of the chairman s and the audit committees.

Outside interests

Phuthuma Nhleko is a non-executive director of Anglo American plc.

Career

He began his career as a civil engineer in the US and as a project manager for infrastructure developments in Southern Africa. Following this he became a senior executive of the Standard Corporate and Merchant Bank in South Africa. He later held a succession of directorships before joining MTN Group, a pan-African and Middle Eastern telephony group represented in 21 countries, as group president and chief executive officer in 2002. During his tenure at the MTN Group he led a number of substantial mergers and acquisitions transactions. He stepped down as group chief executive of MTN Group at the end of March 2011. He was formerly a director of a number of listed South African companies, including Johnnic Holdings (previously a subsidiary of the Anglo American group of companies), Nedbank Group, Bidvest Group and Alexander Forbes.

Relevant experience and skills

Phuthuma Nhleko s background in engineering and his broad experience as a chief executive of a multi-national company enables him to contribute to the board, particularly in the areas of emerging market economies and the evolution of the group s strategy. His financial and commercial experience is relevant to his work on the audit committee.

Andrew Shilston

Current position

Andrew Shilston was appointed a non-executive director of BP on 1 January 2012 and became BP s senior independent director on 12 April 2012.

Board and committee activities

He is a member of the chairman s and the audit committees and attends the nomination committee.

Outside interests

Andrew Shilston is a non-executive director of Circle Holdings plc and chairman of the Morgan Crucible Company plc.

Career

He trained as a chartered accountant before joining BP as a management accountant. He subsequently joined Abbott Laboratories before moving to Enterprise Oil plc in 1984 at the time of flotation. In 1989 he became treasurer of Enterprise Oil and was appointed finance director in 1993. After the sale of Enterprise Oil to Shell in 2002, in 2003 he became finance director of Rolls-Royce plc until his retirement on 31 December 2011.

He has served as a non-executive director on the board of Cairn Energy plc where he chaired the audit committee.

Relevant experience and skills

Andrew Shilston has had a long career in finance within the oil and gas industry. His knowledge and experience as a chief financial officer, firstly in Enterprise Oil and then Rolls-Royce, and as audit committee chairman at Cairn Energy makes him well suited as a member of BP s audit committee. He has also provided valuable insight to the work of the Russia committee. As senior independent director he has attended meetings of the nomination committee.

David Jackson

Current position

David Jackson was appointed company secretary in 2003. A solicitor, he is a director of BP Pension Trustees Limited.

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Executive team

As at 6 March 2013

The executive team represents the principal executive leadership of the BP group. Its membership includes BP s executive directors (Bob Dudley, Iain Conn, Dr Brian Gilvary and Dr Byron Grote) whose biographies appear on pages 105-108) and the senior management listed below.

Mark Bly

Current position

Mark Bly is BP s special advisor to the group chief executive.

Career

Mark Bly joined BP in 1984. From 1986 to 1996, he worked on various engineering and commercial leadership assignments in Houston, a period when BP was establishing itself in the Deepwater Gulf of Mexico. Following which he held business unit leader posts in Alaska and the North Sea as well as strategic performance unit leader for North American Gas. In 2007 he became group vice president, exploration and production (Gulf of Mexico, Trinidad, Angola, North Africa and Egypt) and a member of the exploration and production operating committee.

In 2008 he became group head of safety and operations, with accountability for group level disciplines including projects, operations, engineering, health, safety, security, and environment. In that capacity, he looked after group wide operating management system implementation, capability programs, and audit.

In October 2010 Mark was appointed executive vice president of safety and operational risk. He stepped down from this role on 15 February 2013 and from the BP executive team at this date.

Rupert Bondy

Current position

Rupert Bondy is BP s group general counsel.

Group responsibilities

Rupert Bondy is responsible for legal and compliance matters across the BP group.

Career

Rupert Bondy began his career as a lawyer in private practice, with a focus on mergers and acquisitions. In 1989 he joined US law firm Morrison & Foerster, working in San Francisco, London and New York, and from 1994 he worked for UK law firm Lovells in London. In 1995 he joined SmithKline Beecham as senior counsel for mergers and acquisitions and other corporate matters. He subsequently held positions of increasing responsibility and following the merger of SmithKline Beecham and GlaxoWellcome to form GlaxoSmithKline (GSK) he was appointed senior vice president and general counsel of GlaxoSmithKline in 2001.

In May 2008 he joined the BP group, where he is the group general counsel.

Dr Mike Daly

Current position

Dr Mike Daly is BP s executive vice president, exploration.

Group responsibilities

Dr Mike Daly is accountable for the leadership of BP s access, exploration and resource appraisal activities and the long-term replacement of BP s resource base.

Career

Dr Daly joined BP Exploration in 1986, working as a technical specialist in structural geology. In the early 1990 s he joined BP s global basin analysis group that set the direction of BP s exploration strategy. This work has underpinned BP s exploration and reserves replacement performance for two decades. Following this strategic work he has occupied a series of exploration business and functional roles in South America, the North Sea and new business development globally.

In 2000 he became the president for BP s Middle East and South Asia businesses. In July 2006, Dr Daly was appointed BP s Head of Exploration and New Business Development and in October 2010 was appointed executive vice president, exploration.

External roles

Dr Daly is a member of the board of British Geological Survey and a visiting professor in natural resources at Oxford University. He is also a member of the Arctic Council of the World Economic Forum.

Bob Fryar

Current position

Bob Fryar is BP s executive vice president, safety and operational risk.

Group responsibilities

Bob is responsible for strengthening safety, operational risk management, and the systematic management of operations across the BP corporate group. He is Group Head of Safety and Operations, with accountability for group-level disciplines including projects, operations, engineering, health, safety, security, and environment. In this capacity, he looks after group-wide operating management, system implementation, capability programs and audit.

Career

Bob Fryar has 27 years experience in the oil and gas industry having joined Amoco Production Company in 1985. Most recently Bob was chief executive officer for BP Angola and in his prior role vice president of operations performance unit for BP Trinidad.

Prior to joining BP Trinidad in January 2003, Bob served in a variety of engineering and management positions in the onshore US and deepwater Gulf of Mexico including petroleum engineer, field manager, operations manager, resource manager, asset manager and delivery manager. In addition, he worked on the Vastar integration team.

In October 2010 to February 2013 Bob Fryar was executive vice president production division and was accountable for safe and compliant exploration and production operations and stewardship of resources across all regions. In addition, he was also responsible for local government and stakeholder management, integration of all exploration and production activities at the regional level, technical excellence across safety and operational risk and subsurface, and a robust operating management system to ensure safety, quality and compliance of production activities.

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Andy Hopwood

Current position

Andy Hopwood is BP s chief operating officer, strategy and regions, Upstream.

Group responsibilities

Andy Hopwood is responsible for BP s upstream strategy, including changes to its portfolio and investment planning. He is also responsible for the upstream regional footprint through leadership of its regional presidents, who are the upstream s senior leaders in the regions where the upstream operates.

Career

After joining BP in 1980 as a petroleum engineer, Andy Hopwood gained ten years of operating experience in the North Sea, Wytch Farm, and Indonesia, and developing expertise in reservoir engineering in BP s London headquarters.

In 1989 Andy joined the corporate planning team supporting the formulation of BP s exploration strategy. He also played an integral role in executing the subsequent rationalization of BP s portfolio, divesting BP s Canadian and Egyptian assets.

Following this corporate work, his international endeavours led to positions in South America, first in Mexico and then as commercial manager for BP s Venezuela business, prior to a return to London as the exploration and production planning manager.

In 1999, he was appointed business unit leader in Azerbaijan. He returned to London in 2001 as the Upstream chief of staff, before becoming business unit leader in Trinidad. In 2005 he moved to Houston to become strategic performance unit leader for the North American gas business.

In 2009, he joined the upstream executive as head of portfolio and technology and in October 2010 he was appointed executive vice president, exploration and production, strategy and integration. In 2013 he was appointed chief operating officer, strategy and regions, Upstream.

External roles

Andy serves as chair of the BP Foundation.

Bernard Looney

Current position

Bernard Looney is BP s chief operating officer, production.

Group responsibilities

Bernard Looney is responsible for production operations, well operations, supply-chain management and engineering in the upstream.

Career

Bernard Looney joined BP in 1991 as a drilling engineer, working in the North Sea, Vietnam and the Gulf of Mexico. In 2001 Bernard took on responsibility for drilling operations on Thunder Horse in the Deepwater Gulf of Mexico.

In 2005 Bernard became senior vice president within BP Alaska, before moving in 2007 to be head of the group chief executive s office.

In 2009 he became the managing director of BP s North Sea business in the UK and Norway.

Bernard became executive vice president, developments, in October 2010. He took up his current role in February 2013.

External roles

Bernard is a member of the Stanford University Graduate School of Business Advisory Council and a Fellow of the Energy Institute.

Lamar McKay

Current position

Lamar McKay is BP s chief executive, Upstream.

Group responsibilities

Lamar McKay is responsible for the combined Upstream business which consists of exploration, development and production.

Career

Lamar McKay started his career in 1980 with Amoco and has held a broad range of positions. In 1993, he became general manager for the Arkoma Basin, and in 1997 moved into the role of business unit leader for the Gulf of Mexico Shelf.

During 1998-2000, he worked on the BP-Amoco merger and served as head of strategy and planning for the worldwide exploration and production business in London. In 2000, he became business unit leader for the Central North Sea in Aberdeen, Scotland. In 2001, Lamar became chief of staff for the worldwide exploration and production business, and subsequently served as chief of staff to BP s deputy group chief executive.

Lamar became group vice president, Russia and Kazakhstan in 2003 where he was responsible for BP s Upstream businesses, including BP s interest in the TNK-BP joint venture. He served as a member of the board of directors of TNK-BP from February 2004 to May 2007.

In May 2007, Lamar moved to Houston to assume the role of senior group vice president, BP p.l.c. and executive vice president, BP America where he led BP s efforts to resolve various issues involving the Texas City refinery, Prudhoe Bay field and US trading business. In June 2008, he became executive vice president, special projects focusing on Russia where he led BP s efforts to restructure the governance framework for TNK-BP.

In February 2009, Lamar was appointed chairman and president of BP America Inc, serving as BP s chief representative in the US. In October 2010, he additionally assumed the role of chief executive officer and president for the Gulf Coast Restoration Organization.

On 1 January 2013, he became chief executive, Upstream.

External roles

Lamar is a member of the American Petroleum Institute s Executive Committee, the MIT s External Advisory Board; the University of Houston President s Energy Advisory Board; and the Mississippi State University Dean s Advisory Council.

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Dev Sanyal

Current position

Dev Sanyal is BP s executive vice president, and group chief of staff.

Group responsibilities

Dev Sanyal is the accountable executive for all of BP s corporate activities in central programme management, government and political affairs, policy, group risk management, economics and competitor intelligence.

Career

Dev Sanyal joined BP in 1989 and has held a variety of international roles in London, Athens, Istanbul, Vienna and Dubai. He was appointed chief executive, BP Eastern Mediterranean Fuels in 1999. In 2002, he moved to London as chief of staff of BP s worldwide downstream businesses. In November 2003, he was appointed chief executive officer of Air BP. In June 2006, he 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 accountable for the group s aluminium interests. In January 2012, he became executive vice president, and group chief of staff.

External roles

Dev is a member of the Accenture Global Energy Board, the European Advisory Board of The Fletcher School of Law and Diplomacy and Trustee of the Career Academy Foundation.

Helmut Schuster

Current position

Helmut Schuster is BP s executive vice president, group human resources director.

Group responsibilities

Helmut Schuster became group human resources director on 1 March 2011. In this role he holds accountabilities for the BP human resources function.

Career

Helmut Schuster began his career working for Henkel in a marketing capacity. Since joining BP in 1989 Helmut has held a number of major 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 a vice president, human resources included the refining and marketing segment of BP, and corporate and functions. This role saw him leading the people agenda for roughly 60,000 people across the globe and includes businesses such as petrochemicals, fuels value chains, lubricants and functional experts across the corporation.

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How the board works

BP s governance framework

BP s system of governance begins with the board and is reflected in the governance of our subsidiaries. The governance framework is outlined in the BP board governance principles which sets out the role of the board, its processes and its relationship with executive management. These can be found on *bp.com/governance*.

g	The active consideration of long-term strategy.
g	The monitoring of executive action and the performance of BP.
g	Obtaining assurance that the material risks to BP are identified and that systems of risk management and control are in place to mitigate such risks.
g	Ongoing board and executive management succession planning.

The board seeks to set the tone from the top for the organization by considering specific issues, including health, safety, the environment and BP s reputation and works with management to set the values of the company, which are then reflected in more detail in the company s code of conduct.

Who s on the board?

As at 31 December 2012 the board had 15 directors a chairman, four executive directors and 10 non-executive directors (see page 104).

The nomination committee keeps the composition of the board under review from the perspective of the mix of skills and experience of existing members and the likely tenure of each director. Details of the current skillset of the board and the skills/competencies that the nomination committee has prioritized for future non-executive director appointments is outlined in the report of the nomination committee on pages 125-126.

Role of the chairman

The board is chaired by Carl-Henric Svanberg. The chairman provides leadership of the board and is the main point of contact between the board and management. The chairman speaks on behalf of the board to shareholders and other parties and ensures that systems are in place to provide directors with accurate, timely and clear information to enable the board to consider matters before it and is also responsible for the integrity and effectiveness of the BP board governance principles.

Role of the group chief executive

Bob Dudley is the group chief executive. Through delegation from the board he is responsible for executive management of the group and is supported by the executive team, which he chairs. Membership of the executive team is set out on pages 109-111.

Role of the senior independent director

The senior independent director (SID) is Andrew Shilston, who is available to shareholders if they have concerns that cannot be addressed through normal channels.

In view of the relatively short service of Andrew Shilston, Antony Burgmans, the longest serving non-executive director acts as an internal sounding board for the chairman and serves as intermediary for the other directors with the chairman when necessary.

Neither the chairman nor the SID are employed as executives of the group. The board maintains a succession plan for the chairman and SID, in addition to the group chief executive and senior management.

Director independence

The governance principles require the non-executive directors to be independent in character and judgement and free from any business or other relationship which could materially interfere with the exercise of their judgement. The board has determined that those non-executive directors who served during 2012 were and continued to be independent.

The board also satisfied itself that there is no compromise to the independence of, or existence of conflicts of interest for those directors who serve together as directors on the boards of outside entities or who have other appointments in outside entities. These issues are considered on a regular basis at each board meeting. The nomination committee keeps under review the nature of non-executive directors other interests to ensure that the effectiveness of the board is not compromised.

Succession: board and committee membership

The following changes took place to the composition of the board in 2012:

Dr Brian Gilvary joined the board as an executive director and chief financial officer on 1 January 2012.

Andrew Shilston joined the board as a non-executive director on 1 January 2012, and became senior independent director from April 2012.

Professor Dame Ann Dowling joined the board as a non-executive director on 3 February 2012.

Sir William Castell retired from the board at the AGM in April 2012.

Dr Byron Grote, executive director with responsibility for BP s integrated supply and trading operations, Alternative Energy, shipping, technology and remediation activities will retire from the board at the AGM in April 2013.

Changes to committee membership during 2012 included Ian Davis stepping down as a member of the audit committee on 3 February 2012 and Admiral Frank Bowman joining the Gulf of Mexico committee on the same date. Upon their appointment to the board, Andrew Shilston joined the audit committee and Professor Dame Ann Dowling joined the safety, ethics and environment assurance committee (SEEAC). Professor Dowling later joined the remuneration committee on 25 July 2012. Following the retirement of Sir William Castell in April, Brendan Nelson and Paul Anderson joined the nomination committee. Andrew Shilston, who succeeded Sir William as senior independent director, attends the committee in this capacity.

Ad-hoc board committee Russia

An ad-hoc board committee was established in June 2012 to oversee issues relating to the sale of BP s share in TNK-BP. This committee, known as the Russia committee, is chaired by Antony Burgmans and membership includes Andrew Shilston and Paul Anderson. Carl-Henric Svanberg and Bob Dudley attend the committee meetings. The committee received regular and detailed reports on the process for the sale of the company s stake in TNK-BP and supported the proposal to the board of the binding sale and purchase agreements that were eventually executed with Rosneft. The committee will continue to receive updates through to closing of the agreements with Rosneft (currently anticipated to occur in the first half of 2013).

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Appointment and tenure

The chairman and our non-executive directors (NEDs) serve on the basis of letters of appointment. Letters of appointment (and service contracts for our executive directors) are available for inspection at the registered office of the company. BP does not place a term limit on director s service as it proposes all directors for annual re-election by shareholders (a practice followed since 2004).

Antony Burgmans joined the board in February 2004 and by the 2013 AGM will have served nine years as a director. The board has asked him to stay on for an additional three years as it believes that his experience as the longest serving board director provides valuable insight and continuity.

The board considers that he remains independent despite his length of tenure in view of his clarity of thought, his approach in evaluating events of the last few years and the interaction he has demonstrated in his work on the SEEAC, the nomination and remuneration committees and his chairmanship of the ad-hoc board committee on Russia.

Time commitment and outside appointments

Letters of appointment for non-executive directors do not set out a fixed time commitment for board duties as it is anticipated that the time required by directors may fluctuate depending on demands of the business and other events. It is however expected that directors will allocate sufficient time to the company to perform their duties effectively. This practice was reviewed and confirmed by the nomination committee in 2012. The chairman s appointment letter sets out the time commitment expected of him.

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 127).

Diversity

BP recognizes the importance of diversity, including gender, at all levels of the company as well as the board. The company is committed to increasing diversity across its operations and has in place a wide range of activities to support the development and promotion of talented individuals, including women.

In 2011 the board confirmed its support for the work of Lord Davies and his report on Women on Boards and aimed to increase the number of women on the board by two by 2013 and aspired to reach his recommendation of 25% female board representation by 2015. In 2012, the chairman joined the 30% Club (a group of chairman who have voluntarily committed to bring more women onto UK corporate boards).

In 2012, the nomination committee agreed metrics to monitor the board s diversity mix and implementation of the board s diversity policy. These metrics include the gender split and geographic background of the BP board and are shown below. The board also considered diversity as part of the annual evaluation of its performance and effectiveness.

The work of the BP board in 2012

The board meets in person or by teleconference. Nine meetings were scheduled for 2012, but additional board meetings were called principally to discuss legal issues in the US and the sale of BP s share in TNK-BP, meaning the board met 19 times during the year, with nine of these meetings taking place by telephone. These telephone meetings were by their nature called at short notice and directors who were unable to attend (often due to travel commitments) were briefed separately outside the meeting. For director attendance at board and committee meetings, see the table on page 120.

The board s agenda for the year has focused on key areas of strategy, assurance, risk and reputation.

Board activities

Strategy

The evolution and development of the group s strategy was discussed at each of the regular meetings of the board during the year. These discussions were held against the background of the steps being taken to resolve uncertainties in the US and Russia. More detailed discussions on long-term strategic options were held at two strategy away-days in 2012. Key strategic elements examined included North American gas, Russia, technology and biofuels in Brazil. The board also reviewed the company s planning methodology and strategy development process, looking at energy market structures, long-term price ranges and the assumptions used for BP s investment evaluations.

Assurance

The board received regular updates during the year on legal issues, in particular on litigation and enquiries resulting from events in the Gulf of Mexico. It examined the delivery of major projects and the effectiveness of investment and received a review of BP s integrated supply and trading business.

The board assessed the effectiveness of the group s system of internal controls and risk management and reviewed its financial performance. It received an update on the progress of BP s change management programme, implemented at the end of 2010, and reviewed the work of the central programme management office established to ensure there is an integrated, company-wide approach to the change programme and to minimize disruption in the businesses. The board also received a report from Duane Wilson, the independent expert appointed by the board to provide an objective assessment of BP s progress in implementing the recommendations of the BP US Refineries Independent Review Panel.

Risk

The board and its monitoring committees (audit, SEEAC and Gulf of Mexico) monitored the group risks which had been allocated following the board s review of the annual plan at the end of 2011. The annual plan and the group strategy are central to BP s risk management programme as they provide a framework for the board to consider significant risks and manage the group s overall risk exposure as well as underpin the model of delegation and assurance for the board in its oversight of executive management and other activities.

The group risks allocated to and reviewed by the board over the year included risks associated with the global macroeconomic outlook, the delivery of BP s 10-point plan, the group s exposure to Russia, crisis management, reputational impact and organizational capability. The board held a mid-year discussion to consider any changes required to the allocation of group risks and to confirm the schedule for oversight and governance of these risks by the board and its committees.

Reputation

The board discussed the risks relating to the reputation of the group globally, but in particular relating to the US, and also the processes the company has in place to manage these risks. The result of an external reputation survey was considered, which examined BP s reputation in key markets, including the UK and US. From an internal perspective, feedback from the regular, global survey of employees was examined following the launch of BP s renewed values and updated code of conduct at the end of 2011.

In addition to understanding feedback from external focus groups and employees, the board received regular reports which outlined shareholder sentiment on the company. This includes analyst reports, the annual investor audit, feedback from shareholders on voting on the company s resolutions at the AGM and follow-up discussions post investor roadshows and other one-to-one shareholder meetings (see shareholder engagement on page 116).

Board effectiveness

Induction and board learning

On joining BP, non-executive directors are given a tailored induction programme. This includes one-to-one meetings with management, the external auditors and site visits to operations. The induction will also cover the board committees that a director will join. During the year induction programmes were organized for Andrew Shilston and Professor Dame Ann Dowling. An example of the induction programme given to recently appointed non-executive directors is set out below.

Board and governance

BP s board governance model, directors duties, interests and potential conflicts.

Committee induction.

BP s business

Upstream (exploration, development, production, overview of our operations).

Downstream.

Alternative Energy.

Strategy and planning.

BP s performance relative to its competitors.

Functional input

Finance and tax.

Controls, external auditors and internal audit.

Human resources.

Ethics and compliance.

Safety and operational risk (S&OR), BP s operating management system (OMS) and environmental performance.

Research and technology.

Engineering.

Trading.

The board s learning is continued through board and committee briefings and site visits. In 2012, the board received briefings on key aspects of BP s activities, including the competitive context for the company and BP s projections for energy supply and demand. At the board meeting in Houston, non-executive directors were given the opportunity to meet BP s wider US leadership group at informal lunch and dinner events. In the autumn, the board met leading US political figures in advance of the US presidential elections.

Non-executive directors are expected to attend at least one site visit per year. During 2012 the board made a number of visits, including to BP s Texas paraxylene site, fracking operations in East Texas, the Thunderhorse platform in the Gulf of Mexico and the Buncefield terminal in the UK. The chairman visited the Deepwater Gunashli platform and Sangachal terminal in Azerbaijan, the Kinneil terminal in the North Sea and the Greater Plutonio floating production, storage and offloading facility in Angola. He also held employee town halls and met with regional leadership teams whilst visiting BP s offices in Azerbaijan, Tokyo, the North Sea and Angola.

After each site visit, the board or appropriate committee is briefed on the impressions gained by directors attending the visit.

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Board evaluation

BP undertakes an annual review of the board, its committees and individual directors. The chairman s own performance is evaluated by the chairman s committee (led by Antony Burgmans in consultation with the senior independent director).

For the past three years an external review of the board s performance has been undertaken, and for 2012 the board undertook an evaluation facilitated by external legal counsel on the basis of a questionnaire, which tested key areas of the board s work including strategy, monitoring, risk and governance processes. The evaluation also considered the balance of skills, experience, independence and knowledge of the company on the board, its diversity (including gender), how the board works together as a unit and other factors relevant to its effectiveness. The results of the review were discussed at the board and individually at each committee in January 2013.

Key conclusions from the evaluation

The review concluded that there had been significant progress in dealing with major strategic issues over the year and there had been a continued improvement in board processes, particularly in the areas of time management and board materials.

Going forward, it was agreed that the emphasis on improving board processes would continue and that as the group transitioned to a more stable business environment, the board would focus on re-aligning its agenda to increase the focus on strategic issues. There would also be more use of forward agenda planning to enable this to be realised.

Tracking issues from our previous evaluation

In 2012, the board progressed recommendations of the 2011 board evaluation. The board continued to track the risk management review and the implementation of enhancements to the company s risk management system. Emphasis was given to key governance processes raised by the 2011 evaluation, with board and committee papers adopting a common template and risk matrices in board materials using a consistent methodology aligned with the group s risk management reports. There was also increased focus on financial and non-financial metrics used by the board and this will continue into 2013.

A further outcome of the last evaluation was the wish to move back to a steady state of operation. However, developments during the year led to an increase in the scheduled number of board meetings from 11 to 19; the board will again endeavour to find this equilibrium over the course of 2013.

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Shareholder engagement

The company operates an active programme of investor dialogue, including regular investor meetings, which provides an opportunity to communicate with shareholders and analysts and to understand their views on the company s performance and strategy. The board receives feedback on investor views through results of the investor audit and reports from management and directors who have had shareholder interaction over the year.

Shareholder engagement cycle 2012

January	g	*BP 2030 Energy Outlook* presentation
February	g	4Q results and strategy presentation
	g	Investor roadshows with executive management
March	g	UKSA private shareholder meeting
	g	Chairman and committee chairs meeting
	g	SRI roadshow on *BP Sustainability Review*
	g	Plaintiff s Steering Committee settlement investor call
April	g	Annual General Meeting
May	g	1Q results
June	g	Launch of *BP Statistical Review of World Energy*
July	g	2Q results
September	g	Oil and gas conferences
October	g	Group SRI meeting
	g	Engagement on remuneration
November	g	3Q results and investor update
	g	Oil sands webinar
	g	DoJ resolution investor call
December	g	Upstream investor day

Institutional investors

Executive directors and senior management regularly meet with institutional investors through roadshow, group and one-to-one meetings. Events for socially responsible investors (SRI) are held throughout the year, including a group meeting which discussed managing safety and operational risk in BP, people capability, managing potential risk in wells and the company s progress on the Bly Report recommendations. Whilst held in the UK, this meeting was webcast for US and overseas investors.

During the year the chairman, senior independent director and chairs of the SEEA and remuneration committees held one-to-one meetings with institutional investors to discuss strategy, the board s view on the company s performance, governance, operational practices and the group s remuneration structure. An annual investor event was held in March 2012 with the chairman and chairs of the board committees. This meeting enables BP s largest shareholders to discuss the work of the board and its committees, and for non-executive directors to engage in dialogue with investors. It is intended that a similar event is held in March 2013.

Materials from investor presentations, including information on the work of the board and its committees can be downloaded at *bp.com/investors*.

Private investors

An event for private investors was held in 2012, organized in conjunction with the UK Shareholders Association (UKSA). A group of 40 private shareholders listened to presentations from the chairman and head of investor relations on BP s annual results, strategy and the work of the board. The event enabled shareholders to ask questions on the company s activities and for the company to receive direct private shareholder feedback. The event will be repeated in 2013.

BP s lost shareholder programme was continued over the year. This returns shares and unclaimed dividends to shareholders who have failed to keep their contact details up to date. The amount of unclaimed dividends reunited in 2012 was approximately £750,000.

AGM

BP s shareholder base is geographically diverse and a webcast and an advance electronic and paper voting service is offered to make the meeting accessible to those who cannot attend in person.

The voting levels for the 2012 AGM saw an increase over the previous year to 63.2% (versus 60.6% in 2011). A webcast, speeches and presentations from the AGM are available on *bp.com/agm* after the meeting, together with the outcome of voting on each resolution. At the 2012 AGM all resolutions were passed with votes ranging from 88.2%-99.8% . As in previous years, the board received a report after the AGM giving a breakdown of the vote and feedback from large shareholders on their voting decisions for the meeting.

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Risk in BP

Risk management is the foundation for reinforcing safety, building trust and growing value. In 2012 BP continued to review, refresh and enhance its management of risk.

The role of the board

One of the key tasks of the board is to satisfy itself that the material risks to BP are identified and understood and that systems of risk management, compliance and control are in place to mitigate such risks. The board requires the group chief executive to operate with a comprehensive system of controls and internal audit to identify and manage the risks that are material to BP.

Board governance includes monitoring committees comprised of those directors best suited to serve on them, including the audit; the safety, ethics and environment assurance; and the Gulf of Mexico committees.

The role of executive management

The group chief executive maintains BP s system of internal control. The system of internal control comprises the holistic set of management systems, organizational structures, processes, standards and behaviours that are employed to conduct the business of BP. The system is designed to meet the expectations of internal control of the Corporate Governance Code in the UK and of the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in the US.

Key elements of the system include: BP s set of corporate values, behaviours and code of conduct; group strategic framework, including risk management; how the company is organized and managed; and how we verify that the system is working. BP s risk management system is an integral part of its system of internal control, and is designed to be a simple, consistent and clear framework for managing and reporting all risk from the group s operations to the board.

Executive committees are established by the group chief executive to assist him in discharging his board delegations. Their role includes setting policy, making decisions and overseeing the management of risks and performance. The executive committees are: executive team meeting (ETM); group operations risk committee (GORC); group financial risk committee (GFRC); group disclosure committee (GDC); group people committee (GPC); resource commitments meeting (RCM); and group ethics and compliance committee (GECC).

Review of risk management

In 2012, the review to enhance the clarity, consistency and simplicity of BP s risk management system was completed.

We have embedded common language, concepts and templates for consistent reporting on risks and risk management; enhancements to board and executive processes; and greater alignment of risk management activities and business processes. These improvements build from BP s existing management systems, standards and practices.

A group risk team, effective 1 January 2013, has been established to hold a view of the group risk profile to inform key businesses processes and decisions; co-ordinate group risk reporting activities; and maintain the group risk management system.

Risk management structures

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BP s risk management system

BP s risk management system focuses on three levels of activity:

Day-to-day risk management the system helps facilitate day-to-day risk management in the group s operations and functions, with the approach varying according to the types of risk faced. Risks are to be identified and managed, and actions to improve the management of risk are to be put in place where necessary. The aim is to address each different type of risk as well as we can promoting safe, compliant and reliable operations.

Business and strategic risk management for BP s businesses and functions, risks arising are to be collated periodically, risk management activities are to be assessed, and any necessary further improvements or actions are to be planned. The system is designed to facilitate this by incorporating a standardized form called the risk management report (RMR), for businesses and functions to report consistently the risks they face for management consideration, challenge, resource allocation and intervention. This enables the integration of risk into key business processes such as strategy, planning, performance management, resource allocation and project appraisal.

Board, executive and functional oversight the system facilitates executive and board oversight and governance over the management of significant risks. It requires executive team level involvement in the finalization of risk management activities and improvement plans for the group s most significant individual risks. Using the consistent bottom-up risk identification and assessment process, coupled with top-down executive overview, the system requires that the most significant risks requiring oversight are identified. Oversight of the management of these risks is to be provided through regular review by the board or one of its committees.

Risk management: from operations to the board

BP s risk management system assists in:

Understanding the risk environment for input into the strategy.

Understanding which risk types we operate with, given the strategy.

Identifying and assessing the specific risks and the potential exposure they may represent.

Decision-making on how best to deal with those risks to manage overall potential exposure.

Active management of identified risks.

Reporting to management and the board about how those risks are managed, and monitoring of potential exposure.

Obtaining assurance over the effectiveness of the management of those risks.

Intervening for improvements in the management of those risks where necessary.

Considering the effect of the external environment and business activities on the principal activities of BP s risk management system.

The willingness to take and appropriately manage certain risk is fundamental to the success of any commercial enterprise. For example, in our upstream business we consciously place significant amounts of capital at risk in exploring for new hydrocarbon resources. Where this exploration is successful, we would generally expect it to lead to future increases in our proved reserves and future cash flows. However, exploration expenditure may not yield adequate returns, for example in the case of unproductive wells or discoveries that prove uneconomic to develop.

Risk management and reporting in 2012

During 2012, BP s segments, strategic performance units and functions prepared RMRs. The most significant risks were organized into common categories strategic risks, safety and operational risks and compliance and controls risks so they could be assessed and reported up the line in the standardized form. This helped provide an overall data set of the key risks identified, an assessment of their potential impact and likelihood on a consistent basis, information on how they were being managed and any actions planned or in progress to improve the management of risk. Based on these RMRs, together with additional executive overview, a single group RMR has been prepared. Those risks identified on the group RMR requiring particular group-level oversight in the coming year are allocated to specific board and executive committees for oversight and monitoring. These are discussed below. Also see Risk factors on pages 38-44 for a description of the material risks we face in our business.

Executive and board oversight of risk

The executive and board examine particular group risks both on a periodic basis and as part of the development and review of the annual plan. The board also conducts an annual review of the risk management and internal control systems as required by the UK Corporate Governance Code. During the year there is flexibility to change which risks have been identified as requiring particular oversight and which have been allocated to the executive or board, in the event there are any changes to the internal or external environments or events arising.

The executive committees monitor the group risks in the following areas:

ETM for strategic and commercial risks.

GORC for health, safety, security and environment and operations integrity risks.

GFRC for finance and trading risks.

GDC for financial reporting risk.

GPC for people risks.

RCM for risks related to investment decisions.

GECC for ethics and compliance risks.

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Following review of the 2013 annual plan, the following risks have been allocated for review by the board and its committees:

The board has been allocated several strategic and commercial group risks, including risks associated with the global economic climate, the delivery of BP s 10-point plan, our activities in Russia and reputation management.

The audit committee has been allocated a number of strategic and commercial and compliance and control risks, including risks associated with treasury and trading activities, compliance with applicable laws and regulations and security threats against our digital infrastructure.

The SEEAC has been allocated several safety and operational risks, including risks associated with conducting our operations through joint ventures where BP may not have full operational control. Other safety and operational risks the committee has been allocated include the health, safety, security and environmental risks of incidents associated with the drilling of wells, operation of facilities, pipelines and marine activity.

The Gulf of Mexico committee has been allocated a number of strategic and commercial risks, including risks associated with the extent and timing of costs and liabilities relating to the accident and compliance with plea agreements.

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Committee reports

Board and committee attendance

	Board		Audit committee		SEEAC		Remuneration committee		Gulf of Mexico committee		Nomination committee	
	a	b	a	b	a	b	a	b	a	b	a	b
irectors												
aberg	19	19									4[c]	4
	19	19			6[c]	6			23	19	2	2
owman	19	19			6	6			19	18		
ns	19	17			6	6	5[c]	5			4	4
	19	15			6	4					4	3
ell	3	2			2	2			12	10	1	1
	19	19	11	11			5	5	23	22		
	19	18	1	1			5	5	23[c]	23	4	4
Ann Dowling	18	18			5	5	3	3				
	19	18	11[c]	11							2	2
o	19	17	11	10								
	18	15	10	8								
tors												
	19	19										
	19	18										
	19	18										
	19	19										

a = Total number of meetings the director was eligible to attend.

b = Total number of meetings the director did attend.

c = Committee chairman.

The attendance of certain directors was adversely affected by changes to BP s rhythm of board meetings, resulting in clashes with directors other executive board commitments.

Audit committee

Chairman s introduction

During the year the committee has maintained focus on the review and challenge of BP s financial assessment of its responsibilities arising from the Deepwater Horizon accident. We have continued to operate a delineated model between the board s three monitoring committees of audit, SEEA and Gulf of Mexico and have found our respective areas of oversight to be effective in informing the board s view as to the nature of the uncertainties facing the company and context for ongoing litigation and enquiries.

In addition to this focus, the committee has ensured that the cycle of its normal agenda is maintained. During the year we have reviewed the areas

of group-level risk allocated to the committee for oversight, namely trading and treasury, cyber security and compliance with laws and business regulations (including bribery and corruption, money laundering, competition and anti-trust and international trade regulations). We have also undertaken reviews on key aspects of BP s financial reporting processes, including the assumptions and methodology regarding provisions for litigation, environmental remediation and decommissioning. Other activities in 2012 have included monitoring major project delivery and effectiveness of investment and tracking the progress of implementing BP s finance warehouse programme.

The committee places value on discussing issues directly with management and operational leadership, as well as seeing first-hand the group s risk and control processes in practice. During the year, I have attended visits to the company s fracking operations, a paraxylene manufacturing facility in Texas and the Buncefield terminal in the UK.

In a challenging economic and political climate for business, the committee s work and the company s audit, assurance and compliance frameworks have enabled BP to maintain the integrity of the group s financial and internal controls and the identification and mitigation of risk in response to these uncertainties. The committee has an excellent mix of skills and expertise in commercial, audit and financial matters and is well prepared to face the forthcoming year.

Brendan Nelson

Committee chair

Brendan Nelson committee chair

George David

Ian Davis (retired from the committee on 3 February 2012)

Phuthuma Nhleko

Andrew Shilston (joined the committee 3 February 2012)

The audit committee is composed of independent, non-executive directors selected to provide a wide range of financial, international and commercial expertise appropriate to fulfil the committee s duties.

Brendan Nelson is chair of the audit committee. Formerly vice chairman of KPMG, he is chairman of the group audit committee of The Royal Bank of Scotland Group plc, deputy president of the Institute of Chartered

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Accountants of Scotland and a director of the Financial Skills Partnership. The board is satisfied that Brendan Nelson is the audit committee member with recent and relevant financial experience as outlined in the UK Corporate Governance Code. 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. 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 Nelson may be regarded as an audit committee financial expert as defined in Item 16A of Form 20-F.

Committee role and structure

The role and responsibilities of the audit committee are set out in the appendix of BP s board governance principles which is available at *bp.com/governance*. This includes responsibility for reviewing the effectiveness of the group s financial reporting, internal control policies and procedures for the identification, assessment and reporting of risk. The committee also monitors the integrity of the group s disclosure documents, keeps the relationship with the external auditors under review (including the policy on non-audit services) and monitors the effectiveness of the internal audit function.

The committee met 11 times in 2012 including three joint meetings with the SEEAC. The chairs and secretaries of the audit and SEEA committees have worked together to ensure their respective agendas neither duplicate nor omit coverage of key risk areas.

Each audit committee meeting is attended by the group chief financial officer, the group controller, the general auditor (head of internal audit) and the chief accounting officer. The lead partner of our external auditors is also present.

The committee also holds separate private sessions during the year with the external auditor, the general auditor and the group ethics and compliance officer. These sessions are held without the presence of executive management.

Committee processes

Information and advice

Information and reports for the committee are received from functional and business managers and from external sources. Like our board and other committees, the audit committee can access independent advice and counsel when needed on an unrestricted basis. During 2012, external specialist legal advice in relation to corporate reporting was provided to the committee by Sullivan & Cromwell LLP. As part of its annual evaluation, the committee reviews the adequacy of reliable and timely information from management that enables it to fulfil its responsibilities.

Training and induction

The committee received technical updates from the chief accounting officer on developments in financial reporting and accounting policy. In addition, the external auditors provided their survey on global trends in fraud and a briefing on regulatory developments impacting audit committees as a learning session.

Induction programmes are provided for new members and are tailored around their roles on the audit committee. During 2012 Andrew Shilston attended induction sessions on tax, trading operations, accounting, financial reporting and controls and the structure of BP s finance function. Individual private sessions with the external and internal auditors were also provided.

2012 committee activities

Gulf of Mexico

Whilst the Gulf of Mexico committee has considered the work of the Gulf Coast Restoration Organization (GCRO) and litigation matters, and the SEEAC has reviewed the company s implementation of the recommendations of the Bly Report, the audit committee s focus has been on financial reporting and controls. The committee has reviewed each quarter the provisions and contingencies related to the accident and their disclosure.

Financial reporting

The group s quarterly financial reports, the *BP Annual Report and Form 20-F* and the *BP Summary Review* were reviewed by the committee before recommending their publication to the board. The committee discussed with management how they had applied critical accounting

policies and judgements to these documents, including key assumptions regarding provisions for litigation, environmental remediation and decommissioning. The committee held a deep review of the impairment testing process, methodology and the pricing assumptions that were utilized. In considering the robustness of the valuations, the committee referred to analysis undertaken by the external auditors. The committee also reviewed the company s methodology underpinning its disclosures relating to oil and gas reserves.

Monitoring business risk

The board periodically reviews the company s group risks and allocates monitoring of their management and/or mitigation to itself or its committees. The group risks allocated to the audit committee for 2012 included risks associated with treasury and trading, digital security and compliance with business regulations. For 2013, the board has agreed that the committee will maintain monitoring of these same group risks.

During the year, the committee undertook functional reviews of information technology and services, integrated supply and trading and the governance of major project investment. It examined the recommendations from an external review of controls in the North American gas and power trading business and tracked the progress of their close-out over the year. The committee also reviewed the lessons learned from the company s investment programme to upgrade the Whiting refinery.

Reports on the work of the group financial risk committee the executive-level committee that provides assurance on the management of BP s financial risk were provided during the year by the chief financial officer.

Internal control, audit and risk management

The forward agenda for the audit committee contains standing items on internal control these include quarterly reports of internal audit findings, internal control deficiencies in financial reporting, and an annual assessment of BP s enterprise level controls.

The committee holds an annual joint meeting at the start of each year with the SEEAC to review the company s risk management and internal control systems. At this meeting, the committees review the general auditor s report on internal control and risk management systems for the previous year, with the general auditor outlining his team s findings and management s actions to remedy significant issues identified, including the outcome of work undertaken by the safety and operational risk audit team and the group s financial control team.

A further joint meeting between the two committees was held at the end of the year to review the refreshed description of the company s system of internal control which was subsequently communicated to employees in early 2013.

External auditors

In 2012 the audit committee held two private meetings with the external auditors without management being present. In addition, the chair of the audit committee met privately with the external auditors before each audit committee.

A new lead audit partner is appointed every five years and other senior audit staff are rotated every seven years. No partners or senior staff from Ernst & Young who are connected with the BP audit may transfer to the group. During the year the committee approved the appointment of a new lead partner from Ernst & Young to replace the current partner who reaches five years service in early 2013.

Auditor objectivity and independence is safeguarded through limiting non-audit services to tax and audit-related work that fall within defined categories. For a list of those categories, the process by which non-audit work is approved when the audit committee concludes that it is in the interests of the company to purchase non-audit work from the external auditor (rather than another supplier), see the section on Principal accountants fees and services (page 149). Non-audit work by Ernst & Young is subject to the audit committee s pre-approval policy. Non-audit work undertaken by Ernst & Young and by other accountancy firms is regularly monitored by the committee.

The audit committee annually reviews the audit fee structure and terms of engagement. Fees paid to the external auditor for the year were $54 million, of which 13% was for non-assurance work (see Financial statements Note 16). Non-audit or non-audit-related assurance fees were largely unchanged from 2011 levels, at $7 million. Non-audit or non-audit-related assurance services consisted of tax compliance services, tax advisory

services and services relating to corporate finance transactions. 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 such a fee.

During the year, the committee considered the outcome of the Financial Reporting Council consultation on the UK Corporate Governance Code and Guidance on Audit Committees, with particular focus on provisions for tendering the external audit. The committee has undertaken preparatory work to understand the potential for other audit firms to participate in a tender should this be triggered by criteria which has been agreed with management, including independence, quality of service, audit quality, value for money and regulatory changes. The committee will keep this under review going forward.

The effectiveness of the external auditors is evaluated by the audit committee each year. The auditor assessment tool is completed on an annual basis and examines five main performance criteria robustness of the audit process, independence and objectivity, quality of delivery, quality of people and service, and value-added advice. The composition of the audit team is reviewed annually and the committee has the opportunity to assess specific technical capabilities in the audit firm when addressing specialist topics, such as tax and trading.

The committee has recommended to the board that the reappointment of Ernst & Young as the company s external auditors be proposed to shareholders at the 2013 AGM.

Internal audit

The committee receives quarterly reports from the general auditor which outline the planned schedule of audits as well as tracking key findings and any material actions that are overdue or have been rescheduled. In reviewing the audit programme proposed each year, the committee looks at whether it believes key risks facing the company have been appropriately addressed. The forward programme of internal audit work was reviewed by the audit and SEEA committees during the year.

The general auditor met privately with the committee once during the year, without the presence of executive management or the external auditors. In addition, the committee chair holds regular meetings with the general auditor between committee meetings.

The committee reviewed with the general auditor the number and expertise of his team s staff resources. The committee was satisfied that internal audit had resources sufficient to fulfil the function s role, that it had the appropriate access it required to information and that management had responded to the results of audit findings in a timely manner.

Other activities

One of the joint meetings with the SEEAC was held to review the annual certification report of compliance with the BP code of conduct which is signed by the group chief executive. During the year the committee monitors non-compliance with the BP code of conduct through quarterly reports by the group ethics and compliance officer. At a further joint meeting with the SEEAC, the committee reviewed the work of the ethics and compliance function and its programme for 2013.

The company s employee concerns programme, OpenTalk, has been adopted by the committee for whistle-blower monitoring, and all financial issues that have been flagged through the programme are reviewed by the committee. The committee also receives quarterly updates on fraud and misconduct.

Committee evaluation

Each year the audit committee examines its performance and effectiveness. In 2012, the committee used a survey covering similar questions to 2011 in order to identify trends. Key areas covered included the clarity of its role and responsibilities, the balance of skills and knowledge among its members and the quality and timeliness of information received. Specific areas identified for focus in 2013 included committee training and focus on the length and format of materials.

Safety, ethics and environment assurance committee (SEEAC)

Chairman s introduction

The SEEAC remains committed to monitor closely and provide constructive challenge to management in its drive for safe and reliable operations at all times. The SEEAC has spent considerable time over the past year both in terms of understanding and monitoring key group risks as described below. Additionally it continued to monitor the group s response to the 26 recommendations that were made in BP s investigation report (the Bly Report) into the tragic accident in April 2010 and visited upstream and downstream operations in the US and Angola and downstream sites in the US and UK.

In particular, we would highlight our reviews of key group risks, and associated risk management in: drilling and maintenance of wells; contractor management; non-operated joint ventures; fire and explosion risk at facilities and pipelines and shipping. These in-depth reviews have taken place during our regular meetings with executive management.

In the Upstream we have looked at risks and environmental issues arising in connection with, fracking operations during a visit to our East Texas onshore operations. Other visits have been made to offshore Gulf of Mexico, Houston and Angola. In the Downstream, members of the committee have visited the company s paraxylene manufacturing facility in Texas, the Texas City refinery and the Buncefield terminal in the UK.

Duane Wilson s independent perspective of the company s response to the Baker Panel s recommendations following the fire and explosion at the Texas City refinery in 2005 was completed in May when he delivered his final report to SEEAC. We were pleased to engage him to work, in a global capacity, with the Downstream business. He continues to deliver reports to SEEAC when requested.

We were pleased to complete the engagement of Carl Sandlin in June to report independently to SEEAC on the implementation of the Bly Report recommendations. Carl Sandlin brings a vast amount of experience from his management of drilling operations during his career at ExxonMobil. He will also report to the committee on his observations of process safety culture in the Upstream.

We also welcomed Professor Dame Ann Dowling who brings deep experience in technology and engineering to the committee from February 2012.

Paul Anderson

Committee chair

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Paul Anderson   committee chair

Admiral Frank Bowman

Antony Burgmans

Cynthia Carroll

Sir William Castell (retired from the committee 12 April 2012)

Professor Dame Ann Dowling (joined the committee 3 February 2012)

Committee role and structure

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, including monitoring process safety management, and receive assurance that they are appropriate in design and effective in implementation.

The committee met six times in 2012 including three joint meetings with the audit committee, at one of which the general auditor s report on internal control and risk management systems for the year was reviewed in preparation for the board s report to shareholders in the annual report. In that joint meeting the committees reviewed the internal audit programme for the year ahead to ensure both committees endorsed the coverage. The SEEAC and audit committee worked together, through their chairs and secretaries, to ensure that the agendas did not overlap or omit coverage of any key risks during the year.

In addition to the committee membership, SEEAC meetings were attended by the group chief executive, the executive vice president for safety and operational risk (S&OR) and the representatives from internal audit. The external auditor also attended some of the meetings (and was briefed on the other meetings by the chair and secretary to the committee). The group general counsel also attended meetings. The committee scheduled private sessions for members only (without the presence of executive management) at the conclusion of each meeting to discuss any issues arising and the quality of the meeting.

Committee processes

Information and advice

The committee receives specific reports from the business segments but also receives cross-business information from the functions. These include but are not limited to the safety and operational risk function, internal audit, group ethics and compliance and group security. The SEEAC can access any other independent advice and counsel if it requires, on an unrestricted basis.

Field trips and visits

The committee extended its coverage and number of visits this year by encouraging members to participate individually, or in groups, and report back to the next full meeting. Members have also presented at staff training events, such as Admiral Bowman addressing a meeting of the leadership of the global wells organization (GWO) in

Florida in July and the committee chairman addressing senior leadership at the BP Academy at MIT (where Admiral Bowman also presented later in the year).

Upstream visits

In January the chairman and other members visited Houston to examine how GWO was monitoring and assuring the safety of drilling operations in the Gulf of Mexico. In May a committee member travelled offshore to the Thunder Horse platform in the Gulf of Mexico while other committee members visited drilling and fracking operations in East Texas. In August a committee member travelled to Angola and met with leadership there to receive briefings on implementation of OMS and other safety-related issues.

Downstream visits

Considerable focus also continues to be placed on the Downstream and on the company s response to the BP US Refineries Independent Safety Review Panel recommendations. In January members of the committee visited the Texas City refinery, accompanied by Duane Wilson, to review progress in risk management systems and OMS implementation. During this visit, committee members also visited the nearby petrochemicals facility to observe the extent to which the BP US Refineries Independent Safety Review Panel recommendations had been implemented in the petrochemicals context. In December all members of the committee visited the Buncefield terminal in the UK and received briefings on OMS

implementation as well as other safety-related improvements that had been made following the explosion at the neighbouring terminal in 2005.

2012 committee activities

Safety, operations and environment

The committee received regular reports from the S&OR 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. Operational risk and performance forms a large part of the committee s agenda. The S&OR function has intervention rights in all aspects of the group s technical and operational activities, and the committee sought evidence that this was working in practice. The committee s visits, as mentioned above, provided opportunities to discuss with local staff the interaction between line managers and embedded S&OR staff, and where change had occurred as a result.

During the year the committee received specific reports on the company s management of risks in shipping, wells, pipelines facilities, contractor management and non-operated joint ventures and also reviewed fire and explosion risk at facilities. The committee reviewed these risks, and risk management and mitigation, in depth with the relevant executive management.

When a fatality in the workforce occurs the committee reviews the incident in depth before reporting back to the board. The committee also reviewed specific incidents to understand root causes and actions being taken to prevent recurrence. There has been a particular focus on ensuring lessons learned are communicated widely across the company and not just within the business segment in which the incident occurred.

Upstream independent perspective

Monitoring the company s progress in implementing the 26 recommendations in the Bly Report is a key task for the committee and it received regular updates, including written reports. The BP board identified and engaged Carl

Sandlin to provide further oversight and assurance regarding the implementation of the Bly Report recommendations. He will track BP s progress in implementing the 26 recommendations from the company s internal investigation of the Deepwater Horizon accident and will independently assess the safety, health and environmental work of global drilling operations. As appropriate, Carl Sandlin will share his observations of BP s upstream process safety culture. He will give regular updates directly to the SEEAC and presented his initial work plan to SEEAC in October. He will meet with the committee at least twice a year.

Downstream independent perspective

Since Duane Wilson s appointment by the board in 2007 as an independent expert, he has provided an objective assessment of BP s progress in implementing the recommendations of the BP US Refineries Independent Review Panel and assisted the company in improving process safety performance at BP s five US refineries. In his final report in May, Duane Wilson advised that he had observed continued progress in process safety performance at each visit he has made to the five refineries. At the same time, he also discussed work remaining to be completed and areas requiring special emphasis and noted that some aspects of implementing the Panel s 10 recommendations require ongoing activity and hence could never be complete, but he considers the company to have appropriate systems and processes to continue its work toward process safety leadership.

We were pleased to engage him beginning in May, to work with management on a worldwide basis to continue to embed process safety culture and learnings across the segment. In this new role he will meet with the committee at least twice a year.

TNK-BP

Each year the committee receives a report on the progress made in HSE and process safety at TNK-BP, noting however that formal oversight of their HSE performance and policies is exercised by TNK-BP s own HSE committee. It was reported that, whilst significant areas for improvement remained, TNK-BP had continued to make progress in addressing the main safety, ethical and environmental challenges confronting it since it was formed in 2003. The committee will continue to

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monitor progress regularly until such time as the company completes its exit from TNK-BP.

Committee evaluation

For its 2012 evaluation, the SEEAC again used a questionnaire administered by external consultants to examine the committee s performance and effectiveness. The committee responded to the same questions used in 2011 so that any change trends could be discerned. The topics covered included the balance of skills and experience among its membership, 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 were positive. In particular the committee members considered that the committee possessed the right mix of skills and background, had appropriate support and had received open and transparent briefings from management. The committee is keen to maintain and, if possible, increase the number of field trips it makes and to continue constructive and challenging engagement with management.

Gulf of Mexico committee

Chairman s introduction

The Gulf of Mexico committee met 23 times in 2012, with much of our focus on legal topics. The committee oversaw the resolution of numerous matters in the past year; each was determined to be in the best interests of the company and its shareholders and consistent with the board s overall strategy of reducing key uncertainties.

Settlements have been approved with the Plaintiffs Steering Committee, with regard to private economic and property damages claims, as well as exposure-based medical claims stemming from the Deepwater Horizon accident; and the company reached resolutions with the Department of Justice and the Securities and Exchange Commission. The committee will be overseeing the company s compliance with government settlement agreements arising out of the Deepwater Horizon accident, in co-ordination with the other committees and the board as appropriate.

The committee has overseen the company s strategy for resolving claims not covered by the above settlements; its efforts to mitigate and monitor the effects of the spill; and actions to restore the group s reputation, particularly in the US. We have received regular briefings on the company s preparations for trial on the various civil matters, including the multi-district litigation in New Orleans.

Briefings on a broad range of topics have been provided to the committee by the leadership and counsel of the Gulf Coast Restoration Organization

(GCRO). External counsel have also been invited to join some meetings.

The high frequency of our interactions has facilitated committee members understanding of complex issues and interdependencies. I believe the committee maintains a rigorous approach to its work, providing effective oversight on behalf of the board. The report below summarizes the activities of the committee in 2012. The committee is well prepared to conduct its tasks over the coming year.

Ian Davis

Committee chair

Ian Davis committee chair

Paul Anderson

Admiral Frank Bowman (joined the committee 3 February 2012)

Sir William Castell (retired from the committee 12 April 2012)

George David

The Gulf of Mexico committee has cross-membership with both the SEEAC and the audit committee, helping to inform discussions of matters within the committee s remit. Membership of the Gulf of Mexico committee changed during 2012 and now includes three US-based non-executive directors.

All meetings during the course of the year have been attended by Lamar McKay, president and CEO of the GCRO in 2012, and Jack Lynch, chief counsel to the GCRO. The chairman, group chief executive and group general counsel join meetings whenever possible. Meetings are on occasion joined by others including members of the leadership team of the GCRO, as well as internal and external legal counsel.

Committee role and structure

The purpose of the committee is to provide non-executive oversight of the GCRO; to oversee the management and mitigation of legal and license-to-operate risks arising out of the Deepwater Horizon accident and the subsequent response; and to support efforts to rebuild trust in BP and BP s reputation, with a particular focus on the US.

The committee s work is fully integrated with that of the board on strategy, reputation and financial planning. The committee chairman provides verbal reports at board meetings, and all directors are invited, from time to time, to attend and observe committee meetings. Meeting minutes are sent to the board for review, and the board retains ultimate accountability for oversight of the group s response to the Deepwater Horizon accident.

The committee met 23 times in 2012, frequently by telephone and sometimes at very short notice.

During the course of the year the committee focused on the following tasks:

- Oversee and receive regular reports on work undertaken to complete the response and mitigate the effects of the oil spill in the Gulf of Mexico area.

- Oversee the legal strategy for litigation, investigations and administrative processes involving the group arising from the accident or its aftermath.

Oversee the strategy for resolving claims, recognizing the independent role of first the Gulf Coast Claims Facility (GCCF) and more recently the Deepwater Horizon Court Supervised Settlement Program (DHCSSP).

Oversee GCRO s plans for expenditures and investments on major projects or matters beyond those included within the above referenced independent claims administration processes.

Oversee management s strategy and actions to restore the group s reputation in the US.

Committee processes

Information and advice

The committee receives its information from the leadership of the GCRO, internal personnel and external advisers. Privileged briefings are provided by the group general counsel and chief counsel to the GCRO, along with internal and external counsel who often participate in committee meetings. The committee received reports from internal audit on its reviews of the GCRO and related activities. The audit committee remains the primary forum for the monitoring of financial risk and audit matters relating to the GCRO. Safety risks relating to the GCRO s activities are monitored by the SEEAC.

Training and visits

The high frequency of meetings in 2012 facilitated the committee s understanding of key issues and numerous interdependencies in what at times has been a fast-moving external environment. Committee members have interacted with members of the GCRO leadership team, including at the two meetings of extended duration held in the US in 2012.

2012 committee activities

The committee s activities have included the following:

Legal

Privileged briefings continue to form a significant part of the committee s agenda, given the breadth and pace of legal developments. The committee oversaw the resolution of numerous matters in 2012; each was determined to be in the best interests of the company and its shareholders, and consistent with the overall strategy of reducing key uncertainties. These resolutions included the class-action settlements agreed with the Plaintiffs Steering Committee (PSC), the criminal settlement with the Department of Justice, and the civil resolution with the Securities and Exchange Commission. The committee has overseen the company s continuing preparation for trial in the Multi-District Litigation in New Orleans, as well as a number of other litigation and administrative proceedings including the multi-district litigation in Houston and suspension and debarment proceedings led by the Environmental Protection Agency.

Remediation and restoration

The committee received regular updates on the progress of clean-up and remediation activities. The committee also monitored the Natural Research Damage (NRD) Assessment process, as well as discussions with Natural Resource Trustees on NRD matters including early restoration negotiations and projects.

Claims

The committee monitored claims processes, including those relating to state economic claims and the transition from the independently administered GCCF to the DHCSSP following the agreement of class-action settlements with the PSC[a]. Assessments of potential future claims for provisioning purposes are reviewed by the audit committee.

The committee recently undertook an evaluation of its effectiveness during 2012, as it has at the end of each year since its inception.

Nomination and chairman s committees

Nomination committee

Carl-Henric Svanberg committee chair

Antony Burgmans

Cynthia Carroll

Sir William Castell (retired from the committee 12 April 2012)

Ian Davis

Brendan Nelson (joined the committee April 2012)

Paul Anderson (joined the committee April 2012)

Andrew Shilston attends meetings of the committee in his capacity as senior independent director.

The committee met four times during 2012.

Committee role and structure

The committee identifies, evaluates and recommends candidates for the appointment or re-appointment as directors and for the appointment of the company secretary.

The committee keeps the mix of knowledge, skills and experience of the board under regular review (in consultation with the chairman s committee) to ensure an orderly succession of directors. The outside directorships and broader commitments of the non-executive directors are also monitored by the nomination committee.

The committee reviewed and confirmed these tasks during the year.

Committee activities

During the year the membership of the committee was reviewed. Brendan Nelson and Paul Anderson joined as members and Andrew Shilston was invited to attend as the senior independent director.

The committee reviewed the independence and roles of each of the directors prior to recommending them for re-election at the 2012 AGM. It also discussed the composition of the board and its committees in terms of service, skills and diversity.

Professor Dame Ann Dowling joined the BP board on 3 February 2012 following a recommendation from the committee. The committee had retained the services of external advisors Odgers to assist with the identification of potential candidates for this appointment.

During the year the committee considered the skills and experience required for board members against the strategic direction of the company at two of its meetings. The committee also considered the skills of the current directors and were satisfied that the board had the appropriate balance of skills and experience.

The committee discussed the board s publicly stated aspirations for diversity and agreed metrics as required by the UK Corporate Governance Code. The metrics agreed by the committee on behalf of the board are:

- The absolute number of male and female board members (to measure the board s progress in gender diversity).

- The absolute number of different nationalities on the board (as a measurement of geographic diversity on the board).

The committee agreed that data on these two objectives will be included in the board performance report in the *BP Annual Report and Form 20-F* and reported against in future years (see page 113 for 2012 board diversity data).

The committee considered the position of candidates identified as potential non-executive directors and based on the description of the required skills and experience agreed to commence searches for appropriate candidates for the medium term.

[a] See Plaintiffs Steering Committee settlements on page 60 and Financial statements Note 36 on page 236 for further information.

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The committee discussed the time commitment for non-executive directors. The letters of appointment for BP non-executive directors do not state a time commitment and this is explained annually as part of the compliance statement with the UK Corporate Governance Code. The committee took the view that it would be artificial to set such a metric. The experience of the board over the past three years was that directors had been required to spend such time as was necessary on the business of the company. Whilst it was hoped that the work of the board and its committees would not be as intense in coming years, it was important that directors were able to respond promptly. The committee would keep under review the attendance and commitment of board members.

The committee reviewed the periods of service of the non-executive directors and noted the substantial refreshment of the board over the past three years. The committee was strongly of the view that continuity of service and corporate memory was important to the board s working and accordingly agreed with Antony Burgmans that he would remain as a director for a further three-year period. In coming to this view the committee considered his clarity of thought and his approach in evaluating the events of the last few years and concluded that he remained independent in his judgement. The committee further noted that since 2004 all directors on the board had been subject to annual re-election.

Sir William Castell stood down from the board and as senior independent director in April 2012. The committee discussed Sir William s successor as SID on two occasions and made recommendations to the chairman s committee on appropriate candidates.

Committee evaluation

At the end of the year, the committee undertook an annual examination of its effectiveness and performance, using a questionnaire. As part of its evaluation, the committee considered its role and its task for the year. The evaluation concluded that the committee had worked well and had improved its focus on diversity. Going forward the committee wishes to focus on agenda setting and papers with a view to improving time management and workload.

Chairman s committee

Carl-Henric Svanberg committee chair

Paul Anderson

Admiral Frank Bowman

Antony Burgmans

Cynthia Carroll

Sir William Castell (retired from the committee in April 2012)

George David

Ian Davis

Professor Dame Ann Dowling (joined the committee February 2012)

Brendan Nelson

Phuthuma Nhleko

Andrew Shilston (joined the committee January 2012)

The committee met eight times during 2012.

Committee role and structure

The committee is comprised of the chairman and all the non-executive directors.

The main tasks of the committee are:

- Evaluating the performance and effectiveness of the group chief executive.
- Reviewing the structure and effectiveness of the business organization of BP.
- Reviewing the systems for senior executive development and determining the succession plan for the group chief executive, executive directors and other senior members of executive management.
- Determining any other matter which is appropriate to be considered by all of the non-executive directors.
- Opining on any matter referred to it by the chairman of any committee comprised solely of non-executive directors.

Committee activities

The committee held private discussions between the non-executive directors during the year on a number of key issues for BP.

The committee carried out the evaluation of the chairman and the chief executive early in the year. The committee also set the parameters for these evaluations to take place in early 2013.

The committee received a recommendation from the nomination committee for the appointment of a senior independent director to replace Sir William Castell who was to stand down in April 2012. The committee agreed to recommend to the board that Andrew Shilston be appointed the SID; however Antony Burgmans, as longest serving non-executive director would act as the focal point for internal board matters and would lead the evaluation of the chairman.

The committee reviewed the membership of the board committees and agreed certain modifications.

In addition, during 2012 the committee considered:

The views of some shareholders as relayed by the chairman and the senior independent director.

On several occasions, with the chief executive officer, the strategic direction of the group.

Again with the chief executive officer, the composition and evolution of the top management team and the implications of the implementation of the functional organization.

The information available to the board.

UK Corporate Governance Code compliance

BP complied throughout 2012 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. 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. We believe this wider process lets all board members discuss and approve the chairman s remuneration (rather than solely the members of the remuneration committee).

E.2.4 Printed copies of the *BP Annual Report and Form 20-F 2011* completed mailing outside of the Governance Code period of 20 working days before the AGM (but within the UK Companies Act notice period). This was due to printing being delayed following revisions to the report in view of the class action settlements agreed with the Plaintiffs Steering Committee (PSC) on 3 March 2012.

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Chairman s introduction

Dear shareholder

BP made many further positive steps in its recovery journey during 2012. The remuneration committee recognizes the patience of investors during this period since the 2010 Deepwater Horizon accident. Equally we recognize the persistence of our executives in embedding safe and effective operations deeply into the fabric of the company while systematically restoring value. Progress is being made, reflecting a clear strategy and disciplined execution.

Our remuneration system for executive directors is tied closely to this progress. The company s strategy forms the basis for an annual plan and the measures and targets used for both annual and long-term variable pay. Variable pay, based on performance, makes up the vast majority of total potential remuneration for executive directors, and of that, most is long-term, reflecting the nature of BP s business and providing strong alignment with shareholders.

Our process for determining pay is both rigorous and independent. I have met with a number of our key shareholders again this year to understand their perspectives. We seek to reflect shareholders interests as well as to fairly reward the achievements of our executives, recognizing the contentious nature of top executive pay while ensuring competitiveness for our talented leadership. We believe informed, balanced judgement, and transparency of our decisions is vital. These principles continue to guide the committee s operation and have led to large variability in total remuneration for our executive directors over the past decade, reflecting the underlying performance of the company.

2012 outcomes

The outcomes of the various plans that make up 2012 total remuneration for executive directors are summarized in the table on page 130.

Annual bonus

Overall group performance was assessed at just below target. Annual bonus results were based on performance assessed against targets established at the start of the year and reflected the strategic priorities of safety and operational risk management, rebuilding trust and restoring value.

Safety and risk management results, accounting for 30% of bonus, were generally at or better than plan, with significant improvement and high standards in both loss of primary containment and process safety tier 1 incidents both key indicators of process safety.

Rebuilding trust accounted for 20% of bonus, and the company continued to make important gains as measured by independent surveys.

Restoring value metrics accounted for 50% of bonus with somewhat mixed results. Upstream major project delivery was on target, and divestment targets were exceeded but operating cash flow, underlying replacement cost profit and total cash costs did not achieve plan targets.

Performance shares

No shares vested in the 2010-2012 share element. Performance measures for this plan related to total shareholder return, production, net income, and downstream profitability all relative to the other oil majors. As the starting point for these metrics was prior to the Deepwater Horizon accident, performance failed to meet the level required for vesting.

Other elements

Salaries were increased 3% mid-year for Bob Dudley, Iain Conn and Dr Byron Grote. The deferred bonus component was first introduced following shareholder approval in 2010, and so no plan is yet eligible for vesting and will not be until early 2014. Pension increases reflect the application of relevant plan rules. As Bob Dudley s defined benefit pension is based on three-year average remuneration, its increased value reflects a catching up with his promotion, first to the board in 2009 and secondly to group chief executive in 2010. Similarly, Dr Brian Gilvary s pension increase reflects his promotion to chief financial officer at the start of 2012.

2013 policy

For 2013 our overall policy for executive directors will remain largely unchanged, and is summarized on page 136. The continuity of our pay structure comprising salary, annual bonus, deferred bonus, performance shares, and pension, provides a relatively simple, performance-based system tied directly to strategy. Salaries will be reviewed mid-year taking into consideration both external and internal relativities. Annual bonus will operate in the same way as last year but the metrics have evolved slightly to reflect annual plan priorities and with increased weight on restoring value. Performance shares follow the same format as last year with minor change in the metrics to align with strategy.

Report format

The UK government has issued draft regulations on revised reporting for directors remuneration which are expected to be finalized later this year. We support many of the changes planned and have incorporated these into the current report to the extent we believe is appropriate while still complying with current regulations.

We hope that you find this report both informative and reassuring. Our commitment to both shareholder interests and executive engagement continues, and we are confident that our approach to executive pay aligns well with the recovery of BP s business.

Antony Burgmans KBE

Chairman of the remuneration committee

6 March 2013

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The remuneration policy for executive directors and the decisions of the remuneration committee have, for many years, been guided by key principles:

Linked to strategy	g	A substantial portion of executive remuneration should be linked to success in implementing the company s business strategy.
Performance related	g	The major part of total remuneration should vary with performance, with the largest elements share based, further aligning interests with shareholders.
Long-term based	g	The structure of pay should reflect the long-term nature of BP s business and the significance of safety and environmental risks.
Informed judgement	g	There should be both quantitative and qualitative assessments of performance with the committee making an informed judgement within a framework approved by shareholders.
Shareholder engagement	g	The remuneration committee will actively seek to understand shareholder preferences and be transparent in explaining its remuneration policy and practices.
Fair treatment	g	The total quantum of pay should take account of both external market and company conditions to achieve a balanced fair outcome.

As reflected in the diagram below, the company s strategy forms the core from which key performance indicators are established. The total remuneration for executive directors is then tied to this via the four elements of total remuneration identified in the diagram below. Three of the four vary with performance and the majority of their remuneration is long term. For ease of reference page numbers in the report have been identified for each element where further detail can be found.

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2012 total remuneration outcomes

Overview

Summary of remuneration of executive directors in 2012 (audited)

	Bob Dudley thousand		Iain Conn thousand		Dr Brian Gilvary thousand		Dr Byron Grote thousand	
Annual remuneration	**2012**	2011	**2012**	2011	**2012**	2011[a]	**2012**	2011
Salary	**$1,726**	$1,700	**£741**	£720	**£690**	n/a	**$1,464**	$1,426
Cash bonus[b]	**$837**	$850	**£374**	£396	**£366**	n/a	**$710**	$713
Other emoluments	**$110**	$66	**£39**	£35	**£13**	n/a	**$15**	$15
Total	**$2,673**	$2,616	**£1,154**	£1,151	**£1,069**	n/a	**$2,189**	$2,154
Vested equity								
Deferred bonus and match	**$0**	$0	**£0**	£0	**£0**	n/a	**$0**	$0
Performance shares[c]	**$0**	$788	**£666**[d]	£743	**£299**[d]	n/a	**$0**	$1,450
Total	**$0**	$788	**£666**	£743	**£299**	n/a	**$0**	$1,450
Total remuneration	**$2,673**	$3,404	**£1,820**	£1,894	**£1,368**	n/a	**$2,189**	$3,604
Pension								
Pension value increase[e]	**$7,317**	$4,908	**£940**	£1,209	**£2,132**	n/a	**$987**	$1,750
Cash in lieu of future accrual[f]	**n/a**	n/a	**£259**	£192	**£242**	n/a	**n/a**	n/a
Total including pension	**$9,990**	$8,312	**£3,019**	£3,295	**£3,742**	n/a	**$3,176**	$5,354

Amounts shown are in the currency received by executive directors. Annual bonuses are shown in the year they were earned.

[a] Dr Brian Gilvary joined the board on 1 January 2012.

[b] This reflects the amount of total overall bonus paid in cash with the deferred portion as set out in the conditional equity table below.

[c] Represents vesting of shares made at the end of the relevant performance period based on performance achieved under rules of the plan and includes re-invested dividends on the shares vested.

[d] There was no vesting under the 2010-2012 performance share element. The shares that vested for Iain Conn pertained to a separate restricted award made in 2008 and those for Dr Brian Gilvary to an award granted prior to joining the board. The market price of ordinary shares on respective vesting dates of 7 February 2013 and 15 January 2013 was £4.58.

[e]

Represents the increase in transfer value calculated for defined benefit plans. Increases for Bob Dudley and Dr Brian Gilvary reflect their promotions as per applicable rules.

[f] As for all employees affected by UK pension tax limits and who wished to remain within these limits, with effect from April 2011, Iain Conn and Dr Brian Gilvary received a cash supplement of 35% of basic salary in lieu of future service pension accrual.

Conditional equity to vest in future years, subject to performance

	Bob Dudley		Iain Conn		Dr Brian Gilvary		Dr Byron Gr
bonus in respect of ar[a]	**2012**	2011	**2012**	2011	**2012**	2011	**2012**
y deferral housand)	**$837**	$850	**£374**	£396	**£366**	n/a	**$710**
deferral Value (thousand)	**$837**	$850	**£374**	£396	**£366**	n/a	**$710**
rral converted to shares Shares	**229,380**	218,412	**161,296**	161,304	**157,630**	n/a	**194,556**
ching shares Shares	**229,380**	218,412	**161,296**	161,304	**157,630**	n/a	**194,556**
ate	**Feb 2016**	Feb 2015	**Feb 2016**	Feb 2015	**Feb 2016**	Feb 2015	**Feb 2016**
nce shares	**2012-2014**	2011-2013	**2012-2014**	2011-2013	**2012-2014**	2011-2013	**2012-2014**
maximum shares	**1,343,712**	1,330,332	**660,633**	623,025	**624,434**	n/a	**828,936**
ate	**Feb 2015**	Feb 2014	**Feb 2015**	Feb 2014	**Feb 2015**	Feb 2014	**Feb 2015**

[a] The number of deferred shares is calculated using the three-day average share price following the full-year result announcement which was £4.91/share and $46.70/ADS in February 2012 and £4.64/share and $43.78/ADS in February 2013. Both deferred and matched shares are subject to a safety and environmental hurdle over the three-year deferral period.

Non-executive directors in 2012 (audited)

		£ thousand
	2012	2011
Carl-Henric Svanberg	**750**	750
Paul Anderson	**149**	128
Admiral Frank Bowman	**126**	120
Antony Burgmans	**120**	100
Cynthia Carroll	**98**	85
George David[a]	**135**	128
Ian Davis	**128**	160
Professor Dame Ann Dowling[b c]	**97**	
Brendan Nelson	**119**	103
Phuthuma Nhleko	**123**	113
Andrew Shilston[d]	**125**	

Director leaving the board in 2012		
Sir William Castell[e]	**42**	168

[a] In addition, George David received £28,000 for chairing the BP technology advisory council.
[b] Appointed on 3 February 2012.
[c] In addition, Professor Dowling received £4,166 for her membership of the BP technology advisory council.
[d] Appointed 1 January 2012 and became senior independent director in April 2012.
[e] Retired from the board in April 2012.

Historical TSR performance

This graph shows the growth in value of a hypothetical £100 holding in BP p.l.c. ordinary shares over five years, relative to the FTSE 100 Index (of which the company is a constituent). The values of the hypothetical £100 holdings at the end of the five-year period were £89.60 and £111.79 respectively.

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2012 total remuneration in more depth

This section contains detail on executive directors   remuneration including salary, annual bonus and deferred bonus relating to 2012 and performance shares for 2010-2012.

The charts below summarize the actual total direct remuneration outcome of 2012 for each of the executive directors compared to the potential that would have been realised if variable plans had paid out at maximum.

The definitions for both the charts above and the summary table on the page opposite reflect those that are contained in the draft remuneration reporting regulations proposed by the UK government   s Department for Business Innovation and Skills (BIS). In summary:

Salary   actual salary received during 2012 both for actual and potential.

Cash bonus   actual cash bonus received for 2012 compared to potential cash bonus if maximum of 225% of salary had been achieved and one-third mandatory deferral applied.

Deferred bonus   as per the draft regulations, this reflects deferred bonus from previous years that vested in 2012. The first potential vesting will be in 2014.

Performance shares   shows the actual value of the performance shares that vested at the end of 2012. The potential shows the value that would have been attained if all shares had vested. The same share price was used for both calculations. For Iain Conn, the information also reflects restricted shares awarded in 2008, and for Dr Brian Gilvary an award prior to him joining the board. Further detail can be found on page 133.

Salaries were reviewed in May 2012 relative to other oil majors, other large UK and Europe-based international companies and key US companies. The committee also considered the level of pay increases for executives below board level, as well as different employee groups across the business.

Based on this review, salaries were increased by 3% for Bob Dudley (to $1,751,000), Iain Conn (to £752,000) and Dr Byron Grote (to $1,485,000) effective 1 July 2012. Dr Brian Gilvary   s salary of £690,000, which had been set on his appointment on 1 January, was unchanged.

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Framework

All executive directors were eligible for an overall annual bonus, including deferral, of 150% of salary at target and a maximum of 225% of salary. Bob Dudley s annual bonus was based entirely on group results and Iain Conn s, Dr Brian Gilvary s, and Dr Byron Grote s were based 70% on group results and 30% on their respective segment or function.

Measures and targets for the annual bonus were set at the start of the year and were derived from the company s annual plan which, in turn, reflected its strategy and key performance indicators. Measures were grouped under the three dominant strategy themes of safety and operational risk management (S&OR), rebuilding trust, and restoring value. Targets were set so that meeting plan equates to on-target bonus.

At group level, S&OR was set to account for 30% of total bonus and included targets for loss of primary containment, process safety tier 1

events, and recordable injury frequency. Rebuilding trust was weighted at 20% of the total and included external reputation, and internal morale and engagement. Both components were assessed via results of surveys. Finally, restoring value was set to account for 50% of total bonus and included targets for operating cash flow, underlying replacement cost profit, total cash costs, gearing, divestments, upstream unplanned deferrals, upstream major project delivery, and Downstream net income per barrel.

Additional measures and targets were set for Iain Conn s, Dr Brian Gilvary s and Dr Byron Grote s respective segments or functions. These focused on safety, operating efficiency and profitability for the Downstream segment and key strategic priorities and outcomes for the functions.

As well as the specific measures set out, the committee considers any other results or factors it deems relevant and applies its judgement in determining final bonus outcomes.

Outcomes

2012 annual bonus outcomes

Performance outcomes for the year are summarized in the table above, with a more detailed explanation following.

Safety and operational risk management performance was strong. Loss of primary containment showed a 19% improvement and process safety tier 1 events dropped by 42% over last year. Both metrics are important indicators of process safety performance. Recordable injury frequency (RIF) included, for the first time, the biofuels business acquired last year. Demanding targets had been set to bring overall safety standards in the biofuels business to a level consistent with the rest of the company. In the end, performance in that business improved significantly but failed to meet the targets set and this meant that overall company targets were missed. Excluding biofuels, RIF performance was strong and improved over 2012.

Rebuilding trust showed overall satisfactory results. In terms of external reputation, independent external surveys showed important progress towards rebuilding reputation in both the US and UK. Internally, the pulse survey reflected good and improving overall engagement with 11 of 12 areas of specific ongoing monitoring all showing like-for-like better results than last year.

Performance related to restoring value was somewhat mixed, in part reflecting the priority throughout the company s business of continuing to embed safe and effective operations. Operating cash flow, underlying replacement cost profit and total cash costs all came in between threshold and target. Divestment targets were far exceeded and gearing just below target. Upstream major project delivery was on target but unplanned deferrals missed threshold levels. Downstream net income per barrel also achieved between threshold and target.

® See pages 28-29 for how our bonus measures for 2012 and 2013 are directly linked to business KPIs.

Based on these results, the formulaic outcome for group results was 97% of target. The remuneration committee concluded that this represented fairly the overall performance of the business during the year, and confirmed the score for group purposes. Bob Dudley s total overall bonus therefore was 97% of target, resulting in 146% of salary. The same score was applied to each of the other executive directors for 70% of their bonus that was determined by group results. Combined with the results for their respective segments and functions the total overall scores were 101% of target for Iain Conn, 106% for Dr Brian Gilvary and 97% for Dr Byron Grote.

Of the total bonuses referred to above, one-third is paid in cash, one-third is deferred on a mandatory basis, and one-third is paid either in cash or voluntarily deferred at the individual s discretion. As all four executive directors chose to participate in the voluntary deferral, amounts received by each of the individuals are shown below (as well as in the total remuneration summary chart on page 130).

	Cash bonus thousand	Mandatory deferral thousand	Voluntary deferral thousand
Bob Dudley	$837	$837	$837
Iain Conn	£374	£374	£374
Dr Brian Gilvary	£366	£366	£366
Dr Byron Grote	$710	$710	$710

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Framework

One-third of the total bonus awarded to the executive directors is deferred into shares on a mandatory basis under the terms of the deferred bonus element. Deferred shares are matched on a one-for-one basis and both deferred and matched shares vest after three years contingent on an assessment of safety and environmental sustainability over the three-year deferral period.

Individuals may elect to defer an additional one-third of total bonus into shares on the same basis and subject to the same contingency as the mandatory deferral.

Outcomes

No plans matured in 2012 for executive directors. The deferred element for executive directors was approved by shareholders and implemented in 2010. Therefore the first plan will be eligible to vest in early 2014 following the three-year deferral period and contingent on the assessment of safety and environmental sustainability over the same period.

Dr Brian Gilvary participated in a deferred bonus plan prior to his appointment as an executive director and details of this are provided in the table on page 144.

Framework

Performance shares were awarded to each executive director in early 2010 with vesting after three years dependent on performance relative to measures reflecting the company s strategic priorities at the time. For the 2010-2012 plan, vesting was based one-third on total shareholder return (TSR) compared to the other oil majors, and two-thirds on a balanced scorecard of underlying performance factors compared to the same peers. The underlying performance factors were production growth, Downstream profitability, and underlying net income growth. The peer group includes ExxonMobil, Shell, Chevron, Total and ConocoPhillips. Vesting was set at 100%, 70% and 35% for performance equivalent to first, second and third rank respectively and none for fourth or fifth place of the peer group, with BP s position interpolated amongst them.

Outcomes

As the starting point for all measures was before the Deepwater Horizon accident, the impact of this continues to be dominant. Results for all measures were below the third place required and so no shares vested. The resulting shares and value of the vesting for each individual are shown to the right (as well as in the total remuneration summary chart on page 130).

	Original award	Shares vested (including	Value of vested shares thousand

		dividends)	
Bob Dudley			
performance shares	581,082	0	$0
Iain Conn			
performance shares	656,813	0	£0
restricted shares	133,452	145,489	£666
Dr Byron Grote			
performance shares	801,894	0	$0
Dr Brian Gilvary	82,500	65,414	£299

Iain Conn was awarded restricted shares in early 2008 subject to continued service and satisfactory performance. The first tranche of these vested in February 2011 and the second in February 2013. This final tranche has been included in this year s disclosure for completeness. Dr Brian Gilvary s vesting reflects awards granted prior to him joining the board under equivalent plans below board level which vest at the same time as the executive director performance shares.

Framework

Executive directors are eligible to participate in regular company pension schemes that apply in their home countries which follow national norms in terms of structure and levels.

Bob Dudley and Dr Byron Grote both participate in the US plan and Iain Conn and Dr Brian Gilvary in the UK plan. Full details on these plans are set out in the policy section of this report (page 141).

Outcomes

The table below sets out the change in pension for 2012. This table follows the format required by current UK reporting regulations rather than the draft regulations that are expected to come into effect in late 2013.

Bob Dudley s pension increase is largely due to his promotion to group chief executive in late 2010. Since his pension is based on three-year average salary and bonus, the impact of a promotion takes a number of years to be

fully reflected in his pension. Dr Brian Gilvary s pension, based on final salary, also shows a significant increase due to his promotion in January 2012.

Under the draft regulations, the disclosure of total pension includes any cash in lieu of additional accrual that is paid to individuals in the UK scheme who have exceeded the annual allowance or lifetime allowance under UK regulations. Both Iain Conn and Dr Brian Gilvary fall into this category and in 2012 received cash supplements of 35% of salary in lieu of future service accrual.

In terms of calculating the increase in pension value both a column on 20 times additional pension earned during the year as per the draft regulations, as well as the transfer value increase as currently stipulated have been included in the table below. The summary table on page 130 uses the increase in transfer value (last column below) to which the cash supplements are separately identified.

Pensions (audited)

	Service at 31 Dec 2012	Accrued pension entitlement at 31 Dec 2012	A:Additional pension earned during the year ended 31 Dec 2012[a]	B:Transfer value of accrued benefit at 31 Dec 2011[b]	C:Transfer value of accrued benefit at 31 Dec 2012[b]	Amount of 20 times A	A m
	33 years	$1,381	$433	$15,244	$22,561	$8,660	
	27 years	£316	£9	£6,582	£7,522	£180	
K)	26 years	£317	£64	£5,486	£7,618	£1,280	
S)	33 years	$1,388	$60	$18,251	$19,238	$1,200	

[a] Additional pension earned during the year includes an inflation increase of 4.8% for UK directors and 1.7% for US directors.

[b] Transfer values have been calculated in accordance with guidance issued by the actuarial profession.

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Remuneration committee

The committee was made up of the following independent non-executive directors:

Antony Burgmans chairman

George David

Ian Davis

Professor Dame Anne Dowling (appointed July 2012)

Carl-Henric Svanberg normally attends the meetings.

Tasks

The committee s tasks are formally set out in the board governance principles as follows:

- To determine, on behalf of the board, the terms of engagement and remuneration of the group chief executive and the executive directors and to report on these to the shareholders.

- To determine, on behalf of the board, matters of policy over which the company has authority regarding the establishment or operation of the company s pension schemes of which the executive directors are members.

- To nominate, on behalf of the board, any trustees (or directors of corporate trustees) of such schemes.

- To review and approve the policies and actions being applied by the group chief executive in remunerating senior executives other than executive directors to ensure alignment and proportionality.

- To recommend to the board the quantum and structure of remuneration for the chairman of the board.

Committee activities

During the year, the committee met five times. Key discussions and decision items are shown in the table below.

The committee again undertook an evaluation of its operations using an external questionnaire administered by an external consultant. The committee discussed the findings at its January 2013 meeting. Almost all processes were rated as good to excellent in the report and in discussion the committee identified a number of areas for inclusion in 2013 agendas.

Remuneration committee 2012 meetings

Independence

The committee operates with a high level of independence. The board considers all committee members to be independent (see page 112) with no personal financial interest, other than as shareholders, in the committee s decisions.

The group chief executive is consulted on matters relating to the other executive directors and senior executives who report to him and on matters relating to the performance of the company; neither he nor the chairman of the board participate in decisions on their own remuneration. Both the company s head of human resources and head of group reward attend relevant sections of meetings to ensure appropriate input on matters related to executives below board level.

Gerrit Aronson, an independent consultant, is the committee s independent adviser as well as secretary. He is engaged directly by the committee and not by executive management. Advice is also received from the company secretary, who reports to the chairman of the board; and from other external advisers appointed by the committee for specialist advice and services on particular remuneration matters. In 2012 the committee continued to engage Towers Watson as its principal external adviser, primarily for market information. Freshfields Bruckhaus Deringer LLP provided legal advice on specific matters to the committee. Both firms provide other advice in their respective areas to the group. The independence of the advice is periodically reviewed by David Jackson, the company secretary to ensure it meets a high standard.

Shareholder engagement

The committee values its dialogue with major shareholders on remuneration matters. During the year the committee s chairman and the committee s independent adviser personally met with key shareholders holding around 20% of the company s shares to ascertain their views and discuss important aspects of the committee s policy. They also met key proxy advisers to similarly engage. This engagement provides the committee with an important direct perspective of shareholder interests and, along with the vote at the AGM on the directors remuneration report, is considered when making decisions.

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Directors interests

The figures below indicate and include all the beneficial and non-beneficial interests of each director of the company in shares of BP (or calculated equivalents) that have been disclosed to the company under the Disclosure and Transparency Rules as at the applicable dates.

Current directors	Ordinary shares or equivalents at 1 Jan 2012	Ordinary shares or equivalents at 31 Dec 2012	Change from 31 Dec 2012 to 25 Feb 2013	Ordinary shares or equivalents total at 25 Feb 2013
Carl-Henric Svanberg	942,979	988,077		988,077
Bob Dudley	337,301[a]	346,008[a]		346,008[a]
Paul Anderson	6,000[a]	6,000[a]	24,000[a]	30,000[a]
Admiral Frank Bowman	12,720[a]	16,320[a]		16,320[a]
Antony Burgmans	10,156	10,156		10,156
Cynthia Carroll	10,500[a]	10,500[a]		10,500[a]
Iain Conn	425,169[b]	509,729[b]	70,423	580,152[b]
George David	579,000[a]	579,000[a]		579,000[a]
Ian Davis	10,391	10,866		10,866
Dr Brian Gilvary	236,029	331,977	77,267	409,244
Dr Byron Grote	1,394,819[c]	1,512,616[c]		1,512,616[c]
Brendan Nelson	11,040	11,040		11,040
Phuthuma Nhleko				
Andrew Shilston		15,000		15,000
Directors joining the board	**On appointment**			
Professor Dame Ann Dowling	[d]	11,630		11,630
Directors leaving the board	**At 1 Jan 2012**	**At resignation/ retirement**		
Sir William Castell	82,500	82,500[e]		

[a] Held as ADSs.

[b] Includes 48,024 shares held as ADSs.

[c] Held as ADSs, except for 94 shares held as ordinary shares.

[d] On appointment at 3 February 2012.

[e] On retirement at 12 April 2012.

The table below shows both the performance shares and the deferred bonus element awarded under the BP Executive Directors Incentive Plan (EDIP). These figures represent the maximum possible vesting levels. The actual number of shares/ADSs that vest will depend on the extent to which performance conditions have been satisfied over a three-year period. Additional details regarding the performance shares and deferred bonus elements of the EDIP awarded can be found on pages 143 and 144.

Current directors	Performance shares at 1 Jan 2012	Performance shares at 31 Dec 2012	Change from 31 Dec 2012 to 25 Feb 2013	Performance shares total at 25 Feb 2013
Bob Dudley[a]	2,451,048	3,691,950	1,270,710	4,962,660
Iain Conn	2,103,422	2,305,847	365,314	2,671,161
Dr Brian Gilvary[b]	67,500	669,434	934,620	1,604,054
Dr Byron Grote[a]	2,686,632	2,889,192	446,430	3,335,622

[a] Held as ADSs.

[b] This includes conditionally awarded shares made under the Competitive Performance Plan prior to his appointment as a director. The vesting of these shares is subject to performance conditions.

At 25 February 2013, the following directors of BP p.l.c. held the numbers of options under the BP group share option schemes for ordinary shares or their calculated equivalent, and the number of restricted shares as set out below. None of these are subject to performance conditions. Additional details regarding these options can be found on page 144.

Current directors	Options	Restricted shares
Bob Dudley		
Iain Conn	3,814	
Dr Brian Gilvary	504,191	197,881
Dr Byron Grote		

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 members of senior management who own more than 1% of the ordinary shares in issue. At 25 February 2013, all directors and senior management as a group held interests in 10,878,365 ordinary shares or their calculated equivalent, 12,805,997 performance shares or their calculated equivalent and 6,475,874 options for ordinary shares or their calculated equivalent under the BP group share option schemes.

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2013 remuneration policy

Overview

Remuneration policy summary

Component	Policy and opportunity	2013 operation and performance metrics
Salary	Base salaries should be competitive relative to relevant market peer groups and are normally reviewed annually.	Salaries as at 1 January 2013 are: Bob Dudley $1,751,000, Iain Conn £752,000, Dr Brian Gilvary £690,000 and Dr Byron Grote $1,485,000.
Annual bonus	Annual bonus should be based on performance relative to measures and targets reflecting the annual plan, which in turn reflects the strategic priorities of the company. Achieving plan results should equate to on-target bonus. On-target bonus is set at 150% of salary for executive directors with a maximum of 225% of salary.	Bonus measures for 2013 are: **Safety and operational risk management (30%).** Loss of primary containment. Process safety tier 1 events. Recordable injury frequency. **Value creation (70%).** Operating cash flow. Underlying replacement cost profit.

		Total cash costs.
		Upstream unplanned deferrals.
		Upstream major project delivery.
		Downstream net income per barrel.
		No change from last year on safety and operational risk management. Weight on value creation increased from 50% last year by eliminating rebuilding trust as a measure.
Deferred bonus	A portion of annual bonus should be paid in shares and deferred to add long-term sustainability and shareholder alignment to short-term performance achievement.	One-third of annual bonus is deferred on a mandatory basis and a further one-third can be deferred on a voluntary basis.
		All deferred shares are matched on a one-for-one basis.
		All deferred and matched shares vest after three years contingent on an assessment of safety and environmental sustainability over the three-year deferral period.
		No change from last year.
Performance shares	A large portion of total remuneration for executive directors should be tied to the long-term performance of the company.	The 2013-2015 share element will vest based equally on the following three performance metrics:
	Shares to a value of 5.5 times salary for the group chief executive and 4 times salary for the other executive directors are normally awarded	**Total shareholder return versus oil majors.**

	annually.	
		Operating cash flow.
	Vesting of the shares after three years is dependent on performance relative to measures reflecting the strategic priorities of the company.	**Strategic imperatives.**
	Those shares that vest are held for an additional three-year retention period, after payment of tax on vesting.	Reserves replacement versus oil majors.
		Process safety.
		Major project delivery.
		Executive directors are expected to develop a personal shareholding of five times salary before shares are released.
		No change from last year with the exception of major project delivery replacing rebuilding trust as one of the strategic imperatives, to align with strategy.
Pension and other benefits	Executive directors should participate in the normal company pension and benefit schemes applying in their home countries.	Both UK and US executive directors remain on defined benefit pension plans. UK directors, as for all UK employees who exceed the annual allowance set by legislation, may receive a cash supplement in lieu of future service pension accrual.

See pages 28-29 for how our bonus measures for 2012 and 2013 are directly linked to business KPIs.

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2013 remuneration policy in more depth

Total remuneration is made up of the five components summarized in the table opposite. Each of these is explained in more detail in this section of the report. The total remuneration opportunity for executive directors is strongly performance based and weighted to the long term. As shown below over 90% of the group chief executive s total direct remuneration opportunity (that is at maximum) requires the achievement of demanding performance requirements, and over 80% is long term three years in the case of deferred bonus and six years for the performance shares.

The two charts above provide scenarios for what executive directors may get paid for different levels of performance, consistent with the draft UK regulations on remuneration reporting. Dr Byron Grote s chart shows full-year values for illustration and does not reflect the impact of his announced retirement from the board.

The minimum amount reflects current base salary which is the only part of total direct remuneration that is not performance related.

On-target amounts are based on the following assumptions:

- Current salary.
- Cash bonus reflecting on-target level of 150% of salary of which two-thirds is paid in cash.
- Deferred bonus reflecting one-third of on-target bonus of 150% which is deferred on a mandatory basis and matched on a one-for-one basis.
- Performance shares that vest to a value of one half of the maximum.
- Share prices are assumed to remain constant for calculation purposes.

Maximum amounts are based on the following assumptions:

- Current salary.
- Cash bonus reflecting maximum level of 225% of salary of which one-third is paid in cash.

Deferred bonus reflecting two-thirds of maximum bonus of 225% which is deferred on a mandatory and voluntary basis, and matched one-for-one.

Performance shares that fully vest amounting to 5.5 times salary for the group chief executive and 4 times salary for other executive directors.

Share prices are assumed to remain constant for calculation purposes.

As most components of total remuneration are determined as multiples of salary, the remuneration committee makes careful reviews of salaries, normally annually. These reviews include thorough consideration of other large UK and Europe-based global companies, other oil majors, and

relevant US companies. They also include similar consideration of the salary treatment throughout the company, as well as company performance and investor perspectives. It is expected that salaries for executive directors will be reviewed mid-year in this context.

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Operation

For 2013, all executive directors will again be eligible for a total bonus (including deferral) of 150% of salary at target and 225% at maximum. Bob Dudley s bonus will be based entirely on group measures as will Dr Brian Gilvary s and Dr Byron Grote s. Iain Conn will have 70% of his bonus based on group results and 30% on his business segment.

The group strategy provides the overall context for the company s key performance indicators and the focus for the annual plan. From this, measures and targets are selected at the start of the year for senior managers, including executive directors, to reflect the key priorities of the business. Measures typically include a range of financial and operating metrics as well as those relating to safety and environment.

The committee has a preference for quantifiable, hard targets that can be factually measured and objectively assessed according to well understood principles and definitions. Where it is more appropriate to have more qualitative measures, the information that will be reviewed to arrive at conclusions is established at the start of the year. Targets are set so that achieving plan levels of performance results in on-target bonus.

At the end of each year, performance is assessed relative to the measures and targets established at the start of the year, adjusted for any material changes in the market environment (predominantly oil prices).

As in past years, in addition to the specific bonus metrics, the committee will also review the underlying performance of the group in light of the overall business plan, competitors results, analysts reports, and seek input from other committees on relevant aspects. When appropriate, the committee may make adjustments to a straight formulaic result based on this fuller information. The committee considers that this informed judgement is important to establishing a fair overall assessment.

The rigorous process followed by the committee has resulted in bonus levels varying considerably over the past several years, reflecting the changing fortunes of the company during the period.

The chart below shows the average annual bonus result (before any deferral) and relative to an on-target level for executive directors for 2012 as well as the previous five years.

History of annual bonus results

Performance measures

The measures used to determine bonus results flow directly from the group s annual plan which reflects the strategic priorities of safety and operational risk management, and reinforcing value creation.

A central strategic priority continues to be safety and managing risk. As last year, performance in this area will account for 30% of group results for bonus purposes. The primary measures used to assess performance will be loss of primary containment, process safety tier 1 events, and recordable injury frequency. The first two of these track process safety while the third reflects personal safety and this balance gives an overall perspective on performance. The committee will also seek the input of the safety, ethics and environment assurance committee (SEEAC) to determine if there are any other factors or metrics that should be considered in arriving at a final assessment at year end.

A second set of measures will track performance relative to value creation and account for 70% of group results for bonus purposes. This reflects increased emphasis on restoring value from last year when it accounted for 50%. The rebuilding trust set of measures, accounting for 20% last year, will not feature in 2013. Three financial measures for value creation include operating cash flow, underlying replacement cost profit, and total cash cost. Three additional operating metrics include upstream major project delivery, upstream planned deferrals, and Downstream net income per barrel. This set of metrics provides a balance of financial and operating priorities, as well as significant continuity from last year.

The Downstream segment will include specific safety metrics for the segment. Value metrics will include availability, efficiency, and profitability measures, as well as divestments and major project delivery.

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The structure of deferred bonus, paid in shares, places increased focus on long-term alignment with shareholders, and reinforces the critical importance of maintaining high safety and environmental standards. It effectively translates the outcome of a portion of the annual bonus into a long-term plan with additional performance hurdles. As shown below, the performance results of 2013 will form the basis for determining the deferred bonus in 2014.

Timeline for 2013 deferred bonus

Operation

For 2013, as last year, one-third of the annual bonus will be deferred on a mandatory basis into shares for three years. Under the rules of the plan, the average share price over the three days following announcement of full-year results is used to determine the number of shares. Deferred shares are matched by the company on a one-for-one basis.

Executive directors may defer a further one-third of their annual bonus into shares on a voluntary basis, which will be capable of vesting, and will qualify for matching, on the same basis as set out above.

Both deferred and matched shares will vest in early 2017 contingent on an assessment of safety and environmental sustainability over the three-year deferral period. Where shares vest, the executive director will also receive additional shares representing the value of the re-invested dividends.

Performance measures

Since 2010, the deferred bonus has been subject to a safety and environmental sustainability hurdle, and this will again be applied this coming year.

If the committee assesses that there has been a material deterioration in safety and environmental metrics, or there have been major incidents revealing underlying weaknesses in safety and environmental management, then it may conclude that shares should vest in part, or not at all. In reaching its conclusion, the committee will obtain advice from the SEEAC.

The committee believes that this safety and environmental hurdle is appropriate for several reasons. First, high standards in this area are an important priority of BP s strategy. Second, maintaining safety and environmental standards over the long-term is a good qualitative determinant of the sustainability of the business. Third, this non-financial hurdle will complement the financial and operational performance conditions applicable to performance share awards.

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The performance share element reflects the committee s policy that a large proportion of total remuneration is tied to long-term performance. A three-year performance period, combined with a further three-year retention period for those shares that vest, creates a six-year incentive structure which is designed to ensure executive interests are aligned with those of shareholders.

Timeline for 2013-2015 share element

Operation

Performance shares are awarded conditionally at the start of each year. For 2013, as last year, shares have been awarded to a value of 5.5 times salary for the group chief executive and 4 times salary for the other executive directors (the maximum allowed under the plan).

Performance shares will only vest to the extent that performance conditions, as described below, are met. The committee also has an overriding discretion, in exceptional circumstances, to reduce the number of shares that vest.

Where shares vest, the executive director will receive additional shares representing the value of the re-invested dividends on those shares. Sufficient shares may be sold at vesting to discharge tax liabilities.

The remaining vested shares will normally be subject to a compulsory retention period of a further three years. Furthermore, these shares will only be released once the company s minimum shareholding target of five times salary has been met.

The history of vesting of the share element for the past plan and the five previous ones is shown below, reflecting both demanding performance conditions and poor company performance during this period.

History of share element vesting

2013 performance measures

Performance conditions for the 2013-2015 share element will be aligned with the company s strategic agenda which continues to focus on value creation and reinforcing safety and operational risk management. Vesting of shares will be based one-third on BP s total shareholder return (TSR) compared to other oil majors, reflecting the central importance of restoring the value of the company. A further third will be based on the operating cash flow of the company, reflecting a central element of value creation. The final third will be based on a set of strategic imperatives; in particular, reserves replacement, safety and operational risk, and major project delivery.

For the relative measures, TSR and the reserves replacement ratio, the comparator group will consist of ExxonMobil, Shell, Total and Chevron. This group can be altered if circumstances change, for example, if there is significant consolidation in the industry. While a narrow group, it continues to represent the comparators that both shareholders and management use in assessing relative performance.

The TSR will be calculated as the share price performance over the three-year period, assuming dividends are reinvested. All share prices will be averaged over the three-month period before the beginning and end of the performance period. They will be measured in US dollars.

The reserves replacement ratio is defined according to industry standard specifications and its calculation is audited. As in previous years, the methodology used for the relative measures will rank each of the five oil majors on each measure. Performance shares for each component will vest at levels of 100%, 70% and 35% respectively, for performance equivalent to first, second and third rank. No shares will vest for fourth or fifth place.

Operating cash flow has been identified as a core strategic priority of the company. Targets have been established reflecting agreed plans, $100/bbl oil price and other normal operating assumptions.

Finally the remaining strategic imperatives relating to process safety and major project delivery will be determined by a mixture of internal targets and external assessment. In the case of safety, loss of primary containments, process safety tier 1 incidents and recordable injury frequency will provide the key factual data as well as the input of the SEEAC. Major project delivery component will be based on the commissioning success of major projects.

The committee considers that this combination of quantitative and qualitative measures reflects the long-term value creation priorities of the company as well as the key underpinnings for business sustainability. As in previous years, the committee may exercise its discretion, in a reasonable and informed manner, to adjust vesting levels upwards or downwards if it concludes that the formulaic approach does not reflect the true underlying health and performance of BP s business relative to its peers. It will explain any adjustments in the directors remuneration report following vesting, in line with its commitment to transparency.

Executive directors are eligible to participate in the appropriate pension schemes that apply in their home country and that follow national norms in terms of structure and levels. Details of pension accrual are set out in the table on page 133 and take into account the total amount that could be payable under relevant plans as described further below.

US executive directors

Pension benefits are provided to Bob Dudley and Dr Byron Grote through a combination of tax-qualified and non-qualified benefit plans, consistent with US tax regulations, as applicable.

The BP Retirement Accumulation Plan (US pension plan) is a US tax-qualified plan that features a cash balance formula and includes grandfathering provisions under final average pay formulas for certain members of acquired companies, including Bob Dudley, who participated in the predecessor Amoco pension plan, which was merged into the BP US pension plan effective 1 July 2000.

Bob Dudley was an active member of the Employee Retirement Plan of Amoco Corporation on 30 June 2000 and is classified as an Amoco heritage participant under the US pension plan. As with all Amoco heritage participants, he is entitled to receive the greater of (a) the cash balance benefit under the US pension plan; and (b) the sum of (i) his accrued benefit as of 31 December 2012 under the Amoco heritage plan formula (described below) and (ii) a new cash balance account (established 1 January 2013 with a zero balance). Bob Dudley s benefit under the Amoco heritage plan is based on his average annual eligible earnings (being base salary plus cash bonus, subject to the IRS compensation limit) over the better of (i) the last consecutive 36 months of benefit service preceding his termination date, and (ii) the highest three consecutive calendar years out of his last 10 years of benefit service. Bob Dudley s retirement benefit under the US pension plan is unreduced at age 60 but reduced by 5% per year if taken before age 60.

Dr Byron Grote was an active member of the BP America Retirement Accumulation Plan on 30 June 2000 and is classified as a BP heritage participant. As a BP heritage participant, he is entitled to receive the cash balance benefit under the US pension plan with additional payment options.

BP also provides a number of non-qualified pension plans in which Bob Dudley and Dr Byron Grote participate.

Bob Dudley will receive a benefit under the TNK-BP Supplemental Retirement Plan which is a lump sum benefit based on the same calculation as his benefit under the US pension plan but reflecting his service and earnings at TNK-BP.

The BP Excess Compensation (Retirement) Plan (excess compensation plan) provides a supplemental benefit which is the difference between (a) the benefit accrual under the US pension plan and the TNK-BP Supplement Retirement Plan without regard to the IRS compensation limit (including for this purpose base salary, cash bonus and bonus deferred into a compulsory or voluntary award under the deferred matching element of the EDIP), and (b) the actual benefit payable under the US pension plan and the TNK-BP Supplemental Retirement Plan, applying the IRS compensation limit. The benefit calculation under the heritage Amoco formula includes a reduction of 5% per year if taken before age 60.

Dr Byron Grote will receive a benefit under the BP America Inc. Supplemental Retirement Accumulation Plan (SRAP), which is a lump sum cash balance that only grows with interest based on the greater of the 30-year US

Treasury bond interest rate or 5%.

As of 31 December 2012, Dr Byron Grote will also receive a benefit from the BP Supplemental Executive Retirement Benefit Plan (SERB). The benefit payable under this supplemental plan is based on a target of 1.3% of final average earnings (including for this purpose base salary plus cash bonus and bonus deferred into a compulsory or voluntary award under the deferred matching element of the EDIP) for each year of service (without regard for tax limits) less benefits paid under all other BP (US) qualified and non-qualified pension arrangements. The benefit payable under SERB is unreduced at age 60 but reduced by 5% per year if separation occurs before age 60. Benefits payable under this plan are unfunded and therefore paid from corporate assets. As of 31 December 2012, Bob Dudley will not receive a benefit from this plan due to the value of his benefits under the other plans.

UK executive directors

Iain Conn and Dr Brian Gilvary are members of the regular BP pension scheme in respect of service prior to 1 April 2011. The core benefits under this scheme are non-contributory. They include a pension accrual of 1/60th of basic salary for each year of service, up to a maximum of two-thirds of final basic salary and a dependant s benefit of two-thirds of the member s pension. The scheme pension is not integrated with state pension benefits. Higher accrual rules are offered to employees on the payment of personal contributions.

Since 1 April 2011 the UK directors, Iain Conn and Dr Brian Gilvary, have received a cash supplement in lieu of future service pension accrual in the BP pension scheme. This follows the reduction in the annual allowance applicable to plans such as the BP pension scheme in 2011. Some employees, including the UK directors, have had to cease pension accrual for future service to remain within the new annual allowance. For all these employees the cash supplement is equal to 35% of basic salary.

Until the end of March 2011, pension benefits in excess of the individual lifetime allowance set by legislation were paid via an unapproved, unfunded pension arrangement provided directly by the company. From April 2011 only increases in accrued benefits due to increases in salary in excess of the individual lifetime allowance are covered by their arrangements. Both Iain Conn and Dr Brian Gilvary are covered under this arrangement.

The rules of the BP pension scheme were amended in 2006 such that the normal retirement age is 65. Prior to 1 December 2006, scheme members could retire on or after age 60 without reduction.

Both Iain Conn and Dr Brian Gilvary were in service at 1 December 2006, and therefore special early retirement terms apply to them. In the event of retirement between 60 and 65, they are entitled to an immediate unreduced pension. In the event of retirement between 55 and 60, they are entitled to an immediate unreduced pension in respect of the proportion of their benefit for service up to 30 November 2006, and are subject to such reduction as the scheme actuary certifies in respect of the period of service after 1 December 2006. For retirees leaving in circumstances approved by the committee the scheme actuary has to date applied a reduction of 3% per annum in respect of the period of service from 1 December 2006 up to the leaving date; a greater reduction can be applied in other circumstances. Those leaving before 55 are entitled to a deferred pension that becomes payable from 55 or later, on the basis set out above. Irrespective of the above, an individual leaving in circumstances of total incapacity is entitled to an immediate unreduced pension as from the leaving date.

Executive directors are eligible to participate in regular employee benefit plans and in all-employee share saving schemes applying in their home countries. Benefits in kind are not pensionable.

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Service contracts

Summary details of each executive director s service agreement are as follows:

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	Service agreement date	Salary as at 1 Jan 2013
Bob Dudley	6 Apr 2009	$1,751,000
Iain Conn	22 Jul 2004	£752,000
Dr Brian Gilvary	22 Feb 2012	£690,000
Dr Byron Grote	7 Aug 2000	$1,485,000

Bob Dudley s contract is with BP Corporation North America Inc. He is seconded to BP p.l.c. under a secondment agreement dated 15 April 2012, which expires on 15 April 2014. Dr Byron Grote s agreement is with BP Exploration (Alaska) Inc. He is seconded to BP p.l.c. under a secondment agreement of 7 August 2000, which expires at the date of the 2013 AGM. Both secondments can be terminated by one month s notice by either party and terminate automatically on the termination of their service agreements. Iain Conn s and Dr Brian Gilvary s service agreements are with BP p.l.c.

Each executive director is entitled to pension provision, details of which are summarized on page 133 of this report.

Each executive director is entitled to the following contractual benefits:

- A company car for business and private use, on terms that the company bear all normal servicing, insurance and running costs. Alternatively, the executive director is entitled to a car allowance in lieu.
- Medical and dental benefits; sick pay during periods of absence; tax preparation assistance.
- Indemnification in accordance with applicable law.

Each executive director participates in bonus or incentive arrangements at the committee s sole discretion. Currently, each participates in the discretionary bonus scheme and the EDIP, described on pages 133 and 139 and 140 of this report respectively.

Each executive director may terminate his employment by giving his employer 12 months written notice. In this event, for business reasons, the employer would not necessarily hold the executive director to his full notice period.

Other than in the case of Dr Brian Gilvary (who became a director on 1 January 2012), the service agreements are expressed to expire at a normal retirement age of 60; however, such executive directors could not, under UK law, be required to retire at this (or any other) age following abolition of the default retirement age.

The employer may lawfully terminate the executive director s employment in the following ways:

By giving the director 12 months written notice.

Without compensation, in circumstances where the employer is entitled to terminate for cause, as defined for the purposes of his service agreement.

Additionally, in the case of Iain Conn and Dr Brian Gilvary, the company may lawfully terminate employment by making a lump sum payment in lieu of notice equal to 12 months base salary. The company may elect to pay this sum in monthly instalments rather than as a lump sum.

The lawful termination mechanisms described above are without prejudice to the employer s ability in appropriate circumstances to terminate in breach of the notice period referred to above, and thereby to be liable for damages to the executive director.

In the event of termination by the company, each executive director may have an entitlement to compensation in respect of his statutory rights under employment protection legislation in the UK and potentially elsewhere.

The committee considers that its policy on termination payments arising from the contractual provisions summarised above provides an appropriate degree of protection to the director in the event of termination, and is consistent with UK market practice.

Exit payment policy

If it became necessary for the company to terminate an executive director s employment, and therefore to determine a termination payment, the committee s policy would be as follows in relation to the matters described below:

The director s primary entitlement would be to a termination payment in respect of his service agreement, as set out above. The committee will consider mitigation to reduce the termination payment to a leaving director when appropriate to do so, having regard to the circumstances and the law governing the agreement. Mitigation would not be applicable where a contractual payment in lieu of notice is made. In addition, the director may be entitled to a payment in respect of his statutory rights. Other potential elements are as follows. First, the committee would consider whether the director should be entitled to an annual bonus in respect of the financial year in which the termination occurs; normally, any such bonus would be restricted to the director s actual period of service in that financial year. Second, the committee would consider whether conditional share awards held by the director under the EDIP should lapse on leaving or should, at the committee s discretion, be preserved (in which event the award would normally continue until the normal vesting date and be treated in the manner described on pages 139 and 140 of this report). Any such determination will be made in accordance with the rules of the EDIP, as approved by shareholders. Third, if the departing director is eligible for an early retirement pension, the committee would consider, if relevant under the terms of the plan in which the director participates, the extent of any actuarial reduction that should be applied.

In determining the overall termination arrangements, the committee would have regard to all relevant circumstances, and would therefore distinguish between types of leaver and the circumstances under which the director left the company. This is primarily relevant to consideration of how discretion would be exercised in relation to conditional share awards under the EDIP. It is also relevant where a departing director has a right to an early retirement pension. UK directors who leave in circumstances approved by the committee may have a favourable actuarial reduction applied to their pensions (which has to date been 3%). Departing directors who leave in other circumstances are subject to a greater reduction.

The performance of the leaving director would be taken into account in various respects. In particular, in deciding whether to exercise discretion to preserve EDIP awards, the committee would have regard to the director s performance during the performance cycle of the relevant awards, as well as a range of other relevant factors, including the proximity of the award to its maturity date.

The committee would also have regard to all other relevant factors, including consideration of whether a contractual provision in the director s arrangements complied with best practice at the time the director s employment was terminated as well as at the time the provision was agreed to.

Director leaving the board

Dr Byron Grote will be retiring from the board at the 2013 AGM, and ceasing employment with the company soon after. Under the rules of the EDIP, his outstanding performance share awards pertaining to the 2011-2013, 2012-2014 and 2013-2015 performance periods, as well as the matching share awards in respect of 2010, 2011 and 2012 deferred bonus will all be prorated to reflect actual service during the applicable three-year performance periods. These share awards will vest at the normal time to the extent the performance targets or hurdles are met. His 2013 bonus eligibility will likewise be prorated to reflect his service and based on group results for the year. He will not receive any termination payments on leaving service.

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Further details

Executive directors 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.

During the year, the fees received by executive directors for external appointments were as follows:

Director	Appointee company	Additional position held at appointee company	Total fees
Iain Conn	Rolls-Royce	Senior independent director	£72,000
Dr Byron Grote	Unilever	Audit committee member	Unilever PLC £47,500
			Unilever NV 54,935

Performance shares (audited)

			Share element interests				Interests vested in 2012 and 201		
	Performance period	Date of award of performance shares	Potential maximum performance shares[a] At 1 Jan 2012	Awarded 2012	At 31 Dec 2012	Awarded 2013	Number of ordinary shares vested[b]	Vesting date	Marke of each at v
c	2009-2011	06 May 2009	539,634				101,735	15 Feb 2012	
	2010-2012	09 Feb 2010	581,082		581,082		0		
	2011-2013	09 Mar 2011	1,330,332		1,330,332				
	2012-2014	08 Mar 2012[d]		1,343,712	1,343,712				
	2013-2015	11 Feb 2013				1,393,032			
nn	2008-2013[e]	13 Feb 2008	133,452		133,452		145,489	7 Feb 2013	
	2009-2011	11 Feb 2009	780,816				149,259	15 Feb 2012	
	2010-2012	09 Feb 2010	656,813		656,813		0		
	2011-2013	09 Mar 2011	623,025		623,025				
	2012-2014	08 Mar 2012[d]		660,663	660,663				
	2013-2015	11 Feb 2013				699,535			
n									
	2010-2012[f]	15 Mar 2010	60,000		60,000		65,414	15 Jan 2013	
	2011-2013[f]	14 Mar 2011	67,500		67,500				
	2010-2012[g]	15 Mar 2010	22,500		22,500				

	2011-2013[g]	14 Mar 2011	22,500		22,500			
	2012-2014	08 Mar 2012[d]		624,434	624,434			
	2013-2015	11 Feb 2013				641,860		
on								
	2009-2011	11 Feb 2009	992,928				187,193	15 Feb 2012
	2010-2012	09 Feb 2010	801,894		801,894		0	
	2011-2013	09 Mar 2011	785,394		785,394			
	2012-2014	08 Mar 2012[d]		828,936	828,936			
	2013-2015	11 Feb 2013				859,212		
s								
y								
d	2009-2011	11 Feb 2009	755,512[h]				144,422	15 Feb 2012
	2010-2012	09 Feb 2010	303,948[h]		303,948		0	
	2009-2011	11 Feb 2009	520,544[h]				99,506	15 Feb 2012
	2010-2012	09 Feb 2010	218,938[h]		218,938		0	

[a] BP s performance is measured against the oil sector. For awards under the 2010-2012 plan, performance conditions were measured one-third on TSR against ExxonMobil, Shell, Total, ConocoPhillips and Chevron and two-thirds on a balanced scorecard of underlying performance. For awards under the 2011-2013 plan, performance conditions are measured 50% on TSR against ExxonMobil, Shell, Total, ConocoPhillips and Chevron; 20% on reserves replacement against the same peer group; and 30% against a balanced scorecard of strategic imperatives. For awards under the 2012-2014 plan, performance conditions are measured one-third on TSR against ExxonMobil, Shell, Total and Chevron; one-third on safety and operational risk management; and one-third on a balanced scorecard of strategic imperatives. Each performance period ends on 31 December of the third year.

[b] 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.

[c] Dr Byron Grote and Bob Dudley receive awards in the form of ADSs. The above numbers reflect calculated equivalents in ordinary shares. One ADS is equivalent to six ordinary shares.

[d] The market price of ordinary shares on 8 March 2012 was £4.94 and for ADSs was $47.11.

[e] Restricted award under share element of EDIP. As reported in the 2007 directors remuneration report in February 2008, the committee awarded Iain Conn restricted shares, in two tranches of 133,452 shares each and on vesting include re-invested dividends on the shares vested. The total vesting of the first tranche was 155,695 shares at £4.91 on 22 February 2011. The remaining award, noted above, vested on 7 February 2013, the fifth anniversary of the award at £4.58.

[f] Dr Brian Gilvary was conditionally awarded shares under the Executive Performance Plan prior to his appointment as a director. The vesting of these shares is not subject to further performance conditions.

[g] Dr Brian Gilvary was conditionally awarded shares under the Competitive Performance Plan prior to his appointment as a director. The vesting of these shares is subject to performance conditions.

[h] Potential maximum of performance shares reflect actual service during performance period on a pro-rated basis.

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Deferred shares (audited)

				Deferred share element interests				Interests vested in 201	
			Date of award of deferred shares	Potential maximum performance shares				Number of ordinary shares vested	
us year	Type	Performance period		At 1 Jan 2012	Awarded 2012[a]	At 31 Dec 2012	Awarded 2013		Vesting date
2011	Comp	2012-2014	08 Mar 2012		109,206	109,206			
	Vol	2012-2014	08 Mar 2012		109,206	109,206			
	Mat	2012-2014	08 Mar 2012		218,412	218,412			
2012	Comp	2013-2015	11 Feb 2013				114,690		
	Vol	2013-2015	11 Feb 2013				114,690		
	Mat	2013-2015	11 Feb 2013				229,380		
2010	Comp	2011-2013	09 Mar 2011	21,384		21,384			
	Mat	2011-2013	09 Mar 2011	21,384		21,384			
2011	Comp	2012-2014	08 Mar 2012		80,652	80,652			
	Vol	2012-2014	08 Mar 2012		80,652	80,652			
	Mat	2012-2014	08 Mar 2012		161,304	161,304			
2012	Comp	2013-2015	11 Feb 2013				80,648		
	Vol	2013-2015	11 Feb 2013				80,648		
	Mat	2013-2015	11 Feb 2013				161,296		
2009	DAB	2010-2012	15 Mar 2010	87,394		87,394		95,279	15 Jan 2013
2010	DAB	2011-2013	14 Mar 2011	44,971		44,971			
2011	DAB	2012-2014	15 Mar 2012		73,624	73,624			
2012	Comp	2013-2015	11 Feb 2013				78,815		
	Vol	2013-2015	11 Feb 2013				78,815		
	Mat	2013-2015	11 Feb 2013				157,630		
2010	Comp	2011-2013	09 Mar 2011	26,604		26,604			
	Vol	2011-2013	09 Mar 2011	26,604		26,604			
	Mat	2011-2013	09 Mar 2011	53,208		53,208			
2011	Comp	2012-2014	08 Mar 2012		91,638	91,638			
	Vol	2012-2014	08 Mar 2012		91,638	91,638			
	Mat	2012-2014	08 Mar 2012		183,276	183,276			
2012	Comp	2013-2015	11 Feb 2013				97,278		
	Vol	2013-2015	11 Feb 2013				97,278		
	Mat	2013-2015	11 Feb 2013				194,556		

Comp = Compulsory.

Vol = Voluntary.

Mat = Matching.

DAB = Deferred Annual Bonus Plan.

[a] The market price of ordinary shares on 8 March 2012 was £4.94 and for ADSs was $47.11.

[b] Bob Dudley and Dr Byron Grote 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] Dr Brian Gilvary was granted the shares under the DAB prior to his appointment as a director. The vesting of these shares is not subject to further performance conditions and he receives deferred shares at each scrip payment date as part of his election choice.

Share interests in share option plans (audited)

Option type	At 1 Jan 2012	Granted	Exercised	At 31 Dec 2012	Option price	Market price at date of exercise	Date from which first exercisable
BP SOP	17,835			[b]	$48.99		18 Feb 2005
BP SOP	17,835			17,835	$38.10		17 Feb 2006
SAYE	617		617		£4.87	£4.92[c]	01 Sep 2011
SAYE	605			605	£4.20		01 Sep 2012
SAYE	3,017			3,017	£3.68		01 Sep 2016
SAYE		797		797	£3.16		01 Sep 2015
EXEC	130,000			[b]	£5.72		18 Feb 2005