BP PLC
Form 20-F
March 06, 2012

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 2011

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.

1 St James s Square, London SW1Y 4PD

United Kingdom

Tel +44 (0) 20 7496 5311

Fax +44 (0) 20 7496 4573

(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**
3.125% Guaranteed Notes due 2012	**New York Stock Exchange**
5.25% Guaranteed Notes due 2013	**New York Stock Exchange**
3.625% Guaranteed Notes due 2014	**New York Stock Exchange**
1.7% Guaranteed Notes due 2014	**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**
3.2% Guaranteed Notes due 2016	**New York Stock Exchange**
4.75% Guaranteed Notes due 2019	**New York Stock Exchange**
4.5% 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**

*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	18,975,902,659
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 þ No ¨

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

Yes ¨ No 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

Cross reference to Form 20-F

Contents

Additional information for shareholders

Financial statements

Miscellaneous terms

In this document, unless the context otherwise requires, the following terms shall have the meaning set out below.

ADR

American depositary receipt.

ADS

American depositary share.

AGM

Annual general meeting.

Amoco

The former Amoco Corporation and its subsidiaries.

Atlantic Richfield

Atlantic Richfield Company and its subsidiaries.

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.

Barrel (bbl)

159 litres, 42 US gallons.

b/d

barrels per day.

boe

barrels of oil equivalent.

BP, BP group or the group

BP p.l.c. and its subsidiaries.

Burmah Castrol

Burmah Castrol PLC and its subsidiaries.

Cent or c

One-hundredth of the US dollar.

The company

BP p.l.c.

Dollar or $

The US dollar.

EU

European Union.

GAAP

Generally accepted accounting practice.

Gas

Natural gas.

GCRO

Gulf Coast Restoration Organization.

Hydrocarbons

Crude oil and natural gas.

IFRS

International Financial Reporting Standards.

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.

Liquids

Crude oil, condensate and natural gas liquids.

LNG

Liquefied natural gas.

London Stock Exchange or LSE

London Stock Exchange plc.

LPG

Liquefied petroleum gas.

MDL 2179

Multi-District Litigation proceedings pending in New Orleans.

MDL 2185

Multi-District Litigation proceedings pending in Houston.

mb/d

thousand barrels per day.

mboe/d

thousand barrels of oil equivalent per day.

mmBtu

million British thermal units.

mmboe

million barrels of oil equivalent.

mmcf

million cubic feet.

mmcf/d

million cubic feet per day.

MW

Megawatt.

NGLs

Natural gas liquids.

OECD

Organization for Economic Co-operation and Development.

OPEC

Organization of Petroleum Exporting Countries.

Ordinary shares

Ordinary fully paid shares in BP p.I.c. of 25c each.

Pence or p

One-hundredth of a pound sterling.

Pound, sterling or £

The pound sterling.

Preference shares

Cumulative First Preference Shares and Cumulative Second Preference Shares in BP p.l.c. of £1 each.

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.

SEC

The United States Securities and Exchange Commission.

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.

Tonne

2,204.6 pounds.

Trust

Deepwater Horizon Oil Spill Trust.

UK

United Kingdom of Great Britain and Northern Ireland.

US

United States of America.

Information about this report

This document constitutes the Annual Report and Accounts in accordance with UK requirements and the Annual Report on Form 20-F in accordance with the US Securities Exchange Act of 1934, for BP p.l.c. for the year ended 31 December 2011. A cross reference to Form 20-F requirements is on page 2.

This document contains the Directors Report, including the Business Review and Management Report, on pages 7-138 and 153-172. The Directors Remuneration Report is on pages 139-151. The consolidated financial statements of the group are on pages 173-281 and the corresponding reports of the auditor are on pages 176-177.

BP Annual Report and Form 20-F 2011 and *BP Summary Review 2011* 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 2011* or *BP Summary Review 2011,* forms any part of those documents.

BP p.l.c. is the parent company of the BP group of companies. Unless otherwise stated, the text does not distinguish between the activities and operations of the parent company and those of its subsidiaries.

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).

Cautionary statement

In order to utilize the Safe Harbor provisions of the United States Private Securities Litigation Reform Act of 1995 (the PSLRA), BP is providing the following cautionary statement. This document contains certain forward looking statements within the meaning of the PSLRA with respect to the financial condition, results of operations and businesses of BP and certain of the plans and objectives of BP with respect to these items. These statements may generally, but not always, be identified by the use of words such as will , expects , is expected to , aims , should , may , objective , is likely to , intends , believes , anticipates , p expressions. In particular, among other statements, (i) certain statements in the Chairman s letter (pages 8-11), the Group chief executive s letter (pages 14-17) and the Business review (pages 18-111), including but not limited to statements under the headings Our Strategy , Outlook and Looking Ahead , with regard to strategy and strategic priorities, plans to deliver shareholder value, expectations regarding the 10-point plan , expectations regarding future dividend payments, BP s outlook on global energy trends to 2030 and beyond, the intention to make $38 billion of disposals, anticipated increase in operating cash flow and margins, future capital expenditure, expected level of investments, the anticipated timing for completion of and final proceeds from the disposition of certain BP assets, future production levels including expectations for an increase in high-margin production, the timing and composition of future projects including expected start up, completion, timing of production, level of production and margins, expectations for drilling and rig activity in the Gulf of Mexico, the timing and quantum of and timing for completion of contributions to and payments from the $20-billion Trust fund, the expected terms of the proposed settlement agreement with the Plaintiffs Steering Committee in MDL 2179 and the expected timing of the fairness hearing and court approvals in respect thereof, the expected amount, source and timing of payments under any settlements, expectations regarding regulation and taxation of the energy industry and energy users, future global refinery capacity and utilization, the timing for completion of the Whiting refinery upgrade, plans regarding the implementation of enhancements to BP s risk management system, expectations regarding the reduction of net debt and the net debt ratio, the expected future level of depreciation, depletion and amortization, the expected level of the refining marker margin, the completion of planned and announced divestments, including the planned disposals of the Texas City refinery and the southern part of the US West Coast FVC, dates or periods in which production is scheduled or expected to come onstream or a project or action is scheduled or expected to begin or be completed, and the level of future turnaround activity; (ii) the statements in the Business review (pages 18-111), Corporate governance (pages 119-138), the Directors remuneration report (pages 139-151) and Additional information for shareholders (pages 153-172) with regard to plans to continue the ongoing process of embedding OMS, the timing for the implementation of the Bly report recommendations, 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 for the completion of the Shoreline Clean-up, the timing of, cost of, source of payment and provision for future remediation and restoration programmes and environmental operating and capital expenditures, the anticipated future level of time for conversion of proved undeveloped reserves to proved reserves, expectations regarding Refining and Marketing s intentions to achieve $2 billion in performance improvement by the end of 2012, plans to halve US refining capacity by the end of 2012, the timing for the completion of construction at the Cherry Point refinery, anticipated investment in Alternative Energy, expectations regarding greater regulation and increased operating costs in the Gulf of Mexico in the future, and costs for providing pension and other post-retirement benefits; (iii) the statements in the Business review (pages 103-106) 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, expected payments under contractual and commercial commitments and purchase obligations, and including under Liquidity and capital resources Trend information , with regard to production excluding TNK-BP, the expected level of turnarounds, the marketing environment in fuels, lubricants and petrochemicals, underlying average quarterly charge from Other businesses and corporate, and expectations regarding future disposals; and (iv) certain statements in the Business review (page 84) and Additional information for shareholders (pages 160-166) 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 timing of bringing new fields onstream; the timing of certain disposals; future levels of industry product supply, demand and pricing; 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 all parties to the Deepwater Horizon 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 59-63). 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.

Unless otherwise indicated, 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. The company was incorporated in 1909 in England and Wales and changed its name to BP p.l.c. in 2001. 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 167 for more details).*

The registered office of BP p.l.c., and our worldwide headquarters, is:

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 is BP America Inc.,

501 Westlake Park Boulevard, Houston, Texas 77079.

Tel +1 281 366 2000.

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Group overview

2011 was a year of recovery, consolidation and change. We laid strong foundations, reshaped the portfolio and recovered momentum.

Chairman s letter

Carl-Henric Svanberg

Chairman

Dear fellow shareholder,

In 2011 we re-laid the foundations of BP. Our objective was to ensure your company is able to deliver sustainable shareholder value in the months and years ahead. Above all else, this is dependent on BP having the trust of the societies in which it works today and over the long term.

During the year the board oversaw a major reorganization designed to establish a stronger, safer BP. The progress made demonstrates that the company can and will recover from the consequences of the Deepwater Horizon accident. We remained mindful of the tragic events seen in 2010 and the need to ensure such an accident never happens again.

I thank you for the patience you have shown as we work to rebuild your company.

The board set three priorities for BP. Safety must be enhanced and embedded. Trust must be regained. Value must be created through a clear strategic plan. While these priorities are simple to express, substantial activity is required to turn them into tangible and lasting change.

On safety, the board supported and challenged Bob Dudley and his executive team as they restructured and enhanced BP s processes, systems and culture. Furthermore, the board initiated a review of the way BP manages, reports and acts on risk, including board oversight.

On trust, we ensured that BP continued to meet its commitments in the Gulf of Mexico. We co-operated with every official investigation and prepared for litigation. We worked closely with governments and regulators, and we communicated openly with shareholders and the wider world.

On value, the board set a 10-point plan focused on growing operating cash flow and increasing shareholder returns. The company will play to its greatest strengths and prioritize value over volume. Relentless execution of this strategy is now needed so we deliver value to our shareholders.

BP s financial and operating performance in 2011 has created a springboard for growth. In the upstream, we secured 55 new exploration licences in nine countries, and our Refining and Marketing segment delivered very strong earnings. Our $38-billion divestment programme is strengthening the group s financial position and focusing our portfolio.

In 2011 we restored your dividend, and I am pleased to report that we increased the dividend by 14% in February 2012, in accordance with our policy.

The wider world did not stand still in 2011. We saw rapid and sometimes unpredictable change. This included escalation of the European debt crisis and political upheaval in countries where BP has significant operations, such as Libya and Egypt. We kept a close watch on these developments and acted where required. Our international advisory board assisted us in this task.

The company continually looks for ways to form new relationships and enhance its partnerships around the world. Our new alliance with Reliance Industries in India is a significant venture in a fast-growing market. Russia is particularly important for BP. Our TNK-BP alliance is hugely successful. Since acquiring 50% of the company for around $8 billion, BP has received around $19 billion in dividends - which equates to around $2 billion per year. In 2011, we saw new opportunities in Russia, but these did not progress. This region still has excellent potential for BP and we remain committed to it. The nature of our industry is rarely straightforward, and BP will never shrink from pursuing opportunities simply because they involve challenges.

In my letter last year, I commented on the evolution of the board. This has continued. My goal is to ensure that the board combines a broad set of skills and experience. BP s board should be diverse in the widest sense. It should have the best blend of the best people from our industry and from other sectors. BP remains committed to meritocracy as well as diversity.

Andrew Shilston and Professor Dame Ann Dowling have joined the board as non-executive directors and Brian Gilvary has joined as an executive director.

Left BP s LNG activities are focused on building competitively advantaged liquefaction projects.

Chairman s letter

Andrew, a former finance director at Rolls-Royce, brings substantial experience in the oil and gas industry through previous roles at Enterprise Oil and Cairn Energy. Ann is Head of the Department of Engineering at the University of Cambridge, where she is Professor of Mechanical Engineering. She brings exceptional academic and engineering expertise to BP.

Brian Gilvary is now our chief financial officer. His broad experience of BP, gained over 25 years in influential roles such as the chief executive of integrated supply and trading and as deputy group CFO, makes him a valuable addition. Our previous CFO Byron Grote takes up a new role as the director responsible for corporate business activities. Byron has made a substantial contribution over his lengthy BP career and I am pleased we have retained his services as a board member.

Left The East Azeri platform in the Caspian Sea in Azerbaijan. BP is the largest foreign investor in the country.

Right In 2011, the chairman visited the Alberta oil sands in Canada including the Sunrise Energy Project BP s joint venture with Husky Energy.

In detail

For more information

on the board and its

committees, see

Corporate governance

report.

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Bill Castell has decided not to seek re-election at the forthcoming AGM. Bill has made a substantial contribution to the board, not least as chair of the safety, ethics and environment assurance committee. Bill has devoted all the time that was asked of him and more in the service of the board and the company. I speak for the whole board when I thank him sincerely for all he has done. Bill s role as senior independent director will be taken by Andrew Shilston, who will be supported on internal matters by Antony Burgmans.

The board committees have always played an important oversight role, freeing the main board to concentrate on strategic matters. All of our committees have been heavily involved this year. Each committee has dealt with different challenges, and all of the directors have been unstinting in the time they have given.

The Gulf of Mexico committee, formed in 2010 and chaired by Ian Davis, has been invaluable in allowing the board to prioritize its work during the restoration of the Gulf of Mexico and the ensuing litigation. During the year, Antony Burgmans became chair of the remuneration committee and Brendan Nelson became chair of the audit committee. Paul Anderson took over the chair of the safety, ethics and environmental assurance committee in December.

During the year, the remuneration committee has worked with Bob Dudley and his team to remodel the reward system within the group. The system below the board is now clearly focused on the long term and is similar to that used for executive directors. I believe our approach to rewarding directors balances the company s priorities of driving financial performance, meeting our responsibilities as a corporate citizen and providing value for our shareholders.

Against all of this background, I have been keen to see how the board could work more effectively. During the year, a working group of

non-executive directors reviewed board tasks, roles and processes. This work, coupled with our board evaluation, has led to a number of changes in the way in which the board operates. These are set out in the board performance section of this annual report.

2011 was a testing year for everyone at the company. The board was impressed by the way in which Bob and his executive team tackled a range of considerable issues. We were also struck by the tenacity and dedication of BP s employees. On behalf of the board, I thank everyone for their efforts.

In 2012 we must execute our 10-point plan and continue to meet our commitments in the Gulf of Mexico. While many of the investigations into the causes of the accident have been completed, we still face major litigation in the US during 2012. This must run its course, although we are pleased with the continuing progress that we are making with settling some of these claims.

As part of its strategic role, the board must be mindful of the long-term developments in our industry. *BP Energy Outlook 2030* tells us that rising populations, increasing levels of life expectancy and improving standards of living will continue to generate growing demand for energy. The challenges in terms of supply are immense. I expect these dynamics to provide BP with opportunities for decades to come. The report projects that fossil fuels will be providing around 80% of the world s energy in 2030. This will require companies such as ours to overcome substantial technical and physical challenges. Lower carbon resources and energy efficiency technologies are required to play their part in addressing both demand and emissions. BP must understand and adapt to these changes in order to remain sustainable in this changing world.

I believe BP ended the year stronger and safer, with increasing forward momentum and a clear strategy matched to the world we see ahead. This is a great company, with a strong board and excellent people. I thank you for your continued support. I will report back to you on BP s progress at this point next year.

Carl-Henric Svanberg

Chairman

6 March 2012

Group chief executive s letter

Bob Dudley

Group Chief Executive

Dear fellow shareholder,

Following the tragic Deepwater Horizon accident of 2010, BP entered 2011 facing a range of uncertainties. These included concerns about our ability to operate safely in deep water, meet our financial commitments in the Gulf of Mexico, and recover the trust and value we had lost. We were also subject to intense speculation around the future and direction of the company.

By the end of the year we had successfully resolved some significant uncertainties facing the company. We set new standards for safety, led by our safety and operational risk organization, and we reshaped our upstream business. We strengthened the group s financial position by progressing our divestment programme. We worked to earn back trust through co-operation with the official investigations and actively sharing the lessons learned. We set a clear strategic direction through a 10-point plan focused on building value for shareholders. We also received permission to resume operations in the Gulf of Mexico a significant milestone.

During the year more clarity also emerged over the 2010 accident as official investigation reports were published. Their central conclusions supported that of our own investigation namely that what happened in the Gulf of Mexico was a complex accident involving multiple causes and multiple parties. I am pleased that we were able to reach settlements with Mitsui, Weatherford, Anadarko and Cameron during 2011. On 3 March 2012 we announced a settlement with the Plaintiffs Steering Committee, subject to final written agreement and court approvals, to resolve the substantial majority of legitimate economic loss and medical claims made by individual and business plaintiffs in the Multi-District Litigation proceedings pending in New Orleans (MDL 2179). The legal process continues with other parties.

We recognize there is a great deal more to do, but I can report that BP finished its year of consolidation in robust shape.

Through the year, BP s employees worked with great determination to enhance what we do and how we do it. This work will continue. I want to make it absolutely clear that we are not seeking a return to business as usual. The events of 2010 demand more than that. As we move ahead, our job is to make BP a stronger, safer company by further embedding safety at the heart of the company, continuing to earn back trust, and creating long-term value for shareholders once again. In this letter, I outline in more detail the actions taken in 2011 to achieve these objectives.

Above During the
year BP gained its first
US exploration drilling
permit since the 2010
Deepwater Horizon oil
spill - for the Kaskida
field, Gulf of Mexico.

Safety

During the year, we reorganized our upstream segment to improve clarity and accountability. We introduced new systems and technologies to further enhance oversight of operations. We continued to increase the capacity of our independent safety and operational risk organization, and recruited experts from other high-hazard industries to add new expertise and perspectives. We also renewed the company s performance and reward systems, values and code of conduct, which require whoever works for BP to put safety first.

At the front line, we shut down platforms and operations to make necessary upgrades. We set new, voluntary standards for blowout preventers, which shut off the flow of oil in an emergency. We also designed a new type of capping stack, which now stands ready for deployment anywhere in the world in the event of a leak in deep water.

Trust

Looking back over events in the Gulf of Mexico, I am proud of how BP responded. Just in financial terms, during 2010 and 2011 combined we made a pre-tax cash outlay of more than $26 billion to cover oil spill response costs, meet claims and litigation expenses, support research, promote tourism and help restore the environment. The test of corporate responsibility is whether a company follows up its words with actions. I believe we have. And we will continue to do so.

During the year we were invited to 25 countries to share what we have learned in the Gulf. In turn, we have gone out to gain insights from organizations in other high-hazard sectors, including NASA, the UK Atomic Energy Authority and various naval bodies. We will keep listening to others and applying what we learn.

Value

As I write this letter, the market value of the company remains significantly lower than it was before the incident. Our 10-point plan shows our belief that the company can realize improved returns for shareholders. The plan sets out what you can expect from us, and what you will be able to measure, over the next three years.

- First and foremost, you will see a continuing, relentless focus on safety and risk management.
- You will see the company play to its strengths exploration; managing deepwater activity; giant fields; gas supply chains; our world-class downstream business; and our capabilities in developing technology and building relationships.
- You will see a company that is simpler and more focused as a result of a major divestment programme.
- You will see a company that is organized effectively and applies its standards consistently.
- You will see more visibility from us on our individual businesses.

You will be able to measure the effects of active portfolio management, as we invest more in our areas of strength and generate cash through further divestments.

You will be able to measure the contribution of new upstream projects with higher margins, as they come onstream over the next three years.

You will be able to measure operating cash flow, which we expect to be around 50% higher by 2014.[a]

[a] See footnote c on page 39.

Group chief executive s letter

In detail

For more on the

strategic priorities set

out in the 10-point plan,

see Our strategy.

Pages 37-41

We plan to use around half of the increased cash flow for investment and half for other uses including increased distributions to shareholders.

And finally, you will be able to measure balance sheet strength.

The plan makes a greater priority of creating value for the shareholder, rather than simply increasing production volume. We will sell assets earlier in their lifecycle following discovery if we spot opportunities to reinvest in higher growth areas. We are also being selective in where we invest along the supply chain. For example, we are selling certain mature fields that hold more value for others, and we are selling a number of refining and marketing assets that do not match our aspirations.

I want to say a little more about the areas of strength at the heart of our strategy.

Exploration is our lifeblood. We had a record year for new access in 2011, gaining 55 exploration licences in nine countries. This opened up around 315,000km^2 for exploration. We intend to more than double exploration investment over the next three years.

In deep water, we are confident in our ability to design, engineer and operate large installations safely. 2012 will be a busy year for us in the deepwater regions of Angola, Brazil and the Gulf of Mexico.

Left New investment

announced in 2011 may

extend production at the

Clair field of the UK North

Sea to 2050.

Right February 2011

saw BP announce a

partnership with Reliance Industries spanning the

gas value chain in India,

from exploration to

marketing.

In giant fields, work with our partners has increased output at Iraq s Rumaila field by more than 10%. BP was the first supermajor to exceed its production target in Iraq. During the year we also announced we will be investing approximately $14 billion with our partners in the UK North Sea.

Natural gas is set to be the fastest-growing fossil fuel globally to 2030. Here, we are forging new partnerships, such as the strategic alliance created in 2011 with Reliance Industries in India. We continue to have a significant focus on developing unconventional resources around the world. Taking technology and skills developed in North America, we are working with the governments of Oman and Algeria to develop their large tight gas reservoirs, and we also continue to work in Indonesia to develop their onshore coalbed methane fields.

We also have exceptional expertise in building supply chains. For example, we move gas from 6,000 metres below the Shah Deniz field in Azerbaijan to markets in Western Europe, 3,000 kilometres away.

In Refining and Marketing, our world-class fuels, lubricants and petrochemicals businesses are shifting the balance of their activity towards higher growth markets, including China and India. We are moving forward with our plans to sell around half of our refining capacity in the US, and we have made good progress on the modernization of the Whiting refinery. Looking ahead, we expect our downstream operations to be a material contributor to the cash flow we anticipate over the next few years.

These strengths are supported by our long-standing track record in developing and applying leading technology, and the deep and enduring relationships we form. We were disappointed that our exploration plans with Rosneft did not progress, but we remain committed to our TNK-BP investment in Russia, which continues to be successful.

A well-balanced business

As the *BP Energy Outlook 2030* shows, the world is now in a long wavelength transition to a lower-carbon energy mix. For BP, that means helping to meet current demand through the supply of oil and gas including unconventional resources while developing a number of the lower-carbon options needed at scale tomorrow.

During 2011, we invested a further $1.6 billion in our Alternative Energy business, which takes total investment since 2005 to $6.6 billion. We have a growing biofuels business in Brazil and we added 401MW[a] of wind generation capacity during the year, with interests in more than 1,000 wind turbines now turning across the US. In contrast, solar has evolved into a low-margin commodity market, and in 2011 we began winding down our remaining solar operations as we prepare to exit the business.

Looking ahead

BP is meeting its commitments and moving forward with increasing momentum. 2012 will be a year of milestone delivery, with financial momentum building in 2013 and 2014. In 2012, you can expect high-margin production coming back on stream, major project start-ups and new exploration wells, further progress on our divestment programme, continued improvement in downstream financial performance and completion of payments into the Deepwater Horizon Oil Spill Trust fund.

The company has a strong leadership team and non-executive directors who provide rigorous oversight challenging and supporting executives as circumstances dictate. I want to thank BP s employees for their resilience. They were again tested hard this year. The character of BP s people was evident wherever we operate, not least in Egypt and Libya, where our teams evacuated colleagues and their families safely during the upheavals in the region.

I thank investors for their continued patience through a tough time. One by one, we are addressing the uncertainties facing our company. The days ahead may bring further challenges, but we are in a much stronger position than this time last year. There is a great deal more to do, but we are building a stronger, safer BP that can play an important role in the world for many years to come.

Bob Dudley

Group Chief Executive

6 March 2012

[a] On a gross joint-venture basis (which includes 100% of the capacity of equity-accounted entities where BP has partial ownership). Including BP s share of joint ventures on a net basis, the capacity added was 274MW.

Our market

In 2011, energy markets proved resilient, with continued growth despite volatile conditions in the global economy.

Left Modernization work at BP's Whiting refinery, Indiana, made significant progress in 2011, with the completion of a new pipeline to Canada.

Right Operations at our East Azeri platform. BP production in Azerbaijan is an important source of natural gas for markets in Western Europe.

The growth in world oil consumption slowed in 2011, albeit with continued robust growth in China and certain other non-OECD countries partially offsetting an overall decline in OECD countries. However, despite the slowdown in demand, average crude oil prices in 2011 were significantly higher than in the previous year, exceeding $100 per barrel for the first time (in nominal terms). Natural gas prices diverged globally in 2011. Globally, refining margins improved on average as oil product demand continued to grow.

Economic context

After a very strong 2010, world economic growth slowed in 2011 and we expect subdued global growth to continue in 2012. Emerging economies with stronger productivity and rising populations led by China and India are set to drive growth, while developed countries may lag behind as they seek to address their internal fiscal imbalances.

Energy demand, and in particular oil demand, has followed overall economic trends in recent years, recovering strongly in 2010 but facing more challenging conditions in 2011, especially in OECD markets.

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

Below Work at BP's

Castellón refinery,

Spain. Refining

margins in Europe

increased in 2011,

as demand for

commercial transport

improved.

Crude oil prices

Crude oil prices, as demonstrated by the industry benchmark of dated Brent for the year, averaged $111.26 per barrel in 2011, about 40% above 2010 s average of $79.50 per barrel. This represents the highest annual average ever (in nominal terms), as well as the largest one-year increase ever.

Prices rose early in 2011 and then increased further following the loss of Libyan supplies, which drove prices briefly above $125 per barrel in April. Thereafter, weakening global economic growth, increased production by other OPEC producers and the release of International Energy Agency (IEA) strategic stocks helped to cushion the disruption. While oil prices eased over the remainder of the year, they still ended the year above $100 per barrel.

These record prices prevailed despite the fact that the growth in global oil consumption slowed in 2011 with demand rising by roughly 0.7 million barrels per day for the year (0.8%)[a] in the face of slower economic growth and higher prices. Growth in 2011 was concentrated in non-OECD countries, led by China. There was relatively little change in non-OPEC production and, with the loss of Libyan supplies beginning in February, OPEC crude oil production did not return to its January peak until November. As a result, by mid-year OECD commercial oil inventories were consistently below average for the first time since 2008.

By comparison, global oil consumption in 2010 grew by roughly 2.7 million barrels per day (3.1%)[b], the strongest growth in annual consumption since 2004, driven by a renewed global economy. Crude oil prices in 2010 remained stable in a range of $70-80 per barrel before beginning to increase in the fourth quarter due to rising consumption and continuing OPEC production.

We expect oil price movements in 2012 to continue to be driven by the pace of global economic growth and its resulting implications for oil consumption, and by OPEC production decisions, especially in reaction to the recovery of Libyan supplies and the EU embargo on Iranian crude.

[a] From *Oil Market Report February 2012©,* OECD/IEA 2012, page 5.
[b] *BP Statistical Review of World Energy June 2011.*

Our market

Left Operations at BP s Na Kika field in deepwater Gulf of Mexico. BP is one of the largest producers of hydrocarbons in the region.

Natural gas prices

Natural gas prices diverged globally in 2011, reflecting different regional dynamics. The average US Henry Hub First of Month Index fell to \$4.04/mmBtu, 8% lower than the prices in 2010, while in Europe prices increased.

After a record increase in 2010, global gas consumption growth moderated in 2011. In the US, economic momentum supported gas use in the first half of the year and a hot summer raised demand. Yet domestic production outpaced consumption growth due to further increases in the availability of shale gas. Henry Hub gas prices fell and traded below coal parity in US power generation throughout the year, leading to the displacement of coal by gas. Unusually mild winter weather weakened prices at the end of year. The differentials of production area prices to Henry Hub prices continued to narrow as pipeline bottlenecks were reduced.

In Europe, spot gas prices at the UK National Balancing Point increased by 33% to an average of 56.33 pence per therm for 2011 the highest level since 2008. The loss of Libyan gas supply raised continental European demand for Russian gas in early 2011, but LNG supply and weak general demand kept spot gas prices below oil-indexed contract levels. Competition between spot and contract pipeline supplies continued. High volumes of LNG were available to Europe, despite the Japanese earthquake and tsunami in March 2011, which caused major nuclear outages and significantly increased LNG purchases in Japan. This contributed to a tightening global LNG market over the year.

The economic rebound had led the average Henry Hub First of Month Index to recover in 2010 from eight-year lows, rising by 10% to \$4.39/mmBtu. In the UK, National Balancing Point prices averaged 42.45 pence per therm in 2010 - 38% above the depressed prices in 2009.

In 2012, we expect gas markets to continue to be driven by the economy, weather, domestic production, LNG supply and reductions in nuclear power generation following the Fukushima disaster in Japan in March 2011.

In detail

For more information, see

Refining and Marketing.

Page 94

Refining margins

In 2011, demand for oil products continued to grow, albeit more slowly than a year ago, with all of the demand increase occurring in non-OECD markets and with overall demand in the OECD resuming its structural decline. As new refining capacity continued to be commissioned in Asia and the Far East, global refinery utilization rates fell in 2011. Despite this, a number of factors supported an increase in refining margins across all regions for a second consecutive year. The BP refining marker margin (RMM)[a] averaged $11.64 per barrel in 2011, compared with $10.02 per barrel in 2010 and $9.19 per barrel in 2009.

In 2011, diesel prices relative to crude reached highs not seen since 2008 as the trend to lower-sulphur fuels continued and demand grew. Gasoline prices were volatile in 2011. In the US, short-term supply issues supported gasoline prices in the middle of the year despite a reduction in demand compared with last year. By the fourth quarter, US gasoline prices relative to crude had fallen to the lowest levels seen for at least 23 years. Refining margins improved in Asia Pacific, due to continuing oil demand growth and the disruption to Japanese refining operations caused by the earthquake and tsunami.

US mid-continent crude oils (including the key marker grade of West Texas Intermediate) were heavily discounted throughout the year because of increasing production in the US Lower 48 states and in Canada, coupled with constrained logistics. This allowed refiners that are able to access these crudes to capture additional margins.

The loss of Libyan crude oil supply in the first quarter of 2011 and production problems in the North Sea during the summer resulted in record high prices for low-sulphur grades of crude oil. This adversely impacted the margin for refiners configured to process these grades, particularly in Europe, the US East Coast and Asia.

By contrast, in 2010 the RMM increase compared with 2009 was due to strongly-improved demand for oil products, in line with the economic bounce-back from recession, despite unused refining capacity.

Looking ahead, the overall economic environment is expected to result in limited demand growth such that refinery utilization levels are likely to remain low, despite the announced shutdown of capacity in Europe and the US.

[a] See page 94 for further information on RMM.

Left In 2011, we

received local

government approval

for a 1.25mtpa PTA

plant to be added to

existing BP

petrochemicals facilities

in Zhuhai, China.

Our market: Longer-term outlook

The long-term outlook is one of growing demand for energy and increasing challenges for our industry in meeting the world s needs.

The facts and figures used

in our longer-term outlook commentary in this section

are derived from *BP Energy Outlook 2030,* published in

January 2012, unless otherwise indicated, and represent a 'base case' or most likely projection.

Long-term growth in energy demand

Energy demand is linked to economic growth, development and population. The world s population is projected to increase by 1.4 billion over the next 20 years, while its real income is likely to grow by 100% over the same period. This combination of factors is expected to increase world primary energy consumption by approximately 40% over the next 20 years, with non-OECD energy consumption as much as 70% higher by 2030. Energy and climate policies, efficiency gains and a long-term structural shift in fast-growing economies away from industry towards less energy-intensive activities may act to restrain consumption, but the overall trend is likely to be one of strong growth in energy demand.

Oil and gas are still expected to play a significant part in meeting this demand and we project they will represent 53% of total energy consumption in 2030 (compared with 57% in 2010). Even under the IEA s most challenging climate policy scenario (450 Scenario) that might with difficulty still be achievable, oil and gas together still makes up 49% of the energy mix in 2030, with combined demand projected to exceed current levels.[a] 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. We believe the political, technological, logistical, infrastructure and cost challenges presented by the 450 Scenario make it increasingly unlikely to occur, meaning that demand for fossil fuels would remain at a higher level for longer.

We also expect advances in technology to lead to new and more efficient ways to transform base hydrocarbons (including natural gas and coal) into usable forms of energy, petrochemicals and lubricants.

Beyond 2030, we believe it is currently very difficult to provide meaningful projections. We expect that growing population and per-capita incomes will continue to drive growing demand for the services that energy provides including mobility, heat and light. The way those services are provided will be shaped by future technology developments, changes in tastes, and future policy choices all of which are inherently uncertain. Concerns about affordability, energy security and environmental impacts in particular climate change are all likely to be important considerations for the future. These factors may accelerate the trend towards more diverse sources of energy supply, a lower average carbon footprint, increased efficiency of energy provision and use, and demand management.

We actively monitor developments and continually assess a range of potential outcomes and their implications for our long-term strategy.

[a] From *World Energy Outlook 2011©,* OECD/IEA 2011, page 545.

Above An engineer on board the BP oil tanker British Gannet. At the end of 2011, we had 53 international vessels.

Below The control room at BP's Atlantic LNG facility in Trinidad, where BP has been operating since 1961.

Meeting the energy challenge

We estimate that there are enough energy resources available to meet the increases in demand. As a measure of this availability, 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] Meanwhile, new technologies are improving the availability and affordability of unconventional fossil resources such as shale gas, oil sands and coalbed methane. And emerging renewable resources have the potential for significant growth as their markets mature and technological advances make them more affordable and efficient.

While energy is available to meet demand, action is also required to limit the volumes of carbon dioxide and other greenhouse gases being emitted through energy use. Global economic challenges have reduced the focus of some governments on climate policy, at least in the short term. But the position set out at the UN's 2010 climate change conference in Cancun that deep cuts are required to hold global temperature rises to 2°C, and the commitment by both developed and developing countries in Durban in 2011 to negotiate an agreement by 2015 that requires action from all countries, suggests that in the medium to long term an emphasis on carbon policy will return and grow. We project that under known and probable policy and technology, global CO_2 emissions may be 28% higher in 2030 than they are today, partly as a consequence of coal use in rapidly-growing economies. More aggressive, but still plausible, energy policy and technology deployment could lead to slower growth in CO_2 emissions than expected, with emissions from energy use falling after 2020, but probably not to the extent of putting the world on a global warming trajectory that does not exceed 2°C. And even these policies would require concerted multilateral action from policymakers and a willingness by society to bear a significant cost.

Energy security also represents a major challenge. More than half of the world's natural gas is in just three countries, and more than 80% of global oil reserves are in 10 countries, most of which are located well away from the hubs of energy consumption. The ability and willingness of OPEC members to expand capacity and production is one of the main factors determining the dynamics of the oil market.

[a] *BP Statistical Review of World Energy June 2011*. 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.

Our market: Longer-term outlook

The dual challenges of emissions and energy security underline the value of energy efficiency. Increases in efficiency have the potential to reduce emissions without inhibiting economic growth, and they can help energy-importing countries to reduce their dependency on others. For these reasons, we expect efficiency to remain high on the agenda through to 2030.

A diverse energy mix

We believe the global energy challenge can only be met through a diverse mix of fuels and technologies. This is why BP's portfolio includes oil sands, shale gas, deepwater production, and alternative energies such as biofuels and wind power, in addition to conventional oil and gas. As well as simply meeting growth in overall demand, a diverse mix can help to provide enhanced national and global energy security while supporting the transition to a lower-carbon economy.

Within the energy mix, we see a key strategic role for natural gas as a lower-carbon fuel that is increasingly secure and affordable. Used in place of coal for power, it can reduce CO_2 emissions by half.

Renewables will be essential in addressing the challenges of climate change and energy security over the long term. Renewable energy is already the fastest-growing fuel and is projected to grow 8.2% per annum to 2030   a rate similar to the emergence of nuclear power in the 1970s and 1980s. 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 the commercialization of effective options and technologies, but renewables must ultimately become free from subsidy and commercially self-sustaining. *See Risk factors   climate change and carbon pricing on page 60.*

The future for hydrocarbons

Given the vital role oil will continue to play in meeting demand, substantial investment in new technology will be required to boost recovery from declining fields and commercialize currently inaccessible resources. The industry's ability to increase recovery from mature assets will be profoundly important, particularly in the world's giant fields. Over time, it will become increasingly difficult to reach, extract and manage oil resources, and companies such as BP may be required to move yet further into technically challenging areas. Greater energy intensity could be required to extract these resources; operating costs and greenhouse gas emissions from operations are likely to increase. Along with increasing supply, we believe the energy industry will be required to make hydrocarbons cleaner and more efficient to use.

Carbon capture and storage (CCS) may help to provide a path to cleaner coal and gas, but CCS technologies still face significant technical and economic issues and are unlikely to be in operation at scale in the near future.

Policy and access

If industry and the market are to meet the world's growing demand for energy in a sustainable way, governments must set a stable and enduring framework. 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. Within this framework, we believe that the most effective means of finding, producing and distributing diverse forms of energy is to foster the use of markets that are open and competitive, and in which carbon has a price.

Our organization: Business model

BP's business model is to create value across the entire hydrocarbon value chain. This starts with exploration and ends with the supply of energy and other products that are fundamental to everyday life.

BP is one of the world's leading integrated oil and gas companies.[a] Our objective is to create value for shareholders and supplies of energy for the world in a safe and responsible way. We strive to be a safety leader in our industry, a world-class operator, a responsible corporate citizen and a good employer.

Above When completed in the second half of 2013, modernization work at our Whiting refinery should enable BP to capture additional margins.

At each stage of the hydrocarbon value chain there are opportunities for us to create value both through the successful execution of activities that are core to our industry, and through the application of our own distinctive strengths and capabilities in performing those activities.

We have two main business segments: Exploration and Production, and Refining and Marketing. Through these, our activities are focused on finding, developing and producing essential sources of energy, and turning these sources into products that people need. We provide our customers with fuel for transportation, energy for heat and light, lubricants to keep engines moving, and the petrochemicals products used to make everyday items like plastic bottles.

In detail

For more information about Alternative Energy, see Other businesses and corporate.

Page 101

We also invest in renewable energy sources, which we believe will be an increasing source of value for BP. Our activities are focused on biofuels and wind. These are managed through our Alternative Energy business, which is reported in Other businesses and corporate.

Our projects and operations help to generate employment, investment and tax revenues in countries and communities around the world. The relationships we form with governments, partners, contractors, customers, franchisees and suppliers are very important to the success of our business. We are committed to being responsible, meeting our obligations, and building long-lasting relationships.

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. Around 61% of the group's fixed assets are located in OECD countries, including around 37% in the US and around 18% in Europe.

In detail

For definitions of subsidiaries, joint ventures and associates, see Miscellaneous terms.

Page 4

The significant subsidiaries of the group at 31 December 2011 and the group percentage of ordinary share capital (to the nearest whole number) are set out in Financial statements Note 45 on page 251. For information on significant jointly controlled entities and associates of the group, see Financial statements Notes 24 and 25 on pages 215 and 216 respectively.

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

Our organization: Business model

Value creation in our industry

BP's core activities are similar to those carried out by other global, integrated, oil and gas companies.

First, we acquire the rights to explore for oil and gas. When we are successful in finding hydrocarbon resources, we create value by seeking to develop them into proved reserves or by selling them on if they do not fit with our strategic objectives. We often work with partners to mitigate risk or gain from complementary skills. Through disciplined execution of capital projects we then develop, extract and sell the resources. The benefits are shared with governments and other partners.

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

We manufacture fuels and products, creating value by seeking to operate a high-quality portfolio of well-located assets safely, reliably and efficiently. We use our sales and marketing skills to add value to our fuels and other products.

And we also invest in renewable energy sources, with a focus on biofuels and wind.

Integrated model

BP's distinctive capabilities and sources of value

By operating across the full hydrocarbon value chain we believe we can create more value for shareholders, as benefits and costs can often be shared by our two segments. We can develop shared functional excellence more efficiently in areas such as safety and operational risk, environmental and social practices, procurement, technology and treasury management.

We have a distinctive integrated supply and trading function, which aims to maximize the value of our production while ensuring our refineries are fully supplied. 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. The function also creates value through entrepreneurial trading, where our presence across the major energy trading hubs of the world provides access to vital information on the fundamentals of markets that are increasingly connected.

We consider our ability to build a wide range of strong, long-term relationships to be both a key strength and crucial to our success. We form partnerships with national oil companies and our international oil company peers. We partner with universities and governments in pursuit of improving the technologies available to us, in order to enhance our operations and develop new products. We also actively participate in industry bodies such as the American Petroleum Institute and the Marine Well Containment Company in the US and the Oil Spill Preventions and Response Advisory Group in the UK. Regular review and audit processes enable us to maintain strong links with contractors and suppliers. We work with our partners through the management frameworks embedded in our joint venture and shareholder agreements to ensure safe and reliable operations, and for our mutual commercial benefit.

Left Employees at Prudhoe Bay one of the 15 North Slope oilfields that BP operates in Alaska.

Right During 2011, full commercial operations started at Cedar Creek 2 wind farm in Colorado.

In detail

For more information,

see Technology.

Page 74

We believe our development and application of technology represents a distinctive capability that 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.

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 concerns, including the current emphasis on energy security and efficiency.

Our technology advisory council, which is comprised of eminent technology leaders from business and academia, advises the board and executive management on research and technology matters.

Our organization: Business model

In detail

For more information on

Exploration and Production,

see BP in more depth.

Page 80

Upstream and midstream playing to our strengths

Our Exploration and Production segment is responsible for our activities in oil and natural gas exploration, field development and production; midstream transportation, storage and processing; and the marketing and trading of natural gas, including liquefied natural gas, together with power and natural gas liquids.

Our exploration division obtains access to and finds resources at scale in the world's key hydrocarbon basins. We are an industry leader in seismic imaging, a key technology in the identification of potential hydrocarbon resources. Our developments division develops our hydrocarbon resources, applying effective project execution and capital efficiency. Our production division then extracts resources efficiently and maximizes their recovery.

We focus on areas that play to our strengths deepwater, gas value chains (including the infrastructure required from field to market) and giant fields. We are increasing investment with a particular focus on exploration. We actively manage our portfolio, including divesting assets when we believe they may be more valuable to others than to ourselves. This allows us to focus our leadership, technical resources, and organizational capability on the resources we believe are most likely to flourish in our portfolio.

In 2011, our upstream and midstream activities took place in 30 countries including Angola, Azerbaijan, Canada, Egypt, Norway, Russia, Trinidad & Tobago (Trinidad), the UK, the US and other locations within Asia, Australasia, South America, North Africa and the Middle East. Exploration and Production also includes gas marketing and trading activities, primarily in Canada, Europe and the US. In Russia, we have an important associate through our 50% shareholding in TNK-BP, a major oil company with exploration assets, refineries and other downstream infrastructure.

Upstream technology flagships

In detail

For more information on

Refining and Marketing,

see BP in more depth.

Page 94

Technology will continue to play a critical role in our upstream activities, as the upstream technology flagships diagram demonstrates. In addition, our Project 20K is a significant new initiative that illustrates how new advances have the potential to deliver material value. Through this, we are investing in technology to enable exploration, development and production of reservoirs that were previously beyond reach due to high reservoir pressures, including those at a pressure between 15,000 and 20,000 pounds per square inch. Successful deployment of these technologies would enable us to further develop a number of our existing resources substantially, and we also see opportunities to develop new onshore and offshore resources both as BP and in partnership with national oil companies.

Downstream working across our value chains

Our Refining and Marketing segment 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.

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. In total we market our products in more than 70 countries.

The segment comprises three main businesses: fuels, lubricants and petrochemicals. All of our businesses operate as value chains. Previously we discussed the segment under the headings of fuels value chains and international businesses, but we now report the value chains by business.

The fuels businesses sell refined petroleum products including gasoline, diesel and aviation fuel. Within this, the fuels value chains (FVCs) integrate the

Downstream technology

Our organization: Business model

activities of refining, logistics, marketing, and supply and trading on a regional basis. This recognizes the geographic nature of the markets in which we compete, providing the opportunity to optimize our activities from crude oil purchases to end-consumer sales through our physical assets (refineries, terminals, pipelines and retail stations). In addition, we operate a global aviation fuels business and an LPG marketing business, from which we intend to divest the bulk and bottled LPG marketing operations.

We own or have a share in 16 refineries including five in the US and seven in Europe. Our focus is on complex, upgraded refineries that are able to process cheaper feedstocks yet yield more valuable products. We also market fuels through around 21,800 retail sites, principally in the US, Europe, Australia and southern Africa. Many of our retail sites are now operated by franchisees with whom we work in close partnership as we seek to ensure our standards and brand are consistently applied. We divest assets and businesses when we believe they will be of greater value to others. In 2011, we announced that we are seeking buyers for our Texas City refinery; and for our Carson refinery near Los Angeles, together with its associated integrated marketing business in southern California, Arizona and Nevada.

Our lubricants business is involved in manufacturing and marketing lubricants and related services to markets around the world. In 2011, approximately 45% of our profit from lubricants was generated from non-OECD markets, and we see good opportunities for further growth in these areas. We market lubricants to the automotive, industrial, marine, aviation and energy markets. The business blends and markets lubricants globally through our key brands of Castrol, BP and Aral. Our strategic relationships with our original equipment manufacturing partners provide the ongoing collaboration needed to develop the next generation of high-performance lubricants, such as Castrol EDGE.

Our petrochemicals business operates on a global basis and includes the manufacture and marketing of petrochemicals that are used in many everyday products, such as plastic bottles and textiles for clothing. Future growth in our business is focused on the demand centres of Asia, where our relationships with joint venture partners are key to our strategy in these increasingly important markets. From 2012 we plan to create a new revenue stream in petrochemicals through licensing some of our leading technology.

Above BP is working with Mendel Biotechnology to develop and commercialize seed products with high resistance to environmental stresses, such as water and nutrient limitation.

Left Developed with Imperial College London, new Permasense sensors are helping BP corrosion engineers to see what is happening inside pipes.

Our organization: People and governance

The people of BP are united by a common code of conduct and values, and share an aspiration to make BP a stronger, safer company that makes a positive difference to the world.

Our board

In detail

For more information, see Corporate governance.

Page 119

The board is responsible for the direction and oversight of BP on behalf of shareholders. As at 31 December 2011, it comprised the chairman, nine non-executive directors together with the group chief executive; the chief financial officer and the chief executive of BP's Refining and Marketing segment.

The executive directors have responsibility for the day-to-day running of BP, while the non-executive directors bring independent viewpoints and a breadth of experience, along with insights into how other companies manage key issues. Five of our current non-executive directors have been appointed since 2010.

Above In 2011, BP announced the start of natural gas production from the Serrette field, offshore Trinidad.

Below A team at work in East Texas. As operator, BP drilled 148 wells across the US Lower 48 states in 2011.

Board committees play an increasingly important role. The committees are: the Gulf of Mexico committee; the safety, ethics and environment assurance committee; the audit committee; the remuneration committee; the nomination committee; and the chairman's committee. In addition, an independent international advisory board advises our chairman, group chief executive and board on strategic and geopolitical issues relating to the long-term development of the group.

In 2011, an internal review of risk management systems and processes was undertaken to enhance clarity, simplicity and the consistency of our risk management system, from front-line operations through to the boardroom. *See Our management of risk on page 42 for further information.* Also in 2011, a new board steering group completed a review of board governance. The review looked at the structure, roles, tools and processes involved in board and board committee work. The findings of the review will inform a new set of board governance principles, which will be published later in 2012. *See Board performance report on pages 120-133 for further information.*

Our employees

In detail

For more information on employees, see BP in more depth.

Page 73

We employ approximately 83,400 people (including 14,600 service station staff), the majority of whom are located in the US and Europe. The Deepwater Horizon oil spill in 2010 had a profound effect on our employees, and to strengthen and standardize what we do, we launched a range of internal change projects in 2011. See *How BP is changing on page 36 for more information.*

In addition, we are working hard to address a critical issue facing everyone in our industry a growing skills gap. This, alongside the increasing demand for energy products and complexity of projects, means that attracting and retaining skilled and talented people is vital.

Our leadership has focused on ensuring that appropriate development opportunities and succession plans are in place to build capability. 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 provide a range of professional development programmes and training to build capabilities in our people and are committed to creating an inclusive work environment where everyone is treated fairly, with dignity, respect and without discrimination.

Our organization: **People and governance**

In detail

For more information on contractors, see Working with partners and contractors.

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Contractors and suppliers

Like our peers, BP rarely works in isolation. In 2011, for example, 55% of the 374 million hours worked were carried out by contractors. These individuals play an important role for BP. During the year we initiated a far-reaching review of the way we work with third parties, particularly those involved in potential high-consequence activities. We are now implementing a range of measures based on our findings, with a focus on six key themes: consistent standards and priorities; fewer suppliers to enable deeper, longer-term relationships; detailed and systematic selection of contractors; clear and specific contracts; intensive oversight and verification; and assurance that supplier personnel are competent.

Our values

Our approach is built on respect, being consistent and having the courage to do the right thing. We believe success comes from the energy of our people. We have a determination to learn and to do things better. We depend upon developing and deploying the best technology, and building long-lasting relationships. We are committed to making a real difference in providing the energy the world needs today, and in the changing world of tomorrow. We are one team a group of diverse individuals from around the world united by shared values and a drive to rebuild BP.

These words, taken from the BP code of conduct, capture what we strive to stand for as a company our renewed values. They are an expression of work done across BP in 2011 to define and renew our principles and values. This work was carried out in response to the events of recent years, which have caused us to reflect on what is important and how we do what we do.

We launched our renewed values in 2011. They represent the qualities and actions we wish to see in BP, and those that BP already demonstrates when it is at its best. The values are aligned with our code of conduct and are there to guide the way we do business and the decisions we take, every day. Safety has been re-emphasized as our number one priority.

Left In 2011, we purchased 10 blocks in Brazil from Devon Energy. Here, a worker on the Deep Ocean Clarion moves drilling pipes on to the rig.

Above Technicians on board the *Jack Ryan* drilling ship, Angola. In 2011, BP gained access to five new deepwater blocks, offshore Angola.

In detail

Find out more online

bp.com/values

The values are much more than words we are actively seeking to embed these values at the heart of the systems and processes we are introducing to unify and strengthen our business. We are both enforcing and incentivizing values-led behaviour. For example, our updated performance and reward system, which came into effect on 1 January 2012, now creates an explicit link between our values and the way individuals are judged and rewarded within BP.

Our values

This statement of our values expresses our aspirations and intentions for BP, as we work together to strengthen safety and risk management, earn back trust and create value. Our values are aligned with, and an extension of, our code of conduct.

Safety

Safety is good business. Everything we do relies upon the safety of our workforce and the communities around us. We care about the safe management of the environment. We are committed to safely delivering energy to the world.

Respect

We respect the world in which we operate. It begins with compliance with laws and regulations. We hold ourselves to the highest ethical standards and behave in ways that earn the trust of others. We depend on the relationships we have and respect each other and those we work with. We value diversity of people and thought. We care about the consequences of our decisions, large and small, on those around us.

Excellence

We are in a hazardous business, and are committed to excellence through the systematic and disciplined management of our operations. We follow and uphold the rules and standards we set for our company. We commit to quality outcomes, have a thirst to learn, and to improve. If something is not right, we correct it.

Courage

What we do is rarely easy. Achieving the best outcomes often requires the courage to face difficulty, to speak up and stand by what we believe. We always strive to do the right thing. We explore new ways of thinking and are unafraid to ask for help. We are honest with ourselves, and actively seek feedback from others. We aim for an enduring legacy, despite the short-term priorities of our world.

One Team

Whatever the strength of the individual, we will accomplish more together. We put the team ahead of our personal success and commit to building its capability. We trust each other to deliver on our respective obligations.

Our code

The BP code of conduct sets the standard that we all work to. It is aligned with our values, group standards and legal requirements, and it clarifies the ethics and compliance expectations for everyone who works at BP. The code was updated in 2011 and now puts greater emphasis on a values-based approach. Where rules are not stated explicitly, our everyday business decisions will be guided by our values.

Our organization: Where we operate

2011 saw BP streamline its operational footprint through divestments while increasing new access to resources. The map below shows the group's key operating sites in 2011.

Our organization: How BP is changing

Following the tragic events in the Gulf of Mexico in 2010, we initiated a wide-ranging programme designed to enhance safety and risk management within the group, earn back trust and restore value. Much was achieved in 2011, but there is a great deal more to do.

Safety and operational risk

We are strengthening our group-wide application of enhanced, consistent standards driven by our safety and operational risk function, which is independent from the business segments.

In detail

See Safety, *page 65*

Risk management review

We are enhancing the clarity, consistency and quality of the way risks are understood, reported and acted upon, from front-line operations to the boardroom.

In detail See Our management of risk, *page 42*

Upstream restructuring

We restructured to create three global divisions exploration, developments and production. These constitute the biggest changes in BP s upstream business for 20 years.

In detail See Exploration and Production, *page 80*

Values and behaviours

We have refreshed our values and behaviours and continue embedding these into how we work together.

In detail

See Our values, *page 32*

Individual performance and reward

We have aligned performance and reward with our values and introduced safety and taking

Contractor management

We are driving consistent global standards, strengthening verification and assurance, and

Technology

Through technology, we are strengthening our capability to manage risks, capture business

Joint ventures not operated by BP

We initiated a review into our approach to the management of our relationships with significant

long-term perspective as key indicators.	developing longer-term relationships with contractors.	value and inform strategy development.	non-operated joint venture operators and partners. This work includes safety and operational risk as well as bribery and corruption risk.

In detail See Our values, *page 32*

In detail See Working with partners and contractors, *page 69*

In detail See Technology, *page 74*

In detail See Our partners in joint ventures, *page 69*

Our strategy

Below BP has a significant presence in Trinidad & Tobago, operating 13 offshore platforms and holding an interest in Atlantic LNG.

In 2011, we put forward a clear 10-point plan that defines what you can expect from us, and what you will be able to measure, through to 2014.

Following the tragic Deepwater Horizon oil spill, we set out a strategy designed to deliver stability, and restore trust and value. Our first priority was to work to make BP a safer, more risk-aware business. We pursued that strategy with purpose through 2011 and have now laid out a 10-point plan for BP s future.

Our renewed strategy is designed to make BP a simpler, stronger company that plays to its strengths. It concentrates our distinctive talents on high value, advantaged assets, with new and enhanced structures, process and discipline serving to support and sustain our businesses and operations. Our goal is to grow operating cash flows to enable us to both invest for future growth and increase distributions to shareholders.

Our upstream strategic focus is aligned with what we see as the five key drivers of value growth in our operations. These are: managing risk; increasing investment, with a particular focus on exploration; managing our portfolio actively; growing operating cash faster than production; and focusing on the major growth engines that capitalize on our strengths deepwater, gas value chains and giant fields.

In the downstream, we are in the business of hydrocarbon value chains, and with an intense focus on safe and reliable operations, we believe we now have the platform to sustain and grow a world-class business capable of generating leading returns and cash flow growth.

Above Having achieved our improved production target in 2010, BP and partners are working to refurbish the wells and facilities at the Rumaila field in Iraq.

Our strategy: Strategic priorities

Our 10-point plan

Our 10-point plan is how we intend to build a stronger, safer BP. The first five points are things you can expect from us; the second five are things you can measure.

What you can expect from us

We will keep a relentless focus on safety and managing risk

We are determined that BP will deliver world-class performance in safety, risk management and operational discipline. We will be a company that systematically applies our global standards as a single team.

We will play to our strengths

We have had major successes at finding oil and gas at scale. We are also among the real pioneers of deepwater exploration. We have decades of experience managing giant fields and developing valuable gas value chains. We have built a world-class downstream business. Underpinning these strengths are deep capabilities in building relationships and in developing technologies.

Left BP moves gas from 6,000 metres below the Shah Deniz field in Azerbaijan to markets in Western Europe, 3,000 kilometres away.

Right As part of a $1.2 billion investment announced in 2011, the Kinnoull reservoir, UK North Sea, will be connected to BP's Andrew platform.

We will be stronger and more focused

We intend to be a stronger and more focused BP, with a base of assets that is high graded and high performing.

We will be simpler and more standardized

Our organization is already much more standardized than it was before the Deepwater Horizon oil spill. The transformation of our Exploration and Production segment from a regional business to one that is managed along lines of functional expertise is an example of this. Our footprint is smaller, with fewer assets and operations in fewer countries. Our internal reward and performance processes are more streamlined. This should drive better and more sustainable performance in safety, quality and efficiency, with less variation.

We will improve transparency through our reporting

We will improve transparency in the reporting of our business segments. We now break out the numbers of certain parts of our businesses, such as lubricants and petrochemicals in the downstream. From the first quarter of 2012, the group s investment in TNK-BP will be reported as a separate operating segment.

What you can measure

Active portfolio management

We want to focus our portfolio further on our areas of strength, and deliver increased financial flexibility. By the end of 2013, we expect to have completed $38 billion of disposals since the start of 2010.

New projects with higher margins

We have a strong list of upstream projects due to come onstream over the next three years. By 2014, unit cash margins[a] on production from this new wave of projects are expected to be around double our existing average.[b]

Operating cash flow growth

We are aiming to generate an increase of around 50% net cash provided by additional operating activities by 2014 compared with 2011[C] approximately half from ending Deepwater Horizon Oil Spill Trust fund payments and around half from operations.

Use of cash flow for reinvestment and distributions

We will use additional operating cash prudently. We want to use around half for increased investment in our project inventory for growth, and around half for other purposes. This may include increased distributions to shareholders through dividends or share buybacks or repayment of debt.

Strong balance sheet

We intend to enhance the strength of our balance sheet by targeting our level of gearing[d] at 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 Exploration and Production segment, divided by the total number of barrels of oil and gas equivalent produced for 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 in 2014. The projection reflects our expectation that all required payments into the $20-billion trust fund will have been completed by the end of 2012. 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 249 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 230 for further information including a reconciliation to gross debt, which is the nearest equivalent measure on an IFRS basis.

Left Lingen refinery in

Germany is one of Europe s

most complex refineries due

to its ability to fully upgrade

crude during processing.

Our management of risk

Putting safety and risk management at the heart of the company is the foundation for building trust and creating value. In 2011 we began a process to review, refresh and enhance our management of risk.

The role of the board

The board is responsible for the direction and oversight of BP as set out in its governance principles, which include that it will 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, through its governance principles, 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. *See Risk management: from operations to the board on page 122.*

Our 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 COSO (Committee of Sponsoring Organizations of the Treadway Commission) in the US.

Key elements of the system include: the control environment; the management of risk and operational performance; and the management of people and individual performance. As such, BP s risk management system is an integral part of our 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.

Review of risk management

In 2011, we initiated a review of our risk management system. The review considered the group s existing risk management system, along with good practices in risk management from outside the company, with a view to identifying what might be done to enhance the clarity, simplicity and consistency of our risk management system.

Using the findings of this review, we have begun implementing enhancements to the way we manage and report risks. This has involved the development of common language, concepts and templates for consistent reporting on risks and risk management; designing enhancements to board and executive processes; and greater alignment of risk management activities and business processes. These improvements build from our existing management systems, standards and practices and we will continue to embed these in 2012. *See the information on Safety and operational risk on page 65 for examples of enhancements to the S&OR function and management of safety and operational risks.*

Our risk management system

Our enhanced risk management system focuses on three levels of activity:

First, 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 we face. Risks are to be identified and managed, and actions to improve the management of risk are to be put in place where necessary. Our aim is to address each different type of risk as well as we can promoting safe, compliant and reliable operations.

Second, for our 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 that we call the risk management report (RMR) for businesses and functions to report consistently the risks they face for management consideration, challenge, resource allocation and intervention.

Left Operations at BP's Shah Deniz platform, Azerbaijan. Located offshore, 40 miles south east of Baku, Shah Deniz is thought to hold 1 trillion cubic metres of gas.

Right BP's state-of-the-art Houston monitoring centre provides real-time communications between rigs in the Gulf of Mexico and experts based onshore.

Third, 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.

Drawing on this input, our enhanced risk management system assists us in our:

Understanding of the risk environment for input into our strategy.

Understanding of which risk types we operate with, given our strategy.

Identification and assessment of actual specific risks and the potential exposure they may represent.

Decision-making on how best to deal with those risks to manage our overall potential exposure.

Active management of identified risks.

Reporting to management and the board about how those risks are managed, and monitoring of our potential exposure.

Obtaining of assurance over the effectiveness of the management of those risks.

Interventions for improvements in the management of those risks where necessary.

Consideration of the effect of the external environment and our business activities on the principal activities of our risk management system.

Our management of risk

Above BP's Cooper River petrochemicals plant in South Carolina operates two PTA units. PTA is used in the production of plastic bottles.

Below Working with Falex Corporation, Air BP has developed a faster and more reliable way to test aviation lubricants.

During 2011, functions, strategic performance units, divisions and segments within BP were requested to prepare RMRs using the new, common approach. 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 are 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 as requiring particular group-level oversight in the coming year have been allocated to specific board and executive committees for oversight and monitoring. These are discussed below. *Also see Risk factors on pages 59-63 for a description of the material risks we face in our business.*

Risk management can also be a foundation for creating value. 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.

Safety and operational risk function

We have redefined and strengthened the scope and accountabilities of the group function for safety and operational risk (S&OR), creating a new team independent of business line management to drive safe, compliant and reliable operations in BP. The S&OR function, which continues to build towards its full staffing complement, includes S&OR teams which have been formed to work alongside line management but are independent of them. In pursuit of safe, compliant and reliable operations, S&OR personnel can assist, challenge and escalate or intervene as necessary to promote and assure the operating businesses' systematic and disciplined application of global standards on safety and operational risk. The function helps provide assurance as to whether line operations are carried out in accordance with the group's operating management system, and seeks to facilitate more comprehensive and assured S&OR risk action plans for operational units, more incisive interventions on emerging risk situations, and improved investigations and learning from significant incidents.

How we seek to manage our risks

The following is a summary of how we seek to manage the risks we have identified as having a high priority in 2012. There can be no guarantee that our risk management activities will mitigate or prevent these, or other, risks from occurring.

Strategic risks

In response to risks associated with the general macroeconomic outlook and changes in prices and markets, we monitor early warnings from our treasury team and customer-facing businesses. To manage our liquidity, financial capacity and financial exposure risks, we apply our financial framework (see *Liquidity and capital resources on page 103)* and we conduct liquidity stress testing and scenario-planning interventions.

Our current strategic priorities are set out in our 10-point plan (see *pages 38-39).* Among other things, this 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 performance-monitoring activity, including the planning of disposals; we focus on the delivery of major projects; and we pursue the development of continued technological advances and innovation.

The diverse locations of our operations around the world exposes us to a wide range of political developments and consequent changes to the economic and operating environment. For example, our investments in Russia could be adversely affected by heightened political and other environment risks. As such, we try to actively manage our relationships in Russia, including with the Russian federal government and with TNK-BP. We also seek to manage the group's exposure in Russia through our development of BP's overall portfolio.

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 such joint venture and contractor relationships actively, and this may include monitoring compliance with applicable standards.

As a result of the Deepwater Horizon oil spill there is significant uncertainty regarding the extent and timing of costs and liabilities relating to the incident, the impact of the incident on our reputation and the resulting possible impact on our licence to operate including, among other things, our ability to access new opportunities. In addressing these risks we seek to co-operate with investigators and we encourage the application of responsible and objective scientific analysis in determining outcomes. 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. We seek to engage with local communities in order to foster improved relationships and reputation.

Left Bernard Looney, BP's Executive Vice President, Developments, on board the Deep Ocean Clarion rig in Brazil.

Above Work at BP's Tangguh facility, West Papua, Indonesia; where gas is collected and distributed to energy markets via ship.

Our management of risk

In detail

For more information

on OMS, see Safety.

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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. See *Safety on page 66 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 oversight and control as hostile actions against our staff, our activities 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. We also maintain business continuity plans.

Crisis-management plans are developed to help us to respond effectively to emergencies and to avoid a potentially severe disruption in our business and operations. For deepwater drilling, interim requirements for oil spill preparedness and response, including crisis management response capability, were introduced in 2011 in the Gulf of Mexico. The intention is to build on these interim requirements to put in place group-wide practices for both oil spill preparedness and response and crisis management.

Successful recruitment and development of staff is central to our plans. We have programmes to recruit both graduates and experienced staff and we maintain succession plans for key roles. We also operate training and development programmes, including relating to leadership, and we engage all employees in regular performance-management processes.

Compliance and control risk

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 (see *page 31),* the requirements of which apply to all employees, supported by our various group standards covering issues such as anti-bribery and corruption, anti-money laundering and competition/anti-trust law compliance. 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.

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 and risk organizations. We also seek to maintain a positive and collaborative relationship with regulators and the industry at large.

Our performance

2011 was a year of further stern tests for BP. Our challenge was to stabilize the company and meet our commitments in the Gulf of Mexico while laying firm foundations for the future.

We went into 2011 with a clear set of strategic priorities and determination to rebuild the company. Our employees have worked to make BP a safer business and to earn back trust. We also pushed forward on the journey to grow value over the short, medium and long term. The key measures in this section show our progress in numbers, and here you can also read about some of the significant actions and events that defined our year.

Left The BP-Husky refinery in Toledo, Ohio in operation since 1919.

Right Azeri-Chirag-Guneshli is the largest oilfield under development in the Azerbaijan sector of the Caspian basin.

In detail

For more information, see Safer drilling.

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Safety

Our safety and operational risk function (S&OR) is driving the systematic and disciplined application of global standards in safety and operational risk across the company. We recruited 87 new employees into S&OR during the year, taking its total headcount to around 600 against a target headcount of 800.

During the year, as part of our enhanced focus on safety and operational risk management, we completed a programme of 47 major upstream turnarounds.

We set enhanced voluntary standards for how we drill in the Gulf of Mexico, and implemented new global standards in our operations worldwide. For example, in deepwater drilling, where we use drill rigs that are maintained in position by computer-controlled systems rather than fixed moorings, we require BP-contracted drill rigs to have no fewer than two blind shear rams and a casing shear ram[a] in order to provide additional assurance.

We initiated a review of the way we work with contractors and other industry partners. Guided by our findings, we have implemented a range of new measures, starting with our offshore rigs. We also reviewed and updated our system of risk management see *Our management of risk on pages 42-46.* And we reviewed and updated our values and behaviours, linked them explicitly to an enhanced code of conduct and embedded them in our approach to safety, performance management and reward.

[a] Shear rams are devices within a blowout preventer designed to cut the drill pipe and seal the well in the event of a blowout or other operational emergency.

Our performance

In detail

For more information on the Gulf of Mexico oil spill, see BP in more depth.

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Our upstream business is now reorganized into three divisions exploration, developments and production. We have also reorganized our drilling operations into a single global wells organization (GWO), which forms part of the developments division and takes a consistent, global approach to managing risk. GWO has implemented a number of standard processes since its formation, covering activities such as rig start-up and well cementing.

Trust

Released in January 2011, the report of the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling identified certain failures of management and decision-making within BP and its contractors, as well as regulatory failures, to be contributing factors to the accident. *See Safety on page 65 and Legal proceedings on pages 160-166 for information on other investigations and reports.* We are committed to working with government officials and other operators and contractors to identify and implement operational and regulatory changes that will enhance safety practices throughout the oil and gas industry. BP teams have travelled to 25 countries to share the lessons learned from events in the Gulf of Mexico with our industry, regulators and governments. We also shared equipment and technology developed during the response with the Marine Well Containment Company in the US.

On the ground, the focus of our work in the Gulf of Mexico shifted from response to recovery. The majority of the clean-up work required along the shoreline has now been completed. We are encouraged by local and state reports that indicate tourism in many areas of the region is rebounding. And all federal commercial fishing areas had been reopened by April 2011. We are still at work on the recovery and remain committed to meeting our responsibilities in the region.

By the end of 2011, we had paid $15.1 billion into the $20-billion Deepwater Horizon Oil Spill Trust fund (Trust) set up to meet the costs of the spill. In total, the Trust and BP had paid a total of $7.8 billion in claims, advances and other payments by the end of 2011.

Value

Our profit in 2011 was $25.7 billion compared with a loss of $3.7 billion in 2010. After adjusting for inventory holding gains, our replacement cost profit[a] in 2011 was $23.9 billion compared with a loss of $4.9 billion in 2010. Cash and cash equivalents at the end of 2011 totalled $14.1 billion and our net debt ratio[b] was 20.5%. *See Financial review on pages 56-58 for further information on the group s financial results.*

During 2010 and 2011 combined, we strengthened the group s financial position by completing asset sales totalling almost $20 billion and we have announced our intention to make further disposals that would bring the total to $38 billion by the end of 2013. Previously this disposal target had been set at $45 billion, however it was reduced in November 2011 when we received notice of termination from Bridas Corporation of the agreement for their purchase of BP s 60% interest in Pan American Energy LLC. We intend to reduce our net debt ratio to the lower half of the 10-20% range over time. During 2011 we reached settlements with MOEX USA Corporation (MOEX), Weatherford U.S., L.P. (Weatherford), Anadarko Petroleum Corporation (Anadarko) and Cameron International Corporation (Cameron) totalling $5.5 billion related to the Deepwater Horizon oil spill. All cash received has been paid to the Trust.

[a] Replacement cost profit or loss for the group is not a recognized GAAP measure. The equivalent measure on an IFRS basis is Profit (loss) for the year attributable to BP shareholders . See *footnote b on page 56 and page 110 for further information.*

[b] Net debt ratio is a non-GAAP measure. See Note 35 on page 230 for the equivalent measure on an IFRS basis.

Left BP employees at work in Prudhoe Bay, Alaska the largest oilfield in North America and among the 20 largest fields ever discovered.

Right Operations on the BP-operated Atlantis PQ, Gulf of Mexico - the deepest moored semi-submersible platform in the world when it was installed in 2007.

On 3 March 2012, we announced we had reached a settlement with the Plaintiffs Steering Committee (PSC), subject to final written agreement and court approvals, to resolve the substantial majority of legitimate economic loss and medical claims stemming from the Deepwater Horizon accident and oil spill. The PSC acts on behalf of individual and business plaintiffs in the Multi-District Litigation proceedings pending in New Orleans (MDL 2179). We estimate that the cost of the proposed settlement would be approximately $7.8 billion, but with no net impact on either the income or cash flow statements, since the proposed settlement is expected to be payable from the $20-billion Trust. While this is BP s reliable best estimate of the cost of the proposed settlement, it is possible that the actual cost could be higher or lower than this estimate depending on the outcomes of the court-supervised claims processes. See *Legal proceedings on page 162 for further information.*

[a] See Financial statements Note 6 on page 200.

[b] Based on sales of consolidated subsidiaries only this excludes equity-accounted entities.

Exploration and Production

The replacement cost profit before interest and tax for 2011 was $30,500 million, compared with $30,886 million for the previous year. See *Exploration and Production on page 80 for further information on the segment s financial results.*

Our production was lower than in 2010 due to divestments, the suspension of drilling in the Gulf of Mexico and the high number of turnarounds and maintenance projects undertaken during the year. However, production began to increase from the fourth quarter with the completion of turnarounds in the North Sea, Angola and the Gulf of Mexico. Also, two new major projects were brought onstream during the year the BP-operated Serrette field in Trinidad and the Pazflor field in Angola, operated by Total.

We had our best year for a decade in terms of access to new upstream opportunities, with awards for a total of 55 new exploration licences. We also gained approval for our exploration plan for the Kaskida field in the Gulf of Mexico our first drilling permit for an exploration well in the US since the Deepwater Horizon oil spill.

In India, we completed a transaction that brings us into a unique relationship with Reliance Industries and access to 21 oil and gas blocks which covered approximately 83,000 square miles (216,000 square kilometres). In November 2011 we formed a 50:50 gas marketing joint venture to source and market gas.

In Russia, our plans to form a strategic alliance with Rosneft did not reach fruition. Nonetheless, we remain committed to Russia and the ongoing success of TNK-BP, which comprises 27% of our reserves and 29% of our production.

In Brazil, we acquired assets from Devon Energy, giving us a material position in one of the great deepwater provinces of the world. We started upstream operations during the year.

[a] Combined basis of subsidiaries and equity-accounted entities, on a basis consistent with general industry practice.

[b] Liquids comprise crude oil, condensate, natural gas liquids and bitumen and include totals of 5,153 million barrels for subsidiaries and 5,412 million barrels for equity-accounted entities.

[c] Natural gas is converted to oil equivalent at 5.8 billion cubic feet (bcf) = 1 million barrels and includes 6,273 million barrels of oil equivalent for subsidiaries and 910 million barrels of oil equivalent for equity-accounted entities.

Our performance

[a] See Financial statements Note 6 on page 200. See also Financial and operating performance on page 94.

In the UK North Sea, we announced plans for investments totalling approximately $14 billion with our partners in major new project developments.

In Iraq, working with our partners in the Rumaila Operating Organization, we met a major milestone in reaching initial production targets agreed for the Rumaila field.

Refining and Marketing

Replacement cost profit before interest and tax for 2011 was $5,474 million compared with $5,555 million in 2010. Strong refinery operations enabled us to capture the benefits of BP s location advantage in accessing WTI-based crude grades and, 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 the increased relative sweet crude prices in Europe and Australia, primarily caused by the loss of Libyan production, and the weather-related power outages in the second quarter. *See Refining and Marketing on page 94 for further information on the segment s financial results.*

Operating performance was strong, with Solomon refining availability of 94.8% and utilization rates above the industry average. We made significant progress on the modernization of our Whiting refinery in the US, which is expected to come onstream in the second half of 2013. This project will significantly increase the capability of the refinery to process heavy crude and provide it with access to crude from the Gulf of Mexico, the mid-continent US and Canada.

We achieved strong performance in our lubricants business, despite a difficult marketing environment and increasing base oil prices. In our petrochemicals business we received local government approval for our proposed 1.25 million tonnes per annum purified terephthalic acid (PTA) plant in Zhuhai, China, and are now seeking final central governmental approval.

Left Air BP is one of the world's largest and best-known aviation fuels suppliers.

Above The SECCO facility is BP's single largest investment in China and has a capacity of 3.2 million tonnes of petrochemicals per year.

We continued to sell non-core assets, and we are progressing with our intention to divest about half of our US refining capacity. We completed the divestment of non-strategic terminals and pipelines in the US East of Rockies and West Coast, and of our fuels marketing businesses in several African countries.

In addition, in February 2012 we announced our intent to sell our bulk and bottled LPG marketing businesses in nine countries.

Looking ahead

We believe our actions and achievements in 2011 brought BP to a turning point. As we move into 2012, our operations are regaining momentum and we have a clear strategy for value creation. Maintaining our absolute commitment to safety, our intention is to build on our strengths so we can grow operating cash flows, invest for future growth and increase returns to shareholders.

Our performance

We track performance against key financial and non-financial indicators. This year, in alignment with our 10-point strategic plan, we have introduced gearing as a key measure.

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 the profitability measure used by management. It is a non-GAAP measure. See page 56 for the equivalent measure on an IFRS basis.

In 2011, we returned to profitability following the financial impact of the Deepwater Horizon oil spill in 2010.

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.

The 2011 reserves additions for TNK-BP include the effect of moving from life-of-licence measurement to life-of-field measurement, reflecting TNK-BP s track record of successful licence renewal. Excluding this effect, BP s 2011 reserves replacement ratio would have been 83%.

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.

In 2011, operating cash flow recovered, primarily due to a reduction in cash outflow in respect of the Deepwater Horizon oil spill.

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.

Reported production in 2011 was 10% lower than in 2010, due to higher turnaround and maintenance activity, and the impact of the drilling moratorium in the Gulf of Mexico.

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 230 for the nearest equivalent measure on an IFRS basis and for further information.

In 2011, gearing decreased slightly and we expect it to reduce to the lower half of the 10-20% range over time.

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.

Refining availability decreased slightly in 2011 principally due to the second quarter weather-related power outage at Texas City.

Total shareholder return 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.

In 2011, shareholder return improved with the resumption of dividends.

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.

In 2011, our workforce RIF, which includes employees and contractors combined, was 0.36, compared with 0.61 in 2010 and 0.34 in 2009. The 2010 group RIF was affected by the Gulf Coast response effort.

a This represents reported incidents occurring within BP s operational HSSE reporting boundary. That boundary includes BP s own operated facilities and certain other locations or situations.

The employee satisfaction index comprises 10 questions that provide insight into levels of employee satisfaction across topics such as pay and trust in management.

Our 2010 survey was delayed to allow for organizational changes to be reflected in the survey construction. This was completed and the 2011 survey showed improvements in the level of employee recognition, with the opportunity for clarity about the organization s priorities highlighted as an area for improvement.

b Relates to BP employees.

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.

In 2011, there were 361 losses of primary containment compared to 418 in 2010. Tracking losses of integrity is a way of measuring safety performance and helping drive improvements.

Each year we record the percentage of women and individuals from countries other than the UK and US among BP s group leaders. The number of group leaders in 2011 was 516, compared with 482 in 2010 and 492 in 2009.

BP has increased the percentage of female leaders in 2011 and remains focused on building a more sustainable pipeline of diverse talent for the future.

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.

In 2011, there were 228 oil spills of one barrel or more. We are taking measures to strengthen mandatory safety-related standards and processes, including operational risk and integrity management.

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 70).

The decrease of 3.1Mte in 2011 is primarily explained by temporary reduction in activity in some of our businesses as a result of maintenance work and also by the sale of assets as part of our disposal programme.

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Financial review

Selected financial information[a]

$ million except per share amounts

	2011	2010	2009	2008	2007
Income statement data					
Sales and other operating revenues	**375,517**	297,107	239,272	361,143	284,365
Replacement cost profit (loss) before interest and tax[b]					
By business					
Exploration and Production	**30,500**	30,886	24,800	38,308	27,602
Refining and Marketing	**5,474**	5,555	743	4,176	2,621
Other businesses and corporate	**(2,478)**	(1,516)	(2,322)	(1,223)	(1,209)
Gulf of Mexico oil spill response[c]	**3,800**	(40,858)			
Consolidation adjustment	**(113)**	447	(717)	466	(220)
Replacement cost profit (loss) before interest and taxation[b]	**37,183**	(5,486)	22,504	41,727	28,794
Inventory holding gains (losses)	**2,634**	1,784	3,922	(6,488)	3,558
Profit (loss) before interest and taxation	**39,817**	(3,702)	26,426	35,239	32,352
Finance costs and net finance expense/income relating to pensions and other post-retirement benefits	**(983)**	(1,123)	(1,302)	(956)	(741)
Taxation	**(12,737)**	1,501	(8,365)	(12,617)	(10,442)
Profit (loss) for the year	**26,097**	(3,324)	16,759	21,666	21,169
Profit (loss) for the year attributable to BP shareholders	**25,700**	(3,719)	16,578	21,157	20,845
Inventory holding (gains) losses, net of tax	**(1,800)**	(1,195)	(2,623)	4,436	(2,475)
Replacement cost profit (loss) for the year attributable to BP shareholders[b]	**23,900**	(4,914)	13,955	25,593	18,370
Per ordinary share cents					
Profit (loss) for the year attributable to BP shareholders					
Basic	**135.93**	(19.81)	88.49	112.59	108.76
Diluted	**134.29**	(19.81)	87.54	111.56	107.84
Replacement cost profit (loss) for the year attributable to BP shareholders[b] (basic)	**126.41**	(26.17)	74.49	136.20	95.85
Dividends paid per share cents	**28.00**	14.00	56.00	55.05	42.30
pence	**17.4035**	8.679	36.417	29.387	20.995
Capital expenditure and acquisitions[d]	**31,518**	23,016	20,309	30,700	20,641
Capital expenditure, excluding acquisitions and asset exchanges[e]	**20,235**	19,610	20,001	28,186	19,194
Ordinary share data[f]					
Average number outstanding of 25 cent ordinary shares (shares million undiluted)	**18,905**	18,786	18,732	18,790	19,163
Average number outstanding of 25 cent ordinary shares (shares million diluted)	**19,136**	18,998	18,936	18,963	19,327
Balance sheet data (at 31 December)					
Total assets	**293,068**	272,262	235,968	228,238	236,076
Net assets	**112,482**	95,891	102,113	92,109	94,652
Share capital	**5,224**	5,183	5,179	5,176	5,237
BP shareholders equity	**111,465**	94,987	101,613	91,303	93,690
Finance debt due after more than one year	**35,169**	30,710	25,518	17,464	15,651
Net debt to net debt plus equity[g]	**20.5%**	21.2%	20.4%	21.4%	22.1%

a This information, insofar as it relates to 2011, has been extracted or derived from the audited consolidated financial statements of the BP group presented on pages 173-258. 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 profit or loss reflects the replacement cost of supplies. The replacement cost profit or loss for the year is arrived at by excluding from profit inventory holding gains and losses and their associated tax effect. Replacement cost profit or loss for the group is not a recognized GAAP measure. The equivalent measure on an IFRS basis is Profit (loss) for the year attributable to BP shareholders . Further information on inventory holding gains and losses is provided on page 110.

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

d AII capital expenditure and acquisitions during the past five years have been financed from cash flow from operations, disposal proceeds and external financing. 2008 included capital expenditure of $2,822 million and an asset exchange of $1,909 million, both in respect of our transaction with Husky Energy Inc., as well as capital expenditure of $3,667 million in respect of our purchase of all of 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. 2007 included $1,132 million for the acquisition of Chevron s Netherlands manufacturing company.

e 2011 included $1,096 million associated with deepening our natural gas asset base. 2010 included capital expenditure of $900 million relating to the formation of a partnership with Value Creation Inc.

f The number of ordinary shares shown has been used to calculate per share amounts.

g 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. Further information on net debt is given in Financial statements Note 35 on page 230.

Profit or loss for the year

Profit attributable to BP shareholders for the year ended 31 December 2011 was $25,700 million and included inventory holding gains[a], net of tax, of $1,800 million and a net credit for non-operating items, after tax, of $2,195 million. In addition, fair value accounting effects had a favourable impact, net of tax, of $47 million relative to management s measure of performance. Non-operating items in 2011 included a $3.7 billion pre-tax credit relating to the Gulf of Mexico oil spill. More information on non-operating items and fair value accounting effects can be found on page 58. *See Gulf of Mexico oil spill on page 76 and in Financial statements Note 2 on page 190 for further information on the impact of the Gulf of Mexico oil spill on BP s financial results.*

Loss attributable to BP shareholders for the year ended 31 December 2010 included inventory holding gains, net of tax, of $1,195 million and a net charge for non-operating items, after tax, of $25,449 million. In addition, fair value accounting effects had a favourable impact, net of tax, of $13 million relative to management s measure of performance. Non-operating items in 2010 included a $40.9 billion pre-tax charge relating to the Gulf of Mexico oil spill.

Profit attributable to BP shareholders for the year ended 31 December 2009 included inventory holding gains, net of tax, of $2,623 million and a net charge for non-operating items, after tax, of $1,067 million. In addition, fair value accounting effects had a favourable impact, net of tax, of $445 million relative to management s measure of performance.

The primary additional factors affecting the financial results for 2011, compared with 2010, 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.

The primary additional factors affecting the financial results for 2010, compared with 2009, were higher realizations, lower depreciation, higher earnings from equity-accounted entities, improved operational performance, further cost efficiencies and a more favourable refining environment in Refining and Marketing, partly offset by lower production, a significantly lower contribution from supply and trading (including gas marketing) and higher production taxes.

See Exploration and Production on page 80, Refining and Marketing on page 94 and Other businesses and corporate on page 101 for further information on segment results.

a 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 200 and further information on inventory holding gains and losses is provided on page 110.

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 2011 were $1,246 million compared with $1,170 million in 2010 and $1,110 million in 2009.

Net finance income relating to pensions and other post-retirement benefits in 2011 was $263 million compared with net finance income of $47 million in 2010 and net finance expense of $192 million in 2009. In 2011, compared with 2010, the improvement largely reflected the additional expected returns on assets following the increases in the pension asset base at the end of 2010 compared with the end of 2009.

During 2011 the value of our pension assets declined and this, combined with changes to assumptions used to value benefit obligations, most notably lower discount rates, meant that the deficit relating to pension and other post-retirement benefits increased to $12.0 billion at the end of the year (2010 $7.7 billion).

Taxation

The charge for corporate taxes in 2011 was $12,737 million, compared with a credit of $1,501 million in 2010 and a charge of $8,365 million in 2009. The effective tax rate was 33% in 2011, 31% in 2010 and 33% in 2009. The group earns income in many countries and, on average, pays taxes at rates higher than the UK statutory rate of 26%. The increase in the effective tax rate in 2011 compared with 2010 primarily reflects a higher level of income earned in jurisdictions with a higher tax rate. The decrease in the effective tax rate in 2010 compared with 2009 primarily reflected the absence of a one-off disbenefit that featured in 2009 in respect of goodwill impairment, and other factors.

Acquisitions and disposals

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 194 for further details of the business combinations undertaken during the year.*

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

In Exploration and Production, 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 Refining and Marketing 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 (see *Refining and Marketing on page 97 for more details)* 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. See *above and Financial statements Note 4 on page 196 for further information.* 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 Refining and Marketing 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.

There were no significant acquisitions in 2009. Disposal proceeds in 2009 were $2.7 billion, principally from the sale of our interests in BP West Java Limited, Kazakhstan Pipeline Ventures LLC and LukArco, and the sale of our ground fuels marketing business in Greece and retail churn in the US, Europe and Australasia. Further proceeds from the sale of LukArco were received in 2011.

Business review

Non-operating items

Non-operating items are charges and credits arising in consolidated entities that BP discloses separately because it considers such disclosures to be meaningful and relevant to investors. They are provided in order to enable investors to better understand and evaluate the group s financial performance. An analysis of non-operating items is shown in the table below.

			$ million
	2011	2010	2009
Exploration and Production			
Impairment and gain (loss) on sale of businesses and fixed assets	**2,131**	3,812	1,574
Environmental and other provisions	**(27)**	(54)	3
Restructuring, integration and rationalization costs		(137)	(10)
Fair value gain (loss) on embedded derivatives	**191**	(309)	664
Other[a]	**(1,165)**	(113)	34
	1,130	3,199	2,265
Refining and Marketing			
Impairment and gain (loss) on sale of businesses and fixed assets[b]	**(334)**	877	(1,604)
Environmental and other provisions	**(219)**	(98)	(219)
Restructuring, integration and rationalization costs	**(4)**	(97)	(907)
Fair value gain (loss) on embedded derivatives			(57)
Other	**(45)**	(52)	184
	(602)	630	(2,603)
By business			
Fuels[b]	**(703)**	339	(2,394)
Lubricants	**100**	(47)	(171)
Petrochemicals	**1**	338	(38)
	(602)	630	(2,603)
Other businesses and corporate			
Impairment and gain (loss) on sale of businesses and fixed assets	**275**	5	(130)
Environmental and other provisions	**(220)**	(103)	(75)
Restructuring, integration and rationalization costs	**(39)**	(81)	(183)
Fair value gain (loss) on embedded derivatives[c]	**(123)**		
Other[d]	**(715)**	(21)	(101)
	(822)	(200)	(489)
Gulf of Mexico oil spill response	**3,800**	(40,858)	
Total before interest and taxation	**3,506**	(37,229)	(827)
Finance costs[e]	**(58)**	(77)	
Total before taxation	**3,448**	(37,306)	(827)
Taxation credit (charge)[f]	**(1,253)**	11,857	(240)
Total after taxation	**2,195**	(25,449)	(1,067)

a 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 *(see page 85).*

b 2009 included $1,579 million in relation to the impairment of goodwill allocated to the US West Coast fuels value chain.

c Relates to an embedded derivative arising from a financing arrangement.

d 2011 included charges of $687 million in relation to raw materials purchase contracts associated with our exit from the solar business.

e Finance costs relate to the Gulf of Mexico oil spill. *See Financial statements Note 2 on page 190 for further details.*

f Tax is calculated by applying discrete quarterly effective tax rates (excluding the impact of the Gulf of Mexico oil spill and, for 2011, the impact of a $683-million one-off deferred tax adjustment in respect of an increase in the supplementary charge on UK oil and gas production) on group profit or loss. However, the US statutory tax rate has been used for recoveries relating to the Gulf of Mexico oil spill and expenditures that qualify for tax relief. In 2009, no tax credit was calculated on the goodwill impairment in Refining and Marketing because the charge is not tax deductible.

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 110.

			$ million
	2011	2010	2009
Exploration and Production			
Unrecognized gains (losses) brought forward from previous period	**(527)**	(530)	389
Unrecognized (gains) losses carried forward	**538**	527	530
Favourable (unfavourable) impact relative to management s measure of performance	**11**	(3)	919
Refining and Marketing[a]			
Unrecognized gains (losses) brought forward from previous period	**137**	179	(82)
Unrecognized (gains) losses carried forward	**(74)**	(137)	(179)
Favourable (unfavourable) impact relative to management s measure of performance	**63**	42	(261)
	74	39	658
Taxation credit (charge)[b]	**(27)**	(26)	(213)
	47	13	445
By region			
Exploration and Production			
US	**15**	141	687
Non-US	**(4)**	(144)	232
	11	(3)	919
Refining and Marketing[a]			
US		19	16
Non-US	**63**	23	(277)
	63	42	(261)

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

b Tax is calculated by applying discrete quarterly effective tax rates (excluding the impact of the Gulf of Mexico oil spill and, for 2011, the impact of a $683-million one-off deferred tax adjustment in respect of an increase in the supplementary charge on UK oil and gas production) on group profit or loss.

Reconciliation of non-GAAP information

			$ million
	2011	2010	2009
Exploration and Production			
Replacement cost profit before interest and tax adjusted for fair value accounting effects	**30,489**	30,889	23,881
Impact of fair value accounting effects	**11**	(3)	919
Replacement cost profit before interest and tax	**30,500**	30,886	24,800
Refining and Marketing			
Replacement cost profit before interest and tax adjusted for fair value accounting effects	**5,411**	5,513	1,004
Impact of fair value accounting effects	**63**	42	(261)
Replacement cost profit before interest and tax	**5,474**	5,555	743
Total group			
Profit (loss) before interest and tax adjusted for fair value accounting effects	**39,743**	(3,741)	25,768
Impact of fair value accounting effects	**74**	39	658
Profit (loss) before interest and tax	**39,817**	(3,702)	26,426

Risk factors

We urge you to consider carefully the risks described below. The potential impact of their occurrence could be for our business, financial condition and results of operations to suffer (including through the failure to achieve our current strategic priorities (see *10-point plan pages 38-39))* and the trading price and liquidity of our securities to decline.

Our system of risk management identifies and provides the response to risks of group significance through the establishment of standards and other controls. Any failure of this system could lead to the occurrence, or re-occurrence, of any of the risks described below and a consequent 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; compliance and control; and safety and operational. In addition, we have also set out two further risks for your attention those resulting from the 2010 Gulf of Mexico oil spill (the Incident) and those related to the general macroeconomic outlook.

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

There is significant uncertainty in the extent and timing of costs and liabilities relating to 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. There is also significant uncertainty regarding potential changes in applicable regulations and the operating environment that may result from the Incident. These increase the risks to which the group is exposed and may cause our costs to increase. These uncertainties are likely to continue for a significant period. 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.

We recognized a pre-tax charge of $40.9 billion in 2010 and a pre-tax credit of $3.7 billion in 2011 as a result of the Incident. The total amounts that will ultimately be paid by BP in relation to all obligations relating to the Incident are subject to significant uncertainty and the ultimate exposure and cost to BP will be dependent on many factors. Furthermore, 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 amount and timing of payments under any settlements, and any costs arising from any longer-term environmental consequences of the oil spill, will also impact upon the ultimate cost for BP. Although the provision recognized is the current best estimate of expenditures required to settle certain present obligations at the end of the reporting period, there are future expenditures for which it is not possible to measure the obligation reliably. 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.

The general macroeconomic outlook can affect BP s results given the nature of our business.

In the continuing uncertain financial and economic environment, certain risks may gain more prominence either individually or when taken together. Oil and gas prices can be very volatile, with average prices and margins influenced by changes in supply and demand. This is likely to exacerbate competition in all businesses, which may impact costs and margins. At the same time, 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. Any of these factors may affect our results of operations, financial condition, business prospects and liquidity and may result in a decline in the trading price and liquidity of our securities.

Capital markets are subject to volatility amid concerns over the European sovereign debt crisis and the slow-down of the global economy. If there are extended periods of constraints in these markets, or if we are unable to access the markets, including due to our financial position or market sentiment as to our prospects, at a time when cash flows from our business operations may be under pressure, our ability to maintain our long-term investment programme may be impacted with a consequent effect on our growth rate, 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.

Strategic 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 in new markets could impact our future hydrocarbon production.

Moreover, the Gulf of Mexico oil spill 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 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, arising from the Incident, could increase this risk.

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

Oil, gas and product prices are subject to international supply and demand. Political developments 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 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. 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.

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.

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 and could cause us to incur additional costs. In particular, our investments in the US, Russia, Iraq, Egypt, Libya, Bolivia, Argentina and other countries could be adversely affected by heightened political and economic environment risks. *See pages 34-35 for information on the locations of our major assets and activities.*

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, our reputation and shareholder value could be damaged.

Competition BP s group strategy depends upon continuous innovation 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 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 required or if our innovation lagged the industry.

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 development could lead to loss of value and higher capital expenditure.

Reserves replacement 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, we will be unable to sustain long-term replacement of reserves.

Liquidity, financial capacity and financial 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 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. 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 and to meet our obligations. The change in the group s financial framework during 2010 to make it more prudent may not be sufficient to avoid a substantial and unexpected cash call.

BP s clean-up costs and 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 business, competitive position, financial performance, cash flows, prospects, liquidity, shareholder returns and/or implementation of its strategic agenda, particularly in the US. Furthermore, we recognized a pre-tax charge of $40.9 billion in 2010 and a pre-tax credit of $3.7 billion in 2011, and 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 2 on pages 190-194 and Legal proceedings on pages 160-166.* 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. Fluctuations in exchange rates can therefore give rise to foreign exchange exposures, with a consequent impact on underlying costs and revenues.

See Financial statements Note 26 on page 217 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

Regulatory the oil industry in general, and in particular the US industry following the Gulf of Mexico oil spill, faces increased regulation that could increase the cost of regulatory compliance and limit our access to new exploration properties.

After the Gulf of Mexico oil spill, it is likely that there will be more stringent regulation of 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. The US government imposed a moratorium on certain offshore drilling activities, which was subsequently lifted in October

2010. Similar actions may be taken by governments elsewhere in the world. New regulations and legislation, as well as 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 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 107-110 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, high ethical standards and the behaviours and actions we expect of our businesses and people wherever we operate. Our renewed values, which were launched in 2011, are intended to guide the way we and our employees behave and do business. Incidents of ethical misconduct 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. 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 renewed 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 160-166. For further information on the risks involved in BP s trading activities, see Operational risks Treasury and trading activities on page 63.

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. is one of 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 160-166.*

BP is subject to a number of investigations related to the Incident by numerous federal and State agencies. *See Legal proceedings on pages 160-166.* 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. Such enforcement actions could include criminal proceedings against BP and/or employees of the group. In addition to fines and penalties, such enforcement actions could result in the suspension of operating licences and debarment from government contracts. Debarment of BP Exploration & Production Inc. would prevent it from bidding on or entering into new federal contracts or other federal transactions, and from obtaining new orders or extensions to existing federal contracts, including federal procurement contracts or leases. Dependent on the circumstances, debarment or suspension may also be sought against affiliated entities of BP Exploration & Production Inc. Although BP believes that there are costs arising out of the spill that are recoverable from its partners and other parties responsible under OPA 90, and although settlements have been agreed during 2011 with both partners, one contractor, and the manufacturer of the blowout preventer at the Macondo well, further recoveries are not certain and so have not been recognized in the financial statements (*see Financial statements Note 2 on pages 190-194*).

Any finding of gross negligence for purposes of penalties sought against the group under the Clean Water Act 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 the group with respect to the Incident under enforcement actions outside the Clean Water Act context.

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 the Gulf of Mexico oil spill and any future alleged breaches of safety or environmental regulations.

Claims by individuals and businesses under OPA 90 s claims process have been administered by the Gulf Coast Claims Facility (GCCF) headed by Kenneth Feinberg, who was appointed jointly by BP and the US Administration. The proposed economic loss settlement reached with the Plaintiffs Steering Committee (PSC), acting on behalf of individual and business plaintiffs in MDL 2179, provides for a transition from the GCCF. A court-supervised transitional claims process for economic loss claims will be in operation while the infrastructure for the new settlement claims process is put in place. During this transitional period, the processing of claims that have been submitted to the GCCF will continue, and new claimants may submit their claims.

The proposed settlement is subject to final written agreement and court approvals and payments under the proposed settlement, and any other payments that may be made by BP in respect of any other individual and business claims under OPA 90, could ultimately be higher than the amount for which we have recognized a provision. *See Legal proceedings on pages 160-164 and Financial statements Note 36 on pages 231-234.*

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.

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.

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 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 on page 63.*

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 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.

To help 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, BP has introduced a group-wide operating management system (OMS). Work on the application of OMS in individual operating businesses continues and following the Gulf of Mexico oil spill an enhanced safety and operational risk (S&OR) function was established, reporting directly to the group chief executive. 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 civil strife and 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.

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.

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, including maintenance turnaround programmes, and/or a major programme designed to enhance shareholder value 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 successful recruitment and development of staff is central to our plans on page 63.*

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, 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 injury to people, damage to assets, harm to the environment, 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 and development of staff is central to our plans.

Successful recruitment of new staff, employee training, development and long-term renewal 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.

In addition, significant management focus is required in responding to the Gulf of Mexico oil spill Incident. Although BP set up the Gulf Coast Restoration Organization to manage the group s long-term response, key management and operating personnel will need to continue to devote substantial attention to responding to the Incident and to address the associated consequences for the group. The group relies on recruiting and retaining high-quality employees to execute its strategic plans and to operate its business. The Incident response has placed significant demands on our employees, and the reputational damage suffered by the group as a result of the Incident and any consequent adverse impact on our performance could affect employee recruitment and retention.

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 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.

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.

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 2011, the US enacted additional sanctions against Iran which included lower monetary thresholds for certain investments in Iran for the development or refining of petroleum resources, new restrictions on the petrochemicals industry and restrictions on transactions with the Iran Central Bank, including financial transactions for the purchase of Iranian-origin crude oil. Further legislation is pending in the US Congress which may enact additional sanctions against Iran. The UK adopted sanctions prohibiting UK persons from engaging in any financial transactions with the Iran Central Bank or other financial institutions incorporated in Iran. Both the US and the EU enacted strong sanctions against Syria including a prohibition on the purchase of Syrian-origin crude and a US prohibition on the provision of services by US persons. (Libya sanctions were enacted in early 2011 and largely lifted by the end of the year.) In January 2012, the EU imposed an embargo on Iranian crude, among other measures, to be phased in over a period of months. The EU also adopted more stringent sanctions against Syria including 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 monitors its activities with Sanctioned Countries and keeps them under review to ensure compliance with applicable laws and regulations of the US, the EU and other countries where BP operates.

BP has interests in, and is the operator of, two fields (the North Sea Rhum field and the Azerbaijan Shah Deniz field) and, serving the Shah Deniz field, a gas marketing entity and an entity that owns a gas pipeline (both entities and related assets located outside Iran), in which Naftiran Intertrade Co. Ltd (NICO) 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. It is presently unclear when it may be possible to resume production. The Shah Deniz field, its gas marketing entity and the entity that owns a pipeline (in which NICO has a 10% or less non-operating interest) continues in operation in full compliance with current US and EU sanctions. BP has no operations in Iran and does not purchase or ship crude oil or other products of Iranian origin. Joint venture 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. BP does 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. Until January 2010, BP held an equity interest in an Iranian joint venture that blended and marketed lubricants for sale to domestic consumers in Iran. BP sold its equity interest but continues to sell small quantities of lubricant components to the current owner. Transactions with Iranian shipping companies have been terminated.

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 continues to supply aviation fuel to non-governmental Syrian resellers outside of Syria. Prior to the imposition of Syrian sanctions in 2011, BP sold lubricants through third parties and obtained crude oil and refinery feedstocks for sale to third parties in Europe and for use in certain of its non-US refineries. BP also bought and sold crude oil and refined products into and from Syria and incurred port costs for vessels utilizing Syrian ports. Sales and purchases to and from Syrian shipping companies have been terminated.

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.

BP has equity interests in non-operated joint ventures with air fuel sellers, re-sellers, 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 trademarks in Sanctioned Countries.

Safety

Over the past year, we have been developing and implementing a wide-ranging programme to further enhance safety, risk management and compliance across BP. This programme was initiated in response to the Deepwater Horizon incident in the Gulf of Mexico in April 2010.

The programme emphasizes the continuing importance of personal and process safety within BP. Process safety involves applying good design principles, along with robust engineering, operating and maintenance practices, to managing operations safely. For BP, this means the plant is designed, maintained and operated properly to avoid failures such as spills or explosions that can result in injuries to people and impacts to the environment. It also means that employees and contractors have the appropriate training and competencies to carry out work, as well as observing applicable procedures and policies that help to prevent personal injury.

In 2011, BP reported two workforce fatalities, and we regret the loss of these lives. One was a rail-related fatality in the US, the other died as a result of an unauthorized transfer of fuel in South Africa.

Safety and operational risk

Safety management

Our safety and risk management approach is built on deep experience in the oil and gas industry. This includes learning from the recommendations of investigations into the Deepwater Horizon oil spill in 2010 and the Texas City refinery explosion in 2005, as well as operations audits, annual risk reviews, other incident investigations and from industry practice of sharing experience.

There are three key principles which we intend to be at the heart of our approach:

- Leadership fostering a culture where everyone is focused on safety, on managing and reducing risk and on safe, reliable and compliant operations.
- Our operating management system (OMS) being the way BP seeks to operate.
- Effective checks and balances independent of the business line and self-verification being carried out at all levels of the organization.

While we maintain our focus on processes, practices and protocols, we also place great emphasis on how our workforce applies them, thereby working to strengthen safety culture and workforce capability.

A dedicated function

We established the safety and operational risk (S&OR) function in early 2011. S&OR supports the business line in delivering safe, reliable and compliant operations across the group s operated businesses. It does this in four ways:

- It sets and updates the requirements, including those in OMS, that are used across the business for safety and operational risk management.
- It provides expert scrutiny of safety and operational risk, independent of line managers advising, examining and providing assurance about what our operations do.
- It provides deep technical expertise to the operations.
- It has the authority to intervene and escalate issues to cause corrective action to be taken.

S&OR, as of the end of 2011, was made up of a central team of around 300, as well as nearly 300 more who are deployed in BP s businesses, providing guidance and scrutiny and examining how safety and operating risks are being assessed and managed on oil and gas production and drilling rigs, at refineries and across all our operations. The head of S&OR reports directly to the group chief executive.

The central team serves as the custodian of group requirements, runs safety and operational risk audit and capability programmes and endorses the appointment of individuals for designated safety-critical roles. The central team includes some of BP s top engineers and safety specialists, several of whom have experience of other industries where major hazards have to be managed, including the military, nuclear energy and space exploration.

Our deployed S&OR teams 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 they help provide assurance to the group on how operational risks are being managed, business by business.

Operating businesses remain accountable for delivering safe, reliable and compliant operations. They have the responsibility of managing risks and bringing together people with the right skills and competencies. Working in collaboration with deployed S&OR subject specialists for guidance, they are subject to new levels of independent scrutiny and assurance.

Governance

BP reviews risks at all levels of the organization, with our S&OR function providing an independent view of safety and operational risk. While 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.

The board s safety, ethics and environment assurance committee (SEEAC) receives updates from the group chief executive and the head of S&OR on the work of the group operations risk committee (GORC), on BP s performance in process and personal safety, and our monitoring of major incidents and near misses across the group. Where appropriate other senior managers will attend to provide briefings on safety, environmental and operational integrity in their areas of responsibility. SEEAC also receives information from the Independent Expert appointed to monitor the implementation of recommendations made by the BP US Refineries Independent Safety Review Panel following the 2005 explosion at our Texas City refinery. *See Board performance report on pages* 120-133 *for further information on the activities of the board s committees, including SEEAC and the Gulf of Mexico committee.*

Lessons learned from major incidents are being incorporated into our operating management system and capability development programmes.

Operating management system

Launched in 2008, our operating management system (OMS) serves as our group-wide framework designed to drive a rigorous and systematic approach to safety, risk management, and operational integrity across the group. OMS integrates requirements regarding 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 system.

The principles and standards of OMS are supported by detailed group-wide practices, as well as other technical guidance materials. The goal of OMS is to apply certain standards, group-defined practices and group engineering technical practices on a group-wide basis in our operations; these include, among others, the practices on assessment, prioritization and management of risk; incident investigation; integrity management; and environmental and social requirements for major new projects.

Following the principle of continuous improvement, our OMS evolves over time, for example to reflect implementation experience as well as learnings from incident investigations, audits and risk assessments, and by strengthening mandatory practices.

Transitioning to OMS

The transition to OMS requires operations to develop a local OMS that describes how the operation addresses site-specific local operating risks, applies group standards and practices and manages compliance with applicable health, safety, security and environment legal requirements. As part of the transition, operations conduct a gap assessment against defined aspects of OMS and their local processes and procedures, and then develop a prioritized gap-closure plan. To formally transition to the system, operations issue a local OMS handbook for the workforce to follow, and complete a management-of-change document that details the changes involved.

All of our operations, with the exception of those recently acquired, are now applying our OMS to govern their BP operations and have begun working to achieve conformance to standards and practices required by OMS through the performance improvement cycle process. This includes our global wells organization and global projects organization which were set up in 2011. *See page 69 for information about joint ventures.*

Conformance and continuous improvement

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, as well as to continuously improve their operational performance. Every year, after the initial gap assessment, as part of the annual performance improvement cycle each operating unit   for example, a region like the Gulf of Mexico in our upstream business, or a refinery in our downstream business   is required to conduct another gap assessment and to develop a further prioritized gap closure plan. These actions are risk-prioritized and form an integral part of each operation's annual and three-year planning cycle. Where appropriate, actions are aggregated to provide common solutions. The results of these annual assessments are subject to review by S&OR.

Capability development

BP strives to equip its staff with the skills needed to apply the systems and processes to strengthen further our management of risk and process safety. We have provided extensive and focused training programmes for our operations personnel at all levels.

Training provision for operations personnel 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 Operations Essentials programme, which seeks to embed the BP way of operating as represented by our OMS. To date, approximately 24,000 managers, supervisors and technicians have attended at least one workshop within the operations essentials programme since 2008; additionally, more than 180,000 eLearning modules have been completed.

We communicate our expectations for qualified, competent and experienced contractor personnel through our procurement process and contractual provisions.

Safer drilling

Since the beginning of 2011, all BP-operated drilling and wells activity in the world has been conducted through a single global wells organization (GWO). By bringing functional wells expertise into a single organization with common global standards, we are working to standardize BP drilling and wells operations with the intent of delivering safe and compliant wells. GWO works with our safety and operational risk function with a view to reducing risk in drilling and so reduce the likelihood of an oil spill or incident occurring through prevention efforts. We also aim to reduce the consequences should an incident occur by focusing on containment, spill response, relief wells and crisis management. *See Exploration and Production on page 80 for information about the upstream reorganization.*

Oil spill prevention

We are implementing enhanced drilling safety standards across the organization.

Blowout preventers

We have issued standards for the maintenance, testing, verification and use of subsea blowout preventers (BOPs). For example, we require dynamically positioned drill rigs contracted by BP to have no fewer than two blind shear rams and a casing shear ram sitting within the blowout preventer to enhance its reliability in cutting the drill pipe and sealing the well in the event of a blowout or other operational emergency. We require third-party verification that testing and maintenance of our subsea BOPs are performed

in accordance with industry recommended practice. In addition, BP requires that remotely operated vehicles can activate these BOPs in an emergency.

Cementing

We are enhancing oversight of cementing services by implementing new standards in cement design and testing. We have also strengthened the technical approval process for critical cementing operations, and have brought additional expertise into BP to oversee this. We are implementing quality audits of our cementing contractors' laboratories.

Well start-up procedure

We have introduced a new well start-up procedure. The checklist covers a range of operational areas and verification of conformance is required by leaders from the business line and S&OR before operations can begin on certain wells and on new rigs. In one case, as a result of this process, BP rejected a contractor rig put forward by another operator due to it not meeting BP's standards.

These requirements are designed to help identify and mitigate risks prior to contractors' drilling rigs being put into service for BP. Interventions to date have included repairs to safety systems, additional training of personnel, modifications to equipment, verification of quality and inspection records, revised and clarified roles and responsibilities, enhanced training requirements, and enhanced risk management techniques.

See Environment and social responsibility section on pages 69-73 for further information on BP s approach to oil spill contingency planning and response.

Bly Report internal investigation recommendations and actions taken

In the immediate aftermath of the Deepwater Horizon oil spill, BP launched an internal investigation, drawing on the expertise of more than 50 technical and other specialists within BP and the industry. The investigation team was led by BP's head of safety and operations, and worked independently from BP's other spill response activities and organizations.

The BP investigation (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 recommendations

As a result, the investigation team made 26 recommendations specific to drilling, which we accepted and are working to implement across our worldwide drilling operations. 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.

Interim measures

Shortly following the publication of the Bly Report, BP developed interim measures to immediately address the eight key findings contained within the report. An interim guidance document was issued to each of our 14 operating regions in December 2010 which contained specific requirements, including the well start-up check list. This guidance continues to be in effect across all BP drilling and completions operations. We continue to progress implementation of the recommendations from the Deepwater Horizon investigation report and that work will ultimately replace the interim guidance.

Implementing the recommendations

Implementing the 26 recommendations across the group requires detailed work and many activities from creating new practices and guidance, training and testing appropriate staff, changing requirements and expectations of our contractors, and establishing verification processes to assure the changes are sustainably embedded. We have a team of around 85 people working full-time on this.

A project of this scale takes time; we must work to assure that all actions are delivered to a high standard across all of our well operations, and 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.

The BP board has identified an independent expert to provide further oversight and assurance regarding the implementation of the Bly Report recommendations. The independent expert's engagement is expected to commence in the latter half of May 2012.

Progress update

At the end of 2011, four of the Bly Report recommendations have been completed. These were:

- Recommendation 6: to propose a recommended practice for foam cementing to the American Petroleum Institute.
- Recommendation 8: to strengthen the technical authority's role in cementing and zonal isolation.
- Recommendation 13: to strengthen our rig audit process to improve closure and verification of audit findings across the rigs we own and contract.
- Recommendation 14: to establish key performance indicators for well integrity, well control, and rig safety-critical equipment.

We continue to make progress on all of the remaining recommendations largely in line with our planned schedule, with a further 12 recommendations expected to be completed in 2012. Progress is tracked in the quarterly HSE and operations integrity report supplied to the executive team. *See bp.com/internalinvestigation for the full report and quarterly updates on progress.*

External investigations

In addition, there have been a number of external investigations, 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 United States Coast Guard *(boemre.gov/ooc/press/2011/press0914.htm).* These reports were consistent in their conclusions 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.

Capping and containment

We have developed a mobile deepwater well capping package that includes about 250 pieces of speciality equipment. Maintained in a constant state of readiness in Houston, it is designed to be deployed by air freight and arrive wherever it is needed in just a few days.

We also share capping and containment equipment with other operators in the Gulf of Mexico, through the Marine Well Containment Company, as well as with operators in the UK North Sea. Further, BP provided project management for the Oil and Gas UK Oil Spill Prevention and Response Advisory Group to develop a next generation well capping system, now available in Europe, and is one of nine companies working in the Subsea Well Response Project to enhance the industry's capability to respond globally to subsea well control events.

Relief wells

In responding to the Gulf of Mexico oil spill, we drilled two relief wells. Prior to drilling a deepwater well, BP operations now have relief well plans in place with equipment identified that can be moved to the site if needed. This is of particular benefit in areas that do not have the same infrastructure and support as more active basins such as the Gulf of Mexico.

Oil spill preparedness

We continue to develop and assimilate lessons from the response to the Gulf of Mexico oil spill. In 2011, as a priority we incorporated many of these lessons into new technical requirements for BP operations that drill

in deepwater. Conformance with these requirements is mandatory for all operations drilling in water deeper than 1,000 feet and is subject to a formal assessment and sign-off by technical experts, S&OR and senior leaders. During 2011, we began implementing these requirements in Angola, the North Sea, Brazil, the US and Egypt, where we have deepwater drilling active or planned for 2012.

Crisis management

Crisis management planning is essential to respond effectively to emergencies and to avoid a potentially severe disruption in our business and operations. The intention is to build on interim requirements introduced in 2011 for deepwater drilling to put in place group-wide practices for both oil spill preparedness and response and crisis management.

During the response, we updated our incident action plan an operational crisis planning tool every 12-24 hours, which allowed us to have recent information to aid decision making. This was made possible by developing a common operating picture (COP) which helped us collect and present information in a way that enabled faster, better-informed decisions. The COP created an integrated view across more than 200 different data types. It provided an instant, interactive picture of the spill status and the activities of all responders.

See Environmental and social responsibility on pages 69-73 for further information on BP's approach to oil spill contingency planning and response.

Safer refining

We have been working hard to apply the lessons learned from the tragic accident in our Texas City refinery in 2005 and are committed to implementing the recommendations of the BP US Refineries Independent Safety Review Panel.

Systematic management

The core business of our refineries is the safe storage, handling and processing of hydrocarbons which involves systematic management of the associated operating risks. In seeking to manage these risks, measures are taken by our refineries to:

- Prevent loss of hydrocarbon containment, such as oil spills, through well-designed, maintained and operated equipment.
- Reduce the likelihood of ignition of any hydrocarbon releases which may occur through controlling ignition sources.
- Provide safe locations, emergency procedures and other mitigation measures in the event of a fire or explosion occurring.

For example, across our refining business we are spending more than $700 million to install safety shelters for individuals, move people further away from hydrocarbon containing equipment and reduce the number of vehicles in our sites.

In 2011, we enhanced and standardized a number of technical practices that we intend to implement across our refining business in 2012 and 2013, including practices pertaining to:

- Control of work practices including rules for what work is done, who it is done by, where it is done, when it is done and how it is done.
- Isolation of equipment from hydrocarbon and other energy sources to safely allow maintenance.
- Design, operation, maintenance for instrumented systems throughout their lifecycle to reliably achieve or maintain a safe operating state if unacceptable or dangerous process conditions are detected.
- Procedures and equipment requirements to assure safe handling of hydrogen sulphide containing streams.
- Design and operation of existing fired heaters.
- Identifying operating limits for our processes and equipment.

Risk assessment, prioritization and management

In 2011, all refineries used a consistent methodology to identify risks and prioritize mitigation actions, including addressing low probability, high consequence scenarios. Action plans have been developed for each risk and reviewed by authorized line and S&OR leaders. A multi-year risk profile reduction plan has been approved for each refinery and, learning from our review of all the plans, we are introducing additional requirements to enhance the mitigation of similar risks across our refining business.

Operational planning and controls

Each BP-operated entity develops an annual plan drawing on the output from the performance improvement cycle including the risk management process. The plan is prioritized with the aim of continually driving reductions in the level of risk at the sites. We plan our work taking account of the capacity needed to deliver the safety-related activities required.

Control of work has been an area of major focus in our refining business since 2008. We continue to see improvement in the execution of our maintenance planning, scheduling and work activities across our refining sites as the overall control of work process is better understood, learning shared and efficiency opportunities identified.

Competence and capability

Refinery leaders are experienced operations professionals with many years' experience within the industry and have typically attended the BP Operations Academy. Each refinery, with S&OR direction and expertise, is developing a consistent competency framework against which safety critical roles are assessed. The US refineries completed process safety competency assessments of over 3,500 employees in safety-critical roles and developed gap closure plans in 2011.

A key element within this competency development plan is the development of high fidelity process simulators. 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

Regional vice presidents conduct performance reviews at each refinery. We now use a set of common safety metrics that are standard across all sites to help us proactively identify opportunities for improvement.

A quarterly assurance process has been introduced to enable S&OR to develop an ongoing, independent view of OMS conformance by the sites. Each site is assessed on their OMS self-assessment processes, the strength of existing risk mitigations and progress on risk reduction plans. Periodic S&OR audits against OMS requirements provide valuable insights from experts outside the site and result in actions to close identified gaps.

In 2011, we strengthened and standardized our approach to incident learning in our refining business, issuing briefings and alerts on lessons learned from incidents and near misses and requiring each refinery to assure that similar risks are assessed and appropriate actions completed.

Reports of the US refineries' Independent Expert

L. Duane Wilson was appointed in 2007 by the board as an Independent Expert to provide an objective assessment of BP's progress in implementing the recommendations of the BP US Refineries Independent Safety Review Panel (the Panel) aimed at improving process safety performance at BP's five US refineries. Mr Wilson is expected to deliver his fifth annual report in April 2012, and BP will publish it at *bp.com/independentexpert.* As in prior years, BP will have an opportunity to review and comment on Mr Wilson's draft report for factual accuracy, but he is solely responsible for the report's ultimate content.

The Independent Expert conducts his assessment of BP's implementation of the Panel's recommendations both through sampling and in-depth monitoring, evaluation and confirmation. Mr Wilson visited each BP US refinery at least twice in 2011 and interviewed personnel at many levels in the organization. He also engaged regularly with senior and executive management, both within Refining and Marketing and our safety and operational risk function, to gauge implementation progress. Mr Wilson also reviews progress reports and other documentation from BP. These include implementation status reports, process safety performance reports, overtime reports (to monitor the potential for worker fatigue), open and overdue process safety action item reports, incident investigations reports and safety audit reports.

Mr Wilson reports to the board through the chairman of BP's safety, ethics and environment assurance committee. In addition to an annual written report, he makes periodic oral reports of his observations to the committee, in which he gives status updates on BP's progress in implementing the Panel's recommendations.

Safety performance

Oil spills and loss of primary containment

We monitor the integrity of our operations, tanks, vessels and pipelines 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 record losses of material, including hydrocarbons, from our assets, and losses or spills that reach land or water.

The loss of primary containment metric below includes unplanned or uncontrolled releases from a tank, vessel, pipe, rail car or equipment used for containment or transfer 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 beginning in 2012 in New Orleans will address the amount of oil spilled. *See Financial statements Note 36 on page 233 for information about the volume used to determine the estimated liabilities.*

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

	2011	2010	2009
Loss of primary containment number of all incidents[a]	**361**	418	537
Loss of primary containment number of oil spills[b]	**228**	261	234
Number of oil spills to land and water	**102**	142	122
Volume of oil spilled (thousand litres)	**556**	1,719	1,191
Volume of oil unrecovered (thousand litres)	**281**	758	222

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

BP uses a disciplined framework for managing the integrity of hazardous operating systems and processes. We apply a combination of good design principles, engineering, and operating and maintenance practices to help deliver process safety performance and we monitor the number of process safety events occurring across our operations. The recently introduced American Petroleum Institute RP-754 standard, which sets out leading and lagging process safety indicators, organized into different tiers is used as the basis for our internal process safety-related reporting. API tier 1 process safety events are the losses of primary containment of greatest consequence causing harm to a member of the workforce or costly damage to equipment, or exceeding defined quantities. Seventy-four tier 1 process safety events were reported in BP in 2011.

Personal safety

BP reports publicly on its personal safety performance according to standard industry metrics. In 2011, our overall reported recordable injury frequency (RIF) was 0.36, compared with 0.61 in 2010 and 0.34 in 2009. Our reported day away from work case frequency (DAFWCF) in 2011 was 0.090, compared with 0.193 in 2010 and 0.069 in 2009. The 2010 group personal safety data was affected by the Gulf Coast response effort.

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 2011, more than 55% of the 374 million hours worked by BP were carried out by contractors.

Our ability to fulfil our corporate responsibility 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 confirming operational standards through legally binding agreements. When we select contractors, our due diligence is designed to identify safety, bribery and corruption, money laundering and trade sanctions risks. We expect our suppliers, contractors and partners to comply with legal requirements and operate consistently with the principles of our code of conduct when they work on our behalf.

Within our operating management system we have group-wide and business-specific requirements and practices for working with contractors. 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. For example, in our drilling operations, where we have evaluated differences between our own standards and those of contractors, we require bridging documents to be put in place. These define how two or more safety management systems co-exist to allow co-operation and co-ordination between BP and the contractor.

Contractor management review

Following the Deepwater Horizon oil spill, we began an in-depth review of contractor management practices, with the aim of documenting and learning from best practice throughout BP and across a number of sectors and industries that use contractors in potentially dangerous activities. We studied 21 major organizations in six different sectors airlines, mining, construction, pharmaceuticals and chemicals, nuclear and space.

We found that these organizations working in potentially high-risk arenas tended to have fewer and longer-lasting relationships with contractors, supported by shared structures and practices. Clearly defined responsibilities and decision rights at every stage of each process are needed to make contractor relationships work - including training, monitoring and auditing. Rigorous qualification of suppliers, including competency assessments for critical roles, is also important.

The findings of this review are informing our contractor management approach, with initial work focusing on contracts in our upstream supply chain that involve potentially high-consequence activities.

Our partners in joint ventures

We seek to work in partnership with companies that share our commitment to ethical and sustainable working practices. However, in some of our joint ventures, we do not directly control how our partners and their employees approach these issues.

Typically, our level of influence or control over a project or operation is linked to the size of our financial stake compared to other participants. In some joint ventures we act as the operator. Where we are the operator, and where legal and contractual arrangements allow, our policies, standards and operating systems apply.

In other cases, for example where one of our partners is the designated operator or where the operator is a joint venture company owned by BP and other partners, we are not the day-to-day operator. In those cases our OMS provides for our businesses to consider whether the management system used by the operator provides similar levels of risk and performance management to our own. We seek to influence our partners through dialogue and constructive engagement.

In 2011, BP initiated a review into our approach to the management of our relationships with non-operated joint venture operators and partners. This work includes safety and operational risk as well as bribery and corruption risk.

Environmental and social responsibility

The world's demand for energy is increasing and our business of finding and producing some of that energy means we operate in increasingly diverse locations globally. Many of these locations have environmental and social sensitivities.

To BP, working responsibly means managing our impacts on the areas where we operate, and making this a core principle in all of our activities. From the initial planning stages of a new project through to its eventual decommissioning and any remediation work that follows, our operating management system (OMS) lays out the standards and processes required for environmentally and socially responsible operations.

Wherever we work, we strive to minimize our impact on the environment whether to land, air, water or wildlife and to ensure that local people are engaged, human rights are respected and cultural heritage is conserved.

Our environmental and social practices

We are taking an increasingly systematic approach to the management of the environmental and social impacts of our projects. Our environmental and social practices, which form part of our OMS, set out how the major projects to which they apply should identify and manage environmental and social impacts. The practices also apply to projects that involve new access, projects that could affect an international protected area and some BP acquisition negotiations.

The practices help us deliver on the intent of the relevant sections of the OMS, the BP code of conduct and on our external commitments. They include several key requirements on impact assessment, security and human rights, indigenous people, international protected areas, greenhouse gas emissions, energy management, water management, ozone depleting substances, drilling wastes, and moving communities.

Early in the planning stage, applicable projects complete a screening process to identify environmental and social impacts that could arise from their activities. Between implementation in April 2010 and the end of 2011, nearly 60 projects had completed the screening process with the support of a trained and independent screening facilitator.

More information about our approach to environmental and social issues may be found in the BP Sustainability Review and on bp.com/sustainability.

Working in internationally protected areas

Our environmental and social practices require the projects to which they apply to understand the potential to affect international protected areas. The UNEP World Conservation Monitoring Centre's World Database on Protected Areas is used to inform this screening process. 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 protected status.

Where screening indicates that a proposed BP project may potentially affect an international protected area a high-level risk assessment is carried out. Our safety and operational risk function provides an independent review to inform the risk assessment, and before any physical activity begins permission is sought from senior management, together with appropriate mitigation measures. The Great Australian Bight Project completed this process in 2011.

Oil spill contingency planning and response

Applicable laws generally include requirements for dealing with the environmental and socio-economic impacts of oil spills or leaks. In some countries, regulators require as part of our licences to operate that plans are in place for responding to accidents and unplanned events such as oil spills.

The Deepwater Horizon oil spill demanded a response at an order of magnitude never required before. We learned a great deal and made advances in response technology and systems. As a result we are updating our group requirements and are sharing our knowledge with the industry and regulators.

In 2012, we will be working on the development of enhanced oil spill preparedness and response requirements for all BP entities that handle oil in a way that gives rise to a risk of an oil spill. Once these requirements are incorporated into OMS, they will require relevant businesses to follow a planning process to predict how the spilled oil will behave; identify, assess and understand the environmental and social sensitivities at risk; define effective response strategies and confirm that appropriate response capabilities are in place. This practice will incorporate our deepwater technical requirements, further enabling a single, consistent process across BP.

Sensitivity mapping

Understanding the environmental and socio-economic sensitivities where we operate is an important part of planning for an effective response. We obtain sensitivity information from many sources, including environmental and social impact assessments (ESIAs) for many of our projects. These ESIAs include information about the potential environmental and socio-economic impacts of planned activities and also the potential impacts that might occur in the event of an unplanned event, such as an oil spill. In 2011, we have used high resolution satellite imagery to enhance our sensitivity mapping across thousands of miles of coastlines, and submersibles to characterize the deep ocean. This has helped us better understand our environmental risks in regions like Angola, Brazil and the US.

Contingency planning

Identifying and assessing environmentally and socio-economically sensitive areas helps us to develop appropriate oil spill response and crisis management plans. The objective is to use response techniques to avoid or minimize the environmental and socio-economic impact of a spill to the extent feasible based upon an assessment of the sensitivity of the local environment. These plans are backed up by robust response 'capability', the tools and people required to mount an effective response to an incident.

How we work with designated government regulatory bodies in the event of a spill is critical. Sharing lessons learned and maintaining a dialogue with regulators in the regions where we operate is an important part of our approach. In many countries where BP operates, the regulator will ultimately determine the procedures to deal with the environmental and socio-economic impact.

Acute response plans are often focused on the physical containment and recovery of the spilled oil, though they also recognize that components in dispersed oil will be subject to processes of biodegradation, which may be facilitated and accelerated by the application of chemical dispersants.

For onshore operations, for example, BP refineries' spill response plans include passive and active containment measures that are designed for the specific location and types of operations.

In the event of concurrent spills at multiple locations, each affected facility would activate its independent oil spill response plan and respond accordingly. Although responding to multiple spills of the same magnitude and complexity as occurred in the Gulf of Mexico in 2010 would be a challenge for the group, our response plans are not interdependent.

See Safety on pages 65-69 for further information on BP's approach to oil spill prevention and preparedness.

Gulf of Mexico our long-term commitments

See Gulf of Mexico oil spill on pages 76-79 for further information on BP's response to the incident and environment and economic restoration efforts.

Canadian oil sands

Canada s oil sands are believed to hold one of the world s largest untapped supplies of oil, third in size to the resources in Saudi Arabia and Venezuela. BP is involved in three oil sands projects, 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, and Terre de Grace, which will be BP-operated are still in the early stages of development.

We reviewed and approved the decision to invest in Canadian oil sands projects, taking into consideration greenhouse gas (GHG) emissions, impacts on land, water use and local communities, and commercial viability. As with all joint ventures in which we are not the operator, we will monitor the progress of these projects and the mitigation of risk.

The extraction process to be used, in situ steam-assisted gravity drainage (SAGD) technology, involves the injection of steam underground. The steam liquefies the bitumen, allowing it to flow to the surface through production wells. This production technique reduces land disturbance and aligns to our strengths, particularly to our expertise with wells and improving large-scale reservoir performance. Unlike mining, in situ processes create a smaller physical footprint and do not involve tailing ponds.

A key concern around oil sands operations using SAGD is the amount of greenhouse gas emissions produced for steam generation and the processing of the produced bitumen. A well-to-wheels study conducted in 2009, which measured total GHG emissions from production through to consumption, found the lifecycle emissions for oil sands-based products to be 5-15% higher than those from products from average crude oils consumed in the US.

Climate change

Climate change represents a significant challenge for society, the energy industry and BP. In response to the challenges and opportunities, BP is taking a number of practical steps, including investing in lower-carbon energy products such as biofuels and wind, and ventures focused on sustainable energy solutions; and seeking to manage our own GHG emissions through a focus on operational energy efficiency, reductions in flaring and venting and the engineering design for new projects. We see natural gas playing a key strategic role as a lower-carbon fuel that is increasingly secure and affordable. We also consider the potential impacts of a changing climate on our operations.

Greenhouse gas emissions

Our direct GHG emissions[a] were 61.8 million tonnes (Mte) in 2011, compared with 64.9 Mte in 2010. This decrease of 3.1 Mte is primarily explained by the temporary reduction in activity in some of our businesses as a result of maintenance work and also by the sale of assets as part of our disposal programme. We achieved 0.2 Mte of sustainable emissions reductions in 2011.

Over the long-term it is likely that the carbon intensity of parts of our business will increase. In our upstream operations this is because we expect to move further into technically difficult and potentially more energy intensive areas. The intensity of certain refining operations may also increase with the trend towards processing heavier crudes which requires more energy.

In 2010 we did not report on GHG emissions associated with the Deepwater Horizon incident or response. We have since estimated the CO_2 equivalent emissions from response activities in 2010 to be approximately 481,000 metric tonnes, which includes major vessels deployed. This figure does not include emissions associated with the 'vessels of opportunity programme', the onshore vehicles and equipment and the incident itself, which are estimated to be minor.

a We report GHG emissions on a CO2-equivalent basis, including CO2 and methane. This represents all consolidated entities and BP's share of equity-accounted entities except TNK-BP.

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 low-carbon technologies and businesses. *See Regulation of the group's business Greenhouse gas regulation on page* 109.

To help address potential future regulation, we factor a carbon cost into our investment appraisals and engineering designs for new projects. We do this by requiring 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 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. This helps to assess our investments under scenarios in which the price of carbon emissions is higher than the current market price.

Adaptation to impacts resulting from a changing climate

We have funded research into the impacts of climate change on our operations for many years, to better understand the possible types of climate change impacts, potential effects on the environment and on our facilities and to develop potential responses to these impacts.

In the Beaufort Sea in Canada, for example, where BP is in the early stages of an oil exploration project, we have collaborated with ArcticNet, a local research organization devoted to understanding climate change impacts in the Arctic, on a two-year environmental baseline study. For ArcticNet the information gleaned will provide valuable data for analysis, while for BP the data will provide a useful baseline with which to compare future research, helping us to understand and chart the effects of climate change in this deepwater ocean environment.

Projects implementing our environmental and social practices are required to assess the potential impacts to the project from the changing climate. Any significant potential impacts identified are managed via the project's risk management process. To support this risk assessment process, we continually update and improve our climate impact modelling tools. In the Caspian region, for example, we are working with meteorology and oceanology consultants to enhance the existing modelling capability and develop a regional climate model to provide long-term forecasts and trends of wind speed, wave height and sea level.

We also have a guide on adapting to a changing climate which is available for all projects and operations. This document sets out guidance to help businesses across BP make appropriate allowance for the potential effects of climate change.

For projects where climate change impacts are identified as a risk, our engineers typically seek to address them like any other physical and ecological hazard, rather than as a discrete category. We periodically review and adjust existing design criteria and engineering technology practices. For example, we adapt our drainage design practices based on the frequency and severity of storms as well as rainfall and runoff amounts; if storms are anticipated to become more frequent, or heavier, the engineering design will accommodate this.

Water

We are taking a more strategic approach to water use and assessing water-related risks within our businesses, including those associated with the growing global issue of water scarcity. Our focus is on increasing our ability to forecast, measure and manage emerging water risks and engaging with external organizations to better understand these risks and develop sustainable water management practices, particularly where water is scarce.

With our industry association IPIECA, BP has also participated in the development of a new customized oil and gas version of the World Business Council for Sustainable Development's Global Water Tool, which helps oil and gas companies map their water use and assess risks of freshwater scarcity and related biodiversity impacts, across their portfolio of sites. BP has also invested in a water risk management tool, which is currently being piloted at a number of BP's operations, to investigate the risks of water use and availability at a local level.

In the future, these tools will provide BP with a means of consistently defining water risks and opportunities across a number of our operations, enabling us to establish a more consistent approach to managing water issues throughout the group.

Hydraulic fracturing

Technology helps to make it possible for BP to extract unconventional gas resources safely and responsibly to help meet the growing global demand for gas. Unconventional gas can be classified into three categories: tight gas, coalbed methane and shale gas. BP is pursuing unconventional gas in the US and in other countries such as Algeria, Oman and Indonesia.

Hydraulic fracturing, or 'fracking', is a process of pumping water mixed with a small proportion of sand and chemicals underground at high pressure to fracture the rock and release gas that would otherwise not be accessible. Some stakeholders have expressed concerns about the potential environmental impacts. BP recognizes these concerns and seeks to apply responsible well design and construction, surface operation and fluid handling practices and engages constructively with government and industry to promote sound policies and regulation that protect water resources and the environment. We expect that many of the jurisdictions in which we operate will adopt stricter regulations governing 'fracking' and other unconventional gas extraction technologies in the future which could adversely affect our operations and profitability in our unconventional gas business.

Environmental expenditure

			$ million
	2011	2010	2009
Environmental expenditure relating to the Gulf of Mexico oil spill			
Spill response	**586**	13,628	
Additions to environmental remediation provision	**1,167**	929	
Other environmental expenditure			
Operating expenditure	**704**	716	701
Capital expenditure	**819**	911	955
Clean-ups	**53**	55	70
Additions to environmental remediation provision	**510**	361	588
Additions to decommissioning provision	**4,596**	1,800	169

BP continues to incur significant costs related to the 2010 Gulf of Mexico oil spill. Of the spill response cost of $586 million incurred in the year (2010 $13,628 million) $336 million (2010 $1,043 million) remains as a provision at 31 December 2011.

The environmental remediation provision includes amounts for BP's commitment to fund the Gulf of Mexico Research Initiative, natural resource damage (NRD) assessment costs and emergency NRD restoration projects. In addition, during the year BP entered a framework agreement with natural resource trustees for the United States and five Gulf Coast states, providing for up to $1 billion to be spent on early restoration projects to address natural resource injuries resulting from the Gulf of Mexico oil spill. Further amounts for spill response costs were provided during the year primarily to recognize increased costs of shoreline clean-up, patrolling and maintenance and vessel decontamination. The majority of the active clean-up of the shorelines had been completed by the end of the year.

See Financial statements Note 2 on page 190, Note 36 on page 231 and Note 43 on page 249 for further information relating to the Gulf of Mexico oil spill.

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 $704 million in 2011 was at a similar level to 2009 and 2010.

Similar levels of operating and capital expenditures are expected in the foreseeable future. 2011 capital expenditure was lower than in 2010 due to the completion of various capital projects in our US refineries.

In addition to operating and capital expenditures, we also create 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 2011 largely due to changes in scope reassessments of the remediation plans of a number of our US retail sites. The charge for environmental remediation provisions in 2011 included $12 million in respect of provisions for new sites (2010 $54 million and 2009 $6 million).

In addition, we make provisions on installation of our oil- and gas-producing assets and related pipelines to meet the cost of eventual decommissioning. On installation of an oil or natural gas production facility a provision is established that represents the discounted value of the expected future cost of decommissioning the asset.

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. There was a significant increase in 2010, driven by activity in the Gulf of Mexico and this trend has continued in 2011 as a result of changes in estimation and detailed reviews of expected future costs; the majority of the increase related to our sites in Trinidad, the Gulf of Mexico and the North Sea.

On 15 October 2010, the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) issued Notice to Lessees (NTL) 2010-G05, 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. As a consequence, the timing and methodology of well abandonment have changed, reflected in an increase to the decommissioning provision.

Additionally, 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 set up 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 231.

Respecting human rights

BP supports the Universal Declaration of Human Rights, which lays out the rights to which all human beings are entitled. We have also supported recent multi-stakeholder efforts to establish clear, universally-applicable guidelines on the responsibilities of businesses in relation to human rights issues.

We are a signatory to two voluntary agreements with implications for specific aspects of human rights: the UN Global Compact, which helps businesses align their operations and strategies with 10 principles, including some that are related to human rights, and the Voluntary Principles on Security and Human Rights, which define good practice for security operations in extractive industry companies. We have contributed to the work of oil and gas industry organization IPIECA's human rights task force, which works on human rights issues and develops good practice guidance for companies in our industry.

In 2011 the UN Human Rights Council unanimously endorsed the Guiding Principles on Business and Human Rights. These outline specific responsibilities for businesses in relation to human rights. We participated in discussions on the development of the Guiding Principles, and in 2011 we completed a comparison between our current policies and practices and the expectations in the Guiding Principles, to help us identify what work will be needed to achieve alignment with the principles.

BP's code of conduct makes it clear that certain provisions, such as BP's stance on the rights and dignity of communities, relate directly to human rights. *See page 31 for further information about our code of conduct.*

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 in this area. 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 fully comply with the appropriate mandatory regulations when they come into effect.

We are working to respond effectively to the standards flowing from the UK Bribery Act as well as other anti-corruption legislation such as the Foreign Corrupt Practices 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.

In 2011, we issued 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.

Socio-economic development

We believe each BP project has the potential to benefit local communities by creating jobs, generating tax revenues and providing opportunities for local suppliers. Our presence in a location also has the potential to bring indirect economic benefits.

We run a range of programmes to build the skills of businesses in places where we work and to develop the local supply chain. These range from financing to sharing global standards and practice in areas such as health and safety. The programmes can benefit local companies by empowering them to reach the standards needed to supply BP and other clients. 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 aim to support development programmes that we believe will seek to create a meaningful and sustainable impact one that is relevant to local needs, aligned with BP's business and undertaken in partnership with local organizations.

The programmes we support fall into three broad categories: building business skills and developing enterprise, supporting education and other community needs and sharing technical expertise with local governments. In some developing economies we also support community infrastructure programmes that help people improve their access to basic resources such as drinking water and public health improvements. We work with local authorities, community groups and specialists to deliver these community programmes.

We use our technical knowledge and global reach where relevant to support national and regional governments in their efforts to develop their economies sustainably and provide public resources such as education and health. As well as country-specific projects, we support more general initiatives, including the Oxford Centre for the Analysis of Resource-Rich Economies, which studies how countries that are rich in natural resources such as oil and gas can use their resources for successful development rather than falling prey to mismanagement, corruption or other pitfalls.

Our direct spending on community programmes in 2011 was $103.7 million, which included contributions of $37.5 million in the US, $27.0 million in the UK (including $7.2 million to UK charities, of which $2.5 million for arts and culture, $2.8 million for enterprise development, $1.6 million for education), $2.6 million in other European countries and $36.6 million in the rest of the world. These reported amounts exclude social bonuses paid by BP to governments as part of licence acquisition costs and which have been capitalised 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 77 for details of these contributions.*

Employees

Number of employees at 31 December	US	Non-US	Total
2011			
Exploration and Production	**8,900**	**13,300**	**22,200**
Refining and Marketing[a]	**12,000**	**39,000**	**51,000**
Other business and corporate	**1,900**	**8,200**	**10,100**
Gulf Coast Restoration Organization	**100**		**100**
	22,900	**60,500**	**83,400**
2010			
Exploration and Production	7,900	13,200	21,100
Refining and Marketing[a]	12,400	39,900	52,300
Other business and corporate	1,700	4,500	6,200
Gulf Coast Restoration Organization	100		100
	22,100	57,600	79,700
2009			
Exploration and Production	8,000	13,500	21,500
Refining and Marketing[a]	12,700	38,900	51,600
Other business and corporate	2,100	5,100	7,200
	22,800	57,500	80,300

a Includes 14,600 (2010 15,200 and 2009 13,900) service station staff, all of whom are non-US.

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

We have reviewed the way we express BP's values and required behaviours with the goal of ensuring they support our aspirations for the future, align explicitly with our code of conduct and translate into responsible actions in the work we do every day. We conducted a programme in 2011 to renew employee awareness of our values and the behaviours as we work to reset our priorities as a company. *See bp.com/values for more information.*

We had approximately 83,400 employees at 31 December 2011, compared with approximately 79,700 a year ago. During 2011, our headcount has been most significantly affected by both external hiring in order to build capability and acquisition and divestment activity as part of the strategy to re-shape the business.

The group people committee, chaired by the group chief executive, continues to take overall responsibility for key policy decisions relating to employees. In 2011, some of the key subjects discussed were longer-term people priorities; the design and implementation of a new reward model;

our ambition on diversity and inclusion and a review of the governance of our learning programmes.

Our priorities for managing our people focus on ensuring the safety of our employees, strengthening capability, developing the potential of our own people, increasing diversity and inclusion and retaining the best people by motivating and engaging them.

Strengthening capability

The increasing demand for energy products and the complexity of our projects means that attracting and retaining skilled and talented people is vital to BP's delivery of its 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 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 ensure rigour and objectivity in our hiring and talent processes. They give an in-depth analysis of leadership behaviours, intellectual capacity and the required experience and skills for the role in question.

Our ongoing three-year graduate development programme continued in 2011. It currently has about 1,600 participants from all over the world.

Developing our people

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 per year.

We continue to work to embed appropriate leadership behaviours throughout our organization. In 2011, we delivered a new group leader development programme, designed to help our most senior leaders apply BP's required leadership behaviours in their work. The first phase of the programme has now been completed with about half the group leader population having undertaken eight days of intensive training. We are refreshing the content and will start the next phase in 2012.

Our group-wide suite of management development programmes, Managing Essentials, has now run in 41 countries, with around 32,400 participants.

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. Our revised performance management framework was implemented in 2011.

We encourage employee share ownership. For example, through the ShareMatch plan run in around 50 countries, we match BP shares purchased by our employees.

We aim to treat employees affected by mergers, acquisitions and joint ventures fairly and with respect, through open and regular communication. As part of the divestment programme following the Gulf of Mexico oil spill, BP has been seeking the same or comparable pay and benefits for employees transferring to other companies.

Diversity and inclusion

We are a global company and aim for a workforce that is representative of the societies in which we operate. We work to attract, motivate, develop and retain the best talent from the diversity the world offers our ability to be competitive and to thrive globally depends on it. We believe success comes from the energy of our people.

Through living our values of safety, respect, excellence, courage and one team, 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 review performance on a quarterly basis. They agree strategic direction and group standards which are then implemented through business specific diversity and inclusion plans. We supported the UK government-commissioned Lord Davies review in 2011, which made recommendations on increasing gender diversity on the boards of listed companies.

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.

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 2011, 15% of our group leaders were female and 19% 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. BP has increased the percentage of female leaders in 2011 and remains focused on building a more sustainable pipeline of diverse talent for the future.

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 halls and webcasts to communicate with our employees around the world.

Team meetings and one-to-one meetings are the core of our employee engagement, 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 employee engagement survey to monitor employee attitudes and identify areas for improvement. Our 2010 employee survey was delayed to allow for organizational changes to be reflected in the survey construction. This was completed and we carried out an employee engagement survey in 2011. The 2011 survey found that employees are committed and understand BP procedures and standards. The results show that there are a number of areas that can be improved. These include increasing transparency of the promotion process and being clear about the organization s priorities. Business leadership teams reviewed the results of the survey and have agreed actions to address the identified issues.

The survey includes 10 questions which make up the employee satisfaction index. The overall employee satisfaction index score for 2011 (62%) was below the score from 2009 (65%) but above that of 2008 (59%).

The code of conduct

The BP code of conduct sets the standard that all BP employees are required to work to. It is aligned with our values, group standards and legal requirements, and it clarifies the ethics and compliance expectations for everyone who works at BP. The code was updated in 2011 and now puts greater emphasis on a values-based approach.

The code defines what BP expects of its people in key areas such as safety, workplace behaviour, bribery and corruption and financial integrity.

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, an independent confidential helpline. The number of cases raised through OpenTalk in 2011 was 796, compared with 742 in 2010. 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 2011, 529 dismissals were reported by BP s businesses for non-adherence to the code of conduct or unethical behaviour compared to 552 in 2010.

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.

Technology

Technology in BP

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.

BP s model continues to be one of selective technology leadership, under which we focus on major technology programmes that best support our business priorities and competitive performance.

External assurance is achieved through the technology advisory council, which advises the board and executive management on the state of technology within BP. The council is comprised of eminent business and academic technology leaders.

In 2011 we invested $636 million (of which $12 million related to the response to the Deepwater Horizon incident) in research and development (R&D). This compares with $780 million in 2010 (of which $211 million related to the response to the Deepwater Horizon incident), and $587 million in 2009. The increase in the underlying R&D spend is related to our major technology programmes. *See Financial statements Note 13 on page 208.*

Our innovation ecosystem

BP has hundreds of scientists and technologists across the group, with seven major technology centres in the US, UK and Germany. We 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.

BP has long-term research programmes with major universities and research institutions around the world, exploring areas from reservoir fluid flow to energy biosciences. These include the following programmes:

- The Energy Biosciences Institute (EBI) is BP s largest external R&D investment, being a $500-million 10-year commitment to a multi-disciplinary research partnership with the University of California Berkeley, the Lawrence Berkeley National Laboratory, and the University of Illinois. Now in its fourth year, the EBI is generating multiple innovations, particularly in the field of cellulosic conversion, that give our biofuels business viable opportunities for commercial application.
- BP s energy sustainability challenge (ESC) is a research programme with 13 leading universities to establish trusted peer-reviewed data on the relationships between natural resource usage and different energy pathways. The aim is to better understand the implications of energy production and consumption on potentially-constrained land, water and materials resources, and assess corresponding technology and policy opportunities. One of the early publications resulting from this research is the University of Augsburg s handbook, *Materials critical to the energy industry.*
- In September 2011, BP opened the BP energy innovation laboratory at the Dalian Institute for Chemical Physics (DICP) in China as part of a 10-year extension to our research agreements with DICP.
- In January 2011, BP started a new three-year policy programme at Harvard University s Kennedy School focused on examining current and future potential policies on energy, security and climate change.

BP is a founding member of the UK s Energy Technologies Institute (ETI) a public/private partnership established in 2008 to accelerate low-carbon technology development. As at 31 December 2011, the ETI has commissioned over $200 million of work covering over 30 projects across a wide range of technologies. The ETI has also developed an integrated model of the UK energy system which projects potential pathways out to 2050 to meet the UK s emissions targets.

Exploration and Production

In the upstream, our technology investment directly supports business strategy by focusing on safety and operational risk management; operational efficiency; increased recovery and reserves; and winning new access. Our strengths in exploration, deepwater, giant fields and gas are underpinned by flagship technology programmes that conduct scientific research in proprietary laboratories and in partnership with world-class research institutes and universities, to develop industry-leading technologies in imaging, facilities, well design and completions, and field recovery. These technologies are applied in the field, often in combination with real-time data acquisition and visualization, to drive risk reduction and excellence in exploration, developments and production.

We are applying many of the lessons learned from the Deepwater Horizon incident and response throughout our global deepwater operations. The response required rapid innovation of new technologies to cap the well and contain the spill and in partnership with industry partners, government agencies and leading universities we have continued to develop and deploy new equipment and standards. Among many new developments in BP, we have built a global deepwater well cap and tooling package, now available for global deployment. This new capability includes a containment cap, remote operating vehicle (ROV) intervention system, subsea dispersant injection system, subsea debris removal equipment, and other tools.

BP continues to develop and apply innovative exploration technologies. BP has applied two novel seismic acquisition methods developed in-house. Our distance separated simultaneous sources (DS3) and independent simultaneous sources (ISS®) methods were used to complete ultra-large, high density land seismic surveys in the Middle East and North Africa. BP also has field trials under way to extend these acquisition methods to the offshore.

Through our Field of the Future® flagship technology programme, BP has deployed a range of digital, sensing and control technologies in its operations and is using the data to enhance real-time operating efficiency and recovery. Field of the Future tools are enabling more effective monitoring of production, multiple well components, and well characteristics such as temperature, which help to optimize hydrocarbon production. In addition, improved monitoring of facilities is helping to reduce risk, reducing downtime and saving tens of millions of dollars.

In 2011, we successfully completed BP well advisor module field trials in Azerbaijan, a technology designed to aid decision making, enhance safety, reduce cost and bring wells on line more quickly. Through well advisor, we can harness real-time drilling data from sensors that see ahead of the drill, enabling us to deploy technologies such as early kick detection, which allow adjustments that can minimize down time during this critical phase of development. Rolling field trials will continue throughout 2012 to accelerate deployment.

Enhanced oil recovery (EOR) technologies continue to push recovery factors to new limits. We believe that by increasing the overall recovery factor from our fields by 1%, we could be able to add 2 billion boe to our estimated ultimate recovery from existing fields. As at the end of 2011, BP, using its Designer Water® EOR technology, has treated 78 wells with Bright Water particles (a BP idea) in Alaska, Argentina, Azerbaijan, Pakistan and Russia. These applications have delivered more than 20 million barrels of additional gross recoverable volumes at a development cost of less than $6 per barrel, and with an 80% success rate: BP has pumped almost 90% of all Bright Water treatments in the industry. Bright Water treatments involve the design and deployment of this sweep-improving component with regular injection water over a period of several days. These particles are activated deep in the reservoir to form a waterflood sweep improving diversion at a point between the injection and production wells.

The $7.6 billion Clair Ridge project in the UK North Sea will be the first offshore project to use BP s LoSal® EOR technology to increase the recovery of oil by modifying the salinity of the water injected into the reservoir. (LoSal EOR is part of BP s suite of Designer Water technologies.) Earlier in 2011, BP and its partners also announced plans for the $5 billion redevelopment of the Schiehallion and Loyal fields,

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west of Shetland. The floating production, storage and offloading unit (FPSO) is to be built with full polymer EOR application capability.

Refining and Marketing

Our Refining and Marketing technology focus is both operational and customer facing. In our refineries and petrochemicals assets, we develop and apply technology to monitor operational integrity, to optimize product yields as a function of feedstock changes, to ensure quality attainment, and to improve energy efficiency. We also apply our expertise to create quality brand fuel and lubricant products for customers in on-road, off-road, air, sea and industrial applications globally.

For example:

We continued to expand our integrity monitoring systems, with the deployment of over 1,000 wireless Permasense sensors in 2011, now spanning all of our BP-operated refineries worldwide. These wireless corrosion sensors are the product of collaborative research and development between BP and Imperial College London. The sensors enable frequent, repeatable wall-thickness monitoring and provide previously unavailable insights into the condition of oil and gas assets.

In fuels and lubricants, our technology focus is on creating sustainable, differentiated and competitive products that enable advances in transport and industry. We continue to support our partners and customers in delivering greater energy efficiency and reduced CO_2 emissions in both established and emerging markets. In 2011, BP developed a new range of industrial metalworking fluids that are both safer for workers and less harmful to the environment, a new gear lubricant for maximizing the efficiency of wind turbines, and co-engineered passenger car lubricants for optimizing engine fuel efficiency. We are also working on new fuels and lubricants that deliver improved fuel economy and compatibility with the latest engine technology and with biofuel components. In 2011, we launched our latest generation BP Ultimate gasoline and diesel fuels, and BP s first differentiated-performance heavy duty diesel offer.

In July, we opened a new industrial technology centre in Turin, Italy. It will serve customers across Europe and analyse about 30,000 oil samples a year.

In 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 purified terephthalic acid (PTA), paraxylene and acetic acid. A third PTA plant is currently being engineered for Zhuhai, China. With a capacity of 1.25 million tonnes per year it will be the first to employ BP s latest PTA technology, enabling scale and cost efficiencies which significantly reduce both capital and conversion costs to a lower level than any other PTA technology.

In the field of unconventional feedstocks, we collaborate with KBR to promote, market, and license the slurry-bed residue and coal-upgrading Veba combi-cracking (VCC) technology. VCC is a hydrogen-addition technology suitable for processing crude oil residuum into high-quality distillates or synthetic crude oil in the refining, upstream-field upgrading and coal-to-liquids sectors.

Alternative Energy

In Alternative Energy, we are aligning technology capability with future growth platforms, particularly biofuels.

- In addition to our expanding biofuel production business in Brazil, we are developing advanced technologies that will unlock the commercial potential of next generation biofuels. At our technology centre in San Diego, bioscientists are advancing the technology to commercialize cellulosic biofuels and utilizing our large scale demonstration facility in Louisiana to prove the scale-up of proprietary cellulosic technology. In the UK, BP and its partners have constructed a demonstration plant to accelerate commercial-scale production of biobutanol, a highly-efficient fuel molecule.
- Our portfolio of strategic venturing investments aims at putting BP at the forefront in terms of innovation, particularly in developing sustainable energy solutions. Our emerging business and ventures unit brings together BP s venturing and carbon markets expertise with extensive carbon capture and storage capability and through this unit, we have more than 29 separate investments spanning three broad areas: bioenergy, electrification and carbon solutions.

The investments create insights and develop options to grow value for BP, for both its oil and gas assets as well as its low-carbon businesses. They cover a range of specialized innovations and technologies, such as waste-heat recovery, energy storage, carbon funds and land-carbon projects, new solar and bio-energy technologies. For example, we have an investment stake in GMZ Energy, based in the US, which is commercializing materials that allow the efficient conversion of heat to electricity with a thermoelectric device a building block for a new generation of energy-efficient products. The investment gives us insights into the ability of thermoelectric technology to recover low-grade waste heat sources cost-effectively across the group.

Gulf of Mexico oil spill

From response to restoration - summary

Building on the efforts of 2010, BP has continued to demonstrate its commitment to the US federal, state and local governments and communities of the Gulf Coast following the Deepwater Horizon oil spill. BP s efforts in 2011 included:

- Continuing the clean-up of the waters and shorelines impacted across the Gulf of Mexico and the ongoing protection of fish and wildlife.
- Supporting the economic restoration of impacted sectors of the Gulf Coast economy through targeted support to the tourism and seafood industries.
- Continuing the funding of the $20-billion Deepwater Horizon Oil Spill Trust for the purposes of paying all legitimate individual, business, state and local government claims and funding of settlements and Natural Resource Damages (NRD) assessment and restoration activities.
- Progressing the NRD activities in collaboration with the federal and state trustee agencies and progressing both emergency and early restoration activities, including our voluntary commitment of up to $1 billion in early restoration projects.
- Continuing the support of independent long-term research through the Gulf of Mexico Research Initiative (GoMRI) to improve knowledge of the Gulf ecosystem and to better understand and mitigate the potential impacts of oil spills in the region and elsewhere.

Proposed settlement with the Plaintiffs Steering Committee

On 3 March 2012, BP announced that it had reached a settlement with the Plaintiffs Steering Committee (PSC), subject to final written agreement and court approvals, to resolve the substantial majority of legitimate economic loss and medical claims stemming from the Deepwater Horizon accident and oil spill. The PSC acts on behalf of individual and business plaintiffs in the Multi-District Litigation proceedings pending in New Orleans (MDL 2179).

The proposed settlement is comprised of two separate agreements, one to resolve economic loss claims and another to resolve medical claims. Each proposed agreement provides that class members would be compensated for their claims on a claims-made basis, according to agreed compensation protocols in separate court-supervised claims processes. The proposed agreement to resolve economic loss claims includes a BP commitment of $2.3 billion to help resolve economic loss claims related to the Gulf seafood industry and a fund to support continued advertising that promotes Gulf Coast tourism.

BP estimates that the cost of the proposed settlement, expected to be paid from the $20 billion Trust, would be approximately $7.8 billion. This includes the financial commitment for the Gulf seafood industry.

The proposed economic loss settlement provides for a transition from the Gulf Coast Claims Facility (GCCF). A court-supervised transitional claims process for economic loss claims will be in operation while the infrastructure for the new settlement claims process is put in place. During this transitional period, the processing of claims that have been submitted to the GCCF will continue, and new claimants may submit their claims. BP has agreed not to wait for final approval of the economic loss settlement before claims are paid. The economic loss claims process will continue under court supervision before final approval of the settlement, first under the transitional claims process, and then through the settlement claims process established by the proposed economic loss agreement.

This proposed settlement does not include claims against BP made by the United States Department of Justice or other federal agencies (including under the Clean Water Act and for Natural Resource Damages under the Oil Pollution Act) or by the states and local governments. The proposed settlement also excludes certain other claims against BP, such as securities and shareholder claims pending in MDL 2185, and claims based solely on the deepwater drilling moratorium and/or the related permitting process.

For further details, see the Legal proceedings section on pages 160-164.

Completing the response

Throughout 2011, BP, working under the direction of the US Coast Guard s Federal On-Scene Coordinator (FOSC), and collaboratively with individual federal and state entities, continued to complete the Deepwater Horizon operational response activities as described below.

Source control and site remediation

During the first half of 2011, BP completed the decommissioning of all source control equipment including all vessels used in the response. We also completed plugging and abandonment (P&A) of the second relief well and conducted a seabed survey. BP conducted a further site survey of the Macondo wellhead and the two relief wells during the third quarter of 2011. Following these surveys it was determined that no further activity is necessary at the well site.

During the year we continued our efforts to recover and recycle waste material in order to minimize impacts. We also continued or completed the site remediation of multiple locations that were used during the response.

Residual clean-up in the Gulf of Mexico

Since the beginning of the Deepwater Horizon response multi-party Shoreline Clean-up Assessment Technique (SCAT) teams have continuously and systematically surveyed the shoreline to assess oiling conditions and develop shoreline treatment recommendations (STRs), which are implemented at the direction of the FOSC. Over 110,000 miles of aerial reconnaissance flights were conducted across the 11,000 miles of Gulf Coast shoreline. From this surveillance information, the SCAT teams identified more than 4,300 miles for further, ground-based survey. Of the Gulf Coast shoreline, 635 miles required some measure of mechanical or manual cleaning.

During 2011, mechanical or manual cleaning of the majority of the segments was completed. Patrolling and maintenance activities were initiated and will continue until the shoreline segments meet the applicable clean-up standards for the FOSC to determine that operational removal activity is complete. In November 2011, the FOSC also approved the Shoreline Clean-up Completion plan. This plan describes the process whereby the various shoreline segments included in the area of response operations can be surveyed, verified as meeting the applicable clean-up standards, and moved out of operational activity. It is expected that the majority of the 4,300 miles of the Gulf Coast shoreline within the area of response will be deemed operationally complete within 2012.

Environmentally sensitive areas were often hand cleaned. In some areas cleaning was paused at the direction of, or in consultation with, wildlife scientists, to minimize interference with migration patterns or breeding cycles.

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

Response efforts guided by science

At the direction of the FOSC, scientific studies were conducted to study the status of oil and dispersants in the water and sediments of the Gulf. These studies are being used to guide continuing response activities in the near shore environment and to better understand the potential impacts of residual oil. These results have been published in Operational Scientific Advisory Team (OSAT) reports (OSAT-1 and OSAT-2 reports, and a toxicity addendum) and Net Environmental Benefits Analysis reports (NEBAs).

These reports confirmed the appropriateness of the steps taken to remove oil and mitigate the impact on the environment. The OSAT-2 report determined that further efforts, beyond guidelines established by the FOSC to remove the residual oil from the shoreline, could potentially pose a greater risk to the environment than allowing the residual oil to degrade naturally.

To assess the potential impacts on fauna, the FOSC directed the OSAT scientists to conduct a comprehensive toxicity study. The report, which was an addendum to the OSAT-1 report, was issued on 8 July 2011. Of the approximately 3,500 toxicity tests conducted, 90% showed no statistically significant effects on wildlife.

At the request of the FOSC, several NEBA studies and specialized activities were carried out, including an effort to detect anchors that had been deployed during the response to keep containment boom in place. Based on the NEBA results, the NEBA team recommended that the FOSC let the anchors remain in place to allow them to degrade through natural processes.

Economic restoration

BP continued to support economic recovery in local communities through a variety of actions and programmes in 2011.

Deepwater Horizon Trust activity

BP has established the Deepwater Horizon Oil Spill Trust (the Trust) in the amount of $20 billion to be used in compensating individuals, businesses, government entities and others who have been impacted by the oil spill. The Trust provides funds to satisfy legitimate state and local government claims resolved by BP, final judgments and settlements, legitimate state and local response costs, natural resource damages and related costs, and legitimate individual and business claims administered by the GCCF, which has been managed by Kenneth Feinberg. The proposed economic loss settlement announced on 3 March 2012 with the Plaintiffs Steering Committee on MDL 2179 provides for a transition from the GCCF. A court-supervised transitional claims process for economic loss claims will be in operation while the infrastructure for the new settlement claims process is put in place. During this transitional period, the processing of claims that have been submitted to the GCCF will continue and new claimants may submit their claims. The establishment of the Trust does not represent a cap or floor on BP s liabilities and BP does not admit to a liability of this amount.

In 2011, $1 billion was voluntarily set aside in the Trust for NRD early restoration projects. BP is working with federal and state trustees to select appropriate projects that will enhance habitats, wildlife and access for recreational use.

As at 31 December 2011, BP s cumulative contributions to the Trust amounted to $15.1 billion since its inception, including our second-year commitment of $5 billion and a total of $5.1 billion cash settlements received during 2011 from MOEX USA Corporation (MOEX), Weatherford US., L.P. (Weatherford), and Anadarko Petroleum Corporation (Anadarko). The remaining committed contributions as at 31 December 2011 totalling $4.9 billion are scheduled to be made by the end of 2012. In January 2012, we contributed to the Trust the $250 million settlement received from Cameron International Corporation (Cameron). The Trust disbursed $3.7 billion in 2011 and the total paid out since its establishment amounted to $6.7 billion by the end of 2011.

Claims payments

All payments that were made in 2011 for legitimate claims by individuals, businesses and government entities were paid from the Trust. During the year, individuals and businesses received $3.1 billion in payments through the GCCF. More than 189,000 individual and business claimants accepted full and final settlements, while about 33,000 received interim payments. Since May 2010, more than $6.2 billion has been paid to individuals and businesses through the claims process, with the Trust paying $5.8 billion of this and BP paying the remainder prior to the establishment of the Trust.

Government entities received more than $40 million in claims payments during 2011. Nearly 60 loss-of-revenue claims have been paid to government entities since May 2010. By the end of 2011, BP had resolved over 90% of government claims filed.

During 2011, BP paid a total of $7.7 million to vessel owners whose vessels were involved in clean-up and protection activities as part of the Vessels of Opportunity (VoO) programme. In an effort to ensure fairness, BP instructed the external adjusters to broaden the original compensation guidelines. Once the new guidelines were established, adjusters have and are continuing to re-examine property damage claims from about 1,200 vessel owners, whose property-damage claims had previously been denied or partially paid to ensure that property damages reported by claimants have been adequately addressed.

Business review

Promoting tourism along the Gulf Coast

To support economic restoration in the impacted Gulf Coast communities, BP entered into three-year agreements with the states of Alabama, Florida, Louisiana and Mississippi to promote tourism, monitor seafood safety and promote Gulf seafood.

During 2011, BP made commitments of $92 million in total over three years to support tourism promotion within the four affected states. This is in addition to $87 million in tourism grants provided by BP in 2010. Each state is using its tourism funds to develop specific marketing programmes.

The proposed settlement announced on 3 March 2012 with the Plaintiffs Steering Committee in MDL 2179 includes a fund to support continued advertising that promotes Gulf Coast tourism.

Seafood testing, monitoring and promotion

Federal and state officials continue to collect and test seafood from the Gulf of Mexico, and the results of these tests have indicated that Gulf of Mexico seafood meets the US Food and Drug Administration (FDA) safety guidelines. The National Oceanic and Atmospheric Administration (NOAA) and the FDA are conducting widespread scientific evaluation of seafood samples to protect and reassure consumers. Since May 2010, more than 6,000 seafood samples have been collected by the FDA, NOAA, and state agencies in Louisiana, Mississippi, Alabama, and Florida. The FDA has also visited over 100 seafood processors and wholesalers across the Gulf Coast, collecting seafood samples and inspecting processing plants for biological, chemical, and physical hazards. Levels of residues of oil contamination in seafood have consistently tested between 100 and 1,000 times lower than the safety thresholds established by the FDA. Test results from NOAA, the FDA, and the Gulf of Mexico states are publicly available.

Recreational fishing showed signs of recovery in 2011. To raise public awareness of Gulf of Mexico seafood, BP has committed $34 million for Gulf of Mexico states to conduct seafood testing and $48 million to market Gulf of Mexico seafood.

Rig Worker Assistance Fund

BP established a $100-million Rig Worker Assistance Fund through the Baton Rouge Area Foundation (the Foundation) to support unemployed rig workers experiencing economic hardship as a result of the moratorium on deepwater drilling imposed by the US federal government. In 2011, the Foundation awarded $5.8 million to an expanded pool of applicants, after awarding $5.6 million to nearly 350 rig workers in 2010. With less than 2,000 applying for funds, the Foundation granted $18 million of the BP contribution to community-based organizations through its Future for the Gulf Fund. At the end of 2011, the Foundation was assessing additional funding requests from organizations assisting those impacted by the spill, and has said it hopes to complete the distribution of the BP contribution by the end of 2012.

Environmental restoration

We made progress during 2011 on multiple fronts as part of the ongoing efforts to assess and address injury to natural resources in the Gulf of Mexico.

We continued to support and participate in the Natural Resource Damages (NRD) process. Work has been completed or is under way on more than 150 cooperative studies with federal and state agencies to gather data on potential impacts and injuries to birds, turtles and mammals; fish and shell fish; near shore and shoreline habitats; and the Gulf of Mexico water column and sediment.

We also worked with the Natural Resource Damage Assessment (NRDA) trustees to begin assessing the potential lost human use of these Gulf Coast natural resources. Additional studies focused on the potential impacts on historical and archaeological resources and endangered species.

During the year we also supported two emergency restoration projects and made a major commitment to fund early restoration projects. In addition, the National Fish and Wildlife Foundation funded several projects during 2011 using funds provided by BP in 2010 from the sale of oil recovered from the spill.

We are working with NOAA to prepare and provide access to summaries of the studies completed and data gathered during the cooperative assessment process. We also prepared and participated

in a variety of scientific publications and seminars as part of our efforts to share learnings from the oil spill as broadly as possible.

NRD process under way

In 2011, we continued to work with scientists and trustee agencies through the NRD process to identify natural resources that may have been exposed to oil or otherwise impacted by the incident, and to look for evidence of injury.

As part of the NRD process, trustees from each state and the federal government held a series of public meetings during 2011 in each of the five states affected by the Deepwater Horizon oil spill. These focused on the status of potential injury assessments and of potential restoration process. To date, BP has paid over $600 million for NRD assessment efforts.

Public comments were collected as part of the Programmatic Environmental Impact Statement (PEIS) process, which will inform one of the core planning documents for restoration. A final PEIS is scheduled to be released by the trustees in late 2012.

Emergency restoration projects

Emergency restoration projects are defined under the Oil Pollution Act of 1990 (OPA 90) as preventative measures or actions undertaken to stop continuing injuries to resources and to mitigate potential effects of the spill. During 2011, two emergency restoration projects were completed along the Gulf Coast in support of birds and turtles. A third project is in the planning phase for submerged aquatic vegetation and is scheduled to be implemented in 2012.

Early restoration projects

Under an agreement signed with federal and state trustees in April 2011, BP voluntarily committed to provide up to $1 billion to fund projects that will accelerate restoration efforts in Gulf Coast areas that were impacted by the Deepwater Horizon oil spill.

The agreement enables work on restoration projects to begin at the earliest opportunity, before all of the studies under the NRDA process are complete, and before funding is required by OPA 90. Priority will be assigned to projects aimed at improving areas that offer the greatest benefits to wildlife, habitat, and recreational use that were impacted as a result of the incident.

In December 2011, state and federal trustees unveiled the first set of early environmental restoration projects that are proposed for funding under the agreement. The eight proposed projects are located in Alabama, Florida, Louisiana and Mississippi. Collectively, the projects will restore and enhance wildlife, habitats, the ecosystem services provided by those habitats, and provide additional access for fishing, boating and related recreational uses. More early restoration projects are anticipated in the future.

Funding for the early restoration projects will come from the $20-billion Trust. Additional information about the projects, projected costs and proposed credits can be found on the NOAA website.

Environmental studies and reports

BP is committed to sharing and providing access to the numerous studies and reports generated during the course of the response. In total, since May 2010, more than 150 NRDA studies have been completed or are in progress throughout the Gulf. As the studies are completed, summaries are expected to be published as appropriate either on BP s website or on government websites. Our website also contains numerous technical reports and documentation on a variety of environmental and health-related topics.

National Fish and Wildlife Foundation projects

In 2010, BP donated $22 million from the net revenue of the sale of oil recovered from the spill to the US National Fish and Wildlife Foundation (NFWF) which used the funds to quickly implement several conservation projects along the Gulf Coast.

In 2011, the NFWF announced that it issued $6.9 million in grants from the Recovered Oil Fund for Wildlife for 22 new projects. The grants, which were supplemented by a further $3.3 million from other contributors, were awarded for projects designed to:

- Improve sea turtle hatchling success across 56 miles of priority Florida beaches.
- Increase the capacity of marine mammal and sea turtle treatment facilities.
- Restore a combined 3.5 miles of oyster reefs, which in turn protect sensitive coastal habitat.
- Reduce the incidence of sea turtles being caught in the course of recreational and commercial fishing.

Commitment to long-term oil spill research

In 2010, BP committed $500 million over 10 years to fund independent scientific research through the Gulf of Mexico Research Initiative (GoMRI). The research will improve knowledge of the Gulf ecosystem and help the industry and others to better understand and mitigate the impact of oil spills in the region and elsewhere.

In June 2011, the GoMRI Research Board awarded 17 grants totalling $1.5 million to support scientists as they continue time-sensitive data collection. In August 2011, the Research Board awarded a total of $112.5 million over three years to eight consortia comprised of over 70 research institutions. All eight consortia are led by Gulf Coast institutions. Research recipients will use the grants to investigate the fate of oil released by the spill, and for the development of new tools and technology for responding to future spills and improving mitigation and restoration.

In December 2011, the GoMRI Research Board also issued a request for proposals (RFP) for approximately $7.5 million per year for three years, in smaller grants to individual or small teams of researchers.

Rebuilding trust through effective communications

During 2011, we worked to engage, inform and communicate with a wide range of stakeholders throughout the region. We supported community events and we shared information on a variety of issues and concerns with individuals, community organizations, business leaders, elected officials, non-governmental organizations and the news media.

Financial update

Profit before tax for the group includes a pre-tax credit of $3.8 billion and finance costs of $0.1 billion in relation to the Gulf of Mexico oil spill. The pre-tax credit reflects $5.5 billion in relation to settlements reached with MOEX, Weatherford, Anadarko and Cameron, partially offset by further costs associated with the ongoing spill response, adjustments to provisions, and an increase in the amount provided for legal fees, as well as functional expenses of BP s Gulf Coast Restoration Organization (GCRO).

Provisions were established during 2010 for the environmental expenditure, spill response costs, litigation and claims, and Clean Water Act (CWA) penalties. Most of the costs incurred in 2011 were covered by these existing provisions. Pre-tax charges were recorded in 2011 of $0.4 billion for the functional expenses of the GCRO, $1.1 billion for increases in the amounts provided, primarily related to spill response costs and legal fees, a $0.1 billion finance charge for unwinding of discount on provisions, and $0.1 billion for spill response costs charged directly to the income statement. These charges partially offset the $5.5 billion credit for settlements reached during the year.

As at 31 December 2011, the cumulative charges for provisions to be paid from the Trust and the associated reimbursement asset recognized amounted to $16.6 billion. This represented an increase of $4.0 billion in the provisioned amounts during 2011, primarily for the $2.1 billion expected impact of the proposed settlement announced on 3 March 2012 with the Plaintiffs Steering Committee in MDL 2179, the $1-billion commitment to NRD early restoration and new provisions for personal injury and death claims and Vessel of Opportunity programme claims. A further $3.4 billion could be provided in subsequent periods for items covered by the Trust, with no net impact on the income statement.

BP has provided for all potential liabilities that can be estimated reliably at this time, including fines and penalties under the CWA. The total amounts that will ultimately be paid by BP in relation to all obligations relating to the incident are subject to significant uncertainty.

BP considers that it is not possible to estimate reliably any obligation in relation to NRD claims under OPA 90 (other than the estimated costs of the assessment phase and the costs relating to emergency restoration and the $1 billion agreement for early restoration), any amounts in relation to fines and penalties except for those relating to the CWA and litigation arising from alleged violations of OPA 90. These items are therefore contingent liabilities.

BP holds a 100% interest in the Macondo well, with the lease interests previously held by MOEX and Anadarko now assigned to BP as part of the settlement agreements. MOEX paid BP $1.1 billion in cash and Anadarko paid BP $4 billion in cash to settle all outstanding claims between the companies related to the incident and to the prospect.

For details regarding the impacts and uncertainties relating to the Gulf of Mexico oil spill refer to Financial statements Note 2 on page 190, Note 36 on page 231 and Note 43 on page 249. See also Risk factors on page 59 and Proceedings and investigations relating to the Gulf of Mexico oil spill on pages 160-164.

Legal proceedings and investigations

See Legal proceedings on pages 160-164 for a full discussion of legal proceedings and investigations relating to the incident.

Exploration and Production

At the end of 2010, as part of our response to the Deepwater Horizon oil spill, we announced the decision to reorganize the Exploration and Production segment to create three separate divisions: Exploration, Developments and Production, integrated through a Strategy and Integration organization. This structure was established in March 2011 and each of the four parts is led by an executive vice president reporting directly to the group chief executive. The new organization is designed to change the way we operate, with a particular focus on managing risk, delivering common standards and processes and building technical capability. The new organization has not changed the way we report our operating segments under IFRS.

The Exploration division is accountable for renewing our resource base through access, exploration and appraisal. The Developments division is accountable for the safe and compliant execution of wells (drilling and completions) and major projects and comprises the global wells organization and the global projects organization, which were established in 2011. The Production division is accountable for safe and compliant operations, including upstream production assets, midstream transportation and processing activities, and the development of our resource base. Divisional activities are integrated on a regional basis by a regional president reporting to the Production division. The Strategy and Integration organization is accountable for optimization and integration across the divisions, including the delivery of support from the group s finance, procurement and supply chain, human resources, technology and information technology functions.

From 1 January 2012, the group s investment in TNK-BP will be reported as a separate operating segment, rather than within the Exploration and Production segment, reflecting the way in which the investment is now managed.

The group safety and operational risk (S&OR) function maintains our global safety standards. S&OR staff are deployed at the operating level within the Exploration and Production 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.

Our Exploration and Production segment included upstream and midstream activities in 30 countries in 2011, including Angola, Azerbaijan, Brazil, Canada, Egypt, India, Iraq, Norway, Russia, Trinidad & Tobago (Trinidad), the UK, the US and other locations within Africa, Asia, Australasia and South America, as well as gas marketing and trading activities, primarily in Canada, Europe and the US. Upstream activities involve oil and natural gas exploration, field development and production. Our exploration and appraisal programme is currently focused on Angola, Australia, Azerbaijan, Brazil, Canada, Egypt, the deepwater Gulf of Mexico, the UK North Sea, Oman and onshore US. Major development areas include Angola, Australia, Azerbaijan, Canada, Egypt, the deepwater Gulf of Mexico, North Africa, and the UK North Sea. During 2011, production came from 24 countries. The principal areas of production are Angola, Argentina, Azerbaijan, Egypt, Russia, Trinidad, the UAE, the UK and the US.

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 NGL extraction businesses in Canada, Indonesia, the US and the UK. Our most significant midstream pipeline interests are the Trans-Alaska Pipeline System in the US; the Forties Pipeline System and the Central Area Transmission System pipeline, both in the UK sector of the North Sea; the South Caucasus Pipeline, which runs from Azerbaijan through Georgia to the Turkish border; and the Baku-Tbilisi-Ceyhan pipeline, which runs through Azerbaijan, Georgia and Turkey. Major LNG activities are located in Australia, Indonesia and Trinidad. BP is also investing in the LNG business in Angola.

Additionally, our activities include the marketing and trading of natural gas, power and natural gas liquids. These activities 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.

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.

Upstream operations in Abu Dhabi, Argentina, Bolivia, Chile, Russia, Venezuela and Vietnam as well as some of our operations in Angola, Canada, Indonesia and Trinidad are conducted through equity-accounted entities.

Our market

Energy demand, and in particular oil demand, has followed overall economic trends in recent years, recovering strongly in 2010 but facing more challenging conditions in 2011.

Dated Brent for the year averaged $111.26 per barrel, 40% above 2010 s average of $79.50 per barrel. In 2012, we expect oil price movements to continue to be driven by the pace of global economic growth and its resulting implications for oil consumption, and by OPEC production decisions.

Natural gas prices diverged globally in 2011, reflecting different regional dynamics. The average US Henry Hub First of Month Index fell to $4.04/mmBtu, an 8% decrease from 2010, while in Europe prices increased. Spot gas prices at the UK National Balancing Point increased by 33% to an average of $56.33 pence per therm for 2011.

After a record increase in 2010, global gas consumption growth moderated in 2011. In the US, economic momentum supported gas use in the first half of the year and a hot summer raised demand. Yet domestic production outpaced consumption growth due to further increases in the availability of shale gas.

In 2012, we expect gas markets to continue to be driven by the economy, weather, domestic production, LNG supply and reductions in nuclear power generation following the Fukushima disaster in Japan in March 2011.

Our strategy

In Exploration and Production, 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 with a focus on deepwater, gas value chains and giant fields. Our strategy is enabled by:

- A continued focus on safety and managing risk.
- Strong relationships built on mutual advantage, deep knowledge of the basins in which we operate, and technology.
- Building capability along the value chain in Exploration, Developments and Production.
- Actively managing our portfolio.

We intend to 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.

Our performance

Key statistics

	2011	2010	2009
			$ million
Sales and other operating revenues[a]	**75,475**	66,266	57,626
Replacement cost profit before interest and tax	**30,500**	30,886	24,800
Capital expenditure and acquisitions	**25,535**	17,753	14,896
			$ per barrel
Average BP crude oil realizations[b]	**107.91**	77.54	59.86
Average BP NGL realizations[b]	**51.18**	42.78	29.60
Average BP liquids realizations[b c]	**101.29**	73.41	56.26
Average West Texas Intermediate oil price[d]	**95.04**	79.45	61.92
Average Brent oil price[d]	**111.26**	79.50	61.67
			$ per thousand cubic feet
Average BP natural gas realizations[b]	**4.69**	3.97	3.25
Average BP US natural gas realizations[b]	**3.34**	3.88	3.07
			$ per million British thermal units
Average Henry Hub gas price[e]	**4.04**	4.39	3.99
			pence per therm
Average UK National Balancing Point gas price[d]	**56.33**	42.45	30.85
			thousand barrels per day
Liquids production for subsidiaries[c f]	**992**	1,229	1,400
Liquids production for equity-accounted entities[c f]	**1,165**	1,145	1,135
Total of subsidiaries and equity-accounted entities[c f]	**2,157**	2,374	2,535
			million cubic feet per day
Natural gas production for subsidiaries[f]	**6,393**	7,332	7,450
Natural gas production for equity-accounted entities[f]	**1,125**	1,069	1,035
Total of subsidiaries and equity-accounted entities[f]	**7,518**	8,401	8,485
			thousand barrels of oil equivalent per day
Total production for subsidiaries[f g]	**2,094**	2,492	2,684
Total production for equity-accounted entities[f g]	**1,360**	1,330	1,314
Total of subsidiaries and equity-accounted entities[f g]	**3,454**	3,822	3,998
			million barrels
Estimated net proved crude oil reserves for subsidiaries[c h]	**5,153**	5,559	5,658
Estimated net proved crude oil reserves for equity-accounted entities[c i]	**5,234**	4,971	4,853
Estimated net proved bitumen reserves for equity-accounted entities	**178**	179	
Total of subsidiaries and equity-accounted entities[c h i]	**10,565**	10,709	10,511
			billion cubic feet
Estimated net proved natural gas reserves for subsidiaries[j]	**36,381**	37,809	40,388
Estimated net proved natural gas reserves for equity-accounted entities[k]	**5,278**	4,891	4,742
Total of subsidiaries and equity-accounted entities[j k]	**41,659**	42,700	45,130
			million barrels of oil equivalent
Estimated net proved reserves for subsidiaries[h j]	**11,426**	12,077	12,621
Estimated net proved reserves for equity-accounted entities[i k]	**6,322**	5,994	5,671
Total of subsidiaries and equity-accounted entities[h i j k]	**17,748**	18,071	18,292

a Includes sales between businesses.
b Realizations are based on sales of consolidated subsidiaries only, which excludes equity-accounted entities.
c Crude oil and natural gas liquids.
d All traded days average.
e Henry Hub First of Month Index.
f Net of royalties.
g 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.
h Includes 20 million barrels (22 million barrels at 31 December 2010 and 23 million barrels at 31 December 2009) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

i Includes 310 million barrels (254 million barrels at 31 December 2010 and 243 million barrels at 31 December 2009) in respect of the 7.37% minority interest in TNK-BP (7.03% at 31 December 2010 and 6.86% at 31 December 2009).

j Includes 2,759 billion cubic feet of natural gas (2,921 billion cubic feet at 31 December 2010 and 3,068 billion cubic feet at 31 December 2009) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

k Includes 174 billion cubic feet (137 billion cubic feet at 31 December 2010 and 131 billion cubic feet at 31 December 2009) in respect of the 6.27% minority interest in TNK-BP (7.03% at 31 December 2010 and 6.86% at 31 December 2009).

2011 performance

Safety and operational risk

In Exploration and Production, ensuring safe, reliable and compliant operations remains our highest priority. The organizational and governance changes in Exploration and Production and S&OR have been designed to ensure we achieve this, supported by a systematic framework provided by BP s operating management system (OMS). All Exploration and Production operated businesses, with the exception of those recently acquired, are now applying our OMS to govern their BP operations and have begun working 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 65-66 for more information on OMS.*

Safety performance is monitored by a suite of input and output metrics which focus on personal and process safety including operational integrity, occupational health and all aspects of compliance.

In 2011, there were no workforce fatalities in Exploration and Production. In 2010, there was one workforce fatality.

The recordable injury frequency (RIF), which measures the number of recordable injuries to the BP workforce per 200,000 hours worked, was 0.30. This is lower than 2010 when it was 0.32 and 2009 when it was 0.39. Our day away from work case frequency (DAFWCF) in 2011 was 0.060. This is lower than 2010 when it was 0.063 but higher than 2009 when it was 0.038.

In 2011, the number of reported loss of primary containment (LOPC) incidents in Exploration and Production was 152, down from 194 in 2010. The number of reported oil spills equal to or larger than 1 barrel during 2011 was 71, down from 117 in 2010.

Financial and operating performance

We continually seek access to resources and in 2011, in addition to new access resulting from acquisitions as detailed on page 83, this included Angola, where BP gained access to five new deepwater exploration and production blocks covering 24,200km^2; Australia, where BP was awarded four blocks covering 24,500km^2 in the Ceduna Sub Basin off the coast of South Australia; Azerbaijan, where the republic of Azerbaijan ratified the Shafag-Asiman production-sharing agreement (PSA) covering 1,100km^2 in the Caspian Sea; China, where BP was awarded access to a 9,700km^2 block in the South China Sea; deepwater Gulf of Mexico, where 12 leases from the March 2010 Outer Continental Shelf Lease Sale 213 covering 280km^2 were executed; Indonesia, where BP was awarded four coalbed methane PSAs covering 4,800km^2 in the Barito basin of South Kalimantan and two oil and gas PSAs covering 16,400km^2 offshore in the Arafura Sea; and Trinidad, where BP was awarded two deepwater blocks covering 3,600km^2, subject to government approval.

In September 2011, we announced the Moccasin oil discovery in the deepwater Gulf of Mexico (not BP-operated). In October 2011, we announced the Salmon gas discovery in Egypt s Nile Delta. In 2011, we took final investment decisions on three projects and two major projects came onstream: Serrette in Trinidad and Pazflor in Angola.

Production for 2011 was lower than last year. After adjusting for the effect of entitlement changes in our PSAs and the effect of acquisitions and disposals, underlying production was 7% lower than 2010. This primarily reflects lower Gulf of Mexico production as a result of the impact of the drilling moratorium as well as the impact of turnaround maintenance activities. In 2011, full-year production growth in TNK-BP was 2.8%.

Sales and other operating revenues for 2011 were $75 billion, compared with $66 billion in 2010 and $58 billion in 2009. The increase in 2011, compared with 2010, primarily reflected higher oil and gas realizations, partly offset by lower production. The increase in 2010, compared with 2009, primarily reflected higher oil and gas realizations, partly offset by lower production.

The replacement cost profit before interest and tax for 2011 was $30,500 million, compared with $30,886 million for the previous year. 2011 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. (*See page 58 for further information on non-operating items.*) In addition, fair value accounting effects had a favourable impact of $11 million relative to management s measure of performance. (*See page 58 for further information on fair value accounting effects.*)

The primary additional factors contributing to the 1% decrease in replacement cost profit before interest and tax were higher realizations partially offset by lower production volumes (including in higher margin areas), rig standby costs in the Gulf of Mexico, higher costs related to turnarounds, certain one-off costs and higher exploration write-offs.

Total capital expenditure including acquisitions and asset exchanges in 2011 was $25.5 billion (2010 $17.8 billion and 2009 $14.9 billion). (*See page 83 for further information on acquisitions.*)

Development expenditure of subsidiaries incurred in 2011, excluding midstream activities, was $10.2 billion, compared with $9.7 billion in 2010 and $10.4 billion in 2009.

Provisions for decommissioning increased from $10.5 billion at the end of 2010 to $17.2 billion at the end of 2011. The increase reflects higher cost estimates, which are in part driven by new requirements in the Gulf of Mexico. Decommissioning costs are initially capitalized within fixed assets and are subsequently depreciated as part of the asset.

Prior years comparative financial information

The replacement cost profit before interest and tax for the year ended 31 December 2010 of $30,886 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.

The replacement cost profit before interest and tax for the year ended 31 December 2009 of $24,800 million included a net credit for non-operating items of $2,265 million, with the most significant items being gains on the sale of operations (primarily from the disposal of our 46% stake in LukArco, the sale of our 49.9% interest in Kazakhstan Pipeline Ventures LLC and the sale of BP West Java Limited in Indonesia) and fair value gains on embedded derivatives. In addition, fair value accounting effects had a favourable impact of $919 million relative to management s measure of performance.

The primary additional factor contributing to the 25% increase in the replacement cost profit before interest and tax for the year ended 31 December 2010 compared with the year ended 31 December 2009 were higher realizations, lower depreciation and higher earnings from equity-accounted entities, partly offset by lower production, a significantly lower contribution from gas marketing and trading and higher production taxes.

Outlook

In 2012, we will continue to drive operational risk reduction through the new Exploration and Production segment structure, supported by the S&OR function. Our divisions will work to manage risk and deliver common standards, driving functional excellence across the lifecycle of exploration, development and production, while continuing to focus on building our technical capability for the future. We believe that our portfolio of assets remains well positioned to compete and grow value in a range of external conditions and we continue to increase both investment and operating cash. We expect production in 2012 to be broadly flat, normalizing for divestments and price effects, and excluding TNK-BP. This is the net effect of growth from new projects and new production from India and Brazil being offset by normal base decline. In 2012, we intend to drill 12 exploration wells, start up six major projects, and increase our activity in the Gulf of Mexico to eight operational rigs, subject to approvals by US regulators.

Upstream activities

Exploration

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 2011, our exploration and appraisal costs, excluding lease acquisitions, were $2,398 million, compared with $2,706 million in 2010 and $2,805 million in 2009. 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 76% of 2011 exploration and appraisal costs were directed towards appraisal activity. In 2011, we participated in 308 gross (73.33 net) exploration and appraisal wells in nine countries. The principal areas of exploration and appraisal activity were Angola, Australia, Azerbaijan, Brazil, Canada, Egypt, the deepwater Gulf of Mexico, the UK North Sea, Oman and onshore US.

Total exploration expense in 2011 of $1,520 million (2010 $843 million and 2009 $1,116 million) included the write-off of expenses related to unsuccessful drilling activities in the deepwater Gulf of Mexico ($284 million), Asia Pacific ($61 million) and others ($5 million). It also included $14 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 booking from new discoveries will depend on the results of ongoing technical and commercial evaluations, including appraisal drilling.

Proved reserves replacement

Total hydrocarbon proved reserves, on an oil equivalent basis including equity-accounted entities, comprised 17,748mmboe (11,426mmboe for subsidiaries and 6,322mmboe for equity-accounted entities) at 31 December 2011, a decrease of 2% (decrease of 5% for subsidiaries and increase of 5% for equity-accounted entities) compared with the 31 December 2010 reserves of 18,071mmboe (12,077mmboe for subsidiaries and 5,994mmboe for equity-accounted entities). Natural gas represented about 40% (55% for subsidiaries and 14% for equity-accounted entities) of these reserves. The change includes a net decrease from acquisitions and disposals of 361mmboe (218mmboe net decrease for subsidiaries and 143mmboe net decrease for equity-accounted entities). Acquisitions occurred in Brazil, Canada, India, the UK, the US, Venezuela and Vietnam. Divestments occurred in Algeria, Azerbaijan, Canada, Colombia, Pakistan, Trinidad, the US, the UK, Venezuela and Vietnam.

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 2011, the proved reserves replacement ratio excluding acquisitions and disposals was 103% (106% in 2010 and 129% in 2009) for subsidiaries and equity-accounted entities, 45% for subsidiaries alone and 194% for equity-accounted entities alone. The 2011 reserves additions for TNK-BP include the effect of moving from life-of-licence measurement to life-of-field measurement, reflecting TNK-BP s track record of successful licence renewal. Excluding this effect, our 2011 reserves replacement ratio excluding acquisitions and disposals would have been 83%.

In 2011, net additions to the group s proved reserves (excluding production and sales and purchases of reserves-in-place) amounted to 1,320mmboe (348mmboe for subsidiaries and 972mmboe for equity-accounted entities), through revisions to previous estimates, improved recovery from, and extensions to, existing fields and discoveries of new fields. Of our subsidiary reserves additions through improved recovery from, and extensions to, existing fields and discoveries of new fields, approximately 26% were associated with new projects and were proved undeveloped reserves additions. The remaining additions were in existing developments where they represented a mixture of proved developed and proved undeveloped reserves. Volumes added in 2011 principally relied on the application of conventional technologies. The principal reserves additions in our subsidiaries were in the US (San Juan North, Mad Dog, Ursa, Prudhoe Bay, Hawkville), Trinidad (Cashima, Juniper) and Indonesia (Tangguh). The principal reserves additions in our equity-accounted entities were in Russia (Orenburg, Slavneft, Verkhnechonskoye, Uvat, Talinskoye), Venezuela (Petromonagas) and Argentina (Cerro Dragon).

Twelve per cent of our proved reserves are associated with PSAs. The countries in which we operated under PSAs in 2011 were Algeria, Angola, Azerbaijan, Egypt, India, Indonesia, Oman, Trinidad and Vietnam. In addition, the technical service contract (TSC) under which we operate in Iraq functions as a PSA.

Production

Our total hydrocarbon production during 2011 averaged 3,454 thousand barrels of oil equivalent per day (mboe/d). This comprised 2,094mboe/d for subsidiaries and 1,360mboe/d for equity-accounted entities, a decrease of 16% (decreases of 19% for liquids and 13% for gas) and an increase of 2% (increases of 2% for liquids and 5% for gas) respectively compared with 2010. In aggregate, after adjusting for entitlement impacts in our PSAs and the effect of acquisitions and disposals, production was 7% lower than 2010. For subsidiaries, 37% of our production was in the US, 20% in Trinidad and 8% in the UK.

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.

Acquisitions and disposals

During 2011, we undertook a number of acquisitions and disposals. In total, disposal transactions generated $1.1 billion in proceeds during 2011 including repayment of the $3.5 billion disposal deposit relating to Pan American Energy. *See Financial statements Note 5 on page 197*. With regards to proved reserves, 211mmboe were acquired in 2011 (approximately 94mmboe for subsidiaries and approximately 117mmboe for equity-accounted entities), while 572mmboe were disposed of (approximately 312mmboe for subsidiaries and approximately 260mmboe for equity-accounted entities).

Acquisitions

- On 24 January 2011, BP exercised a preferential right to acquire Shell s working interest in the Marlin and Dorado producing fields in the Gulf of Mexico for a total consideration of $257 million. This brought BP s working interest in both fields to 100%.
- On 12 May 2011, BP completed the purchase of 10 exploration and production blocks in Brazil from Devon Energy, concluding the agreement announced in 2010.
- On 30 August 2011, BP completed its acquisition from Reliance Industries Limited (RIL) of a 30% stake in 21 oil and gas PSAs that RIL operates in India for an aggregate consideration of $7.0 billion. In November 2011, the two companies formed a 50:50 joint venture for the sourcing and marketing of gas in India. *See India for further information on page 87.*

Disposals

- On 24 January 2011, following the approval of the Colombian authorities, BP completed the sale of its oil and gas exploration, production and transportation business in Colombia to a consortium of Ecopetrol, Colombia s national oil company, and Talisman of Canada. The sale had been announced in August 2010.
- On 22 February 2011, BP announced its intention to sell its interests in a number of operated oil and gas fields in the UK including the Wytch Farm onshore oilfield in Dorset and all of BP s operated gas fields in the southern North Sea, including associated pipeline infrastructure and the Dimlington terminal. The sale of Wytch Farm to Perenco UK Limited completed on 14 December 2011 for consideration of up to $610 million in cash, which includes $55 million contingent on Perenco s future development of the Beacon field and on oil prices in 2011-2013. A sale of the southern North Sea assets has yet to be concluded. The assets do not yet meet the criteria to be reclassified as non-current assets held for sale and it is not yet possible to estimate the financial effect of the intended disposal of these assets.
- In April 2011, the Wattenberg Plant in Colorado was divested to Anadarko for $575 million.
- In April 2011, an exchange agreement was signed with Bluestone Natural Resources, LLC for the divestment of a mature gas field in South Texas in exchange for acreage in a non-operated property in Eagle Ford.
- In June 2011, BP completed the sale of its upstream businesses in Venezuela to TNK-BP.
- On 5 July 2011, BP sold half of the 3.29% interest in the Azeri-Chirag-Gunashli development in the Caspian Sea which had been acquired from Devon Energy in 2010 to Azerbaijan (ACG) Limited, an affiliate wholly owned and controlled by the State Oil Company of the Republic of Azerbaijan (SOCAR) for $485 million.
- On 16 September 2011, the sale of BP s upstream assets in Pakistan to United Energy Group (UEG) was completed. UEG has now assumed control of the upstream assets. The sale, for $775 million, had been announced at the end of 2010.
- In October 2011, BP completed the sale of Tuscaloosa assets in Louisiana to Hilcorp Energy I LLC for $110 million.
- Also in October 2011, BP completed the sale of its 35% interest in the Lan Tay and Lan Do gas fields in Vietnam to TNK-BP. The sale of BP s interests in the associated pipeline completed in November 2011. The sale of BP s interest in the Phu My 3 power generation plant is expected to complete in 2012. As at 31 December 2011, this was classified as assets held for sale.
- On 5 November 2011, BP received a notice from Bridas Corporation of termination of the agreement for their purchase of BP s 60% interest in PAE. As a result of their decision and action, the share purchase agreement governing this transaction, originally agreed on 28 November 2010, has been terminated. BP has repaid the deposit for the transaction of $3.5 billion received at the end of 2010. *For details of payments in respect of the termination of restrictive covenants see page 85.*

On 1 December 2011, BP announced the sale of its Canadian Natural Gas Liquid (NGL) business to Plains All American Pipeline L.P. for $1.67 billion subject to closing adjustments. BP s Canadian NGL business owns, operates and has contractual rights to assets involved in the extraction, gathering, fractionation, storage, distribution and wholesale marketing of NGLs across Canada and in the Midwest US. As at 31 December 2011 these assets were held as assets held for sale, awaiting completion of the sale.

On 28 December 2011, BP completed the sale of its interests in the Pompano and Mica fields in the deepwater Gulf of Mexico to Stone Energy Corporation for $204 million. The sale includes BP s 75% operated working interest in the Pompano field and assets and 50% non-operated working interest in the Mica field, together with a 51% operated working interest in Mississippi Canyon block 29 and interests in certain leases located in the vicinity of the Pompano field.

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 has agreed to pay BP $1.2 billion in cash. Completion of the agreement is subject to closing conditions including the receipt of all necessary governmental and regulatory approvals. The sale is currently expected to complete on 30 March 2012.

The following discussion reviews operations in our Exploration and Production business by continent and country, and lists associated significant events that occurred in 2011. 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

United Kingdom

BP is the largest producer of hydrocarbons in the UK. Key aspects of our activities in the North Sea include a focus on in-field drilling and selected new field developments.

On 16 November 2010, production from the Rhum gas field in the central North Sea was suspended in relation to certain aspects of the EU sanctions. This action was taken to comply with the notification requirements in the relevant EU Regulation. 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. The restart and safe operation of Rhum remains contingent on the availability of third parties to provide services to Rhum. Such services are not as yet all available and it is presently unclear when resumption of production may be possible.

On 13 July 2011, BP and its co-venturers announced an agreement to progress a major redevelopment of the Schiehallion and Loyal oilfields to the west of the Shetland Islands. The investment of circa $5 billion in the redevelopment of the fields is expected to extend the field life to 2035. The project involves replacing the existing Schiehallion Floating, Production, Storage and Offloading (FPSO) vessel with a new FPSO which is scheduled to be installed in 2015. BP will have a 36.3% ownership interest in the new FPSO. There will also be a major investment in the upgrading and replacement of the subsea facilities to enable full development of the reserves. Production is scheduled to commence from the new facilities in 2016.

On 6 September 2011, BP and its co-venturers announced an agreement to invest up to $1.2 billion to progress a project to develop the Kinnoull reservoir in the central UK North Sea (BP 77.06%). The reservoir will be connected to BP s Andrew platform, enabling production from the Andrew area to extend to 2021.

On 13 October 2011, BP announced that a major milestone had been reached on the Devenick gas project (BP 88.7%) with the installation of a 600-tonne module to receive gas and condensate from the Devenick reservoir. Production from the field is due to commence in 2012.

On 13 October 2011, BP announced the successful completion of a well drilled to establish a southwest extension of the Clair field, west of Shetland in the UK North Sea. This well confirmed recoverable oil from a new portion of the field, and also discovered oil in a new, shallower reservoir horizon. During 2012, a further seismic survey of the field is planned, to understand the reservoir structure in more detail.

Also on 13 October 2011, BP announced that the UK government had granted BP and its partners Shell, ConocoPhillips and Chevron, approval to proceed with the $7.6 billion Clair Ridge project (BP 28.6%), the second phase of development of the Clair field.

Rest of Europe

Our activities in the Rest of Europe are in Norway.

In 2011, the Valhall redevelopment project continued, with production switch-over to the new facility scheduled for 2012. The redevelopment consists of a new processing platform required as a result of the existing platform suffering subsidence from extraction of hydrocarbons and includes a power from shore system eliminating all gas-fired equipment offshore.

On 14 August 2011, the FPSO vessel for the Skarv field arrived on location in the Norwegian Sea. Hook up of risers and commissioning work is ongoing and production is due to commence at the Skarv field in 2012.

On 6 October 2011, the Ula field on the Norwegian Continental Shelf celebrated 25 years of production.

North America

United States

Our activities within the US take place in three main areas: deepwater Gulf of Mexico, Lower 48 states and Alaska.

Deepwater Gulf of Mexico

For further information on the activities of BP s Gulf Coast Restoration Organization established following the Deepwater Horizon oil spill, *see pages 76-79.*

BP is the largest producer of hydrocarbons and the largest acreage holder in the deepwater Gulf of Mexico, operating seven production hubs.

Following BP s success in lease sale 213 in March 2010, seven of the leases awarded in 2010 were executed in 2011 and a further five leases from the sale were awarded and executed in 2011.

During 2011, preparations for safely restarting drilling operations in the Gulf of Mexico were progressed. In July 2011, BP announced the implementation of a new set of voluntary drilling standards for its operations in the Gulf of Mexico. The standards go beyond existing regulatory obligations and have been developed through lessons learned following the Deepwater Horizon oil spill in 2010. By the end of 2011 there were five BP-operated deepwater rigs engaged in abandonment and appraisal activities in the Gulf of Mexico. A permit to drill an appraisal well at Kaskida was approved and drilling operations commenced in October. Looking forward to 2012, plans include the drilling of exploration, appraisal and development wells and the start-up of additional three rigs, subject to receiving approvals from the US regulators.

On 7 September 2011, BP announced the drilling of a successful appraisal well in a previously untested northern segment of the Mad Dog field in the Gulf of Mexico. The well, located on Green Canyon Block 738, approximately 140 miles south of Grand Isle, Louisiana, confirms a significant resource extension for the Mad Dog field complex, which includes the existing field, in production since 2005, and appraisal drilling of the Mad Dog South field in 2008 and 2009. Due to the materiality of the Mad Dog South finds, BP has been advancing development options to increase production from Mad Dog and has now sanctioned the final investment decision on Mad Dog Phase 2. This will be the first BP-operated, standalone facility in a decade and will develop significant additional resources through the addition of subsea water injection and installation of a new production host.

On 14 December 2011, the Bureau of Ocean Energy Management held its first western Gulf of Mexico lease sale since August 2009. BP bid on leases for 15 blocks and expects to be awarded leases for 11 blocks in early 2012.

Lower 48 states

The North America Gas business operates onshore in the Lower 48 states producing natural gas, natural gas liquids and coalbed methane across nine states. In 2011, BP drilled 148 wells as operator across the US, including the Wyoming, San Juan, Anadarko, Arkoma and East Texas basins. BP also continues to participate in Eagle Ford, Fayetteville and other non-operated positions. *For further information on the use of fracking in our shale gas assets see page 71.*

Alaska

BP operates 15 North Slope oilfields (including Prudhoe Bay, Endicott, Northstar, and Milne Point) and four North Slope pipelines, and owns a significant interest in six other producing fields.

The Point Thomson Unit (PTU) was terminated by administrative decision of the State of Alaska Department of Natural Resources (DNR) in November 2006 (BP 32%). ExxonMobil, the operator, and the other unit owners, including BP, appealed the unit termination in the Alaska Superior Court. On 11 January 2010, the Alaska Superior Court reversed the DNR s administrative decision to terminate the unit, and in the second quarter of 2010, the State of Alaska Supreme Court granted the DNR s petition for a limited review. Briefs have been submitted to the Alaska Supreme Court, and a decision is expected in 2012. In the meantime, ExxonMobil and the State of Alaska have also informed the other unit owners, including BP, that they have reached a preliminary settlement agreement. BP and the other owners asked to participate in the settlement discussions but were precluded. We are currently analysing the agreement.

In light of the closure of the Denali operations *(see page 88 for further details)* BP continues to explore ways to commercialize its North Slope gas resources.

On 29 November 2007, BP Exploration (Alaska) Inc. (BPXA) pled guilty to a misdemeanour violation under the US Water Pollution Control Act to settle the criminal allegations by the state and federal government related to leaks in 2006 from oil transit lines in the Prudhoe Bay unit. The penalty included payment of $20 million with three years probation that was due to expire on 29 November 2010. On 29 November 2009, a spill of approximately 360 barrels of crude oil and produced water was discovered beneath a ruptured frozen three-phase flow line running from a well pad to the Lisburne Processing Center. On 17 November 2010, the US Probation Officer filed a petition in federal district court to revoke BPXA s probation based on an allegation that the Lisburne spill was a criminal violation of state or federal law. In November 2011, a hearing was held in federal court in Anchorage. On 27 December 2011, the court issued a final decision denying the government s petition and releasing BPXA from probation. *See page 165 in Legal proceedings for further details.*

Canada

In Canada, BP is focused on oil sands, and will 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 recovery wells. BP holds an interest in several oil sands leases through the Sunrise oil sands and Terre de Grace oil sands partnerships and the Pike Oil Sands joint venture. BP also develops and produces natural gas, markets natural gas and has significant exploration interests in the Canadian Beaufort Sea.

The Pike Oil Sands joint venture and the Terre de Grace partnership successfully completed winter drilling programmes in 2011, which were conducted to further appraise in situ oil sands resources. In late 2011, Pike Phase 1 moved to project appraisal status.

The Sunrise operator, Husky Energy Inc., commenced building facilities, drilling wells and creating operational systems to bring Phase 1 into production. First production of Phase 1 bitumen is expected in 2014, potentially building to 60,000 barrels per day gross capacity over the subsequent 24 months.

Interpretation of the 3D seismic survey acquired in 2009 and the seismic data for the EL446 field acquired in 2010 in the Canadian Beaufort Sea continued in 2011 and is nearing completion.

South America

Brazil

On 12 May 2011, after receiving approval from the Brazilian National Petroleum, Natural Gas and Biofuels Agency (ANP), BP concluded the purchase of Devon Energy do Brasil (later renamed BP Energy do Brasil), adding 10 exploration and production blocks to its portfolio. The acquired blocks give BP a diverse and broad deepwater exploration acreage position offshore Brazil, with interests in seven licence blocks in the Campos basin, one in the Camamu-Almada basin in water depths ranging from 330 to 9,100 feet (100 to 2,780 metres), as well as two onshore licences in the Parnaíba basin. The Campos basin blocks include three discoveries Xerelete, Pre-Salt Wahoo, and Itaipú and the Polvo Field in shallow water, which is currently producing around 19,000boe/d net. BP completed the drilling of ltaipú-2, the first appraisal well in the Itaipú deepwater discovery in November 2011 and is in the process of finishing a second appraisal well.

Argentina, Bolivia and Chile

BP conducts activity in the Southern Cone region of South America (Argentina, Bolivia and Chile) through PAE, an equity-accounted joint venture with Bridas Corporation in which BP has a 60% interest.

Following the announcement in November 2011 of the termination of the sale of BP s interest in PAE to Bridas, BP no longer classifies these assets as assets held for sale. Under the share purchase agreement BP was required to make a payment of $700 million to Bridas upon termination in full settlement of any and all past claims between the two companies and also as consideration for amendments to the PAE agreement which terminate certain legacy restrictive covenants among BP, PAE and Bridas. Subsequent to payment of this amount by BP in November 2011, Bridas returned this $700 million to BP claiming that the share purchase agreement was void; BP disputes this claim by Bridas and maintains that the share purchase agreement and its terms which survive termination (including the settlement and termination of legacy restrictive covenants) remain valid and binding. The $700 million returned to BP is shown in the balance sheet at 31 December 2011 within cash and cash equivalents and within current trade and other payables.

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. No formal nationalization process has yet commenced. PAE and its shareholders BP and Bridas intend to vigorously defend their legal interests under the Caipipendi Operations Contract and available Bilateral Investment Treaties.

Trinidad & Tobago

BP holds exploration and production licences covering 917,000 acres offshore of the east coast. Facilities include 13 offshore platforms and one onshore processing facility. Production is comprised of oil, gas and natural gas liquids (NGLs).

On 25 July 2011, BP announced that it had been awarded two deepwater exploration and production blocks by the government of the Republic of Trinidad & Tobago. The award was for a 100% interest in blocks 23(a) and TTDAA 14 offshore Trinidad s east coast, both under PSAs. Government approval is expected in early 2012. These blocks will increase the acreage in the region by 889,000 acres.

On 26 August 2011, BP announced that first gas had been achieved from the Serrette platform. Serrette, sanctioned in May 2009, has a design capacity of 1 billion cubic feet per day and may deliver a peak production of up to 500 million standard cubic feet per day. It is the fifth normally unmanned installation (NUI) to be designed and constructed in Trinidad & Tobago. The platform will tie into the Cassia B platform.

Africa

Angola

BP is present in four major deepwater licences offshore Angola (Blocks 15, 17, 18 and 31) and is operator in Blocks 18 and 31. In addition, BP holds a 13.6% interest in the first Angolan LNG project.

During the second quarter of 2011, a 40-day planned maintenance shutdown was conducted on the Greater Plutonio field. Corrosion in the high pressure gas cooling systems had restricted operations from September 2010, necessitating a complex replacement project that was safely completed in June 2011.

The Pazflor deepwater development, located in block 17 (BP 16.67%), came onstream on 24 August 2011, ahead of schedule. It encompasses a new build FPSO, 49 subsea wells, 180 kilometres of flowlines and 10,000 tonnes of equipment on the seabed. Pazflor is expected to have a plateau production rate of 220,000boe/d gross which will come from the Perpetua, Hortensia, Acacia and Zinia fields. The FPSO has topside facilities to process both Oligocene and Miocene age oils.

In December 2011, BP gained access to five new deepwater exploration and production blocks offshore Angola. These gave BP a leading position in Angola, with interests in nine blocks accounting for a total acreage of 30,842km^2. BP was awarded operatorship of Blocks 19 and 24 with 50% interest, and additional non-operating interests in Blocks 20 (20%) and 25 (15%) covering 19,400km^2 in the Kwanza and Benguela basins. BP has also taken a 40% stake in the 4,840km^2 Block 26 in the Benguela basin, by agreeing a farm-in deal with Brazilian national oil company, Petrobras, which operates the block. The five new blocks, including block 26, cover a total area of 24,000km^2 in water depths from 200 to 2,500 metres, and increase BP s total Angolan acreage by 275%.

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. BP is also in a joint venture with Sonatrach in the Rhourde El Baguel (REB) oilfield (BP 60%), an enhanced oil recovery project 75 kilometres east of the Hassi Messaoud oilfield. In addition, BP is in a joint venture with Sonatrach in the Bourarhet Sud block, located to the south west of In Amenas.

In 2011, development of the In Salah Southern Fields was approved and the primary engineering contracts awarded. First gas is expected in 2014.

On 22 December 2011, BP and Sonatrach reached an agreement for BP to withdraw from the REB PSA at the end of 2011.

Libya

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 ratified in December 2007 (BP 85%). BP s total assets in Libya at 31 December 2011 were $437 million. To date, all of the 3D seismic commitment has been completed but no exploration wells have yet been drilled.

Due to the outbreak of civil unrest leading to the regime change in Libya, the BP office in Tripoli was closed on 21 February 2011 and our Libyan operations suspended. BP declared force majeure the contractual mechanism which flows from the suspension of our activities in Libya and the imposition of sanctions. We intend to resume exploration activities with agreement of the new authorities, and when we are sure it is safe to do so. We are currently assessing how long it will take to re-establish exploration operations.

Business review

Egypt

BP has a long-standing history in Egypt, successfully operating there for close to 50 years. To date BP with its partners has produced almost 40% of Egypt s entire oil production and supplies more than 35% of the domestic gas demand. BP s total assets in Egypt at 31 December 2011 were $8,784 million ($4,768 non-current and $4,016 current).

The 25 January 2011 civil uprising resulted in the BP office in Cairo closing for a period of 10 days, reopening on 7 February. Production and operations were, and continue to be, unaffected. Parliamentary elections started in late November 2011 and are expected to run until mid-March 2012. We continue to closely monitor the developing situation in the country and its potential impact on the business and our people.

In October 2011, BP announced the Salmon gas discovery in the North El Burg (BP 50% and operator) offshore concession in the Nile Delta. Salmon is the third discovery in the concession, following the Satis 1 and Satis 3 gas discoveries. Further appraisal work to evaluate the resources is under way.

Asia

Western 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 coalbed methane (CBM) PSA (BP 38%), a brownfield, unconventional development overlaying the conventional PSA. Sanga-Sanga CBM is the cornerstone of the BP Asia Pacific CBM growth strategy.

In March 2011, the first CBM long-term production test well was tied into the system that supplies Bontang LNG plant.

On 1 April 2011, BP signed four new CBM PSAs Tanjung IV, Kapuas I, II, and III in the Barito Basin of Central Kalimantan, covering a contiguous area of approximately 4,800km^2. 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. Subsurface evaluation of the areas covered by the new PSAs is under way.

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%). Yacheng supplies gas to the Castle Peak Power Company for up to 70% of Hong Kong s gas-fired electricity generation. Additional gas is sold to the Hainan Holdings Fuel & Chemical Corporation Limited.

On 10 January 2011, BP announced that it had signed a new agreement with CNOOC for deepwater exploration in Block 43/11 in the South China Sea and government approval was received on 30 January 2012.

Azerbaijan

BP is the largest foreign investor in the country. BP operates two PSAs, Azeri-Chirag-Gunashli (ACG) and Shah Deniz, and also holds other exploration leases.

In June 1996, when the Shah Deniz PSA was awarded, Oil Industries Engineering and Construction, an affiliate of the National Iranian Oil Company and assignor to the current Iranian interest holder, Naftiran Intertrade Co. Ltd (NICO), was selected as a Shah Deniz project participant by the State of Azerbaijan, and has a 10% non-operating interest under the Shah Deniz PSA. NICO also has a 10% or less, non- operating, interest in both the Shah Deniz project gas marketing entity and its gas transportation entity, both of which were incorporated in 2002 and derive from the award of the Shah Deniz PSA. Under article 30 of the new EU Regulations concerning restrictive measures against Iran, any body, entity or holder of rights derived from an award of a PSA before the entry into force of the EU Regulations by a sovereign government other than Iran, shall not be considered an Iranian person, entity or body for the purposes of the main operative provisions of the EU Regulations. As such, the restrictive measures do not apply to NICO and Shah Deniz continues to operate in full compliance with EU and US law.

On 6 May 2011, the Parliament of the Republic of Azerbaijan ratified the new PSA between BP and the State Oil Company of Azerbaijan (SOCAR) on joint exploration and development of the Shafag-Asiman structure in the Azerbaijan sector of the Caspian Sea. The ratification follows the signing of the PSA in Baku in October 2010. Under the PSA, which has a 30-year term, BP will be the operator with 50% interest while SOCAR will hold the remaining 50% interest.

Following the Memorandum of Understanding signed in June 2010 between Turkey and Azerbaijan for gas sales and transportation of gas from the new Shah Deniz full field development to be sold to consumers in Turkey and across Europe, on 25 October 2011, Azerbaijan and Turkey signed a number of key gas export related agreements to enable Turkey to buy gas from Azerbaijan and to transit gas from Azerbaijan through Turkey to Europe. The documents signed included an intergovernmental agreement between the government of Azerbaijan and the government of Turkey, gas sales agreements between SOCAR and BOTAS and also between the Azerbaijan Gas Supply Company (AGSC) and BOTAS International Limited (BIL), a gas transit agreement between SOCAR and BIL and a framework agreement setting the general terms and conditions for transit of gas sourced from Azerbaijan through the territory of Turkey. The agreements provide a legal framework to regulate the sale of Shah Deniz gas to Turkey and its transportation to European markets through Turkey.

Russia

In May 2011, BP announced that both the Rosneft[a] share swap agreement and the Arctic Opportunity, originally announced on 14 January 2011, had terminated. This termination was a result of the deadline for the satisfaction of conditions precedent having expired following delays resulting from interim orders granted by the English High Court and a UNCITRAL arbitration tribunal. This followed applications brought by Alfa Petroleum Holdings Limited

(Alfa) and OGIP Ventures Limited (OGIP) against BP International Limited (BPIL) and BP Russian Investments Limited (BPRIL) alleging breach of the TNK-BP shareholders agreement (SHA). These interim orders did not address the question of whether or not BP breached the SHA. The UNCITRAL arbitration proceedings with Alfa, Access and Renova (AAR) which are subject to strict confidentiality obligations are ongoing. *See Legal proceedings on page 166 for further information.*

TNK-BP

TNK-BP, an associate owned by BP (50%) and AAR (50%), is an integrated oil company operating in Brazil, Russia, Ukraine, Venezuela and Vietnam. TNK-BP s strategic goal is to become an international oil and gas company with a leading position in the Russian oil and gas industry. BP s investment in TNK-BP is reported in the Exploration and Production segment. From 2012 onward TNK-BP will be reported as a separate operating segment, as explained more fully on page 80. The TNK-BP group s major assets are held in OAO TNK-BP Holding. Other assets include OAO Slavneft, an equity-accounted joint venture. The workforce is comprised of more than 50,000 people. TNK-BP s main board is currently comprised of four BP, four AAR, and one independent director, with two vacancies for independent directors. The boards of key TNK-BP subsidiaries have both BP and AAR directors. In December 2011, two independent non-executive directors of TNK-BP Limited, Gerhard Schroeder and James Leng, announced that they would be stepping down from their positions on the board at the end of 2011.

Upstream, TNK-BP operates either directly, or through equity-accounted joint ventures, a number of oil and gas fields in Russia, Vietnam and Venezuela which produced approximately 1.99mboe/d in 2011.

Downstream, TNK-BP has interests in six refineries in Russia and Ukraine (including Ryazan and Lisichansk and Slavneft s Yaroslavl refinery), with throughput of approximately 711 thousand barrels per day in 2011. TNK-BP has over 1,400 branded retail stations in Russia and Ukraine.

a BP already holds a 1.3% investment in Rosneft Oil Company with a carrying value of $873 million.

In March 2011, TNK-BP completed the acquisition of 74.9% of CJSC Toplivozapravochny kompleks Sheremetyevo , the operator of jet fuel storage and into-wing fuelling services at Sheremetyevo International Airport in Moscow.

In June 2011, TNK-BP completed the acquisition from BP of stakes in three upstream assets in Venezuela. Acquisition of these assets was announced in October 2010.

In October 2011, TNK-BP entered into an agreement with HRT Oil & Gas for the acquisition of a 45% stake in 21 blocks in the Brazilian Solimoes Basin. These oil and gas exploration blocks are operated by HRT Oil & Gas, and cover an area of approximately 48,000km^2.

Also in October 2011, TNK-BP announced that the Vietnamese Ministry of Investment and Trade granted TNK Vietnam, a Vietnam-based subsidiary of TNK-BP, the investment licence to operate offshore gas Block 6.1. TNK-BP acquired BP s 35% stake in Block 6.1, an integrated gas to power project which contains the Lan Tay and Lan Do gas condensate fields. As part of the deal, TNK-BP also acquired BP s 32.7% interest in the Nam Con Son Pipeline. Acquisition of these assets was announced in October 2010.

Five minority shareholders of OAO TNK-BP Holding (TBH) filed a civil action in Tyumen, Siberia, against BP Russia Investments Limited and BP p.I.c. seeking to recover alleged losses of $13 billion relating to BP s attempt to form a strategic alliance with Rosneft in January 2011. The action was dismissed by the Tyumen court fully on its merits. The Omsk Appellate court confirmed the Tyumen court of first instance s dismissal of the minority suits. *See Legal proceedings on page 166 for further information.*

On 9 February 2012, BP reached agreement with its Russian partners in TNK-BP on temporary amendments to the memorandum and articles of association of TNK-BP Limited and the SHA that reduce quorum requirements to require presence of directors nominated by BP and AAR only. The amendments are aimed at enabling the continuing functioning of the board of directors of TNK-BP (board of directors) while two independent directors who recently resigned are being replaced. This change is currently set to expire on 31 March 2012, unless both independent directors are appointed earlier.

On 9 February 2012, BP also reached agreement with its Russian partners in TNK-BP regarding certain changes to the management board of its main management company in Russia OAO TNK-BP Management (management board). The changes were aimed at restructuring and optimizing the management board, following the elimination of the deputy TNK-BP group chief executive officer role. The restructured management board will now consist of six people. BP will have the right to nominate the chairman of the management board, as well as two executive directors in charge of upstream and downstream respectively (the BP members). AAR will have the right to nominate two other executive directors (the AAR members). The sixth member the chief financial officer will be nominated by the chairman of the management board. The chairman of the management board will in time also have the right to nominate the executive directors, subject to prior concurrence by the respective shareholder. All of the aforementioned nominations will require approval by the board of directors as a majority matter, except for the chairman of the management board whose appointment will require approval as a unanimous reserved matter. As part of the agreement, BP and AAR agreed to approve the continued appointment of the chief executive officer and the appointment of their respective executive directors, with such appointments to expire no later than 31 December 2013.

All other provisions of the SHA (including those related to the review of new business opportunities, the board of directors and dispute resolution) remain unchanged.

Sakhalin

BP has interests in Sakhalin through a joint venture company, Elvary Neftegaz, in which BP holds a 49% equity interest, and its partner, Rosneft, holds the remaining 51% interest. In 2011, the process to exit the licence areas held by Elvary Neftegaz and liquidate the joint venture commenced. This follows the write-down of BP s investment at the end of 2010 following an unsuccessful exploration programme.

Middle East

Production in the Middle East consists principally of the production entitlement of associates in Abu Dhabi, where 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 reduction in production of approximately 140mb/d.

In the first quarter of 2011, extended well test production began in Oman.

In August 2011, the seismic survey of the Risha concession in Jordan was successfully completed.

India

On 30 August 2011, BP and Reliance Industries Limited (RIL) announced the completion of BP s acquisition of a 30% stake in 21 oil and gas PSAs that RIL operates in India, including the producing KG D6 block. BP paid RIL an aggregate consideration of $7.0 billion for the interests acquired in the 21 PSAs. Further performance payments of up to $1.8 billion could be paid in case of exploration success in certain blocks that result in the development of commercial discoveries. This step commenced the planned alliance which will operate across the gas value chain in India, from exploration and production to distribution and marketing.

On 17 November 2011, the two companies formed a 50:50 joint venture for the sourcing and marketing of gas in India.

Iraq

Following a successful bid with PetroChina to run the Rumaila oilfield in June 2009, the technical service contract (TSC) became effective on 17 December 2009. BP holds a 38% working interest and is the lead contractor. Rumaila is one of the world s largest oilfields and was discovered by BP in 1953 and comprises five producing reservoirs. BP together with its partners is actively refurbishing the wells and facilities. With the achievement of the improved production target on 25 December 2010, BP and PetroChina became eligible for service fees pursuant to the TSC. In 2011 both companies lifted cargoes from the Basra terminal as payment for service fees due.

Australasia

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 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 which is part of the Greater Gorgon project (Chevron, ExxonMobil and Shell) and is currently being developed.

In January 2011, BP announced that it had been awarded four deepwater offshore exploration blocks in the Ceduna Sub Basin within the Great Australian Bight, off the coast of South Australia. The exploration work is to be phased over six years with a 3D seismic survey covering approximately 12,500km^2 commenced in November 2011 and continuing into 2012. Following interpretation of the seismic survey, BP will drill four deepwater wells in this frontier exploration basin.

Eastern Indonesia

BP has a 100% interest in an exploration asset, 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) and covering an area of just over 5,000km^2. In addition, BP owns a 32% interest in Chevron s operated West Papua I and III PSAs, located circa 120 kilometres to the south of the Tangguh LNG plant (see *Liquefied natural gas on page 88).*

In December 2011, BP signed contracts with the Government of Indonesia for 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, covering areas of 8,100km^2 and 8,300km^2 respectively. BP holds 100% interest in the PSAs and expects to commence seismic operations in the near future.

a An LNG train is a processing facility used to liquefy and purify LNG.

Midstream activities

Oil and natural gas transportation

The group has direct or indirect interests in certain crude oil and natural gas transportation systems. The following narrative details the significant events that occurred during 2011 by country.

BP s onshore US crude oil and product pipelines and related transportation assets are included under Refining and Marketing (see *page 94).*

Alaska

BP owns a 46.9% interest in the Trans-Alaska Pipeline System (TAPS), with the balance owned by four other companies. The TAPS transports crude oil from Prudhoe Bay on the Alaska North Slope to the port of Valdez in south-east Alaska. BP also owns a 50% interest in a joint venture company called Denali -The Alaska Gas Pipeline (Denali).

On 16 May 2011, Denali announced that its open season efforts did not result in the commitments necessary to continue work on the Alaska North Slope gas pipeline project. Denali also indicated that it planned to close out its operations over the remainder of 2011. As a 50% owner in Denali, BP, along with co-owner ConocoPhillips, was directly involved in the decision to terminate Denali s activities. BP s focus as an owner in Denali was to create a viable alternative for the owners of the North Slope gas resource to commercialize their gas. BP has determined that the North American natural gas market does not support the project at this time. The Denali effort marked an important step in advancing the industry understanding of the gas pipeline opportunity in Alaska. BP will continue to pursue ways to commercialize our Alaskan gas resource.

North Sea

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 50 fields in the central North Sea. The system has a capacity of more than 1 million barrels per day, with average throughput in 2011 of 473mboe/d. 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 2011 was 39mboe/d. CATS offers natural gas transportation and processing services. In addition, BP operates the Sullom Voe oil and gas terminal in Shetland and the Dimlington/Easington Terminals in Humberside. Dimlington and Easington form part of the southern gas assets that BP announced its intention to sell in February 2011 (see *Disposals on page 83).*

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 to the eastern Mediterranean port of Ceyhan and has a capacity of 1.2 million barrels per day. 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 780mmscf/d. In addition, BP operates the Azerbaijan section of 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 focused on building competitively advantaged liquefaction projects, establishing diversified market positions to create maximum value for our upstream natural gas resources and capturing third-party LNG supply to complement our equity flows. Assets and significant events in 2011 included:

In Trinidad, BP s net share of the capacity of Atlantic LNG trains 1, 2, 3 and 4 is 6 million tonnes of LNG per year (292 billion cubic feet equivalent regasified). 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 US, the Dominican Republic, Spain, the UK, Japan, India and South Korea.

We have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company, which in 2011 supplied 5.76 million tonnes of LNG (297 billion cubic feet equivalent regasified).

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. Construction and implementation of the project is proceeding and the plant is expected to start up in 2012.

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 13% of the total gas feed to Bontang, one of the world s largest LNG plants. The Bontang plant produced more than 15 million tonnes of LNG in 2011.

Also in Indonesia, BP has its first operated LNG plant, Tangguh (BP 37.16%), in Papua Barat. The asset comprises of 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 long-term contracts. BP is currently progressing options to expand the Tangguh facilities.

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 one of five partners in the Browse LNG venture (operated by Woodside) and holds approximately a 17% interest. A greenfield LNG development at a proposed state government LNG precinct in the Kimberley region is currently in the early design stage and remains subject to regulatory, company and partner approvals.

BP has a 30% equity stake in the 7mtpa 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 in which BP has an interest.

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.

Gas marketing and trading activities

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 and increased pipeline builds in North America. This has resulted in limited basis differentials and faster changes in production volumes in response to price movements. However, new markets are continuing to develop with continental European markets opening up and LNG becoming more liquid. The business (including support functions) operates primarily from offices in Houston and London and employs around 1,500 people.

In connection with its trading activities, the group uses a range of commodity derivative contracts and 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

a See footnote a on page 87.

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 to manage and oversee the financial risks associated with this trading activity, which is described in Note 26 to the Financial statements on pages 217-222. 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 111.

Oil and gas disclosures

The following tables provide additional data and disclosures in relation to our oil and gas operations.

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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										
2011										
Liquids[d]	**107.83**	**106.89**	**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
2009										
Liquids[d]	62.19	60.73	53.68	30.77	52.48	57.40		61.27	57.22	56.26
Gas	4.68	7.62	3.07	3.53	2.50	3.61		3.30	5.25	3.25
Equity-accounted entities[e]										
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
2009										

Liquids[d]	–	–	–	–	51.01	–	47.27	5.59	–	41.93
Gas					1.90		1.51	5.25		1.68

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 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										
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
2009	12.38	10.72	7.26	14.45	2.20	6.05		4.35	1.60	6.39
Equity-accounted entities										
2011					**9.04**		**5.68**	**2.70**		**5.58**
2010					6.32		5.04	2.61[c]		4.83[c]
2009					6.12		4.63	2.52[c]		4.50[c]

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.
c A minor amendment has been made to comparative periods.

Licence expiry

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.

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 re-categorized 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 four 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, acquisition and disposal activity 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 re-categorized 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. The group will only book proved reserves where development is scheduled to commence after 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 2011, BP had material volumes of proved undeveloped reserves held for more than five years in Trinidad, as well as non-material volumes in Australia, Azerbaijan, Norway, 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.

BP has a three year average track record (since the adoption of the modernised rules for reporting) of converting 20% of our proved undeveloped reserves (excluding disposals) to proved developed reserves. This equates to a turnover time of five years. We expect the turnover time to remain at or below five years and anticipate no increase in the volume of proved undeveloped reserves held for more than five years.

In 2011, we converted 1,062mmboe of proved undeveloped reserves to proved developed reserves through ongoing investment in our upstream development activities. Total development expenditure in Exploration and Production, excluding midstream activities, was $13,329 million in 2011 ($10,194 million for subsidiaries and $3,135 million for equity-accounted entities). The major areas converted in 2011 were Argentina, Indonesia, Russia, Trinidad and the US. Revisions of previous estimates for proved undeveloped reserves are due to the impact of

year-end price (net of 1%) and changes relating to field performance or well results (99%). The table below describes the changes to our proved undeveloped reserves position through the year.

	volumes in mmboe
Proved undeveloped reserves at 1 January 2011	7,899
Revisions of previous estimates	693
Improved recovery	522
Discoveries and extensions	92
Purchases	77
Sales	(302)

Total in year proved undeveloped reserves changes	8,981
Progressed to proved developed reserves	(1,062)
Proved undeveloped reserves at 31 December 2011	7,919

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; and (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.
- 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.

BP s vice president of segment reserves is the petroleum engineer primarily responsible for overseeing the preparation of the reserves estimate. He has over 25 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 vice 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 Exploration and Production 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 Exploration and Production 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 (IFRSs) 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 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 as at 31 December 2011

Seventy-five per cent of our total proved reserves of subsidiaries at 31 December 2011 were held through unincorporated joint ventures (75% in 2010), and 33% of the proved reserves were held through such unincorporated joint ventures where we were not the operator (31% in 2010).

Estimated net proved reserves of liquids at 31 December 2011[a b c]

million barrels

	Developed	Undeveloped	Total
UK	288	445	733
Rest of Europe	69	230	299
US	1,685	1,173	2,858[d]
Rest of North America			
South America	27	48	75[e]
Africa	311	315	626
Rest of Asia	177	279	456
Australasia	59	47	106
Subsidiaries	2,616	2,537	5,153
Equity-accounted entities	3,201	2,211	5,412[f]
Total	5,817	4,748	10,565

Estimated net proved reserves of natural gas at 31 December 2011[a b]

billion cubic feet

	Developed	Undeveloped	Total
UK	1,411	909	2,320
Rest of Europe	43	450	493
US	9,721	3,831	13,552
Rest of North America	28		28
South America	2,869	6,529	9,398[g]
Africa	1,224	2,033	3,257
Rest of Asia	1,034	364	1,398
Australasia	3,570	2,365	5,935
Subsidiaries	19,900	16,481	36,381
Equity-accounted entities	3,367	1,911	5,278[h]
Total	23,267	18,392	41,659

Net proved reserves on an oil equivalent basis

million barrels of oil equivalent

	Developed	Undeveloped	Total
Subsidiaries	6,048	5,378	11,426
Equity-accounted entities	3,781	2,541	6,322[i]
Total	9,829	7,919	17,748

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 2011 marker prices used were Brent $110.96/bbl (2010 $79.02/bbl and 2009 $59.91/bbl) and Henry Hub $4.12/mmBtu (2010 $4.37/mmBtu and 2009 $3.82/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 82 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 20 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

f Includes 310 million barrels of crude oil in respect of the 7.37% minority interest in TNK-BP.

g Includes 2,759 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

h Includes 174 billion cubic feet of natural gas in respect of the 6.27% minority interest in TNK-BP.

i Total proved reserves held as part of our equity interest in TNK-BP is 4,802mmboe comprising 100 million barrels in Venezuela, 14mmboe in Vietnam and 4,688mmboe in Russia. In 2011 BP aligned its reporting with TNK-BP by moving to a life of field reporting basis. Reasonable certainty of licence renewals is demonstrated by evidence of Russian subsoil law, track record of renewals within the industry and track record of success in obtaining renewals by TNK-BP. This has resulted in a 253mmboe increase in proved reserves.

Business review

BP s net production by major field for 2011, 2010 and 2009.

Liquids

Subsidiaries	Field or area	2011	2010	2009
		thousand barrels per day		
		BP net share of productiona		
UK[b]	ETAP[c]	**22**	28	34
	Foinaven[d]	**26**	24	29
	Other	**65**	85	105
Total UK		**113**	137	168
Norway[b]	Various	**32**	40	40
Total Rest of Europe		**32**	40	40
Total Europe		**145**	177	208
Alaska	Prudhoe Bay[d]	**64**	67	69
	Kuparuk	**39**	42	45
	Milne Point[d]	**19**	23	24
	Other	**31**	34	43
Total Alaska		**153**	166	181
Lower 48 onshore[b]	Various	**69**	90	97
Gulf of Mexico deepwater[b]	Thunder Horse[d]	**77**	120	133
	Atlantis[d]	**34**	49	54
	Mad Dog[d]	**8**	30	35
	Mars	**19**	23	29
	Na Kika[d]	**14**	25	27
	Horn Mountain[d]	**8**	14	25
	King[d]	**15**	21	22
	Other	**56**	56	62
Total Gulf of Mexico deepwater		**231**	338	387
Total US		**453**	594	665
Canada[b]	Various[d]	**2**	7	8
Total Rest of North America		**2**	7	8
Total North America		**455**	601	673
Colombia[b]	Various[d]	**1**	18	23
Trinidad & Tobago	Various[d]	**31**	36	38
Brazil[b]	Various	**7**		
Total South America		**39**	54	61
Angola	Greater Plutonio[d]	**51**	73	70
	Kizomba C Dev	**21**	31	43
	Dalia	**12**	20	32
	Girassol FPSO	**12**	18	22
	Other	**27**	28	44
Total Angola		**123**	170	211
Egypt[b]	Gupco	**34**	47	55
	Other	**11**	12	16
Total Egypt		**45**	59	71
Algeria[b]	Various	**22**	17	22
Total Africa		**190**	246	304
Azerbaijan[b]	Azeri-Chirag-Gunashli[d]	**86**	94	94
	Other	**8**	9	7
Total Azerbaijan		**94**	103	101
Western Indonesia[b]	Various	**2**	2	5
Iraq	Rumaila	**31**		
Other	Various	**11**	14	17
Total Rest of Asia[b]		**138**	119	123
Total Asia		**138**	119	123
Australia	Various	**23**	30	31
Other	Various	**2**	2	
Total Australasia		**25**	32	31
Total subsidiaries[e]		**992**	1,229	1,400
Equity-accounted entities (BP share)				
Russia TNK-BP[b]	Various	**865**	856	840

Total Russia		**865**	856	840
Abu Dhabi[f]	Various	**209**	190	182
Other	Various	**1**	1	12
Total Rest of Asia[b]		**210**	191	194
Total Asia		**1,075**	1,047	1,034
Argentina	Various	**74**	75	75
Venezuela[b]	Various	**16**	23	25
Bolivia[b]	Various			1
Total South America		**90**	98	101
Total equity-accounted entities		**1,165**	1,145	1,135
Total subsidiaries and equity-accounted entities		**2,157**	2,374	2,535

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 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. In 2009, BP assumed operatorship of the Mirpurkhas and Khipro blocks in Pakistan, swapped a number of assets with BG Group plc. in the UK sector of the North Sea, divested some minor interests in the US Lower 48, divested its holdings in Indonesia s Offshore Northwest Java to Pertamina, divested its interests in LukArco to Lukoil and the Bolivian government nationalized, with compensation payable, Pan American Energy s shares of Chaco.

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 BP-operated.

e Includes 28 net mboe/d of NGLs from processing plants in which BP has an interest (2010 29mboe/d and 2009 28mboe/d).

f The BP group holds interests, through associates, in onshore and offshore concessions in Abu Dhabi, expiring in 2014 and 2018 respectively.

Natural gas

Subsidiaries	Field or area	million cubic feet per day BP net share of production[a] 2011	2010	2009
UK[b]	Bruce/Rhum[c]	**20**	100	110
	Other	**335**	372	508
Total UK		**355**	472	618
Norway[b]	Various	**13**	15	16
Total Rest of Europe		**13**	15	16
Total Europe		**368**	487	634
Lower 48 onshore[b]	San Juan[c]	**603**	629	659
	Jonah[c]	**145**	185	227
	Anadarko	**141**	137	146
	Arkoma Central	**136**	164	194
	Wamsutter[c]	**122**	126	146
	Arkoma East	**115**	112	67
	Arkoma West	**109**	128	65
	Other	**274**	394	451
Total Lower 48 onshore	Total	**1,645**	1,875	1,955
Gulf of Mexico deepwater[b]	Various	**176**	263	303
Alaska	Various	**22**	46	58
Total US		**1,843**	2,184	2,316
Canada[b]	Various	**14**	202	263
Total Rest of North America		**14**	202	263
Total North America		**1,857**	2,386	2,579
Trinidad & Tobago	Mango[c]	**308**	544	664
	Cashima/NEQB[c]	**570**	679	571
	Kapok[c]	**464**	541	540
	Cannonball[c]	**99**	156	225
	Amherstia[c]	**296**	252	197
	Other[c]	**456**	301	233
Total Trinidad		**2,193**	2,473	2,430
Colombia[b]	Various	**4**	71	62
Total South America		**2,197**	2,544	2,492
Egypt[b]	Temsah	**74**	90	118
	Ha py[c]	**99**	73	94
	Taurt[c]	**61**	75	73
	Other	**210**	192	177
Total Egypt		**444**	430	462
Algeria	Total	**114**	126	159
Total Africa		**558**	556	621
Pakistan[b]	Various[c]	**73**	150	173
Azerbaijan	Various[c]	**140**	132	126
Western Indonesia[b]		**59**	70	106
India[b]	KGD6	**121**	–	–
	Other	**25**		
Total India		**146**		
Vietnam[b]	Various[c]	**69**	77	63
China	Yacheng	**70**	95	83
Oman		**20**		
Sharjah	Various[c]	**41**	50	59
Total Rest of Asia		**618**	574	610
Total Asia		**618**	574	610
Australia	Perseus/Athena	**170**	165	142
	Goodwyn	**72**	118	139
	Angel	**126**	133	120
	Other	**87**	46	39
Total Australia		**455**	462	440
Eastern Indonesia	Tangguh[c]	**340**	323	74

Total Australasia		**795**	785	514
Total subsidiaries[d]		**6,393**	7,332	7,450
Equity-accounted entities (BP share)				
Russia TNK-BP[b]	Various	**699**	640	601
Total Russia		**699**	640	601
Western Indonesia	Various	**26**	30	31
Vietnam[b]		**8**	–	–
Kazakhstan[b]	Various			11
Total Rest of Asia		**34**	30	42
Total Asia		**733**	670	643
Argentina	Various	**371**	379	378
Bolivia[b]	Various	**14**	11	11
Venezuela[b]	Various	**7**	9	3
Total South America		**392**	399	392
Total equity-accounted entities[d]		**1,125**	1,069	1,035
Total subsidiaries and equity-accounted entities		**7,518**	8,401	8,485

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 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. In 2009, BP assumed operatorship of the Mirpurkhas and Khipro blocks in Pakistan, swapped a number of assets with BG Group plc. in the UK sector of the North Sea, divested some minor interests in the US Lower 48, divested its holdings in Indonesia s Offshore Northwest Java to Pertamina, divested its interests in LukArco to Lukoil and the Bolivian government nationalized, with compensation payable, Pan American Energy s shares of Chaco.

c BP-operated.

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.

Refining and Marketing

Our Refining and Marketing segment 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. 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; in total we market our products in more than 70 countries.

The segment operates hydrocarbon value chains covering three main businesses: fuels, lubricants and petrochemicals. Previously we referred to lubricants and petrochemicals as international businesses, but to provide greater transparency of the performance of these businesses we are now providing our financial information separately for fuels, lubricants and petrochemicals.

The fuels businesses sell refined petroleum products including gasoline, diesel, aviation fuel and liquefied petroleum gas (LPG). Within this, the fuels value chains (FVCs) integrate the activities of refining, logistics, marketing, and supply and trading on a regional basis. This recognizes the geographic nature of the markets in which we compete, providing the opportunity to optimize our activities from crude oil purchases to end-consumer sales through our physical assets (refineries, terminals, pipelines and retail stations). In addition, we operate a global aviation fuels marketing business and an LPG marketing business.

Our lubricants business is involved in manufacturing and marketing lubricants and related services to markets around the world. We market lubricants to the automotive, industrial, marine, aviation and energy markets through our key brands of Castrol, BP and Aral. Our Castrol brand is a highly recognized and popular lubricant brand worldwide. Distinctive brands, cutting-edge technology and building and sustaining customer relationships are cornerstones to our approach to market and underpin our success. We are particularly strong in Europe and key Asia Pacific markets including India.

Our petrochemicals business operates on a global basis and includes the manufacture and marketing of petrochemicals that are used in many everyday products, such as plastic bottles and textiles for clothing. Technology is at the heart of our business and we own proprietary world class technology for each of our main products. Our technological advantage, operational experience and project execution track record has made us an attractive partner which leads to material and distinctive growth opportunities. Petrochemicals growth is focused on the demand centre of Asia.

Our market

Overall world economic growth slowed in 2011, as did growth in world oil consumption. Global oil demand grew by 0.7 million b/d, but in the OECD, demand contracted again after growing for the first time in five years in 2010. By contrast, there was demand growth in Australia and Japan, where oil partially replaced nuclear power after the earthquake and tsunami. Aggregate OECD oil demand in 2011 was 4.3 million b/d below the 2005 peak.

The annual average BP refining marker margin (RMM) in 2011 was 16% higher than in 2010, averaging $11.64 per barrel. Margins followed a typical seasonal pattern, with a peak in the second quarter in the run-up to the summer driving season. The RMM is an environmental indicator, similar to those used by many of our competitors, and is weighted regionally based on our refining capacity in that part of the world. Each regional marker margin is based upon product yields and a marker crude oil deemed appropriate for the region.

The RMM uses regional crack spreads to calculate the margin indicator, and does not include estimates of fuel costs and other variable costs. The RMMs may not be representative of the margins achieved by BP in any period because of BP s particular refinery configurations and crude and product slate. However, the RMM is useful for understanding the indicative refining margin environment that is available to refiners in each region.

				$ per barrel
	Crude marker	**2011**	2010	2009
Refining marker margin (RMM)				
US West Coast	ANS	**13.63**	13.09	13.40
US Gulf Coast	Mars	**11.87**	10.17	9.16
US Midwest	LLS	**7.46**	6.00	6.02
Northwest Europe	Brent	**11.85**	10.36	8.95
Mediterranean	Azeri Light	**9.03**	8.82	7.93
Singapore	Dubai/Tapis blend	**14.57**	10.69	8.51
BP Average RMM		**11.64**	10.02	9.19

In 2011, refining margins increased in all the main US regions, despite a contraction in domestic gasoline demand, with reduced gasoline import volumes compensated for by higher domestic crude runs.

In Europe, where diesel accounts for a large proportion of regional consumption, refining margins increased for a second year running despite the loss of Libyan sweet crude supplies for much of the year, as demand for commercial transport improved.

Refining margins also improved in Asia Pacific, averaging $14.57 per barrel due to continuing oil demand growth and the disruption to Japanese refining operations caused by the earthquake and tsunami.

US mid-continent crude oils (including West Texas Intermediate (WTI)) were heavily discounted throughout the year because of increasing production in the US mid-continent and Canada, coupled with constrained infrastructure for crude transportation. This particularly benefited BP s location-advantaged refineries of Toledo and Whiting in the US Midwest. In addition, fuel oil price discounts versus crude oil widened in 2011, benefiting our highly upgraded refineries that produce relatively little fuel oil.

In oil markets in 2011, supply was hampered by geo-political issues and a series of technical problems in non-OPEC crude production. This supply deficit brought OECD stocks down from historical highs to near-average levels within the first nine months of the year. After very low volatility levels in the second half of 2009 and in 2010, 2011 saw a return towards more average volatility.

In lubricants, we saw modest improvement in demand for the automotive and industrial sectors early in the year, but this came under increasing pressure as the year progressed and by the fourth quarter demand was declining in many geographies. Base oil prices rose markedly in the first half of the year, increasing our input costs. We continued to see a gradual shift towards higher-quality and higher-margin premium and synthetic lubricants.

In the first half of 2011, the petrochemicals margin environment was markedly different from the second half, due to strong demand for purified terephthalic acid (PTA) coupled with supply interruptions in both PTA and paraxylene (PX) leading to robust margins. In contrast the second half of the year saw the installed capacity run normally along with significant new capacity coming onstream. In addition concerns over the global economy affected demand, leading to a rapid reduction in margins. Acetic acid had a similar margin profile to PTA with supply interruptions in the first half leading to higher margins followed by weaker margins in the second half of the year as additional capacity came onstream.

Our strategy

Refining and Marketing is the product and service-led arm of BP, focused on fuels, lubricants and petrochemicals products and related services. 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. We pursue competitive returns and sustainable growth, underpinned by safe manufacturing operations and technology, as we serve customers and promote BP and our brands through high-quality products.

We are focused on a consistent set of priorities executed in a systematic and disciplined way. These priorities begin with safety and include excellence of execution, portfolio quality and integration and growing margin share via exposure to growth. This is all underpinned by a disciplined financial framework. We believe that we now have a platform to sustain a world-class downstream business, which will enable us to be a leader in each of our chosen markets. Over time, we expect to shift the balance of participation and capital employed from established to growth regions.

In March 2010, we set a target to shareholders to deliver a performance improvement of at least $2 billion by 2012 relative to a 2009 baseline and we believe we are on track to deliver this by the end of 2012[a]. In addition, post-2012, we plan to grow our margin further through our focus on growth markets and expansion of our margin capture capability, which we expect to achieve through projects such as those described below.

In our fuels business, as previously announced, we are planning to dispose of our Texas City refinery and the southern part of the US West Coast FVC before the end of 2012. We are investing in our existing operations to sustain safe, compliant standards and selectively investing in cash margin capture projects. The largest of these projects is the repositioning of the Whiting refinery towards heavy feedstock advantage, which is already under way and scheduled to come onstream in the second half of 2013. In addition to the repositioning of the Whiting refinery, margin capture projects include the Cherry Point refinery clean diesel project, Toledo refinery continuous catalytic reforming project, Gelsenkirchen refinery margin improvement programme and the recently announced Brazil aviation acquisition (see *Acquisitions and disposals section on page 97).*

We are also well positioned for growth in our lubricants and petrochemicals businesses. In our lubricants business, around half of our profit growth in recent years has come from the emerging economies in non-OECD countries as we have expanded in these markets. We have a material presence in the Indian automotive lubricant market. These positions provide a strong base to capture further long-term growth. In petrochemicals around 45% of our capacity is in the demand centre of Asia. Growth options are enabled by our distinctive technology, operational capability and access through key strategic relationships. During 2011 the latest example of our strategy deployment was the signing of a memorandum of understanding with IndianOil Corp (IOC) to explore the potential for establishing a 50:50 joint venture to invest in a 1 million tonne per annum (mtpa) acetic acid plant in Gujarat, India. The joint venture will use BP s latest Cativa® catalyst and technology, while the associated gasification facilities would utilize petroleum coke feedstock from IOC. Additionally, in 2011 BP received local government approval for a 1.25mtpa PTA plant in Zhuhai, China, and is now seeking final central governmental approval.

From 2012 we plan to create a new revenue stream in petrochemicals through licencing our technology, beginning with our aromatics products of PX and PTA.

As part of our drive towards more efficient operations, we have been transforming our back office. In 2011, we made further progress on our global SAP implementation within the fuels and lubricants businesses. We also continued to expand the scale of our business service centres (BSCs). BSCs are regional centres for certain finance, operational procurement and IT services for the BP group.

a This performance improvement will be measured by comparing Refining and Marketing s replacement cost profit before interest and tax for 2009 with that of 2012, after adjusting for non-operating items, fair value accounting effects and 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 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 closely tracked by management as an important indicator of segment performance.

Our performance

2011 performance

Safety and operational risk

Safety remains the top priority across BP, and we are committed to leadership in process safety and to ensuring that our operations are safe, compliant and reliable with regard to both personal and process safety.

Refining and Marketing utilizes the group s operating management system (OMS). OMS provides a set of group-wide requirements and a systematic way of working to continuously improve the way we operate. *(OMS is explained in more detail on page 65).* While all Refining and Marketing entities have transitioned on to OMS, we continue to work to enhance local systems and processes at all our sites.

All our major manufacturing entities (refineries and petrochemicals sites) have been through two performance improvement cycles (PIC) of OMS, and all other entities across our FVCs will have completed their second PIC by the end of 2012. The PIC is a management review carried out within each entity of their local operating management system, which identifies areas where further actions can be taken to enhance our systems and processes. These actions are risk-prioritized and form an integral part of each entity s annual and longer-term planning. Where appropriate, actions are aggregated to provide common solutions.

Direction and oversight of safety in Refining and Marketing is provided by the segment operating risk committee (SORC) chaired by the chief executive officer of Refining and Marketing. Monitoring of safety and compliance in our operations is conducted by the newly-formed safety and operational risk function, for which there is a Refining and Marketing segment team independent of the segment CEO.

As outlined on page 65, BP has further strengthened its risk review process, and this process was applied to Refining and Marketing to ensure that appropriate risk management and mitigating actions were prioritized throughout the segment.

We measure our personal safety performance through the employment of a recordable injury frequency (RIF) rate and a days away from work case frequency (DAFWCF) rate, as well as a severe vehicle accident rate.

In 2011, our RIF (measured by the number of recordable injuries to the BP workforce per 200,000 hours worked) was 0.37, slightly higher than the 2010 rate of 0.35. The 2011 DAFWCF (a subset of the RIF that measures the number of cases where an employee misses one or more days from work) was 0.108, compared with 0.114 in 2010. There was a significant improvement in the severe vehicle accident rate (SVAR) in 2011 with 61 severe vehicle accidents compared with 77 in 2010.

While progress has been made in the area of personal safety, there were two workplace fatalities in 2011. These tragic events have been fully investigated, and the learnings shared and actioned.

Process safety is measured by the process safety incident index (PSII), a weighted index which reflects both the number and severity of events per 200,000 hours worked. The PSII for 2011 was 0.36, equal to the 2010 rate, and better than the 2009 rate of 0.48. While the number of PSII events has increased from 2010, the overall severity of the events has reduced.

In terms of operational integrity, the number of losses of primary containment (LOPC), a measure of unplanned or uncontrolled releases of material from primary containment, was 5% lower in 2011 than in 2010. The number of oil spills greater than one barrel was slightly higher in 2011 (145) than 2010 (132) however the volumes of oil spills were significantly lower in 2011 than in 2010 at 0.4 million litres compared with 1.3 million litres respectively.

In our US refineries, we continue to implement the recommendations of the BP US Refineries Independent Safety Review Panel and regulatory bodies. *See the Safety section on page 67 for further information on progress.*

Financial and operating performance

			$ million
	2011	2010	2009
Replacement cost profit (loss) before interest and tax[a]			
Fuels[b]	**3,003**	2,628	(914)
Lubricants	**1,350**	1,357	1,059
Petrochemicals[c]	**1,121**	1,570	598
	5,474	5,555	743
Sales and other operating revenues[d]	**344,116**	266,751	213,050
Capital expenditure and acquisitions	**4,130**	4,029	4,114
			thousand barrels per day
Total refinery throughputs[e]	**2,352**	2,426	2,287
			%
Refining availability[f]	**94.8**	95.0	93.6
			thousand tonnes
Total petrochemicals production[g]	**14,866**	15,594	12,660

a Income from petrochemicals produced at our Gelsenkirchen and Mulheim sites is reported within the fuels business. Segment level overhead expenses are included within the fuels business.

b 2009 includes a $1.6 billion impairment of goodwill in the US West Coast FVC.

c 2010 includes $338 million gain from non-operating items.

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 1,699kte of petrochemicals produced at our Gelsenkirchen and Mulheim 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 2011 was $5,474 million, compared with $5,555 million for the previous year. The full-year results included a net loss for non-operating items of $602 million, compared with a 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 58 for further information on non-operating items).* In addition, fair value accounting effects had a favourable impact of $63 million, compared to a favourable impact of $42 million in 2010. (*See page 58 for further information on fair value accounting effects.)*

After adjusting for non-operating items and fair value accounting effects, Refining and Marketing reported record earnings in 2011[a].

Strong refinery operations enabled us 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.

In the fuels business, financial performance for the full year was impacted by the factors noted above. Operational performance was strong with Solomon refining availability at 94.8% and refinery utilisation at 88% for the year.

Performance in our lubricants business in 2011 was impacted by an increasingly difficult marketing environment characterized by significant base oil price increases and weaker demand. These impacts were partly offset by supply chain efficiencies, and the strength of our products and brands, which has allowed the increased cost of goods to be largely recovered 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.

a In 2011, there was a charge of $602 million for non-operating items and a favourable impact of $63 million for fair value accounting effects. After adjusting for these impacts, replacement cost profit before interest and tax was $6,013 million. This is a non-GAAP measure, which management believes is useful to investors because it is viewed and closely tracked by management as an important indicator of segment performance.

Sales and other operating revenues for 2011, analysed in the table below, were $344 billion, compared with $267 billion in 2010 and $213 billion in 2009. These increases were primarily due to increasing oil prices.

Sales and other operating revenues[a]	2011	2010	2009
			$ million
Sale of crude oil through spot and term contracts	**57,055**	44,290	35,625
Marketing, spot and term sales of refined products	**273,940**	209,221	166,088
Other sales and operating revenues	**13,121**	13,240	11,337
	344,116	266,751	213,050

a Includes sales between businesses.

The following table sets out oil sales volumes by type for the past three years. Marketing sales volumes were 3,311mb/d, slightly lower than 2010, principally reflecting reduced demand in some OECD markets and simplification of our portfolio.

Refined products volumes	2011	2010	2009
			thousand barrels per day
Marketing sales[a]	**3,311**	3,445	3,560
Trading/supply sales[b]	**2,465**	2,482	2,327
Total refined product marketing sales	**5,776**	5,927	5,887
Crude oil[c]	**1,532**	1,658	1,824
Total oil sales	**7,308**	7,585	7,711

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. 79 thousand barrels per day relate to revenues reported by Exploration and Production.

Prior years comparative financial information

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. Almost half of this gain related to our petrochemicals business, mainly relating to the disposal of our share of BP s interests in ethylene and polyethylene production in Malaysia to Petronas. 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 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.

The replacement cost profit before interest and tax for the year ended 31 December 2009 of $743 million included a net charge for non-operating items of $2,603 million. The most significant non-operating items were restructuring charges and a $1.6 billion one-off non-cash loss to impair all of the segment s goodwill in the US West Coast FVC relating to our 2000 ARCO acquisition. This resulted from our annual review of goodwill as required under IFRS and reflected the prevailing weak refining environment that, together with a review of future margin expectations in the FVC, led to a reduction in expected future cash flows.

Acquisitions and disposals

We have been managing our portfolio actively, investing in businesses where we have strengths in terms of location, configuration, integration, technology and brand, while divesting assets that do not display these strategic characteristics.

- We completed the divestment programme of non-strategic pipelines and terminals in the US East of Rockies and West Coast, announced in 2009.
- We completed the disposal of our fuels marketing businesses in Malawi, Namibia, Tanzania, Zambia and Zimbabwe following the 2010 disposal of the business in Botswana. This portfolio rationalization now allows us to focus our activities within the continent on South Africa and Mozambique.
- We also announced our intention to divest the Texas City refinery and the southern part of the US West Coast FVC, including the Carson refinery, roughly halving our US refining capacity. BP is aiming to complete the sales by the end of 2012 subject to signing definitive agreements for the sales and subsequent satisfaction of any legal, regulatory or other conditions. BP will ensure that the fulfilment of current regulatory obligations associated with the Texas City refinery is reflected in any transaction. These assets are classified as held for sale in the group balance sheet as at 31 December 2011.
- In December 2011, Air BP announced the purchase of aviation fuels assets at seven Brazilian airports from Shell Brasil Holding B.V. and Cosan S.A. Industria e Commercio for approximately $100 million. The acquisition will give Air BP access to several new airports in Brazil as well as increasing capacity at existing Air BP operations. This deal is expected to be completed in the first quarter of 2012 subject to regulatory approvals.
- In February 2012, we announced our intent to sell our bulk and bottled LPG marketing businesses in nine countries.

Fuels

Our fuels business is made up of six regionally organized integrated FVCs (as shown in the refineries table below), the Texas City refinery, our global aviation fuel and LPG marketing businesses, and a number of regionally-focused fuels marketing businesses notably the UK, Turkey, China and France. At the end of 2011, the operating capital employed relating to the fuels business was approximately $44 billion.

Fuels value chains

The six 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 (*see map on pages 34-35*). 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 feedstock-advantaged, upgraded, well-located refineries integrated into advantaged logistics and marketing. Consequently, in the US we intend to roughly halve our US refining capacity by the end of 2012 (subject to all necessary legal and regulatory approvals) (see *also the Acquisitions and disposals section on this page).*

In our remaining FVCs, we believe that we have a portfolio of well-located refineries, integrated with strong marketing positions offering the potential for improvement and growth. We currently own or have a share in 16 refineries, which refine crude oil and produce refined fuel products which we supply to retail and commercial customers. Strategic investments in our refineries are focused on securing the safety and reliability of our assets while improving our competitive position.

Key to our future refining capability is the Whiting refinery modernization project (WRMP), which will allow the capture of additional margin through the processing of heavy Canadian crudes. The project continued to make significant progress in 2011. The coker s six new drums are now set in place, and the Southern Lights pipeline to Canada, and Whiting s interconnection to it, are in operation. This new pipeline capability allows transport of diluent streams back to Canada which are used to dilute heavy Canadian oils to facilitate their flow back to the US. WRMP is expected to come onstream in the second half of 2013.

The following tables summarize the BP group s interests in refineries and average daily crude distillation capacities as at 31 December 2011.

	thousand barrels per day
	Crude distillation capacitiesa

	Refinery	Fuels value chain	Group interest[b] %	Total	BP share
US					
California	Carson	US West Coast	100.0	266	266
Washington	Cherry Point	US West Coast	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		100.0	475	475
Total US				1,548	1,468
Europe					
Germany	Bayernoil[c]	Rhine	22.5	217	49
	Gelsenkirchen	Rhine	50.0	265	132
	Karlsruhe[c]	Rhine	12.0	322	39
	Lingen	Rhine	100.0	93	93
	Schwedt[c]	Rhine	18.8	239	45
Netherlands	Rotterdam	Rhine	100.0	377	377
Spain	Castellón	Iberia	100.0	110	110
Total Europe				1,623	845
Rest of World					
Australia	Bulwer	ANZ	100.0	102	102
	Kwinana	ANZ	100.0	146	146
New Zealand	Whangerei[c]	ANZ	23.7	118	28
South Africa	Durban[c]	Southern Africa	50.0	180	90
Total Rest of World				546	366
Total				3,717	2,679

a Crude distillation capacity is gross rated capacity, which is defined as the highest average sustained unit rate for a consecutive 30-day period.
b BP share of equity, which is not necessarily the same as BP share of processing entitlements.

c Indicates refineries not operated by BP.

Business review

The table below 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 below.

			thousand barrels per day
Refinery throughputs[a]	**2011**	2010	2009
US	**1,277**	1,350	1,238
Europe	**771**	775	755
Rest of World	**304**	301	294
Total	**2,352**	2,426	2,287
Refinery capacity utilization			
Crude distillation capacity at 31 December[b]	**2,679**	2,667	2,666
Refinery utilization[c]	**88%**	91%	86%
US	**87%**	93%	85%
Europe	**91%**	91%	89%
Rest of World	**84%**	84%	83%

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 annual throughput divided by crude distillation capacity, expressed as a percentage.

Overall refinery throughputs decreased by 74mb/d in 2011 relative to 2010, mainly due to the second quarter weather-related power outages in the US.

We continue to invest to develop the capability of producing cleaner fuels to meet the requirements of our customers and their communities. For example, in April 2011, BP announced a major investment in a new hydrotreater unit and hydrogen plant at our Cherry Point refinery, called the clean diesel project. This project will 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 will allow improved operation of naphtha reforming units at the refinery.

In addition to refined petroleum products, we also blend and market biofuels at our refineries. 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.

Downstream of our refineries, our priorities are to operate an advantaged infrastructure and logistics network (which includes pipelines, storage terminals and road or rail tankers), 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 also supply commercial customers within the transport and industrial sectors.

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) and these joint ventures in China operate around 700 dual branded sites.

As at 31 December 2011, BP s worldwide retail network consisted of some 21,800 sites across the US, Europe, Australia, New Zealand and southern Africa. This is a reduction of 300 since 2010, primarily due to a focus on fewer higher throughput sites and portfolio changes such as the southern African disposals. These retail sites are primarily branded BP, ARCO and Aral. We expect the number of sites to fall in 2012 as we dispose of the southern part of our US West Coast FVC. In 2011, branded fuels sales in the US continued to recover from the oil effects of the Deepwater Horizon oil spill, and market share stabilized but remained lower than before the oil spill, partly caused by the slowdown in US gasoline demand. We continue to invest in our fuels marketing in growing markets, for example in 2011, we piloted a new convenience retail offer in Poland with Carrefour.

The table below shows the number of BP-branded retail sites by region.

			Number of retail sites operated under a BP brand
Retail sites[a b]	**2011**	2010	2009
US	**11,300**	11,300	11,500
Europe	**8,200**	8,400	8,600
Rest of World	**2,300**	2,400	2,300
Total	**21,800**	22,100	22,400

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 which are dual-branded.

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 *ampm,* Wild Bean Café and Petit Bistro and includes partnerships with leading retailers such as Marks & Spencer in the UK and Carrefour in Poland.

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 1,500 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 111)*. 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 to manage and oversee the financial risks associated with this trading activity, *see Financial statements Note 26 on pages 217-222.*

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 450 thousand 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.

LPG

Our global LPG marketing business sells bulk, bottled, automotive and wholesale LPG products in 10 countries, with sales of over 50 thousand barrels per day. As noted in the Acquisitions and disposals section, BP announced in February 2012 its intent to sell the bulk and bottled LPG businesses in nine countries, and will retain the autogas and wholesale LPG sales from refineries which will be integrated into the fuels value chains.

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. At the end of 2011, the operating capital employed relating to the lubricants business was approximately $5 billion including goodwill of around $3 billion (*see Financial statements Note 10 on pages 206-207*).

We organize our lubricants business into customer sectors. The automotive sector serves the needs of land-based vehicles including cars, trucks, motorbikes, buses, tractors, earth movers and other vehicles. Our industrial sector serves customers who run or maintain plant and equipment; our marine sector serves users of river and sea-going vessels; aviation serves aircraft operators and maintenance industries; and our energy sector serves the oil and gas and power industries.

In the automotive lubricants sector, which accounts for more than two-thirds of our lubricants sales, 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.

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. BP s industrial lubricants business is a leading supplier to those sectors of the market involved in the manufacturing of automobiles, trucks, machinery components and steel. We are also a leading supplier of lubricants for the oil, gas and aviation industries. In the oil and gas industry we supply some of world s largest production and drilling companies, and we estimate that we supply over 30% of the world s subsea control fluids. In the aviation industry, we are the lubricants supplier for around 40% of the jet engines of the world s commercial airlines.

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% of staff are located in China and India alone. We are particularly strong in Europe and key Asia Pacific markets including India.

Our lubricants business markets primarily through our major brands of Castrol and BP, and through the Aral brand in specific European markets, notably Germany. Castrol is a recognized brand worldwide and we believe it provides us with a significant competitive advantage.

Distinctive brands, superior technology and building and sustaining customer relationships remain the cornerstones of our long-term strategy.

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 which best meets their needs.

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 27 wholly-owned and operated blending plants worldwide and joint ownership in five others operated by third parties.

Our focus is on developing premium products, and we often work alongside original equipment manufacturers (OEMs) in doing this. The new Castrol EDGE professional range was launched in 2011 to the franchised workshop market in Europe and Africa.

In 2011, approximately 45% of the lubricants replacement cost profit before interest and tax was generated from non-OECD markets.

Petrochemicals

Our petrochemicals business is global, with 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, and, through joint ventures, olefins and derivatives (O&D). We also produce a number of other speciality petrochemicals products. At the end of 2011, the operating capital employed relating to the petrochemicals business was approximately $5 billion.

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 100%-owned 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 and Asian markets. The SECCO joint venture between BP, Sinopec and its subsidiary, Shanghai Petrochemical Company, is our main O&D site and is BP s single largest investment in China. BP also co-owns one other naphtha cracker site outside Asia, which is integrated with our Gelsenkirchen refinery in Germany.

The petrochemicals business runs 16 manufacturing sites in the UK, the US, Belgium, Germany, China, Indonesia, South Korea, Malaysia and Taiwan, including our joint ventures, and we also have two petrochemicals plants which are managed by the fuels business as they utilize feedstock from our Gelsenkirchen refinery.

Business review

The table below summarizes BP s petrochemicals production capacity, at 31 December 2011.

Petrochemicals production capacity[a b]

Geographical area	Site	Product	Group interest %	BP share of capacity thousand tonnes per year
US				
	Cooper River	Purified terephthalic acid (PTA)	100.0	1,345
	Decatur	PTA	100.0	1,026
		Paraxylene (PX)	100.0	1,101
		Naphthalene dicarboxylate	100.0	29
	Texas City	Acetic acid	100.0[c]	583[c]
		PX	100.0	1,271
		Metaxylene	100.0	123
				5,478
Europe				
UK	Hull	Acetic acid	100.0	544
		Acetic anhydride	100.0	157
		Ethylidene diacetate	100.0	4
Belgium	Geel	PTA	100.0	1,330
		PX	100.0	631
Germany[d]			50.0 to	
	Gelsenkirchen	Olefins and derivatives	61.0	1,837[b e]
	Mülheim	Solvents	50.0	130[b]
				4,633
Rest of World				
China	Caojing	Olefins and derivatives	50.0	3,230[b]
	Chongqing	Acetic acid	51.0	217 [b]
		Esters	51.0	52[b]
	Nanjing	Acetic acid	50.0	274[b]
	Zhuhai	PTA	85.0	1,564[f]
Indonesia	Merak	PTA	50.0	253[b]
South Korea	Ulsan	Acetic acid	51.0	267[b]
		Vinyl acetate monomer	34.0	65[b]
Malaysia	Kertih	Acetic acid	70.0	391 [b]
	Kuantan	PTA	100.0	610
Taiwan	Kaohsiung	PTA	61.4	847[b]
	Taichung	PTA	61.4	474[b]
	Mai Liao	Acetic acid	50.0	181[b]
				8,425
Total BP share of capacity at 31 December 2011				18,536

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 Group interest is quoted at 100%, reflecting the capacity entitlement which is marketed by BP.
d 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.
e Group interest varies by product.
f BP Zhuhai Chemical Company Ltd is a subsidiary of BP, the capacity of which is shown above at 100%.

Outlook

In 2012, we expect the overall economic environment to be challenging, with below-average growth. Emerging economies are likely to drive growth, while developing countries are expected to lag behind. We expect that refiners will continue to operate with excess capacity globally, despite the announced shutdown of refineries in the US East Coast and Europe. The RMM in 2012 is expected to remain in a range of $8-12 per barrel. We expect the differential between WTI and Brent crude to eventually return to lower levels as additional US pipeline capacity is brought online. The level of BP s refinery turnaround activity is expected to be broadly similar in 2012 compared with 2011.

We expect the marketing environment for lubricants to remain challenging given the outlook for global economic growth. Longer term however, we expect to see growth in global lubricants demand through to 2020 as a result of continued growth in the number of vehicles, continuing industrialization in emerging markets, and expanding world trade. This growth is expected to be concentrated in non-OECD markets. Lubricants demand is also expected to continue to shift towards higher quality, premium products as new vehicles adopt advanced, smaller, more efficient engines placing greater demands on lubricant performance.

In the petrochemicals industry, we expect significant new capacity to come onstream in acetic acid and PTA in 2012, 7% and 15% of global capacity respectively. Demand is expected to remain robust in 2012, but not sufficient to absorb the additional capacity, hence we expect the margin environment to be weaker in 2012 than in 2011.

Our priorities in 2012 remain consistent with those in 2011 and 2010. We will continue to focus on delivering safe, reliable and compliant operations, improving the performance of our integrated FVCs, and driving further cost efficiencies across all our businesses. We intend to increase our investment levels slightly in 2012 versus 2011 and 2010, focusing on key safety and operational integrity priorities, maintaining our quality manufacturing and marketing portfolio, strengthening our US East of Rockies FVC business through the Whiting refinery modernization project, and continuing to grow our advantaged petrochemicals business in China. We intend to continue to upgrade our portfolio through investments in advantaged assets and the completion of our divestment programme, including the US southern west coast FVC and the Texas City refinery, announced in February 2011.

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. It also included the group s aluminium business until its disposal in 2011.

The replacement cost loss before interest and tax for the year ended 31 December 2011 was $2,478 million, compared with $1,516 million for the previous year. 2011 included a net charge for non-operating items of $822 million. *(See page 58 for further information on non-operating items.)* The primary additional factors affecting 2011 s result compared with that of 2010 were significantly higher functional and corporate costs; loss of aluminium contribution following disposal of the group s aluminium business in 2011; impacts of restructuring in the Alternative Energy business; higher Shipping losses, partly offset by improved foreign exchange hedging results.

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 replacement cost loss before interest and tax for the year ended 31 December 2009 included a net charge for non-operating items of $489 million.

The primary additional factors reflected in 2010 s result compared with that of 2009 were improved business performance, more favourable foreign exchange effects and cost efficiencies.

Key statistics

			$ million
	2011	2010	2009
Sales and other operating revenues[a]	**2,957**	3,328	2,843
Replacement cost (loss) before interest and tax	**(2,478)**	(1,516)	(2,322)
Capital expenditure and acquisitions	**1,853**	1,234	1,299

[a] Includes sales between businesses.

Alternative Energy

Alternative Energy comprises BP s low-carbon businesses and future growth options outside oil and gas, which we believe have the potential to be a material source of low-carbon energy and are aligned with BP s core capabilities. These are biofuels, wind and a range of strategic investments.

Our market

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 40% between 2010 and 2030. Supported by government policies, renewables global share of power generation, is expected to be 11% by 2030. Between 2010 and 2030, biofuels are expected to account for 23% of transport energy demand growth[a].

Our performance

In 2011, our biofuels business acquired the Brazilian sugar and ethanol producer Companhia Nacional de Açúcar e Álcool (CNAA) for $705 million. Our wind business added 401MW of gross generation capacity during 2011 (274MW net), with the commercial start-up of the Cedar Creek 2 and Sherbino 2 wind farms. At the end of 2011, BP began winding down its remaining solar operations as it prepares to exit the solar business.

Alternative Energy continues to make progress against its commitment to invest $8 billion in low-carbon businesses by 2015. Our investment since 2005 is $6.6 billion[b].

a *BP Energy Outlook 2030.*

b The majority of costs have been capitalized, 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 around the most efficient transformation of sustainable and low-cost sugars into a range of fuel molecules. 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 Alternative Energy on page 76 for further information.*

BP has production facilities operating, or in the planning and construction phases, in the US, Brazil and the UK.

The 2011 CNAA acquisition included mills located in Goiás and Minas Gerais states that supply both Brazilian and international markets with ethanol. We have also increased our share in the Brazilian biofuels company, Tropical BioEnergia S.A., to 100%, by acquiring the remaining 50% for cash consideration of approximately $71 million. The acquisition included an operating ethanol mill, located in Goiás state. BP now owns and operates three producing ethanol mills in Brazil, with a total crush capacity[a] of 7.2 million tonnes per annum. The blending and distribution of biofuels continues to be carried out by our Refining and Marketing segment, in line with regulation.

a Crush capacity represents a maximum capacity to process biofuels feedstock.

Wind

In wind power, BP has focused its business in the US, where we have developed one of the leading wind portfolios.

During 2011, full commercial operations commenced at the Cedar Creek 2 wind farm in Colorado with a gross capacity of 251MW (BP 50%) and in Texas at the 150MW Sherbino 2 wind farm. Construction is nearly complete at a further Texas wind farm, the 225MW Trinity Hills facility, and construction has commenced at the 141MW Mehoopany wind farm in Pennsylvania, and at the 470MW Flat Ridge wind farm in Kansas.

BP increased its net wind generation capacity to 1,048MW during 2011, an increase of 35% over the prior year.

	2011	2010	2009
Wind net rated capacity at year-end (megawatts)[a]	**1,048**	774	711

a Net wind capacity is the sum of the rated capacities of the assets/turbines that have entered into commercial operation, including BP s share of equity-accounted entities. The equivalent capacities on a gross-JV basis (which includes 100% of the capacity of equity-accounted entities where BP has partial ownership) were 1,763MW in 2011, 1,362MW in 2010 and 1,237MW in 2009. This includes 32MW of capacity in the Netherlands which is managed by our Refining and Marketing segment.

Solar

BP has been involved in solar for more than 35 years and in the last two years the industry has changed radically into a low margin commodity market. At the end of 2011, BP began winding down its remaining solar operations as it prepares to exit the solar business. BP will take the necessary steps to transfer its obligations and assets to its affiliates or to third parties.

Emerging business and ventures

Our emerging business and ventures unit brings together BP s venturing and carbon markets expertise with extensive carbon capture and storage capability. Through venturing we have 29 separate venturing investments spanning three broad areas: bioenergy, electrification and carbon solutions. We are able to deploy specialist carbon capture and storage capabilities on our own operations and to monitor CO_2 storage opportunities, such as the In Salah gas field where we have injected almost 4 million tonnes of CO_2 since 2004.

In September 2011, SCS Energy, an independent power producer involved in clean power projects, acquired the Hydrogen Energy California joint venture project from BP and Rio Tinto.

Separately, the 400MW Hydrogen Power Abu Dhabi project with CCS is awaiting further decisions, including arrangements for CO_2

transportation and storage. The project is a joint venture between BP (40%) and Masdar (60%).

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 2011, we had 53 international vessels (37 medium-size crude and product carriers, three very large crude carriers, one North Sea shuttle tanker, eight LNG carriers and four 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.

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 12 offshore support vessels).

Time-charter vessels

At the end of 2011 BP had 93 hydrocarbon-carrying vessels above 600 deadweight tonnes on time-charter, all of which are double-hulled. All these vessels participate in BP s time-charter assurance programme.

Spot-charter vessels

BP spot-charters vessels, typically for single voyages. These vessels are always vetted for safety assurance 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 trading reasons and we consider it safe to do so, we will continue to trade vessels through these areas, subject to the adoption of heightened security measures.

2011 has seen continuing pirate activity in the Gulf of Aden, Indian Ocean (up to approximately 200 miles west of the Indian coast) and the Arabian Sea. Activity has further extended into the north Arabian Sea (approximately 200 miles south of Pakistan) and the southern Red Sea. Despite an increasing level of piracy activity the number of vessels actually attacked and/or hijacked has remained roughly the same as in 2010, and the percentage success rate of the pirates has reduced. This is as a result of stronger naval intervention off the Somali coast, heightened awareness of the threat, and protective measures adopted by transiting ships.

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 piracy is known to occur e.g. West Africa and the South China Sea.

Aluminium

During 2011, we terminated our interest in this business with the disposal of our wholly-owned subsidiary, ARCO Aluminum Inc., to a consortium of Japanese companies for cash consideration of $680 million.

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 217.*

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.

Liquidity and capital resources

Following the Deepwater Horizon oil spill in 2010, the group initially faced significant costs relating to the immediate response activities as well as significant uncertainty regarding the ultimate magnitude of its liabilities and timing of cash outflows. During 2011 the impact on the group s liquidity and capital resources has stabilized, allowing steps to be taken to enhance the strength of the balance sheet.

The group s long-term credit ratings are A (stable outlook) from Standard & Poor s, strengthened from A (negative outlook) in July 2011, and A2 (stable outlook) from Moody s Investor Services.

BP renegotiated its committed bank facilities during 2011 putting in place $6.9 billion of facilities with 25 international banking counterparties, mostly for a term of three years. In addition the group has increased its access to commercial bank letters of credit (LC) by putting in place committed LC facilities of $5.1 billion and secured LC arrangements of $2.2 billion, to supplement its uncommitted and unsecured LC lines.

The disposal programme of $30 billion initially announced in 2010 has been increased to $38 billion, for completion by the end of 2013. By the end of 2011 agreements had been signed for more than $21 billion, with cash receipts totalling $17 billion in 2010 and $2.7 billion in 2011.

BP accessed US and European capital markets throughout the year with bond issuances amounting to $10.7 billion in 2011.

A further $0.8 billion of US Industrial Revenue/Municipal bonds were re-issued in term-out mode of between three to 10 years during the year.

During 2011 BP repaid $2.9 billion of the $5.3 billion of borrowings raised in 2010 that were secured against working capital and other assets, or 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 50% in 2014 compared to 2011[b]. Half of the increase will arise as the remaining payments into the Deepwater Horizon Oil Spill Trust fund complete by the end of 2012, and half from operations. BP plans to use half of the expected additional cash flows to increase investments and half for other purposes.

We intend to maintain a significant liquidity buffer and to reduce our net debt ratio to the lower half of the 10-20% gearing range over time. *See Financial statements Note 35 on page 230 for gross debt, which is the nearest equivalent measure to net debt on an IFRS basis, and for further information on net debt and net debt ratio.*

a Operating cash flow is net cash provided by (used in) operating activities, as stated in the group cash flow statement on page 181.
b Assuming an oil price of $100 per barrel in 2014. The projection reflects our expectation that all required payments into the $20-billion trust fund will have been completed by the end of 2012. 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. See Financial statements Note 43 on page 249, for further information on contingent liabilities.

Dividends and other distributions to shareholders

On 1 February 2011, BP announced the resumption of quarterly dividend payments, with a fourth-quarter 2010 dividend of 7 cents per share. The resumption followed the suspension of dividend payments for the first three quarters of 2010 announced in June 2010 in light of the Deepwater Horizon oil spill and commitments to fund the $20-billion Trust. The same level of dividend was maintained for the first three quarters of 2011.

The total dividend paid to BP shareholders in 2011 was $4.1 billion with shareholders also having the option to receive a scrip dividend, compared with $2.6 billion paid in 2010. The dividend is determined in US dollars, the economic currency of BP.

On 7 February 2012, BP announced a dividend of 8 cents per share in respect of the fourth quarter 2011.

During 2011 and 2010, 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 170.

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 page 59 for further information on risks associated with the general macroeconomic outlook, including the stability of the eurozone and Financial statements Note 26 on page 217.*

The group s finance debt at 31 December 2011 amounted to $44.2 billion (2010 $45.3 billion). Of the total finance debt, $9.0 billion is classified as short term at the end of 2011 (2010 $14.6 billion). The short-term balance includes $4.9 billion for amounts repayable within the next 12 months relating to long-term borrowings (2010 $6.9 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 2011, outstanding commercial paper amounted to $3.6 billion (2010 $1.0 billion). Also included within short-term debt at the end of 2010 was $6.2 billion relating to deposits received for announced disposal transactions still pending legal completion post the balance sheet date. At the end of 2011 the balance was de minimis at $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 2011, the amount drawn down against the DIP was $11.6 billion (2010 $12.3 billion). In addition, the group has in place an unlimited US shelf registration statement under which it may raise debt with maturities of one month or longer. None of the capital market bond issuances since the Deepwater Horizon oil spill contain 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 229.

Net debt was $29.0 billion at the end of 2011, an increase of $3.1 billion from the 2010 year-end position of $25.9 billion. The ratio of net debt to net debt plus equity was 20.5% at the end of 2011 (2010 21.2%). 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 230 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 $14.1 billion at 31 December 2011 (2010 $18.6 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 $1.2 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 pages 217-222, and on the cash position in Financial statements Note 30 on page 223.

The group also has access to significant sources of liquidity in the form of committed bank facilities. At 31 December 2011, the group had available undrawn committed standby borrowing facilities of $6.9 billion (2010 $12.5 billion), made up of:

- $6.8 billion of standby facilities available to draw and repay by mid-March 2014.
- 625 million Chinese yuan ($0.1 billion) of 365-day standby facilities available to draw and repay until the second half of 2012.

During 2011 $7.2 billion of 364-day facilities expired and were not renewed.

Business review

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 Deepwater Horizon oil spill and the implications for future activities. *See Risk factors on pages 59-63, and Financial statements Note 2 on page 190, Note 36 on page 231 and Note 43 on page 249 for further information.*

Off-balance sheet arrangements

At 31 December 2011, the group s share of third-party finance debt of equity-accounted entities was $7,003 million (2010 $6,987 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 2011 are $415 million (2010 $404 million) in respect of liabilities of jointly controlled entities and associates and $1,430 million (2010 $1,339 million) in respect of liabilities of other third parties. Of these amounts, $220 million (2010 $355 million) of the jointly controlled entities and associates guarantees relate to borrowings and for other third-party guarantees, $1,267 million (2010 $1,324 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 208.

Contractual commitments

The following table summarizes the group s principal contractual obligations at 31 December 2011, 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 229 and more information on operating leases is given in Financial statements Note 14 on page 208.

							$ million
Expected payments by period under contractual							Payments due by period
obligations and commercial commitments	Total	2012	2013	2014	2015	2016	2017 and thereafter
Balance sheet obligations							
Borrowings[a]	47,242	9,570	7,812	7,262	5,438	4,586	12,574
Finance lease future minimum lease payments	1,034	454	54	49	49	48	380
Deepwater Horizon Oil Spill Trust funding liability	4,884	4,884					
Decommissioning liabilities[b]	19,693	610	546	433	305	346	17,453
Environmental liabilities[b]	3,646	1,665	588	232	187	192	782
Pensions and other post-retirement benefits[c]	29,171	1,945	1,933	1,944	1,938	1,921	19,490
Total balance sheet obligations	105,670	19,128	10,933	9,920	7,917	7,093	50,679
Off-balance sheet obligations							
Operating leases[d]	16,072	4,182	3,286	2,207	1,630	1,223	3,544
Unconditional purchase obligations[e]	197,404	115,679	18,155	12,388	8,311	7,168	35,703
Total off-balance sheet obligations	213,476	119,861	21,441	14,595	9,941	8,391	39,247
Total	319,146	138,989	32,374	24,515	17,858	15,484	89,926

a Expected payments include interest payments on borrowings totalling $3,751 million ($896 million in 2012, $746 million in 2013, $582 million in 2014, $443 million in 2015, $333 million in 2016 and $751 million thereafter), and exclude disposal deposits of $30 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 2012 include purchase commitments existing at 31 December 2011 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 217.

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

$ million

Unconditional purchase obligations	Total	2012	2013	2014	2015	2016	2017 and thereafter
	Payments due by period						
Crude oil and oil products	130,824	90,690	9,095	5,684	3,344	2,853	19,158
Natural gas	38,370	17,591	5,258	3,589	2,516	2,087	7,329
Chemicals and other refinery feedstocks	9,962	2,573	1,129	1,115	1,028	979	3,138
Power	3,038	2,169	644	212	11	2	
Utilities	892	181	154	106	97	75	279
Transportation	8,061	1,183	957	926	731	661	3,603
Use of facilities and services	6,257	1,292	918	756	584	511	2,196
Total	197,404	115,679	18,155	12,388	8,311	7,168	35,703

The group expects its total capital expenditure, excluding acquisitions and asset exchanges, to be around $22 billion in 2012. The following table summarizes the group s capital expenditure commitments for property, plant and equipment at 31 December 2011 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	2012	2013	2014	2015	2016	2017 and thereafter
Committed on major projects	32,951	15,113	7,443	4,268	2,828	1,535	1,764
Amounts for which contracts have been placed	12,517	7,689	2,789	1,094	511	315	119

In addition, at 31 December 2011, the group had committed to capital expenditure relating to investments in equity-accounted entities amounting to $610 million. Contracts were in place for $332 million of this total.

Cash flow

The following table summarizes the group s cash flows.

			$ million
	2011	2010	2009
Net cash provided by operating activities	22,154	13,616	27,716
Net cash (used in) investing activities	(26,633)	(3,960)	(18,133)
Net cash provided by (used in) financing activities	482	840	(9,551)
Currency translation differences relating to cash and cash equivalents	(492)	(279)	110
Increase (decrease) in cash and cash equivalents	(4,489)	10,217	142
Cash and cash equivalents at beginning of year	18,556	8,339	8,197
Cash and cash equivalents at end of year	14,067	18,556	8,339

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 to $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 provided by operating activities for the year ended 31 December 2010 was $13,616 million compared with $27,716 million for 2009, the reduction primarily reflecting a net cash outflow of $16,019 million in respect of the Gulf of Mexico oil spill. Excluding the impacts of the Gulf of Mexico oil spill, profit before taxation increased by $10,986 million and a decrease in working capital requirements contributed $842 million. This higher profit before tax did not result in an equivalent net increase in operating cash flow because it included $4,854 million in net gains on disposals, net of impairments, a decrease of $1,160 million in depreciation, depletion, amortization and exploration expense, and a decrease of $787 million in the net charge for provisions, less payments, all of which are non-cash items.

Net cash used in investing activities was $26,633 million in 2011, compared with $3,960 million and $18,133 million in 2010 and 2009 respectively. 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. The decrease in 2010 compared with 2009 reflected an increase of $14,273 million in disposal proceeds and a decrease in capital expenditure and investments of $2,445 million, partly offset by an increase in acquisitions of $2,469 million.

Net cash provided by financing activities was $482 million in 2011 compared with $840 million net cash provided in 2010 and $9,551 million net cash used in 2009. 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 net increase in cash provided in 2010 compared with 2009 reflected a decrease in dividends paid of $7,957 million, an increase in net proceeds from long-term financing of $1,686 million and a decrease in net repayments of short-term debt of $786 million.

The group has had significant levels of capital investment for many years. Cash flow in respect of capital investment, excluding acquisitions, was $18.8 billion in 2011, $18.9 billion in 2010 and $21.4 billion in 2009. 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 $29.0 billion at the end of 2011, $25.9 billion at the end of 2010 and $26.2 billion at the end of 2009.

During the period 2009 to 2011, our total sources of cash amounted to $87 billion, while our total uses of cash amounted to $90 billion. The net cash usage of $3 billion, and the increase in cash and cash equivalents held of $6 billion, were financed by an increase in finance debt of $9 billion over the three-year period. During this period, the price of Brent crude oil has averaged $84.14 per barrel. The following table summarizes the three-year sources and uses of cash.

	$ billion
Sources of cash	
Net cash provided by operating activities	63
Disposals	24
	87
Uses of cash	
Capital expenditure	59
Acquisitions	13
Net repurchase of shares	
Dividends paid to BP shareholders	17
Dividends paid to minority interests	1
	90
Net use of cash	(3)
Increase in finance debt	9
Increase in cash and cash equivalents	6

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 $16 billion per year. Dividends paid to BP shareholders totalled $17 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. The balance of cash and cash equivalents held has been increased in light of the group s current circumstances, as noted above.

Trend information

For information on external market trends, see Our market on pages 18-24.

We expect production excluding TNK-BP in 2012 to be broadly flat compared with 2011, after adjusting for divestments and at an oil price of $100 per barrel.

In Refining and Marketing, the level of BP s refinery turnaround activity is expected to be broadly similar in 2012 compared with 2011. We also expect the marketing environment in fuels, lubricants and petrochemicals to remain subdued given the outlook for global demand.

In 2012, we expect the quarterly loss, excluding non-operating items, for Other businesses and corporate to average around $500 million. As in previous years, this is likely to be volatile on an individual quarterly basis.

We expect capital expenditure, excluding acquisitions and asset exchanges, to increase to around $22 billion in 2012, as we invest to grow in our Exploration and Production segment.

Having completed disposals of almost $20 billion during 2010 and 2011 combined, we expect to make further disposals that would bring the total to $38 billion by the end of 2013.

We intend to reduce the net debt ratio to the lower half of the 10-20% range over time. Net debt is a non-GAAP measure.

Depreciation, depletion and amortization in 2012 is expected to be around $1.0 billion higher than in 2011.

The discussion above contains forward-looking statements, particularly those regarding external market trends, the future level of production excluding TNK-BP, the expected level of turnarounds, the marketing environment in fuels, lubricants and petrochemicals, the expected quarterly loss for Other businesses and corporate, the expected level of capital expenditures, expectations regarding future disposals, net debt and net debt ratio, and future levels of depreciation, depletion and amortization. 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 5 and Risk factors on pages 59-63, 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 our 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 will 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 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 our products, operations and activities. Current and proposed fuel and product specifications, emission controls and climate change programmes under a number of environmental laws may have a significant effect on the production, sale and profitability of many of our products.

There are also environmental laws that require us to remediate and restore areas damaged by the accidental or unauthorized release of hazardous substances or petroleum 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* 231 *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 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 71.*

Approximately 56% 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 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 our 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, and 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 regulation 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 oil spill. 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 will be additional costs associated with this increased regulation. In 2012, 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 oil spill we have 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 page 160.*

On 31 March 2009, the United States filed a complaint seeking civil penalties and damages relating to oil leaks from oil transit lines operated by BP Exploration (Alaska) Inc. (BPXA) at the Prudhoe Bay unit on the North Slope of Alaska. *(See Legal proceedings on page 165.)* The complaint also involved claims related to asbestos handling, allegations of non-compliance at multiple facilities for failure to comply with EPA s spill prevention plan regulations, and for non-compliance with US Department of Transportation orders and regulations. The parties settled the dispute and on 13 July 2011 the Court entered a Consent Agreement in which BPXA agreed to pay a $25-million penalty and to perform certain injunctive measures over the next three years with respect to pipeline inspection and maintenance.

Various environmental groups and the EPA have challenged certain aspects of the air permits issued by the Indiana Department of Environmental Management (IDEM) for upgrades to the Whiting refinery. In response to these challenges, the IDEM has reviewed the permits and responded formally to the EPA. BP is in discussions with EPA, the IDEM and certain environmental groups over these and other CAA issues relating to the Whiting refinery. BP has also been 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 EU Climate and Energy Package and the Emissions Trading Scheme (ETS) Directive (see *Greenhouse gas regulation on page 109).*
- 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)) are in the process of transposition by the EU Member States. 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 key to our major sites is expected in 2012/2013. The IED transposition and output from the BREF revisions may result in requirements for further emission reductions at our EU sites.
- 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 our EU sites.
- 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.
- The EU Fuels 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 as described in Greenhouse gas regulation above, and tighter environmental fuel quality standards for petrol and diesel (for example see *Greenhouse gas regulation on page 109).*
- 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 those 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. Substances registered in 2010 are subject to evaluation and/ or authorization/restriction procedures by the authorities and this may impact activities, product sales and their profitability.
  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 us 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 completed updates for all chemicals substances we manufacture and market in the EU by the compliance deadline of 3 January 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. The proposed regulation aims to introduce harmonized regulation of the potential environmental, health and safety impacts of the offshore oil and gas industry throughout EU waters. Although it is at an early stage in the legislative process, as published the proposal is not entirely aligned with the regime 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, 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) Convention 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.

- International marine fuel regulations under International Maritime Organization (IMO) and International Convention for the Prevention of Pollution from Ships (MARPOL) regimes impose stricter sulphur emission restrictions on ships in EU ports and inland waterways and the North and Baltic seas since 2010 and with a stricter global cap on marine sulphur emissions beginning in 2012. Further reductions are to be phased in thereafter. These restrictions require the use of compliant heavy fuel oil (HFO) or distillate, or the installation of abatement technologies on ships. These regulations will 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.

- The Kyoto Protocol commits the parties and other entities to meet emissions targets in the first commitment period from 2008 to 2012.
- The UN summit in Cancun in December 2010 where 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 commit 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 (COP 17) 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 and run for five or eight years. However, it will not include the US, Canada, Japan and Russia, and quantitative targets and the rules for carry-over of allowances from the first commitment will not be agreed until the end of 2012.

These international concerns and agreements are reflected in national and regional measures to limit GHG emissions. Additional stricter measures can be expected in the future. These measures can increase our production costs for certain products, increase demand for competing energy alternatives or products with lower-carbon intensity and affect the sales and specifications of many of our products. Current measures and developments potentially affecting our 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 EU Emissions Trading Scheme (ETS); 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 EU ETS Phase 3. EU ETS 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. The EU ETS regulates approximately one-fifth of our reported 2011 global GHG emissions and can be expected to require additional expenditure from 2013 when Phase 3 comes into effect. Finally, EU energy efficiency policy is currently addressed via national energy efficiency action plans.
- Article 7a of the revised EU Fuels 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 is scheduled to take effect from 1 July 2012 with a fixed price of $23 Australian dollar (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. The agriculture sector (45% of New Zealand s GHG emissions) has been proposed to join the NZ ETS in January 2015. New Zealand also employs a portfolio of mandatory and voluntary complementary measures aimed at GHG reductions. A September 2011 review of the scheme recommended effective delays to near-term emissions reductions targets, citing a lack of international action on cutting emissions.
- In the US, with no current potential for passing comprehensive climate legislation, 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 (GHGRR) in 2009 and continues to make amendments to the rule. The first reports under the GHGRR were due on or before 30 September 2011. The majority of BP s US businesses were affected by the GHGRR and submitted their first GHG emissions reports to the EPA under the GHGRR on or before the 30 September 2011 deadline. In addition to direct emissions from affected facilities, producers and importers/ exporters of petroleum products, certain natural gas liquids, and GHG s were required to report product volumes and notional GHG emissions should these products be fully combusted. The EPA released direct emission data and a small subset of product supplier data on 11 January 2012, with certain confidential business information protections, in a tool enabled database which allows transparency to the individual facility/entity level. Release of the balance of the product supply data is expected soon along with release of additional non-confidential information which will enable aggregation of reported emissions to the highest level US parent company.

The EPA finalized permitting requirements for new or modified large GHG emission sources in 2010, with these regulations taking effect in January 2011 and the second phase taking effect on 1 July 2011. The EPA has committed to additional actions, beginning in 2012, relating to smaller sources of GHG emissions.

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; the EPA was unable to meet the December deadline, which may delay final rulemaking. The EPA has communicated that they are considering three options for these standards, energy management, command and control (source specific emission limits) and benchmarking (e.g. a Solomon-type GHG intensity index or variation).

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 a preliminary injunction filed in late December 2011 is preventing its implementation. California issued final rules for its cap and trade programme in December 2011, with the scheduled start of the scheme to begin January 2012, with 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, five provinces and eight cities were selected as pilots for low carbon development, and seven provinces/cities were formally given instruction to start emission trading trials. 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 this initiative.

Certain definitions

Unless the context indicates otherwise, the following terms have the meaning shown below:

Replacement cost profit

Replacement cost profit or loss reflects the replacement cost of supplies. The replacement cost profit or loss for the year is arrived at by excluding from profit or loss inventory holding gains and losses and their associated tax effect. Replacement cost profit or loss for the group is not a recognized GAAP measure.

BP believes that replacement cost profit before interest and taxation for the group is a useful measure for investors because it is the profitability measure used by management. *See Selected financial information on page 56 for the nearest equivalent measure on an IFRS basis, which is Profit (loss) for the year attributable to BP shareholders .*

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.

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 58.

Commodity trading contracts

BP s Exploration and Production and Refining and Marketing 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 Exploration and Production on pages 88-89 and in Refining and Marketing on page 98. 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 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.

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Directors and senior management

Directors and senior management

The following lists the company s directors and senior management as at 28 February 2012.

Directors		Initially elected or appointed
C-H Svanberg	Chairman	Chairman since January 2010 Director since September 2009
R W Dudley	Executive Director (Group Chief Executive)	Group chief executive since October 2010 Director since April 2009
P M Anderson	Non-Executive Director	February 2010
F L Bowman	Non-Executive Director	November 2010
A Burgmans	Non-Executive Director	February 2004
C B Carroll	Non-Executive Director	June 2007
Sir William Castell	Non-Executive Director (Senior Independent Director)	July 2006
I C Conn	Executive Director (Chief Executive, Refining and Marketing)	July 2004
G David	Non-Executive Director	February 2008
I E L Davis	Non-Executive Director	April 2010
Professor Dame Ann Dowling	Non-Executive Director	February 2012
Dr B Gilvary	Executive Director (Chief Financial Officer)	January 2012
Dr B E Grote	Executive Director (Executive Vice President, Corporate Business Activities)	August 2000
B R Nelson	Non-Executive Director	November 2010
F P Nhleko	Non-Executive Director	February 2011
A Shilston	Non-Executive Director	January 2012
Senior management		Initially elected or appointed
M Bly	Executive Vice President (Safety and Operational Risk)	October 2010
R Bondy	Group General Counsel	May 2008
Dr M C Daly	Executive Vice President (Exploration)	October 2010
R Fryar	Executive Vice President (Production)	October 2010
A Hopwood	Executive Vice President (Strategy and Integration)	October 2010
B Looney	Executive Vice President (Developments)	October 2010
H L McKay	Executive Vice President (Chairman and President of BP America Inc.)	June 2008
D Sanyal	Executive Vice President and Group Chief of Staff	January 2012
Dr H Schuster	Executive Vice President (Human Resources)	March 2011

Mr F P Nhleko was appointed as a director on 1 February 2011, Dr B Gilvary and Mr A Shilston were appointed as directors on 1 January 2012 and Professor Dame Ann Dowling was appointed as a director on 3 February 2012. Dr H Schuster was appointed as executive vice president, human resources on 1 March 2011 and Mr D Sanyal was appointed as executive vice president and group chief of staff on 1 January 2012.

Mr D J Flint and Dr D S Julius retired as directors on 14 April 2011. Mr S Westwell retired as executive vice president, strategy and integration on 31 December 2011.

At the company s 2011 annual general meeting (AGM), the following directors retired, offered themselves for election/re-election and were duly elected/re-elected: Mr P M Anderson, Mr F L Bowman, Mr A Burgmans, Mrs C B Carroll, Sir William Castell, Mr I C Conn, Mr G David, Mr I E L Davis, Mr R W Dudley, Dr B E Grote, Mr B R Nelson, Mr F P Nhleko and Mr C-H Svanberg.

Sir William Castell will retire at the conclusion of the 2012 AGM. His role as senior independent director will be taken by Andrew Shilston upon his retirement. All of the other directors will offer themselves for election/re-election at the company s 2012 AGM.

David Jackson (59) was appointed company secretary in 2003. A solicitor, he is a director of BP Pension Trustees Limited.

Directors

C-H Svanberg

Chairman of the chairman s and nomination committees and attends meetings of the Gulf of Mexico and remuneration committees

Carl-Henric Svanberg (59) joined BP s board in September 2009 and became chairman of BP on 1 January 2010. From 2003 until December 2009, he was president and chief executive officer of Ericsson, also serving as the chairman of Sony Ericsson Mobile Communications AB. He continues to be a non-executive director of Ericsson.

R W Dudley

Robert Dudley (56) joined the Amoco Corporation in 1979 for whom he worked until its merger with BP in 1998. Following a variety of posts in the US, the UK, the South China Sea and Moscow, in 2001 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 in Moscow. He was appointed an executive director in April 2009 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. On 1 October 2010 he became BP s group chief executive.

P M Anderson

Member of the chairman s and Gulf of Mexico committees and chairman of the safety, ethics and environment assurance committee

Paul Anderson (66) was appointed a non-executive director of BP on 1 February 2010. He is a non-executive director of BAE Systems PLC and of Spectra Energy Corp. He was formerly chief executive at 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 re-joined these latter boards in 2006 as a non-executive director, retiring on 31 January 2010. Previously he served as a non-executive director on numerous boards in the US and Australia.

F L Bowman

Member of the chairman s, Gulf of Mexico and safety, ethics and environment assurance committees

Frank Bowman (67) joined BP s board on 8 November 2010. He served for over 38 years in the United States Navy, during which time he served as commander of the nuclear submarine *USS City of Corpus Christi and* commander of the submarine tender *USS Holland,* director of political-military affairs on the joint staff and chief of naval personnel. He was director of the naval nuclear propulsion programme in the Department of Navy and Department of Energy. After retiring from the Navy as an admiral, he became president and chief executive officer of the Nuclear Energy Institute. He served on the BP Independent Safety Review Panel and on the BP America Advisory Panel. He is president of Strategic Decisions, LLC and a director of Morgan Stanley Mutual Funds.

A Burgmans, KBE

Member of the chairman s, nomination and safety, ethics and environment assurance committees and chairman of the remuneration committee

Antony Burgmans (65) joined BP s board in 2004. He was appointed to the board of Unilever in 1991. In 1999, he became chairman of Unilever NV and vice chairman of Unilever PLC. In 2005, he became non-executive chairman of Unilever PLC and Unilever NV, retiring from these appointments in 2007. He is also a member of the supervisory boards of Akzo Nobel N.V., Aegon N.V. and SHV Holdings N.V.

C B Carroll

Member of the chairman s, nomination and safety, ethics and environment assurance committees

Cynthia Carroll (55) joined BP s board in 2007. She started her career at Amoco and in 1989 she joined Alcan, where in 2002 she was appointed president and chief executive officer of Alcan s primary metals group and an officer of Alcan, Inc. She was appointed as chief executive of Anglo American plc, the global mining group, in 2007. She is also a director of De Beers s.a. and chairman of Anglo Platinum Ltd.

Sir William Castell, LVO

Member of the chairman s, Gulf of Mexico, nomination and safety, ethics and environment assurance committees

Sir William (64) joined BP s board in 2006 and is the senior independent director. From 1990 to 2004, he was chief executive of Amersham plc and subsequently president and chief executive officer of GE Healthcare. He was appointed as a vice chairman of the board of GE in 2004, stepping down from this post in 2006 when he became chairman of the Wellcome Trust. He remains a non-executive director of GE. He will retire from the BP board at the conclusion of the 2012 AGM.

I C Conn

lain Conn (49) joined BP in 1986. Following a variety of roles in oil trading, commercial refining, retail and commercial marketing operations, and exploration and production, in 2000 he became group vice president of BP s refining and marketing business. From 2002 to 2004, he was chief executive of petrochemicals. He was appointed group executive officer with a range of regional and functional responsibilities and an executive director in 2004. He was appointed chief executive of Refining and Marketing in 2007. He is a non-executive director and senior independent director of Rolls-Royce Holdings plc, chairman of The Advisory Board of Imperial College Business School and a member of The Council of The Imperial College.

G David

Member of the chairman s, audit, Gulf of Mexico and remuneration committees

George David (69) began his career in 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 1977. 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.

I E L Davis

Member of the chairman s, nomination and remuneration committees and chairman of the Gulf of Mexico committee

Ian Davis (60) joined BP s board on 2 April 2010. 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. He retired as senior partner of McKinsey & Company in July 2010. He is a non-executive director of Johnson & Johnson, Inc and a senior adviser to Apax Partners. He is also a non-executive member of the UK s Cabinet Office.

Professor Dame Ann Dowling

Member of the chairman s and safety, ethics and environment assurance committees

Dame Ann (59) joined BP s board on 3 February 2012. She was appointed a Professor of Mechanical Engineering in the Department of Engineering at the University of Cambridge in 1993. Between 1999 and 2000 she was the Jerome C Hunsaker Visiting Professor of Aerospace Systems 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 and Head of the Department of Engineering at the University of Cambridge in 2009. 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.

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 Advisory Board. She chaired the Royal Society/Royal Academy of Engineering study on Nanotechnology.

Directors and senior management

Dr B Gilvary

Brian Gilvary (50) joined BP in 1986. Following a variety of roles in exploration and production, downstream and trading, in 2000 he became chief of staff of BP s refining and marketing business and held a number of executive roles in the business, including chief financial officer and commercial director from 2002 to 2005. In 2003 he was appointed 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. On 1 January 2012 he was appointed to the board of BP p.l.c. and became chief financial officer.

Dr B E Grote

Byron Grote (63) joined BP in 1987 following the acquisition of the Standard Oil Company of Ohio, where he had worked since 1979. He became group treasurer in 1992 and in 1994 regional chief executive in Latin America. In 1999, he was appointed an executive vice president of Exploration and Production, and chief executive of chemicals in 2000. He was appointed an executive director of BP in 2000. Between 2002 and 31 December 2011 he was BP s chief financial officer. In January 2012 he became executive vice president, corporate business activities. He is a non-executive director of Unilever NV and Unilever PLC.

B R Nelson

Member of the chairman's committee and chairman of the audit committee

Brendan Nelson (62) joined BP s board on 8 November 2010. He is a chartered accountant and was admitted as a partner of KPMG in London 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 is a non-executive director of The Royal Bank of Scotland Group plc where he is chairman of the group audit committee. He is Vice President of the Institute of Chartered Accountants of Scotland, a member of the Financial Reporting Review Panel and a director of the Financial Skills Partnership.

F P Nhleko

Member of the chairman s and audit committees

Phuthuma Nhleko (51) joined BP s board on 1 February 2011. He began his career as a civil engineer in the United States 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, as group president and chief executive officer in 2002. He stepped down as group chief executive of MTN Group at the end of March 2011 and became vice-chairman of the MTN Group and chairman of MTN International. He is a non-executive director of Anglo American plc.

A Shilston

Member of the chairman s and audit committees

Andrew Shilston (56) 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. Andrew has served as a non-executive director on the boards of AEA Technology plc and Cairn Energy plc where he chaired the remuneration and audit committees. He recently joined the board of Circle Holdings plc as a non-executive director. He will become senior independent director at the conclusion of the 2012 AGM.

Senior management

M Bly

Mark Bly (52) joined BP in 1984. Following various engineering and commercial leadership assignments he held business unit leader posts in Alaska and the North Sea and was strategic performance unit leader for BP's North America Gas business. In 2007, he became group vice president, Exploration and Production and a member of the exploration and production operating committee. In 2008, he became group head of safety and operations and in October 2010 he was appointed executive vice president of safety and operational risk.

R Bondy

Rupert Bondy (50) joined BP as group general counsel in 2008. In 1989, he joined US law firm Morrison & Foerster, working in San Francisco and London. From 1994 to 1995, 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, he was appointed senior vice president and general counsel of GlaxoSmithKline in 2001.

Dr M C Daly

Mike Daly (58) joined BP in 1986 as a technical specialist in structural geology, subsequently joining BP s global basin analysis group. After a series of exploration business and functional roles in South America, the North Sea and new business development, in 2000 he became president of BP s Middle East and South Asia businesses. In 2006, he was appointed BP's head of exploration and new business development and in October 2010 he was appointed executive vice president, exploration.

R Fryar

Bob Fryar (48) joined Amoco Production Company in 1985, serving in a variety of engineering and management positions in the onshore US and deepwater Gulf of Mexico. In 2003, he was appointed vice president of operations performance unit for BP Trinidad and later, in 2009, he became chief executive officer for BP Angola. In October 2010, he was appointed executive vice president, production.

A Hopwood

Andy Hopwood (54) joined BP in 1980 as a petroleum engineer. Following a series of operational and corporate planning roles, in 1999 he was appointed business unit leader in Azerbaijan, returning to London in 2001 as the upstream chief of staff. He became strategic performance unit leader for BP s North America Gas business in 2004, returning to London in 2009 as head of portfolio and technology for BP's upstream businesses. In October 2010, he was appointed executive vice president of strategy and integration.

B Looney

Bernard Looney (41) joined BP in 1991 as a drilling engineer, working in a variety of roles in the North Sea, Vietnam and the Gulf of Mexico and later in the exploration and technology group. In 2005, he became senior vice president for BP Alaska, before moving to be head of the group chief executive s office. He was appointed vice president for Norway and infrastructure in 2008 and then, in 2009, he became managing director of BP s North Sea business. In October 2010, he was appointed executive vice president, developments.

H L McKay

Lamar McKay (53) was appointed chairman and president of BP America, Inc. in 2009. He joined Amoco Production Company as a petroleum engineer in 1980. He held a variety of roles before becoming group vice president for Russia and Kazakhstan in 2003, also being appointed to the board of TNK-BP in 2004. In 2007, he was appointed senior group vice president of BP and executive vice president of BP America. In early 2008, he became executive vice president of BP p.l.c. special projects, focusing on Russia, subsequently joining the group executive management team. In October 2010, in addition to his current duties, he was appointed president and chief executive officer of the Gulf Coast Restoration Organization.

D Sanyal

Dev Sanyal (46) 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 2003, he was appointed chief executive officer of Air BP following which in 2006, he became 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. He was appointed an executive vice president and group chief of staff with effect from 1 January 2012.

Dr H Schuster

Helmut Schuster (51) joined BP in 1989. He held a number of roles working in most parts of refining, marketing, trading and gas and power in the US, UK and Continental Europe. In 2007 he became vice president, human resources for Refining and Marketing in BP and in 2010 he added corporate and functions to his portfolio. On 1 March 2011 he became group human resources director and a member of BP s executive team.

Directors interests

The figures below indicate and include all the beneficial and non-beneficial interests of each director of the company in shares of the company (or calculated equivalents) that have been disclosed to the company under the Disclosure and Transparency Rules as at the applicable dates.

Current directors	At 31 Dec 2011	At 1 Jan 2011	Change from 31 Dec 2011 to 1 Mar 2012
C-H Svanberg	933,971	925,000	
R W Dudley	287,945[a]	280,799[a]	49,356
P M Anderson	6,000[a]	6,000[a]	
F L Bowman	12,720[a]	2,520[a]	
A Burgmans	10,156	10,156	
C B Carroll	10,500[a]	10,500[a]	
Sir William Castell	82,500	82,500	
I C Conn	425,169[b]	339,637[b]	72,332
G David	579,000[a]	159,000[a]	
I E L Davis	10,391	10,000	
Dr B E Grote	1,394,819[c]	1,372,643[c]	89,784
B R Nelson	11,040		
Directors leaving the board	At resignation/ retirement	At 1 Jan 2011	
D J Flint	15,000[d]	15,000	
Dr D S Julius	15,000[d]	15,000	
Directors joining the board	At 31 Dec 2011	On appointment	Change from 31 Dec 2011 to 1 Mar 2012

Professor Dame		
Ann Dowling	[e]	
Dr B Gilvary	236,029[f]	95,059
F P Nhleko	[g]	
A Shilston	[f]	

a Held as ADSs.

b Includes 48,024 shares held as ADSs at 1 January 2011 and at 31 December 2011.

c Held as ADSs, except for 94 shares held as ordinary shares.

d On retirement at 14 April 2011.

e On appointment at 3 February 2012.

f On appointment at 1 January 2012.

g On appointment at 1 February 2011.

The following performance shares were awarded on 9 March 2011 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.

Director	Potential maximum performance shares 2011 EDIP awards
R W Dudley[a]	1,330,332
I C Conn	623,025
Dr B E Grote[a]	785,394

a Held as ADSs.

Additional details regarding performance shares awarded can be found in the Directors remuneration report on page 149.

Executive directors are also deemed to have an interest in such shares of the company held from time to time by the BP Employee Share Ownership Plan (No. 2) to facilitate the operation of the company s option schemes.

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.

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Corporate governance

Over this coming year we will maintain focus, discipline and follow through at the board as we continue to deal with a volume of issues.

Corporate governance

Board performance report

Dear shareholder,

In my letter to shareholders earlier in this report I have endeavoured to give an overview of the challenges which the company has faced in 2011 and the work of the board in meeting those challenges.

In this letter, and in the report which follows, my aim is to give shareholders, and indeed all those with whom the company interacts, a deeper insight into the evolution of the BP board, the review which it has undertaken and the changes that have been made, and which are continuing to be made, to govern your company at the highest standard.

BP has a clear system of governance based upon the BP board governance principles. This serves BP and its board well. It is vital that the system of governance, what the board does, evolves with the company and with the thinking of those charged with its governance.

The tragic events in the Gulf of Mexico require that the board consider how it operates; however the substantial change in directors has meant there have been new views on the role of the board. This has resulted in the evolution that I have mentioned. In undertaking strong governance of the company, I believe that the board should provide leadership and challenge, but also support to executive management. In its activities this year, the board has strived to achieve this role.

The tasks of the board set out later in this report have not and will not change. It was clear though that a board which governs a company of the scale and scope of BP needs to have a clear view of its role and the steps it can take to support or challenge and the information which it needs.

The board is initiating modifications in all of these areas and will keep those changes under review. The actions from this work are important as we operate a system of governance throughout the company. The framework for how the board works is articulated in our board governance principles, available on our website at *bp.com/governance.*

Over this coming year we will maintain focus, discipline and follow through at the board as we continue to deal with a volume of issues. Looking forward into 2012, one of our aims is to get back into a steady rhythm of board meetings. We hope to do this through strengthening our forward agenda and board planning processes. We will also maintain our focus on the skills and experience of our directors, the composition of our board and succession planning.

Diversity within UK boards was a topic of debate in 2011 and will remain so going forward. BP is a company with global reach and we believe that it is important to have a board that is diverse in the widest sense; the company remains committed to meritocracy as well as to diversity. As part of the update of our board governance principles we have included a policy on board diversity. At the time of writing we have 12.5% female representation on the board. Our goal is to increase the number of women on the board to three by 2013 and to work towards 25% representation by 2015.

In the governance report which follows we have outlined key elements of the activities of the board and its committees during the year.

Carl-Henric Svanberg

Chairman

How the board works

BP s governance framework

BP s system of governance begins with the board and continues into 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.

The board s core activities include:

- The active consideration of long-term strategy.
- The monitoring of executive action and the performance of BP.
- 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.
- Ongoing board and executive management succession.

In all its work the board sets the tone from the top for the organization by considering specific issues, including health, safety, the environment and BP s reputation and working with management to set the values of the company.

During 2011 the board undertook a review of its corporate governance model. A working group consisting of the chairman and three non-executive directors (Paul Anderson, Antony Burgmans and Cynthia Carroll) examined key aspects of BP s system of governance, including the system of delegation, board processes, information, risk and the tasks and role of the committees. During the review, input was sought from board members and from executive management, both through board and working group discussions and individually through our board evaluation process.

The review concluded that BP s system of governance is robust but that further clarity on board processes would help reinforce the board s delegation to the group chief executive and strengthen the board s monitoring and assurance role.

Who s on the BP board?

The composition of the board and the mix of knowledge, skills and experience that our directors bring to the company is a key area of focus for the nomination committee. The committee keeps this mix under review and regularly maps the skillset of our existing board membership against the likely tenure of individual directors. This is viewed against the potential demands placed on the board due to developments in our strategy and business activities. Further detail 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 later in this section.

Full biographies of our board members can be found on our website.

Succession: board and committee membership

Since the beginning of 2011, the following changes have taken place to the composition of the board:

- Phuthuma Nhleko joined the board as a non-executive director on 1 February 2011.
- Dr DeAnne Julius and Douglas Flint retired from the board at the AGM in April 2011.
- Dr Brian Gilvary joined the board as an executive director and chief financial officer (CFO) on 1 January 2012.
- Andrew Shilston joined the board as a non-executive director on 1 January 2012.
- Professor Dame Ann Dowling joined the board as a non-executive director on 3 February 2012.

Dr Byron Grote stepped down as CFO at the end of 2011 but will remain on the board as an executive director during 2012, with responsibility for BP s integrated supply and trading operations, Alternative Energy, shipping, technology and remediation activities.

Sir William Castell has decided not to seek re-election at this year s AGM and will retire from the board at the meeting. Andrew Shilston will succeed Sir William as the senior independent director from the 2012 AGM and will be available to shareholders who have concerns that cannot be addressed through normal channels. He will work closely with

Antony Burgmans who, given his length of service on the board, will respond to any internal board matters, act as a sounding board for the chairman and serve as an intermediary for other directors if necessary.

Sir William stepped down as chairman of the safety, ethics and environment assurance committee (SEEAC) and Paul Anderson became its chairman from 9 December 2011.

Ian Davis stepped down as a member of the audit committee on 3 February 2012 and Frank Bowman joined the Gulf of Mexico committee on the same date.

Neither the chairman nor the senior independent director are employed as executives of the group. The board maintains a succession plan for the chairman and senior independent director, in addition to the group chief executive and senior management.

Appointment and tenure

The chairman and our non-executive directors (NEDs) serve on the basis of letters of appointment. BP does not place a term limit on director s service as we propose all directors for annual re-election by shareholders (a practice we have followed since 2004).

The governance principles require our 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 2011 fulfilled this requirement and were 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 board meetings. 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. The

committee may make recommendations to the board if it concludes that a director s other commitments are inconsistent with those required by BP.

Time commitment and outside appointments

Letters of appointment for non-executive directors do not set out a fixed time commitment for board duties as we believe that the time required by directors may fluctuate depending on demands of the business and other events. However, it is expected that directors will allocate sufficient time to the company to perform their duties effectively. The chairman s appointment letter sets out the time commitment expected of him.

Following an approach from the Volvo Group, the chairman discussed with the board, through the chairman s committee, whether to take an additional post as a part-time non-executive chairman of Volvo. During this process, our senior independent director led a discussion of non-executive directors without the chairman present to hear their views. The board concluded that Mr Svanberg has sufficient time to carry out both commitments and supported the chairman taking on this additional role. The chairman will step down from his existing non-executive directorship at Ericsson before assuming the chairmanship of Volvo in April 2012; he also confirmed to the board that he does not intend to seek any additional roles outside those at BP and Volvo.

Executive directors are permitted to take up one external board appointment, subject to the agreement of the chairman and provided such external appointment is reported to the BP board. Fees received for an external appointment may be retained by the executive director and are reported in the Directors remuneration report.

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 our operations and has in place a wide range of activities to support the development and promotion of talented individuals, including women.

During the year, the board responded to Lord Davies report on gender diversity and confirmed its goal to increase the number of women on the BP board to three by 2013 and work towards the recommendation of 25% female representation by 2015. With the appointment of Professor

Dame Ann Dowling, BP currently has two female board members, equating to 12.5% of our directors.

The board has agreed a board diversity policy which will be included in our board governance principles. The policy states that when considering the composition of the board, directors will be mindful of diversity, inclusiveness and meritocracy. As part of its workplan for this year, the nomination committee will develop and agree a set of measurable objectives for implementing this policy and report back on these to shareholders.

Induction and board learning

On joining BP non-executive directors are given a tailored induction programme. This programme includes one-to-one meetings with senior management, our auditors and site visits to our operations. The induction will also cover the board committees that a director will join. An example of the initial induction programme for one of our recently joined non-executive directors is set out below.

Director induction programme

Board and governance

BP s board governance model, directors duties, interests and potential conflicts.

Committee induction.

Strategy and planning.

Group investor event on governance and board activities.

BP s business

History of the integrated oil company and BP.

Upstream (exploration, development, production, overview of our operations).

Refining and Marketing.

Alternative Energy.

Functional input

Controls, external auditors and internal audit.

Finance and corporate reporting.

HR.

Legal.

Ethics and compliance.

Safety and operational risk (S&OR), BP s operating management system (OMS) and environmental performance.

Research and technology.

Engineering.

We continue the board s learning through board and committee events. At our May 2011 board meeting in Houston, we ran a day-long event to give our non-executive directors an insight into how BP manages its learning and capability development, including briefings on seismic interpretation, the company s technical education programme and trading. Non-executive directors are expected to attend at least one site visit per year. During 2011, such visits included Texas City and Whiting refineries with the independent expert, L. Duane Wilson, an offshore visit to the Gulf of Mexico, visits to global wells organization leadership teams in the Gulf of Mexico and the North America gas business, our business centre in Budapest and BP s offices in Houston and Canary Wharf. During the year our chairman visited BP s operations in Alaska and our oil sands projects in Canada.

Board effectiveness

Board evaluation

We undertake an annual review of the board, its committees and individual directors. The chairman undertakes the evaluation of individual directors, with the chairman s own performance evaluated by the chairman s committee (led by the senior independent director).

In 2009 and 2010, we undertook an external review of the board s performance. In 2011, we decided to continue external facilitation as a

way of building on the past year s results and providing a robust, third-party insight into the board s effectiveness. To enable continuity and comparability of results over the two year period, we used the same external facilitator as for the 2010 review.

Evaluation process for 2011

Each director (with the exception of those appointed in 2012) was sent a questionnaire and a list of discussion topics.

The facilitator held one-to-one reviews with each participating director, using the questionnaire and discussion topics as a starting point.

Each committee held its own review using online questionnaires that were developed by us using an externally generated question bank. The results from these questionnaires were then discussed with the external facilitator by each committee (these are outlined in the reports of our committees).

A paper on the key themes and views from the one-to-one reviews and the evaluation of the committees were sent to the board to review.

The board held a discussion with the external facilitator to assess these views and the issues raised.

The board agreed on actions for the forthcoming year based on this discussion.

Key conclusions of the 2011 evaluation

The review concluded the board had operated well in 2011. It had been an eventful year and the board continues to deal with events from the Gulf of Mexico. There was a strong view that the board had an open and transparent style of discussion, with good engagement and contribution from all members, particularly around strategic planning and risk management. The board also considered that its focus, discipline and follow through had strengthened over the year, which was seen as important given the events of the previous 18 months and the volume of issues dealt with by the board. It hoped to continue this trend in 2012.

The review also found that there was potential for continuous improvement in areas such as board materials (including the length of papers) and agendas, and that as the board endeavours to move back into a steady state of operation, it would need to revisit its collective expectation around governance processes and style.

Tracking issues from our previous evaluation

Over 2011, the board acted upon the recommendations from the 2010 board evaluation. The board determined to conduct additional site visits and participate in detailed briefings in order to gain further insight into the company s operations and activities which it achieved through an active programme over the year attended by individual or groups of directors. The board set up a working group to review and revise the company s board governance principles to ensure that BP s governance processes were effective. The board also reviewed BP s crisis and continuity plan, including specific focus on the process through which board involvement is triggered as part of its action to clarify the board s role in the crisis planning process. Finally, the board had extensive engagement with executive management in forward-looking strategy discussions and an overview of BP s risk management systems.

Risk management: from operations to the board

One of the board s tasks 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, through its governance principles, 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. Authority for the design and implementation of this system of internal control is delegated by the board to the group chief executive. Components of our system of internal control (which includes the risk management system) are management systems, organizational structures, processes, standards and behaviours employed to conduct the business of BP.

Risk management in BP is a top-down and bottom-up process. The bottom-up process starts at the day-to-day level with businesses and functions identifying and managing their risks using existing company standards and practices, e.g. OMS. The most significant risks are organized into common categories strategic risks, safety and operational risks and compliance and controls risks so they can be reported up the line in a standardized form.

During the year a review of BP s risk management system was initiated which has built on our current system of risk management. Using the findings of this review, BP has started to implement enhancements to drive consistency and clarity in how risks are reported and understood in all levels of our organization from operations to the board. *See Our management of risk on page 42* for further discussion of the risk management system and 2011 review.

Within BP s risk management system, functions set standards, provide guidance and provide a view of group risks in their functional area of expertise, independent of line management. Certain functions also deliver assurance that the activities to manage the risks are working as intended in the businesses.

Group risks are allocated to one of the committees established by the group chief executive for management and monitoring. These executive level committees are sub-committees of our senior management team and their role includes setting policy, making decisions and overseeing the management of risks and performance. The executive committees are:

- Group operations risk committee (GORC) for risks of a safety, environment or operations nature.
- Group financial risk committee (GFRC) for finance and trading risks.
- Group disclosure committee (GDC) for financial reporting risks.
- Group people committee (GPC) for people risks.
- Resource commitments meeting (RCM) for risks related to investment decisions.

At the group level, risk is examined by the board to apply a top-down perspective. The group risks identified as requiring particular oversight in the coming year are selected for discussion with the board. These are then allocated for review by the board or one of its committees. A common agenda for the review is established to enable the board or committee to discuss risk in a consistent manner with executive management.

The board examines group risks both on a periodic basis and as part of its 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 board and its committees, in the event there are any changes to the internal or external environments or events arising.

Following its review of the 2012 annual plan, the risks described above have been allocated for review by the board and its committees as follows:

- The board has been allocated several strategic and safety and operational group risks, including risks associated with the macroeconomic outlook, the delivery of the 10-point plan, the group s exposure to Russia, crisis management, reputational impact and the recruitment and development of staff.
- The audit committee has been allocated a number of compliance and control and safety and operational risks, including risks associated with treasury and trading activities, compliance with applicable laws and regulations and security threats against our digital infrastructure.
- The safety, ethics and environment assurance committee has been allocated several safety and operational and strategic risks, including risks associated with conducting our operations through joint ventures or associates and through contracting and sub-contracting arrangements where BP may not have full operational control. Other safety and operational risks the committee have been allocated include the health, safety and environmental risks of incidents associated with the drilling of wells, operation of facilities and transportation of hydrocarbons.
- The Gulf of Mexico committee has been allocated a number of strategic risks, including risks associated with the extent and timing of costs and liabilities relating to the incident and the possible impact on our licence to operate.

Board activities during 2011

2011 was another active year for the board, which met 15 times. The board s focus remained on the incident in the Gulf of Mexico both to understand what happened and how the company can apply the lessons learned. Within the board and its committees, debate and assurance has been ongoing with management on key aspects such as the impact on the group s reputation, accounting treatment and provisioning, implementation of the recommendations of the Bly Report and the legal and communication strategy for litigation arising from the incident. The challenge has remained for the board to ensure that it devoted enough time to the ongoing business of the company whilst holding these important discussions. Periodic meetings throughout the year of the non-executive directors comprising the chairman s committee, together with liaison between the chairman and the chairs of the board committees, have assisted in managing this challenge. Areas discussed by the board included the following:

Strategy

The board is engaged at the early stages of discussion on strategy and the annual plan in order to provide constructive challenge. During the year two day-long meetings were held for strategic discussions. After the February 2011 update to the market the board continued to develop the company s strategy with respect to milestones and deliverables, resulting in a further market update in October on the company s 10-point-plan . Over the year, the board considered key strategic elements, including biofuels, Canadian heavy oil and the company s disposal programme. The board also spent considerable time discussing strategic opportunities and implications of the strategic alliance that had been proposed with Rosneft and the new relationship with Reliance.

Corporate governance

Assurance

The board undertook a number of activities as part of its assurance role, including assessing the effectiveness of the company's system of internal controls and risk management. The group s financial performance was considered, as was a review of BP s technology function and the performance and role of the technology group within the outlook for energy demand and supply.

The board received an overview of BP s activities in the US and received several updates during the year on legal issues, in particular on litigation and enquiries resulting from events in the Gulf of Mexico. The board discussed the UK Bribery Act and the steps the company was taking to comply with the Act; as a result of this discussion the board endorsed the updated anti-bribery policy outlined in BP's code of conduct.

L. 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, presented his fourth annual report to the board where he assessed BP's progress against the Panel s 10 recommendations. Further details of Mr Wilson's work are outlined in the report of the SEEAC and his report is published on BP s website at *bp.com/independentexpert.*

Risk

The board discussed the progress and outcome of the review of BP s risk management system over the year. The outcome of the review has resulted in clearer and more consistent reporting, definitions and templates for BP s risk management activities, as well as greater alignment of these risk management activities with existing BP business processes.

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 2010. The annual plan and the group strategy are central to our 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.

Reputation

The board considers reputation from two perspectives the reputational risks to the group and the processes the company has in place to manage these risks. During the year, the board reviewed external reputation data which looked at BP's reputation in the UK and US. It also discussed the group s communications strategy and its reputation management plan.

BP s group-wide renewed values were launched in 2011 as part of a programme of change called We are BP , by which the renewed values will be reflected in how employees performance is assessed and rewarded. The renewed values were also embedded within the updated code of conduct.

Governance

As described above, over the year the board reviewed its system of board governance and established a working group to assist in this process. The main outcomes of the review were strengthened board processes around information, risk and revisiting the role and tasks of the board and its

committees.

The board seeks to understand the views of its shareholders, and feedback from investors is given to the board either directly following meetings with the chairman or other board members or indirectly through an annual investor audit undertaken by a third party. Following our AGM in April 2011, the board examined the voting results for each resolution and considered the comments received from institutional investors to explain their voting position.

Shareholder engagement

The company continued its open dialogue with shareholders. Our executive directors and members of our executive management team held investor meetings following our strategy and financial results. We also held meetings on operating and non-financial issues, including presentations on BP s *Energy Outlook 2030,* an update on BP's activities in Canadian oil sands, our Alternative Energy and Refining and Marketing businesses and BP s environmental and social requirements for new projects. These events were intended to give shareholders a wider perspective on the company's thinking behind its strategy and an understanding of the processes and standards we use to underpin our operations.

The chairman, senior independent director and chair of our remuneration committee held a number of one-to-one meetings with institutional investors to discuss strategy, the board s view on the company's performance and governance and our remuneration structure. In addition the chairman, with two members of our senior executive team, spoke at group investor events in the US and UK to outline the company s progress on the Bly Report recommendations, the remit and work of the safety and operational risk function and the work of the board. In March 2011 we held our annual investor event with our chairman and the chairs of our board committees. We continue to receive positive feedback on this event and find it an effective way for our largest shareholders to hear about the work of our board and our committees, and for our non-executive directors to engage in dialogue with investors. We intend to hold a similar event in March 2012.

During the year we focused on enhancing communication with our private shareholders, including a revision of dividend materials and the shareholder information pages of our website. We continued our 'lost shareholder' programme which returns shares and unclaimed dividends to shareholders who have failed to keep their contact details up to date. Materials from our investor presentations, including information on the work of our board and its committees can be downloaded from the investors page of our website.

Board and committee attendance in 2011

	Board		Audit committee*		SEEAC*		Remuneration committee		Gulf of Mexico committee		Nomination committee		Chairman s committee	
	a	b	a	b	a	b	a	b	a	b	a	b	a	b
Non-executive directors:														
Carl-Henric Svanberg	15	15									5[c]	5	9[c]	9
Sir William Castell	15	15			9[c]	9			16	14	5	5	9	9
Paul Anderson	15	14			9	9			16	16			9	9
Frank Bowman	15	15			9	9							9	8
Antony Burgmans	15	15			9	7	7[c]	7			4	4	9	9
Cynthia Carroll	15	13			9	7					4	3	9	8
George David	15	14	11	11			7	7	16	16			9	9
Ian Davis	15	15	11	10			7	7	16[c]	16	5	5	9	9
Douglas Flint	8	7	5[c]	5							1	1	3	3
DeAnne Julius	8	8					2[c]	2			1	1	3	3
Brendan Nelson	15	13	11[c]	11									9	8
Phuthuma Nhleko	15	13	7	6									8	8
Executive directors:														
Bob Dudley	15	14												
lain Conn	15	14												
Byron Grote	15	15												

a Total number of meetings the director was eligible to attend.
b Total number of meetings the director did attend.
c Committee chairman.
* Attendance for audit committee and SEEAC includes a joint meeting between the two committees. NB: The chairman also attends meetings of the remuneration and Gulf of Mexico committees.

AGM

We continue to have a well-attended annual general meeting, usually attracting over a thousand people. Our shareholder base is geographically diverse and we offer a webcast and advance voting to make our meeting accessible to those who cannot attend in person.

The voting levels for our 2011 AGM saw a moderate increase over 2010 levels to 60.6% (59.6% in 2010). Viewers of our 2011 AGM webcast increased by fivefold over the previous year. We make our webcast, speeches and presentations from the AGM available on our website after the meeting, together with the outcome of voting on each resolution.

International advisory board

In 2009, BP formed an international advisory board (IAB) whose purpose is to advise the chairman, group chief executive and our 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 our previous chairman, Peter Sutherland. Its membership in 2011 included Kofi Annan, Lord Patten of Barnes, Josh Bolten, President Romano Prodi, Dr Ernesto Zedillo and Dr Javier Solana. Our chairman and chief executive attend meetings of the IAB. Issues discussed during the year included developments in the eurozone, events in the Middle East and the world energy outlook.

UK Corporate Governance Code compliance

BP complied throughout 2011 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 the 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).

Committee reports

Audit committee

Chairman s introduction

In the first quarter of the year the committee, under Douglas Flint s chairmanship, continued to spend considerable time reviewing and challenging BP s assessment of its financial responsibilities relating to the tragic incident in the Gulf of Mexico in April 2010. This task has remained a key area of focus under my chairmanship during the remainder of the year. We have continued to seek assurance that where liabilities are estimable, they are fully provided for, and where uncertainty is too great to support a provision that appropriate disclosure is made. Some greater clarity developed during the year as experience was gained about the operation of the Deepwater Horizon Oil Spill Trust fund, and as settlements were reached with two of the partners in the Macondo well and two of the contractors involved. However, as reported elsewhere in this document, major uncertainty remains in respect of litigation, potential fines and penalties and other matters which will require significant attention from the audit committee for the foreseeable future. The committee has therefore taken care to preserve its regular agenda content so as to continue fulfilling its remit to the board with respect to monitoring risk management systems and internal controls and financial reporting.

Amongst other topics, we have reviewed controls in trading, debt and liquidity management and the company s response to the UK Bribery Act. During the course of the year, I have also participated in the group chief executive s audit forum and the group financial risk committee (GFRC). In preparation for audit committee meetings, I have met regularly with the chief financial officer, general auditor and the lead partner of the external auditors. I also spent time with the leadership team of the internal audit function.

I valued the time I took to visit one of the company s largest data centres in London, its European business service centre in Budapest, and the trading floors in Houston and London. Such visits and interaction with staff at all levels of the organization enhance both our understanding of the company s activities and our assurance over the way they are being managed.

Although we lost Douglas Flint from the committee when he stepped down from the board, I am delighted that Andrew Shilston has now joined us. Andrew s experience as the CFO at Rolls Royce, and his previous background in the energy business, complements the skills already present in the committee s membership. I believe we have a very good mix of commercial, financial and audit expertise to address the complex accounting, audit and risk issues which the committee monitors. I would also like to thank Ian Davis for his contribution to the audit committee over the last two years. Ian is now stepping down from the committee in anticipation of a period of heavier workload related to the Gulf of Mexico committee.

Our report below seeks to highlight the key activities undertaken in 2011 and provide some insight into the outcomes of the committee s work. I believe 2012 will be equally intense but the committee is well equipped to address the tasks it faces.

Brendan Nelson

Chairman of the audit committee

Committee members

Brendan Nelson committee chair (from 14 April 2011)

George David

Ian Davis (retired from the committee on 3 February 2012)

Phuthuma Nhleko (appointed 1 February 2011)

Andrew Shilston (appointed 3 February 2012)

Members who left during the year:

Douglas Flint previously chair of the committee (retired 14 April 2011)

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 became chair of the audit committee upon the retirement of Douglas Flint from the board in April 2011. Mr Nelson, who was formerly vice chairman of KPMG, is chairman of the Group Audit Committee of The Royal Bank of Scotland Group plc, a member of the Financial Reporting Review Panel, Vice President of the Institute of Chartered Accountants of Scotland and a director of the Financial Skills Partnership. The board is satisfied that Mr Nelson, in succession to Mr Flint, 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 Mr 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 on our website. We keep these under review and test their effectiveness in our annual evaluation of the audit committee. In addition, the chairs and secretaries of the audit and safety, ethics and environment assurance committees have worked together to ensure their respective agendas neither duplicate nor omit coverage of key risk areas.

The committee met 11 times over the past year including one joint meeting with the safety, ethics and environment assurance committee (SEEAC). This joint meeting reviews the general auditor s report on internal control and risk management systems for the year in preparation for the board s report to shareholders in the annual report. It also reviews the general auditor s audit programme for the year ahead to ensure both committees endorse the coverage.

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 (Ernst & Young) is also present.

The committee also holds separate private sessions during the year with the external auditor and the general auditor these sessions are without the presence of executive management.

The board is kept updated and informed of the audit committee s activities and any issues arising through verbal reports at its meetings from the committee chair and the circulation of the committee s minutes.

Audit committee processes

Information and advice

Information and reports for the committee are received directly from accountable functional and business managers and from relevant external sources. In addition, like our board and other committees, the audit committee can access independent advice and counsel when needed on an unrestricted basis. During 2011, 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. The 2011 evaluation indicated that members recognized the openness and transparent nature of the materials and presentations provided by management.

Training and visits

In continuing to respond to the consequences of the Gulf of Mexico oil spill, the committee placed emphasis on receiving appropriate briefings on the relevant applications of accounting policy, particularly provisioning and related disclosure. The committee received regular technical updates from the chief accounting officer on developments in financial reporting and an annual briefing on oil and gas reserves disclosures. In addition the external auditors provided insight and commentary on international accounting policy developments.

Induction programmes are provided for new members and are tailored around their roles on the audit committee. During 2011 Brendan Nelson and Phuthuma Nhleko completed their audit committee induction programmes. This included 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. During 2012 we will undertake an audit committee induction for Andrew Shilston.

When the board visited Houston in May, audit committee members took the opportunity to visit the computing facility and the trading floor at the Westlake complex. During the May trip, two members of the committee, including the chairman, also visited the Atlantis offshore platform in the Gulf of Mexico. In July the committee visited the company s data centre in London to review IT service and security matters. Earlier in the year Mr Nelson accompanied SEEAC members on a visit to the Whiting refinery where they were briefed on the progress of the major modernization project. These visits enable the committee to see first-hand examples of risk management and to address questions directly to employees on site.

2011 Audit committee activities

Gulf of Mexico

The responsibilities of the board's monitoring committees in reviewing the company s response to the Gulf of Mexico incident have been carefully delineated. Whilst the Gulf of Mexico committee has considered the ongoing 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 incident and their disclosure. It has also received a report from the group controller on the status of financial controls in the GCRO.

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. In undertaking this review, 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 also reviewed the impairment testing process and the pricing assumptions that were utilized. In considering the robustness of the valuations the committee also referred to analysis undertaken by the external auditors. This year, with a number of assets held for sale, the committee was appropriately engaged in reviewing their accounting treatments. Further details on impairment reviews are included in the *Financial statements Note 5*. The committee also reviewed the company s methodology underpinning its disclosures relating to oil and gas reserves.

Monitoring business risk

As discussed elsewhere in this annual report, the board periodically reviews the company s group risks and allocates monitoring of their management and/or mitigation to itself or its committees. Within the audit committee s area of monitoring in 2011 were liquidity management, trading risk and corruption risk. During the year, the committee also undertook functional reviews of information technology and services, integrated supply and trading, business service centres and the governance and control of major project investment. Each year the committee also reviews risk, governance and the control environment relating to TNK-BP.

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 also received a joint report from the group controller and chief information officer on access controls and segregation of duties.

An important input into the board's review of the company s risk management and internal control systems is the annual joint meeting between the audit committee and the SEEAC. This takes place at the start of each year to review the general auditor s report on internal control and risk management systems for the previous year. The general auditor reviews his team s findings and management s actions to remedy significant issues identified in that work. His report also included information on the results of audit work undertaken by the safety and operational risk audit team and reviews by the group s finance control team. As noted earlier, this joint meeting also reviews the coming year's forward programme of audit work.

External auditors

In 2011 the committee held two scheduled meetings with the external auditors without management being present. These sessions provided the opportunity for direct feedback and dialogue between the committee and the auditors. In addition, the chair of the audit committee met privately with the external auditors before each audit committee.

Performance of the external auditors is evaluated by the audit committee each year. This year the committee put particular focus on assessing audit quality against a set of agreed key performance indicators. The company has also developed an auditor assessment tool which will be completed on an annual basis and apply 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 committee reviews the composition of the audit team annually and meets the relevant partners when undertaking business or function reviews. Additionally, the committee has the opportunity to assess specific technical capabilities in the audit firm when addressing specialist topics, such as environmental provisioning and impairment testing.

We maintain auditor independence 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 Principal accountants fees and services on page* 136. 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.

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.

Fees paid to the external auditor for the year were $55 million, of which 20% was for non-audit work (see *Financial statements Note 16).* Non-audit fees increased from $8 million in 2010 to $11 million in 2011 due to additional work undertaken in providing services related to corporate finance transactions. This increase resulted from Ernst & Young s engagement to carry out financial due diligence in connection with actual and proposed sales of assets in North America.

The audit committee considers both the fee structure and the audit engagement terms and monitors progress during the year. In October the committee reviewed with management the criteria which would trigger tendering the audit. The criteria considered were independence, quality of service, audit quality, cost/value for money and regulatory changes. The committee and management believe that assessed against each of these criteria there is no case for recommending going to tender this year. Nonetheless, preparatory work has been undertaken to understand the potential for other audit firms to participate in a tender should this be indicated at a future date. The committee has recommended to the board that the re-appointment of Ernst & Young as the company's external auditors be proposed to shareholders at the 2012 AGM.

Internal audit

The committee receives quarterly reports from the general auditor which enable the committee to monitor the progress of the internal audit against its planned schedule of audits as well as to track 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 programme for 2011 was approved by the committee in January 2011.

The general auditor met privately with the committee once during the year, without the presence of executive management or the external auditors. This is complemented by regular meetings with the committee chair between meetings.

The committee reviewed with the general auditor the number and expertise of his team s staff resources. The internal audit function provides a source of skilled staff to many parts of the company and to maintain its resources the general auditor recruits from both inside the company to bring in deep business expertise into the team and externally to bring professional auditing skills. The committee has sought assurance that these resources are sufficient to fulfil the function s role, and the general auditor has undertaken benchmarking work with other major companies in the industry. In addition, an external review on internal audit effectiveness has been undertaken in 2012. This review concluded that BP had an effective internal audit function that compared favourably with other complex and industry equivalents.

During 2011 the committee was satisfied that internal audit had the appropriate access it required to information and that management had committed to the provision of that information and had responded to the results of audit findings in a timely manner.

Other activities

The committee monitors fraud and misconduct through quarterly updates from the general auditor and any non-compliance with the BP code of conduct through quarterly reports by the group ethics and compliance officer. Actions arising are monitored to close out. The annual certification report of compliance with the code of conduct, which is signed by the group chief executive, is also reviewed by the committee.

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 are reviewed by the committee. The quarterly reports the committee receives track trends in both the case type and time taken to close out queries and reports.

Committee evaluation

Each year the audit committee examines its performance and effectiveness, and ensures that its tasks and processes remain appropriate. In 2011, the committee used an internally-designed questionnaire administered by external consultants. The same question set was used as in 2010 so that any trends could be identified. Key areas covered included the clarity of its role and responsibilities, the balance of skills among its members and the effectiveness of reporting its work to the board. Specific areas identified for focus in 2012 included trading, provisioning and the effectiveness of internal audit. Regarding process, members noted that fulfilling the committee s remit had led to lengthy meetings, but at the same time they recognized a wish to extend deep dives into specific topics. The committee noted that, in areas of common interest such as compliance and ethics, it needed to continue to work closely with the SEEAC. It also commented on the need for pre-read papers to be well focused to ensure best use of agenda time. Overall the committee considered it had the right composition in terms of expertise and had effectively undertaken its activities and reported them to the board during the year.

Safety, ethics and environment assurance committee (SEEAC)

Chairman's introduction

Whilst the Gulf of Mexico committee, as reported elsewhere in this document, has focused its work on the company s restoration activities in the Gulf area and on oversight of ongoing litigation, the SEEAC spent considerable time over the past year monitoring the group s response to the 26 recommendations that were made in BP's investigation report (the Bly Report) into the tragic incident in April 2010. Our role has been to seek assurance on behalf of the board that each of those 26 recommendations

is being pursued globally with pace and commitment. We have received progress reports at each of our meetings and made visits to meet key members of the teams in the exploration and production and S&OR organizations that are leading these changes. This included visiting an offshore platform to get closer to the front line, two in-depth discussions with managers in the Houston office and participating in management s wells inspection programme. We have put fresh emphasis on getting a deeper perspective into the organization. In part we have achieved this through individual committee members undertaking visits and meeting staff outside the boardroom environment and then reporting back to the committee at the first opportunity. We believe this approach both deepens our collective understanding of risk and of management s controls, and enables us to make more informed, and hence more valuable, challenges. We have endeavoured to follow this approach to all of our work undertaken throughout 2011. As always, for a committee reviewing management s assessment and mitigation of non-financial risk, this work has extended to a wide range of topics. The report below provides more detail but we would highlight our reviews of risks and risk management in pipelines, shipping and drilling. We have also taken a deeper look at risks in our petrochemicals business, including a visit by three members of the committee to the company s paraxylene manufacturing facility in Texas.

We have continued to be very well served by L. Duane Wilson s independent perspective of the company s response to the 'Baker Panel recommendations following the fire and explosion at the Texas City refinery in 2005. We will shortly be appointing a highly experienced individual to report independently to SEEAC on the implementation of the Bly Report recommendations.

Overall this has been a year of significant change which will take time to fully embed but we believe we have observed real and enduring progress.

In February 2012 we welcomed to the committee Professor Dame Ann Dowling who brings deep experience in technology and engineering.

We concluded during the year it would be appropriate for the SEEAC chairmanship to transfer to Paul Anderson once the restructuring and reorganization within the company was largely established. This introduction to the committee s report is therefore written by both of us. We share the same commitment to monitor closely, and provide constructive challenge to, management in its drive for safe and reliable operations at all times. We believe that the extensive breadth and depth of committee members experience will serve us well in the endeavour which is so central for a company whose business encompasses the production and distribution of hazardous materials.

Paul Anderson
Chairman (from December 2011)

Sir William Castell
Chairman (to December 2011)

Committee members

Paul Anderson committee chair (from 9 December 2011)

Sir William Castell committee chair (to 8 December 2011)

Frank Bowman

Antony Burgmans

Cynthia Carroll

Professor Dame Ann Dowling (from 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 nine times in 2011 including a joint meeting with the audit committee at 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 auditor s audit programme for the year ahead to ensure both committees endorsed the coverage. SEEAC also reviewed the planned work of the S&OR audit function and noted an enhanced focus on integrating audit work across the company. 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, each SEEAC meeting was attended by the group chief executive, the executive vice president for safety and operational risk, the general auditor and the external auditors. The general counsel also attended most meetings. The committee held private sessions for the committee members only (without the presence of executive management) at the conclusion of its meetings to discuss any issues arising and the quality of the meeting. Between meetings, committee members took opportunities to visit company sites and received informal briefings through the committee chair, the secretary, the external auditor s lead partner, the general auditor and executive management.

SEEAC 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. During the year, the main external input into the committee has been from L. Duane Wilson, the independent expert (for *further information, see the section on independent expert below).* As for the board and other committees, SEEAC can access any other independent advice and counsel if it requires, on an unrestricted basis.

Training 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 the operations academy at MIT in Boston. A key area of focus has been following up on the implementation of the Bly Report s 26 recommendations and on the progress of the new S&OR function. In March the chairman and secretary visited Houston to discuss how S&OR management was being embedded in the upstream production and development divisions and committee members made a further visit to Houston in January 2012. In 2011, a committee member also participated in an S&OR leadership event in London. Another committee member accompanied the executive vice president for developments on two inspection visits to oil and gas wells leadership teams. In May the committee travelled offshore to the Atlantis platform in the deepwater Gulf of Mexico, and also visited the upstream learning centre in Houston to see the capability development activity being undertaken and its global reach.

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 March two members of the committee visited the Whiting refinery, accompanied by the independent expert, Mr Wilson, to review progress in risk management systems and OMS implementation. In January 2012 members of the committee revisited Texas City refinery, again accompanied by Mr Wilson. This followed previous committee visits in March 2010, April 2008 and September 2007. During this visit, committee members also visited the nearby petrochemicals facility to follow up on presentations it had received in May and October and to gain plant level experience, as well as to observe the extent to which the BP US Refineries Independent Safety Review Panel recommendations had been implemented in the petrochemicals context.

In addition to the extensive learning experiences provided by these visits and meetings with executive management, induction programmes are organized for new members of SEEAC. Frank Bowman, who joined the committee in November 2010, completed his induction programme in 2011.

2011 SEEAC activities

Safety, operations and environment

The committee receives 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 include 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. In 2011, the committee put particular focus on gaining assurance that the new S&OR organization was developing as envisaged. The S&OR function has intervention rights in all aspects of the group's technical and operational activities, including key investment decisions 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. The committee was satisfied with the progress being made but will continue to monitor this in 2012 along with the enhancement of standard practices and processes within OMS.

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 from the executive vice president for developments, at five of its 2011 meetings. The BP board has identified an independent expert to provide further oversight and assurance regarding the implementation of the Bly Report recommendations. The engagement of the independent expert is expected to commence in the latter half of May 2012. The independent expert will report directly to the board. He will track BP s progress in implementing the 26 recommendations from the company's internal investigation of the Deepwater Horizon oil spill and will independently assess the safety, health and environmental work of global drilling operations. He will give regular updates directly to the SEEAC.

During the year the committee received specific reports on the company s management of risks in shipping, wells and pipelines. The potential environmental consequences of loss of containment in these activities gave particular focus to the approaches to risk management employed. These included design, such as double bottomed hulls in tankers, and training, such as drilling simulators and naval cadet training programmes. The committee noted that all new projects in environmentally sensitive areas are submitted to the requirements of the company's environmental and social review process.

When a fatality in the workforce occurs the committee reviews the incident in depth before reporting back to the board. The committee also reviews 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.

Independent expert

Since L. Duane Wilson s appointment by the board in 2007 as an independent expert to provide an objective assessment of BP s progress in implementing the recommendations of the BP US Refineries Independent Review Panel, he has presented to the committee at least four times a year in person. His role has been to assist the company in improving process safety performance at BP s five US refineries. Annually the committee approves his work plan for the year ahead and receives a full written report which is made public on the company s website. In his last verbal report Mr Wilson advised that he had observed continued progress in process safety performance at each visit he has made to the five refineries. He also discussed work remaining to be completed and areas requiring special emphasis. As process safety performance has reached higher levels in recent years, he noted that the rate of change has naturally slowed, but site metrics continued to demonstrate improvements. Mr Wilson also 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 towards process safety leadership. Mr Wilson's reports are published in full and available on our website at *bp.com/independentexpert.*

Regional and functional reports

Each year the committee receives a report on the progress made in HSE at TNK-BP, noting however that formal oversight of 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 monitor progress regularly.

The committee continued to receive reports on the joint venture operations in Iraq, and in particular was briefed by the company s head of security on the risks and management of security in Iraq. As mentioned above, the committee reviewed the company s shipping activities in 2011 and was briefed on the function s response to the threat of piracy in the waters off the Somali coast.

The committee also examined quarterly audit reports from BP s internal audit and safety and operational risk functions which highlighted key findings and material actions arising from audits which had taken place at segment, functional and regional levels and tracked their close out. During the year the committee also received written reports from the group ethics and compliance officer.

Activities from the executive-level group operations risk committee (GORC) are reported to the SEEAC by the group chief executive and executive vice president S&OR at each meeting. Improved co-ordination of agenda planning was achieved to facilitate executive management level review of key risk topics prior to board level review at SEEAC. The SEEAC also received regular updates on the company s interaction with regulatory agencies.

Committee evaluation

For its 2011 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 as used in 2010 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.

In 2010 the committee had concluded that it should increase its site visits and training. In 2011, as reported above, the committee believed it had increased these activities significantly and agreed it should continue to do so in 2012. It also noted that given its broad remit across non-financial risk, it would need to continue to balance that breadth with heightened focus on specific risk and performance topics. It viewed its increased use of member visits and briefings as important tool towards achieving that heightened focus. Overall the committee considered that its current membership provided a well-balanced and experienced resource, and also noted the valuable contribution made by Mr Wilson in his capacity as the independent expert.

Gulf of Mexico committee

Chairman s introduction

The Gulf of Mexico committee was very active in 2011, meeting 16 times over the course of the year. In addition to overseeing efforts to mitigate the effects of the spill, the company s strategy for resolving claims, and actions to restore the group s reputation, the committee focused a considerable portion of its attention on legal matters. Some of these legal matters included settlements reached with BP s partners in the Macondo well and various contractors, preparations for the upcoming trial in the Multi-District Litigation and ongoing governmental investigations.

We have been joined in meetings by the leadership, management and counsel of the Gulf Coast Restoration Organization (GCRO), which was formed in mid-2010 to manage the company s long-term response to the tragic Deepwater Horizon oil spill. The committee members understanding of the important issues and numerous interdependencies has been facilitated by the frequency of meetings and the breadth of topics covered.

I believe the committee has maintained a rigorous approach to its work, providing effective oversight on behalf of the board, to which reports are provided following committee meetings. The report below summarizes the activities of the committee in 2011. I anticipate 2012 will be an equally demanding year but the committee is well prepared to conduct its tasks.

Ian Davis

Gulf of Mexico committee chair

Committee members

Ian Davis committee chair

Paul Anderson

Frank Bowman (joined the committee 3 February 2012)

Sir William Castell

George David

In 2011 the membership of the Gulf of Mexico committee remained the same as in 2010, including two US-based non-executive directors and the previous and present chairmen of the SEEAC. There is cross-membership with the audit committee, helping to inform discussions at the latter regarding financial controls and incident-related costs. Frank Bowman joined the committee in February 2012.

Each meeting of the committee is attended by Lamar McKay, President and CEO of the GCRO, and by Jack Lynch, chief counsel to the GCRO. The chairman, group chief executive and group general counsel join the meeting whenever possible. Meetings also include private sessions attended by non-executive members only.

Committee role and structure

The purpose of the committee is to provide non-executive oversight of the GCRO and to support efforts to rebuild trust in BP and BP s reputation with a particular focus on the US.

The work of the committee is fully integrated with the work of the board on reputation, safety, strategy and financial planning, and the board retains ultimate accountability for oversight of the group s response to the incident.

Directors are invited to attend and observe committee meetings. Committee meeting minutes are circulated to the board, and the committee chairman provides verbal reports on the committee s activities at board meetings.

The committee met 16 times in 2011.

During the course of 2011, the committee has undertaken the following tasks:

- Oversee and receive regular reports on work undertaken to mitigate the effects of the oil spill in the Gulf of Mexico area.
- Oversee GCRO's co-ordinated response programme for affected communities and states, along with its strategies for managing external relationships on issues relating to the incident.
- Oversee the legal strategy for litigation and investigations involving the group arising from the incident or its aftermath.
- Oversee GCRO's strategy for resolving claims, recognizing the independent role of the Gulf Coast Claims Facility.

- Oversee GCRO s plans for expenditures and investments on major projects or matters beyond those included within the established claims administration processes.
- Oversee management 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 and external advisers. Privileged legal briefings are regularly provided by the group general counsel and chief counsel for the GCRO, who are joined on occasion in committee meetings by other internal and external legal counsel.

BP s internal audit function has conducted reviews of various GCRO activities and processes, and these have been summarized for the committee s review. Primary monitoring of financial risk associated with GCRO s activities is undertaken by the audit committee. Safety risks related to GCRO s activities are monitored by the SEEAC.

Training and visits

The high frequency of meetings in 2011 has facilitated the committee s understanding of the important issues and numerous interdependencies. Three of these meetings were held in the US and were of extended duration, providing the opportunity for the committee to interact with members of the GCRO leadership team.

Committee activities

The committee s activities have included the following:

- Legal: legal updates from the chief counsel to the GCRO have formed a significant part of the committee s agenda, given the breadth and pace of activities. The committee has overseen the GCRO s integrated legal approach, which incorporates all government, civil and criminal investigations, the Multi-District Litigation, the Natural Resource Damage Assessment process, and legal aspects of the claims processes. The committee has overseen the company s preparation for trial, as well as the settlements entered into with the other working interest owners in the Macondo well and with some sub-contractors working on the development. The committee has continued to monitor engagement with other responsible parties and contractors.
- Claims: the committee has monitored the status of claims from individuals and businesses administered by the independent Gulf Coast Claims Facility; and the status of claims from government entities, which continue to be administered by BP. Assessments of potential future claims for provisioning purposes are reviewed by the audit committee.
- Remediation: the committee has received regular updates on the progress of clean-up and remediation activities. The committee also monitored discussions with Natural Resource Trustees, with whom agreement was reached on early restoration projects.
- GCRO controls: the committee oversaw the continued development of financial controls underpinning the breadth of the GCRO s complex tasks. The audit committee remains the primary forum for the oversight of these controls and associated audits.

Remuneration committee report

The report of the remuneration committee is contained in the Directors remuneration report on pages 139 to 151.

Nomination and chairman s committees reports

Chairman s introduction

I chair both the nomination and the chairman s committees. Set out below are reports on their activities during the year. As in previous years there is often an overlap between the work of the committees as the nomination committee may wish to sound out the view of the other non-executive directors in the chairman s committee on a particular issue, such as executive succession or the skills and experience needed for non-executive directors.

Carl-Henric Svanberg

Chairman

Nomination committee report

Committee members

Carl-Henric Svanberg committee chair Antony Burgmans (joined in May 2011) Cynthia Carroll (joined in May 2011) Sir William Castell Ian Davis

Members who left during the year

Douglas Flint (retired 14 April 2011)

DeAnne Julius (retired 14 April 2011)

The committee met five times during 2011.

Committee s role

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.

Committee activities

The committee reviewed the independence and roles of each of the directors prior to recommending them for re-election at the 2011 AGM. It also discussed the composition of the board and its committees in terms of service, skills and diversity.

Since the start of 2011, there were changes to the composition of the board, with Phuthuma Nhleko, Andrew Shilston and Professor Dame Ann Dowling joining on 1 February 2011, 1 January 2012 and 3 February 2012 respectively. The committee retained the services of external advisers Egon Zehnder and Odgers to assist with the identification of potential candidates over the period.

In undertaking its search for potential candidates for board membership, the committee carried out a review of skills and experience of existing board members and considered this against the board succession plan based on tenure and other factors, including diversity. This process enabled the committee to develop a list of selection criteria for future appointments, which it then used with its external advisers to develop a shortlist. Based on this, the committee determined an initial focus on candidates in the fields of science and technology.

An outline of skills for our current board membership is as follows:

Director	Key skills and experience
Paul Anderson	Oil and gas industry experience
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
Sir William Castell	Nuclear and medical science industry; technology
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

The committee also considered the succession of our chief financial officer and the skillset and experience needed in light of the role and the company s strategy. There was an extensive process in which Egon Zehnder advised the committee on both internal and external candidates. The committee made its recommendation to the chairman s committee, and CFO succession was then discussed by all the non-executive directors. It was agreed that Brian Gilvary, previously deputy chief financial officer, was the preferred candidate and he became CFO on 1 January 2012.

During the year the committee considered the recommendations of Lord Davies report on gender diversity. In line with the report, the committee agreed to a set of aspirational targets to work towards by 2015 and recommended changes to BP s board governance principles to include a policy on board diversity, which emphasizes considerations of diversity, inclusiveness and meritocracy when considering board composition. The committee has determined to develop during 2012 a set of measurable objectives for implementing its board diversity policy on which it will report back to shareholders.

At the end of the year, the committee undertook its annual examination of its effectiveness and performance, using an internally administered 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 report

Committee members

Carl-Henric Svanberg committee chair

Sir William Castell

Paul Anderson

Frank Bowman

Cynthia Carroll

George David

Ian Davis

Professor Dame Ann Dowling (appointed 3 February 2012)

Brendan Nelson

Phuthuma Nhleko (appointed 1 February 2011)

Andrew Shilston (appointed 1 January 2012)

Members who left during the year

Douglas Flint (retired 14 April 2011)

DeAnne Julius (retired 14 April 2011)

The committee met nine times during 2011.

Committee s role

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 key issues for the group, including its strategic direction, activities in Russia and risk management.

The chairman s committee worked closely with the nomination committee in matters around executive and non-executive succession, in particular the succession of the chief financial officer (CFO) and in redefining the roles of the CFO and executive director for corporate business activities. It was agreed that outgoing CFO Byron Grote would stay on the board as an executive director with responsibility for BP s corporate business activities, including its integrated supply and trading operations, Alternative Energy, shipping, technology and remediation activities.

The committee evaluated the performance of the group chief executive at the half year and the full year. It reviewed succession planning within the group and discussed the structure of the senior executive team.

The outcomes of the main board evaluation were discussed within the chairman s committee. The committee also reviewed the skills of the board and discussed what would be needed to meet the challenges of the company s strategy. Issues of governance around committees and their composition were examined. Led by the senior independent director, the committee evaluated the performance of the chairman as part of BP s annual evaluation programme for the board and its directors.

Facilitated by the senior independent director, the committee met to discuss an approach to the chairman by the Volvo Group to become their part-time, non-executive chairman. The discussion was held without the presence of the chairman and considered the time commitment of this additional role, given that Carl-Henric Svanberg would be stepping down from his existing non-executive directorship at Ericsson before taking on the potential position at Volvo. The committee concluded it was supportive of the chairman taking on this additional role.

Risk management and internal control review

In discharging its responsibility for the company s risk management and internal control systems under the UK Corporate Governance Code, the board, through its governance principles, 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. The governance principles are reviewed periodically by the board and are consistent with the requirements of the UK Corporate Governance Code including principle C.2 (risk management and internal control).

The board has an established process by which the effectiveness of the system of internal control (which includes the risk management system) is reviewed as required by provision C.2.1 of the UK Corporate Governance Code. This process enables the board and its committees to consider the system of internal control being operated for managing significant risks, including strategic, safety and operational and compliance and control risks, throughout the year. Material joint ventures and associates have not been dealt with as part of the group in this process.

As part of this process, the board and the audit, Gulf of Mexico and safety, ethics and environment assurance committees requested, received and reviewed reports from executive management, including management of the business segments, divisions and functions, at their regular meetings.

In considering the systems, the board noted that such systems are designed to manage, rather than eliminate, the risk of failure to achieve business objectives and can only provide reasonable, and not absolute, assurance against material misstatement or loss.

During the year, the board, through its committees, regularly reviewed with executive management processes whereby risks are identified, evaluated and managed. These processes were in place for the year under review, remain current at the date of this report and accord with the guidance on the UK Corporate Governance Code provided by the Financial Reporting Council. In December 2011, the board considered the group s significant risks within the context of the annual plan presented by the group chief executive.

A joint meeting of the audit and safety, ethics and environment assurance committees in February 2012 reviewed a report from the general auditor as part of the board s annual review of the risk management and internal control systems. The report described the annual summary of internal audit s consideration of elements of BP s system of internal control over significant risks arising in the categories of strategic, safety and operational and compliance and control and considered the control environment for the group. The report also highlighted the results of audit work conducted during the year and the remedial actions taken by management in response to significant failings and weaknesses identified.

During the year, these committees engaged with management, the general auditor and other monitoring and assurance providers (such as the group ethics and compliance officer, head of safety and operational risk and the external auditor) on a regular basis to monitor the management of risks. Significant incidents that occurred and management s response to them were considered by the appropriate committee and reported to the board.

Subject to determining any additional appropriate actions arising from items still in process, the board is satisfied that, where significant failings or weaknesses in internal controls were identified during the year, appropriate remedial actions were taken or are being taken.

In the board s view, the information it received was sufficient to enable it to review the effectiveness of the company s system of internal control in accordance with the Internal Control Revised Guidance for Directors (Turnbull).

Corporate governance practices

In the US, BP ADSs are listed on the New York Stock Exchange (NYSE). The significant differences between BP s corporate governance practices as a UK company and those required by NYSE listing standards for US companies are listed as follows:

Independence

BP has adopted a robust set of board governance principles, which reflect the UK Corporate Governance Code and its principles-based approach to corporate governance. As such, the way in which BP makes determinations of directors independence differs from the NYSE rules.

BP s board governance principles require that all non-executive directors be determined by the board to be independent in character and judgement and free from any business or other relationship which could materially interfere with the exercise of their judgement . The BP board has determined that, in its judgement, all of the non-executive directors are independent. In doing so, however, the board did not explicitly take into consideration the independence requirements outlined in the NYSE s listing standards.

Committees

BP has a number of board committees that are broadly comparable in purpose and composition to those required by NYSE rules for domestic US companies. For instance, BP has a chairman s (rather than executive) committee, nomination (rather than nominating/corporate governance) committee and remuneration (rather than compensation) committee. BP also has an audit committee, which NYSE rules require for both US companies and foreign private issuers. These committees are composed solely of non-executive directors whom the board has determined to be independent, in the manner described above.

The BP board governance principles prescribe the composition, main tasks and requirements of each of the committees (see *the board committee reports).* BP has not, therefore, adopted separate charters for each committee.

Under US securities law and the listing standards of the NYSE, BP is required to have an audit committee that satisfies the requirements of Rule 10A-3 under the Exchange Act and Section 303A.06 of the NYSE Listed Company Manual. BP s audit committee complies with these requirements. The BP audit committee does not have direct responsibility for the appointment, re-appointment or removal of the independent auditors instead, it follows the UK Companies Act 2006 by making recommendations to the board on these matters for it to put forward for shareholder approval at the AGM.

One of the NYSE s additional requirements for the audit committee states that at least one member of the audit committee is to have accounting or related financial management expertise . The board determined that Brendan Nelson possessed such expertise and also possesses the financial and audit committee experiences set forth in both the UK Corporate Governance Code and SEC rules (see *audit committee report).* Mr Nelson is the audit committee financial expert as defined in Item 16A of Form 20-F.

Shareholder approval of equity compensation plans

The NYSE rules for US companies require that shareholders must be given the opportunity to vote on all equity-compensation plans and material revisions to those plans. BP complies with UK requirements that are similar to the NYSE rules. The board, however, does not explicitly take into consideration the NYSE s detailed definition of what are considered material revisions .

Code of ethics

The NYSE rules require that US companies adopt and disclose a code of business conduct and ethics for directors, officers and employees. BP has adopted a code of conduct, which applies to all employees, and has board governance principles that address the conduct of directors. In addition BP has adopted a code of ethics for senior financial officers as required by the SEC. BP considers that these codes and policies address the matters specified in the NYSE rules for US companies.

Code of ethics

The company has adopted a code of ethics for its group chief executive, chief financial officer, group controller, general auditor and chief accounting officer as required by the provisions of Section 406 of the Sarbanes-Oxley Act of 2002 and the rules issued by the SEC. There have been no waivers from the code of ethics relating to any officers.

BP also has a code of conduct, which is applicable to all employees. This was updated (and published) on 1 January 2012.

Controls and procedures

Evaluation of disclosure controls and procedures

The company maintains disclosure controls and procedures', as such term is defined in Exchange Act Rule 13a-15(e), that are designed to ensure that information required to be disclosed in reports the company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including the company s group chief executive and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating our disclosure controls and procedures, our management, including the group chief executive and chief financial officer, recognize that any controls and procedures, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. Further, in the design and evaluation of our disclosure controls and procedures our management necessarily was required to apply its judgement in evaluating the cost-benefit relationship of possible controls and procedures. Also, we have investments in certain unconsolidated entities. As we do not control these entities, our disclosure controls and procedures with respect to such entities are necessarily substantially more limited than those we maintain with respect to our consolidated subsidiaries. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. The company s disclosure controls and procedures have been designed to meet, and management believes that they meet, reasonable assurance standards.

The company s management, with the participation of the company s group chief executive and chief financial officer, has evaluated the effectiveness of the company s disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b) as of the end of the period covered by this annual report. Based on that evaluation, the group chief executive and chief financial officer have concluded that the company s disclosure controls and procedures were effective at a reasonable assurance level.

Management s report on internal control over financial reporting

Management of BP is responsible for establishing and maintaining adequate internal control over financial reporting. BP s internal control over financial reporting is a process designed under the supervision of the principal executive and financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of BP s financial statements for external reporting purposes in accordance with IFRS.

As of the end of the 2011 fiscal year, management conducted an assessment of the effectiveness of internal control over financial reporting in accordance with the Internal Control Revised Guidance for Directors on the Combined Code (Turnbull). Based on this assessment, management has determined that BP s internal control over financial reporting as of 31 December 2011 was effective.

The company s internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with IFRS and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of BP; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of BP s assets that could have a material effect on our financial statements. BP s internal control over financial reporting as of 31 December 2011 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report appearing on page 177 of this *Annual Report and Form 20-F 2011*.

Changes in internal control over financial reporting

There were no changes in the group s internal controls over financial reporting that occurred during the period covered by the Form 20-F that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

Principal accountants fees and services

The audit committee has established policies and procedures for the engagement of the independent registered public accounting firm, Ernst & Young LLP, to render audit and certain assurance and tax services. The policies provide for pre-approval by the audit committee of specifically defined audit, audit-related, tax and other services that are not prohibited by regulatory or other professional requirements. Ernst & Young are engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit nature. Tax services were awarded either through a full competitive tender process or following an assessment of the expertise of Ernst & Young relative to that of other potential service providers. These services are for a fixed term.

Under the policy, pre-approval is given for specific services within the following categories: advice on accounting, auditing and financial reporting matters; internal accounting and risk management control reviews (excluding any services relating to information systems design and implementation); non-statutory audit; project assurance and advice on business and accounting process improvement (excluding any services relating to information systems design and implementation relating to BP s financial statements or accounting records); due diligence in connection with acquisitions, disposals and joint ventures (excluding valuation or involvement in prospective financial information); income tax and indirect tax compliance and advisory services; employee tax services (excluding tax services that could impair independence); provision of, or access to, Ernst & Young publications, workshops, seminars and other training materials; provision of reports from data gathered on non-financial policies and information; and assistance with understanding non-financial regulatory requirements. BP operates a two-tier system for audit and non-audit services. For audit related services, the audit committee has a pre-approved aggregate level, within which specific work may be approved by management. Non-audit services, including tax services, are pre-approved for management to authorize per individual engagement, but above a defined level must be approved by the chairman of the audit committee or the full committee. The audit committee has delegated to the chairman of the audit committee authority to approve permitted services provided that the chairman reports any decisions to the committee at its next scheduled meeting. Any proposed service not included in the approved service list must be approved in advance by the audit committee chairman and reported to the committee, or approved by the full audit committee in advance of commencement of the engagement.

The audit committee evaluates the performance of the auditors each year. The audit fees payable to Ernst & Young are reviewed by the committee in the context of other global companies for cost effectiveness. The committee keeps under review the scope and results of audit work and the independence and objectivity of the auditors. External regulation and BP policy requires the auditors to rotate their lead audit partner every five years. *(See Financial statements Note 16 on page 209 and Audit committee report on page 127 for details of audit fees.)*

Memorandum and Articles of Association

The following summarizes certain provisions of the company s Memorandum and Articles of Association and applicable English law. This summary is qualified in its entirety by reference to the UK Companies Act 2006 (Act) and the company s Memorandum and Articles of Association. For information on where investors can obtain copies of the Memorandum and Articles of Association see Documents on display on page 170.

At the AGM held on 17 April 2008 shareholders voted to adopt new Articles of Association, largely to take account of changes in UK company law brought about by the Act. Further amendments to the Articles of Association were approved by shareholders at the AGM held on 15 April 2010. These amendments reflect the full implementation of the Act, among other matters.

Objects and purposes

BP is incorporated under the name BP p.l.c. and is registered in England and Wales with the registered number 102498. The provisions regulating the operations of the company, known as its objects , were historically stated in a company s memorandum. The Act abolished the need to have object provisions and so at the AGM held on 15 April 2010 shareholders approved the removal of its objects clause together with all other provisions of its Memorandum that, by virtue of the Act, are treated as forming part of the company s Articles of Association.

Directors

The business and affairs of BP shall be managed by the directors. The company s Articles of Association provide that directors may be appointed by the existing directors or by the shareholders in a general meeting. Any person appointed by the directors will hold office only until the next general meeting and will then be eligible for re-election by the shareholders. There is no requirement for a director to retire on reaching any age.

The Articles of Association place a general prohibition on a director voting in respect of any contract or arrangement in which the director has a material interest other than by virtue of such director s interest in shares in the company. However, in the absence of some other material interest not indicated below, a director is entitled to vote and to be counted in a quorum for the purpose of any vote relating to a resolution concerning the following matters:

- The giving of security or indemnity with respect to any money lent or obligation taken by the director at the request or benefit of the company or any of its subsidiaries.

Any proposal in which the director is interested, concerning the underwriting of company securities or debentures or the giving of any security to a third party for a debt or obligation of the company or any of its subsidiaries.
Any proposal concerning any other company in which the director is interested, directly or indirectly (whether as an officer or shareholder or otherwise) provided that the director and persons connected with such director are not the holder or holders of 1% or more of the voting interest in the shares of such company.
Any proposal concerning the purchase or maintenance of any insurance policy under which the director may benefit.

The Act requires a director of a company who is in any way interested in a contract or proposed contract with the company to declare the nature of the director s interest at a meeting of the directors of the company. The definition of interest' includes the interests of spouses, children, companies and trusts. The Act also requires that a director must avoid a situation where a director has, or could have, a direct or indirect interest that conflicts, or possibly may conflict, with the company s interests. The Act allows directors of public companies to authorize such conflicts where appropriate, if a company's Articles of Association so permit. BP s Articles of Association permit the authorization of such conflicts. The directors may exercise all the powers of the company to borrow money, except that the amount remaining undischarged of all moneys borrowed by the company shall not, without approval of the shareholders, exceed the amount paid up on the share capital plus the aggregate of the amount of the capital and revenue reserves of the company. Variation of the borrowing power of the board may only be affected by amending the Articles of Association.

Remuneration of non-executive directors shall be determined in the aggregate by resolution of the shareholders. Remuneration of executive directors is determined by the remuneration committee. This committee is made up of non-executive directors only. There is no requirement of share ownership for a director's qualification.

Dividend rights; other rights to share in company profits; capital calls

If recommended by the directors of BP, BP shareholders may, by resolution, declare dividends but no such dividend may be declared in excess of the amount recommended by the directors. The directors may also pay interim dividends without obtaining shareholder approval. No dividend may be paid other than out of profits available for distribution, as determined under IFRS and the Act. Dividends on ordinary shares are payable only after payment of dividends on BP preference shares. Any dividend unclaimed after a period of 12 years from the date of declaration of such dividend shall be forfeited and reverts to BP.

The directors have the power to declare and pay dividends in any currency provided that a sterling equivalent is announced. It is not the company s intention to change its current policy of paying dividends in US dollars.

At the company s AGM held on 15 April 2010, shareholders approved the introduction of a Scrip Dividend Programme (Programme) and to include provisions in the Articles of Association to enable the company to operate the Programme. The Programme enables ordinary shareholders and BP ADS holders to elect to receive new fully paid ordinary shares (or BP ADSs in the case of BP ADS holders) instead of cash. The operation of the Programme is always subject to the directors decision to make the scrip offer available in respect of any particular dividend. Should the directors decide not to offer the scrip in respect of any particular dividend, cash will automatically be paid instead.

Apart from shareholders rights to share in BP s profits by dividend (if any is declared or announced), the Articles of Association provide that the directors may set aside:

- A special reserve fund out of the balance of profits each year to make up any deficit of cumulative dividend on the BP preference shares.
- A general reserve out of the balance of profits each year, which shall be applicable for any purpose to which the profits of the company may properly be applied. This may include capitalization of such sum, pursuant to an ordinary shareholders resolution, and distribution to shareholders as if it were distributed by way of a dividend on the ordinary shares or in paying up in full unissued ordinary shares for allotment and distribution as bonus shares.

Any such sums so deposited may be distributed in accordance with the manner of distribution of dividends as described above.

Holders of shares are not subject to calls on capital by the company, provided that the amounts required to be paid on issue have been paid off. All shares are fully paid.

Voting rights

The Articles of Association of the company provide that voting on resolutions at a shareholders meeting will be decided on a poll other than resolutions of a procedural nature, which may be decided on a show of hands. If voting is on a poll, every shareholder who is present in person or by proxy has one vote for every ordinary share held and two votes for every £5 in nominal amount of BP preference shares held. If voting is on a show of hands, each shareholder who is present at the meeting in person or whose duly appointed proxy is present in person will have one vote, regardless of the number of shares held, unless a poll is requested. Shareholders do not have cumulative voting rights.

Holders of record of ordinary shares may appoint a proxy, including a beneficial owner of those shares, to attend, speak and vote on their behalf at any shareholders meeting.

Record holders of BP ADSs are also entitled to attend, speak and vote at any shareholders meeting of BP by the appointment by the approved depositary, JPMorgan Chase Bank N.A., of them as proxies in respect of the ordinary shares represented by their ADSs. Each such proxy may also appoint a proxy. Alternatively, holders of BP ADSs are entitled to vote by supplying their voting instructions to the depositary, who will vote the ordinary shares represented by their ADSs in accordance with their instructions.

Proxies may be delivered electronically.

Matters are transacted at shareholders meetings by the proposing and passing of resolutions, of which there are two types: ordinary or special. An annual general meeting must be held once in every year.

An ordinary resolution requires the affirmative vote of a majority of the votes of those persons voting at a meeting at which there is a quorum. A special resolution requires the affirmative vote of not less than three-fourths of the persons voting at a meeting at which there is a quorum. Any AGM requires 21 days notice. The notice period for a general meeting is 14 days subject to the company obtaining annual shareholder approval, failing which, a 21-day notice period will apply.

Liquidation rights; redemption provisions

In the event of a liquidation of BP, after payment of all liabilities and applicable deductions under UK laws and subject to the payment of secured creditors, the holders of BP preference shares would be entitled to the sum of (i) the capital paid up on such shares plus, (ii) accrued and unpaid dividends and (iii) a premium equal to the higher of (a) 10% of the capital paid up on the BP preference shares and (b) the excess of the average market price over par value of such shares on the LSE during the previous six months. The remaining assets (if any) would be divided pro rata among the holders of ordinary shares.

Without prejudice to any special rights previously conferred on the holders of any class of shares, BP may issue any share with such preferred, deferred or other special rights, or subject to such restrictions as the shareholders by resolution determine (or, in the absence of any such resolutions, by determination of the directors), and may issue shares that are to be or may be redeemed.

Variation of rights

The rights attached to any class of shares may be varied with the consent in writing of holders of 75% of the shares of that class or on the adoption of a special resolution passed at a separate meeting of the holders of the shares of that class. At every such separate meeting, all of the provisions of the Articles of Association relating to proceedings at a general meeting apply, except that the quorum with respect to a meeting to change the rights attached to the preference shares is 10% or more of the shares of that class, and the quorum to change the rights attached to the ordinary shares is one-third or more of the shares of that class.

Shareholders meetings and notices

Shareholders must provide BP with a postal or electronic address in the UK to be entitled to receive notice of shareholders meetings. Holders of BP ADSs are entitled to receive notices under the terms of the deposit agreement relating to BP ADSs. The substance and timing of notices is described on page 137 under the heading Voting rights.

Under the Act, the AGM of shareholders must be held within the six-month period once every year. All general meetings shall be held at a time and place determined by the directors within the UK. If any shareholders meeting is adjourned for lack of quorum, notice of the time and place of the meeting may be given in any lawful manner, including electronically. Powers exist for action to be taken either before or at the meeting by authorized officers to ensure its orderly conduct and safety of those attending.

Limitations on voting and shareholding

There are no limitations imposed by English law or the company s Memorandum or Articles of Association on the right of non-residents or foreign persons to hold or vote the company s ordinary shares or BP ADSs, other than limitations that would generally apply to all of the shareholders.

Disclosure of interests in shares

The Act permits a public company to give notice to any person whom the company believes to be or, at any time during the three years prior to the issue of the notice, to have been interested in its voting shares requiring them to disclose certain information with respect to those interests. Failure to supply the information required may lead to disenfranchisement of the relevant shares and a prohibition on their transfer and receipt of dividends and other payments in respect of those shares. In this context the term interest is widely defined and will generally include an interest of any kind whatsoever in voting shares, including any interest of a holder of BP ADSs.

Remuneration overview

Executive directors remuneration

Non-executive directors remuneration

Remuneration overview

Dear shareholder,

For the senior executives of BP, remuneration is directly linked to strategy, strongly performance related and heavily weighted towards the long term. In a year of consolidation following the events of 2010, the company achieved a creditable performance overall in 2011. The outcome of the various plans that make up 2011 total remuneration for executive directors is set out in the table opposite.

The remuneration committee is keenly aware of its responsibility to balance sometimes conflicting perspectives in making judgements on senior executive pay. We recognize a concern by government, and society at large, of excess in this area, but cannot ignore the reality of a global competitive market for top executive talent. We respect investors expectation for pay to be strongly tied to performance while also wanting to ensure that executives receive fair reward for their achievements.

The committee s commitment to exercising judgement in a balanced way and being transparent in communicating its conclusions continues. In years where performance has been strong, bonuses have reflected that and when performance has been poor, bonuses have appropriately been reduced and even in some cases, as in 2010, eliminated. The long-term plan has, over the last five years, vested less than 10% of the possible shares, reflecting the impact of major incidents.

In this context, the committee carefully considered 2011 performance against targets set at the start of the year. Safety and risk management metrics were all met or exceeded including recordable injury frequency, loss of primary containment, implementation of change programmes and capability building. Group results were at or near target for financial metrics, including replacement cost profit, cash costs, upstream operating cash and downstream profitability. External survey results show some modest recovery in the company s external reputation, as well as good results on internal employee morale. The overall assessment of group results based on the above was judged to be on-target for the group as a whole.

Bob Dudley s bonus was based entirely on group results, resulting in an amount, including the deferred element, at on-target level, lain Conn s and Byron Grote s bonuses were based 70% on group results and 30% on their respective business or functional units. Mr Conn's results met or exceeded targets resulting in a bonus just above on-target , and Dr Grote s largely met resulting in an on-target bonus. In all cases one-third of their bonus is deferred into shares on a mandatory basis, matched, and will vest in three years subject to a review of safety and environmental sustainability during the period. They may elect to defer an additional one-third into shares on the same basis as the mandatory deferral, which they all chose to do for this year s bonus. All of the above is reflected in the table opposite.

The 2009-2011 share element included performance conditions relating to total shareholder return, production growth, group net income, and Refining and Marketing profitability all relative to the other oil majors. Of these all but Refining and Marketing profitability missed the level required to vest. Refining and Marketing profitability compared to the other oil majors was strong, and based on this, the overall vesting was 16.67% of the shares again reflected in the table opposite. The committee concluded that the result from a straight numerical assessment relative to agreed metrics provided an appropriate vesting level in light of overall company performance during the period.

For 2012 the overall policy for executive directors will remain largely unchanged, as summarized below. The committee will continue to monitor trends and external perspectives in reviewing the quantum and structure of total remuneration. It will also continue to operate with independence and rigour in making its judgements. Ultimately decisions will be guided by our commitment to both shareholder interests and executive engagement.

Antony Burgmans, KBE

Chairman of the remuneration committee

6 March 2012

Summary of remuneration components

Salary	Salaries as at 1 January 2012 are: Bob Dudley $1,700,000, lain Conn £730,000, Brian Gilvary £690,000 and Byron Grote $1,442,000.
Bonus	On-target bonus of 150% of salary and maximum of 225% of salary based on performance relative to targets set at start of year relating to financial and operational metrics.

Deferred bonus and match	One-third of actual bonus awarded as shares with three-year deferral and the ability to voluntarily defer an additional one-third. All deferred shares matched one-for-one, with vesting of both subject to an assessment of safety and environmental sustainability over the three-year period.
Performance shares	Award of shares of up to 5.5 times salary for group chief executive, and 4 times for other executive directors. Vesting after three years based on performance relative to other oil majors and strategic imperatives. Three-year retention period after vesting before release of shares.
Pension	Final salary scheme appropriate to home country of executive.

Summary of remuneration of executive directors in 2011 (audited)

	R W Dudley		I C Conn		Dr B E Grote	
Annual remuneration	**2011**	2010	**2011**	2010	**2011**	2010
Salary	**$1,700,000**[a]	$1,175,000	**£720,000**	£690,000	**$1,426,500**	$1,380,000
Annual cash performance bonus[b]	**$850,000**	0	**£396,000**	£207,000	**$713,250**	$207,000
Other emoluments	**$66,000**	$564,000[c]	**£227,500**[d]	£34,000	**$15,000**	$10,000
Total	**$2,616,000**	$1,739,000	**£1,343,500**	£931,000	**$2,154,750**	$1,597,000
Vested equity[e]						
Performance share element plan period	**2009-2011**	2008-2010	**2009-2011**	2008-2010	**2009-2011**	2008-2010
Vesting date	**Feb 2012**	Feb 2011	**Feb 2012**	Feb 2011	**Feb 2012**	Feb 2011
Shares vested[f]	**101,735**	0	**149,259**	155,695[g]	**187,193**	0
Value	**$788,300**	0	**£743,300**	£764,000	**$1,450,400**	0
Conditional equity[e]						
Deferred bonus in respect of bonus year[h]	**2011**	2010	**2011**	2010	**2011**	2010
Vesting date	**Feb 2015**	Feb 2014	**Feb 2015**	Feb 2014	**Feb 2015**	Feb 2014
Mandatory shares (including one-for-one match)	**218,412**	0	**161,304**	42,768	**183,276**	53,208
Voluntary shares (including one-for-one match)	**218,412**	0	**161,304**	0	**183,276**	53,208
Performance share element	**2011-2013**	2010-2012	**2011-2013**	2010-2012	**2011-2013**	2010-2012
Vesting date	**Feb 2014**	Feb 2013	**Feb 2014**	Feb 2013	**Feb 2014**	Feb 2013
Potential maximum shares	**1,330,332**	581,084	**623,025**	656,813	**785,394**	801,894

Amounts shown are in the currency received by executive directors. Annual bonuses are shown in the year they were earned.

a Increase in salary for Mr Dudley relates to his appointment to group chief executive in October 2010.

b This reflects the amount of total bonus paid in cash with the deferred bonus as set out in the conditional equity section.

c This amount includes costs of London accommodation and any tax liability thereon that ceased at the end of 2010 following Mr Dudley s appointment as group chief executive.

d As for all employees affected by the new UK pension tax limits and who wished to remain within these limits, with effect from April 2011, Mr Conn received a cash supplement of 35% of basic salary in lieu of future service pension accrual amounting to £191,625.

e Mr Dudley and Dr Grote hold shares in the form of ADSs. The above numbers reflect calculated equivalent in ordinary shares.

f 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. The market price of ordinary shares on 14 February 2012 was £4.98 and for ADSs was $46.49.

g There was no vesting under the performance share element. The shares that vested in February 2011 for Mr Conn pertained to a separate restricted award made in 2008.

h It is anticipated that the 2011 deferred bonus award will be made in early March 2012. The number of deferred shares is calculated using the three-day average share price following the full-year result announcement which was £4.84/share and $46.68/ADS in February 2011 and £4.91/share and $46.70/ADS in February 2012. Both deferred and matched shares are subject to a safety and environmental hurdle over the three-year deferral period.

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 £96.37 and £105.95 respectively.

Remuneration of non-executive directors in 2011 (audited)

£ thousand

	2011	2010
C-H Svanberg	**750**	750
P M Anderson	**128**	118
F L Bowman	**120**	17
A Burgmans	**100**	90
C B Carroll	**85**	90
Sir William Castell	**168**	147
G David	**128**[a]	135
I E L Davis	**160**	69
B R Nelson	**103**	17
F P Nhleko[b]	**113**	
Directors leaving the board in 2011		
D J Flint	**35**	108
Dr D S Julius	**32**[c]	100

a In addition, George David received a £28,000 fee for chairing the BP technical advisory council.

b Appointed on 1 February 2011.

c This figure excludes a superannuation gratuity of £1,543.

While fees were held at 2010 levels, in 2011 actual fees paid to non-executive directors were affected by changes in committee membership and the number of intercontinental meetings for which an attendance allowance was paid.

Executive directors remuneration

Remuneration committee

During the year the committee met seven times, and was made up of the following independent non-executive directors:

Mr Antony Burgmans (chairman from 2011 Annual General Meeting (AGM))

Mr George David

Mr Ian Davis

Dr DeAnne Julius was chairman of the committee until her retirement at the 2011 AGM. Mr Svanberg has attended all meetings.

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.

The committee s tasks are set out in the board governance principles:

- 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.

The committee operates with a high level of independence. The board considers all committee members to be independent (see *page 121).* They have no personal financial interest, other than as shareholders, in the committee s decisions. Each member of the remuneration committee is subject to annual re-election as a director of the company.

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 David Jackson, the company secretary, and from the company secretary s office, which is independent of executive management and reports to the chairman of the board.

The committee also appoints external advisers to provide specialist advice and services on particular remuneration matters. The independence of the advice is subject to periodic review. In 2011, the committee continued to engage Towers Watson as its principal external adviser, primarily for market information. Towers Watson also provided other remuneration and benefits advice to parts of the group. Freshfields Bruckhaus Deringer LLP provided legal advice on specific matters to the committee, as well as providing some legal advice to the group.

The committee values its dialogue with major shareholders on remuneration matters. The committee is accountable to shareholders through its annual report on executive directors remuneration. It will consider the outcome of the vote at the AGM on the directors remuneration report and take into account the views of shareholders in its future decisions.

Executive directors remuneration 2011

This section contains detail on executive directors remuneration including salary, annual bonus and deferred bonus relating to 2011 and the share element for the performance period 2009-2011.

Salary

Mr Dudley s current salary of $1,700,000 was unchanged during 2011. As reported in last year s remuneration report, Mr Conn s and Dr Grote s salaries were increased in April 2011 to £730,000 and $1,442,000 respectively, their first increase since 2008.

Annual bonus

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. Mr Dudley s annual bonus was based entirely on group results and Mr Conn s and Dr Grote s based 70% on group results and 30% on their respective segment and 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 strategic priorities of reinforcing safety and risk management, rebuilding trust and reinforcing value creation. Targets are set so that meeting plan equates to on-target bonus.

At group level, the safety and risk management component included targets for recordable injury frequency, loss of primary containment and implementation of change programmes. Rebuilding trust was focused on external reputation as measured by external surveys and internal morale as measured by surveys. Finally, the value component included measures for underlying replacement cost profit, total cash costs, upstream operating cash and downstream profitability.

Mr Conn s Refining and Marketing segment similarly included targets for various safety measures, onstream availability, cost efficiency and profitability. Dr Grote s functional segment included measures for IST compliance, succession and divestments.

Apart from the specific measures set out, the committee may consider any other results that it deems relevant and apply its judgement in determining final bonus scores.

Results

Outcomes for the year are summarized in the table below, with a more detailed explanation following.

2011 bonus measures and outcomes

Key measures for 2011 bonus	Below target	On target	Better than target
Safety and risk management			
Recordable injury frequency			
Loss of primary containment			
Implementation of change programmes			
Retaining and building capability			
Rebuilding trust			
External reputation			
Internal alignment and morale			
Restoring value			
Underlying replacement cost profit			
Total cash costs			
Upstream operating cash			
Refining and Marketing profitability			

Safety and risk management performance was strong with most targets exceeded. Loss of primary containment showed a 14% reduction on the number of incidents that occurred in the previous year and process safety related high potential incidents dropped 26% both metrics are important indicators of process safety performance. Recordable injury frequency was better than target. A major change programme related to safety and risk management progressed very well. A central part of this was the completed implementation of the safety and operational risk function as a group-wide organization independent of line management. The change programme also included a major upstream reorganization, the introduction of a contractor management process, global rollout of a values and behaviours charter, implementation of a new individual performance and reward framework and completion of a risk management review.

Rebuilding trust showed some early signs of improvement but with clear work remaining to be done related to the long-term impact of the Deepwater Horizon oil spill. Independent external surveys reflect some recovery of trust and reputation in key markets as the year progressed. Internal employee alignment and morale remained encouragingly strong through a difficult period for the company. Employee satisfaction, as measured by survey, was near pre-Deepwater Horizon levels and a new progress index was implemented to track specific employee alignment related to the company s strategic priorities.

Rebuilding value measures were at or near target. Relative to target, underlying replacement cost profit was around 90% and total cash costs were 7% above. Upstream operating cash was some 3% better than target and Refining and Marketing profitability met its plan level. Refining and Marketing had a strong year overall with record earnings, good safety, and high utilization availability.

Based on these results, the committee assessed group performance to be on-target. Mr Dudley therefore received a total bonus of 150% of salary including deferral, reflecting on-target performance. Mr Conn s total bonus of 165% of salary reflected achievements above target for the Refining and Marketing segment. Dr Grote s total bonus of 150% of salary reflects on-target results at both group and function level.

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. Amounts, as received by the individuals, are shown in the table on page 141.

Deferred bonus

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. Their deferred shares are matched on a one-for-one basis and will vest in 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 into shares on the same basis as the mandatory deferral. All three executive directors chose to participate in the voluntary deferral. Again this is reflected in the table on page 141.

All deferred bonuses will be converted to shares based on the average price of BP shares over the three days following the company s announcement of 2011 results (£4.91/share, $46.70/ADS).

2009-2011 share element

Framework

Performance shares were awarded to each executive director in early 2009 with vesting after three years dependent on performance relative to measures reflecting the company s strategic priorities at the time. For the 2009 plan, vesting was based 50% on total shareholder return (TSR) versus the oil majors, and 50% on a balanced scorecard of underlying performance factors versus the same peers. The underlying performance factors were production growth, Refining and Marketing profitability, and underlying net income growth. The peer group included ExxonMobil, Shell, Total, Chevron 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.

Results

Reflecting the impact of the Deepwater Horizon oil spill, the TSR, production growth and net income growth measures for the three-year period 2009-2011 were all below the third place required for vesting. Refining and Marketing profitability was strong and based on a first place ranking achieved full vesting for that portion. Based on the agreed formula, this resulted in a vesting of 16.67% of the original award.

The committee considered this result was a fair reflection of overall performance over the period. The resulting shares and value of the vesting is shown in the table on page 149.

2011 total remuneration outcomes

The charts below summarize the actual total remuneration outcome of 2011 for each of the executive directors.

The salary is the amount actually received during the year and the cash bonus reflects the portion of total bonus for 2011 that is received in cash.

The deferred bonus reflects that portion of total bonus for 2011 that is deferred, either on a mandatory or voluntary basis. The value shown is converted to shares, matched one-for-one and vests after three years contingent on the review of safety and environmental sustainability over the three years.

Finally the share element portion reflects the value of the vesting that occurred for the 2009-2011 plan. These shares now enter a further three-year retention period before they are released to the individual.

Remuneration policy

This section provides information on principles underlying the company s remuneration policy followed by an overview and an in-depth review of the policy.

Remuneration principles

Remuneration policy for executive directors is guided by key principles:

- Link to strategy A substantial portion of executive remuneration should be linked to success in implementing the company's business strategy.
- Performance linked The major part of total remuneration should vary with performance, with the largest elements share based, further aligning interests with shareholders.
- Long-term based The structure of pay should reflect the long-term nature of BP's business and the significance of safety and environmental risks.
- Rigorous process Performance conditions for variable pay should be set by the committee at the start of each year and assessed by the committee at the end of each performance period. Assessment should take into account material changes in the market environment (predominantly oil prices) and BP s competitive position (primarily vis-à-vis other oil majors).
- Informed judgement There should be both quantitative and qualitative assessments of performance with the committee making an informed judgement within a framework approved by shareholders.
- Fair treatment The committee reviews the pay policy and levels for executives below board, as well as pay and conditions of employees throughout the group. These are considered when determining executive directors remuneration. Salaries should be reviewed annually, in the context of the total quantum of pay, and taking into account both external market and internal company conditions.
- Personal shareholding Executives should develop and be required to hold a significant shareholding as this represents the best way to align their interests with those of shareholders.
- Shareholder engagement The remuneration committee will actively seek to understand shareholder preferences and be transparent in explaining its remuneration policy and practices.

These principles result in a remuneration policy that is directly linked to strategy, strongly performance related and heavily weighted towards long term.

The chart below shows the range of results possible for the group chief executive depending on performance outcomes.

The on-target column assumes one-third of total bonus is deferred and matched, and the share element is valued at half the award.

The maximum column assumes that two-thirds of the total bonus is deferred and matched, and full vesting of the share element.

Remuneration is strongly performance dependent:

- Bonus based on metrics from annual plan.
- Deferred bonus vesting based on additional safety and environment sustainability assessment.
- Share element based on metrics reflecting strategic priorities.

It is also heavily weighted towards the long term:

- Deferred bonus three years.
- Share element six years.

Remuneration policy overview

Component	Policy	2012 application
Salary	Base salaries should be competitive relative to relevant market peer groups.	Peer group for executive directors includes large European multinationals and the oil majors.
Pension and other benefits	Executive directors should participate in the normal pension and benefit schemes applying in their home countries.	Both UK and US executive directors remain on defined benefit pension plans reflecting respective national norms. 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.
Variable remuneration		
Annual bonus	Annual bonus should be based on performance relative to measures and targets reflecting the annual plan. 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 2012 are: **Safety and risk management (30%).** Recordable injury frequency. Loss of primary containment. Process safety related major incident announcements and high potential incidents. **Rebuilding trust (20%).** External reputation. Internal morale and alignment. **Value creation (50%).** Operating cash flow. Underlying replacement cost profit. Total cash costs. Gearing. Divestments. Upstream production efficiency. Upstream major project delivery. Refining and Marketing net income per barrel.
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.
Performance shares	A large portion of total remuneration for executive directors should be tied to the long-term performance of the company. 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 annually. Vesting of the shares after three years is dependent on performance relative to measures reflecting the strategic priorities of the company. Those shares that vest are held for an additional three-year retention period, after payment of tax on vesting.	The 2012-2014 share element will vest based equally on the following three performance metrics: **Total shareholder return versus oil majors.** **Operating cash flow.** **Strategic imperatives.** Reserves replacement versus oil majors. Process safety. Rebuilding trust.
Personal shareholding in BP	Executive directors should develop significant personal shareholding in order to align their interests with shareholders.	Executive directors are required to develop, and maintain, a shareholding equivalent to five times salary, within a reasonable time of appointment.

Remuneration policy for 2012 in more depth

This section contains a more detailed explanation of the components of total remuneration for executive directors and how they will be implemented in 2012.

Salary

The committee normally reviews salaries annually, taking into account other large Europe-based global companies, other oil majors, and relevant US companies. It also considers salary treatment throughout the company when determining appropriate increases for executive directors.

Annual bonus

The group strategy provides the context for the company s annual plan, from which measures and targets are derived at the start of the year for senior managers including executive directors. Measures typically include a range of financial and operating metrics as well as those relating to safety and environment, and people.

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). Assessment includes both quantitative and qualitative views as well as input from the other committees on relevant aspects. The committee considers that this informed judgement is important to establishing a fair overall assessment.

The chart below shows the average annual bonus result (before any deferral) and relative to an on-target level for executive directors for the current year and previous five.

For 2012, all executive directors will again be eligible for a total bonus (including deferral) of 150% of salary at target and 225% at maximum. Mr Dudley s bonus will be based entirely on group measures. Mr Conn, Dr Gilvary and Dr Grote will have 70% of their bonus based on group results and 30% on their respective segment or function.

The measures used to determine bonus results flow directly from the group's annual plan which reflects the strategic priorities of reinforcing safety and risk management, rebuilding trust, and reinforcing value creation.

At group level, safety and risk management measures include recordable injury frequency, loss of primary containment and process related major incident announcements and high potential incidents. Rebuilding trust will be measured via surveys to assess both external reputation and internal staff alignment and morale. Restoring value will provide the dominant set of measures and include operating cash flow, underlying replacement cost profit, total cash costs, gearing, divestments, upstream production efficiency, major project delivery and Refining and Marketing profitability.

The Refining and Marketing segment will include specific safety metrics for the segment. Value metrics will include availability, efficiency, and profitability metrics, as well as divestments and major project delivery. Finance function measures will include divestments, gearing and major project delivery. The corporate business function will include profitability and compliance measures for IST and Alternative Energy.

In all cases, targets for each measure are set so that achieving plan levels of performance equates to an on-target bonus. 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 competitors results, analysts reports and the views of the chairmen of the other committees. Based on this broader view, the committee can decide to adjust bonuses where it is warranted and, in exceptional circumstances, to pay no bonuses.

Deferred bonus

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 performance bonus into a long-term plan with additional performance hurdles. As shown below, the results of 2012 will form the basis for determining the deferred bonus in 2013.

For 2012, as last year, one-third of the annual bonus will be deferred into shares for three years and matched by the company on a one-for-one basis. 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. Both deferred and matched shares will vest in February 2016 contingent on an assessment of safety and environmental sustainability over the three-year deferral period. 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 safety, ethics and environment assurance committee (SEEAC).

Executive directors may voluntarily defer a further one-third of their annual bonus into shares, which will be capable of vesting, and will qualify for matching, on the same basis as set out above. Where shares vest, the executive director will also receive additional shares representing the value of the re-invested dividends.

Performance shares

The performance share element reflects the committee s policy that a large proportion of total remuneration is tied to long-term performance. Performance shares are awarded at the start of each year and vesting, after three years, is based on performance relative to measures and targets derived from the company s strategic priorities. Those shares that vest are then held for a further three-year retention period before being released to the executive after payment of tax on vesting. This gives executive directors a six-year incentive structure, which is designed to ensure their interests are aligned with those of shareholders. Where shares vest, the executive director will receive additional shares representing the value of the re-invested dividends.

The maximum number of shares that can be awarded will be 5.5 times salary for the group chief executive and 4 times salary for the other executive directors. Performance shares will only vest to the extent that performance conditions, as described below, are met and subject to the committee concluding that this is appropriate. The history of vesting of the share element is shown below.

Performance conditions

Performance conditions for the 2012-2014 share element will be aligned with the company s strategic agenda which continues to focus on value creation, reinforcing safety and risk management, and rebuilding trust. Vesting of shares will be based one-third on BP s total shareholder return (TSR) compared to the other oil majors, reflecting the central importance of restoring the value of the company. A further one-third will be based on the operating cash flow of the company, reflecting a central element of value creation. The final one-third will be based on a set of strategic imperatives; in particular, reserves replacement, process safety, and rebuilding trust.

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 re-invested. 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. As has been communicated publicly, the target is to grow operating cash flow to $33 billion by 2014 based on $100/bbl oil price assumption. Below $31 billion, there will be no vesting under this component. Between $31 billion and $35 billion there will be a straight line vesting from 60% to 100% respectively.

Finally the remaining strategic imperatives relating to process safety and rebuilding trust will be determined by a mixture of internal targets and external assessment. In the case of process safety, high potential incidents and major incident announcements will provide the key factual data as well as the input of the SEEAC. The rebuilding trust component will include both external and internal surveys that will be used by the committee, along with input from the other board committees, to judge performance. The results will be explained in subsequent directors' remuneration reports.

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.

Shareholding policy

The committee s policy, reflected in the Executive Directors Incentive Plan (EDIP), continues to be that each executive director builds and maintains a significant personal shareholding in BP to create strong alignment with shareholders. Executive directors, under the policy, are required to build a share base equating to five times salary, within a reasonable time from their appointment. Each director s shareholding as at 31 December 2011 is set out on page 117.

Directors remuneration report

Pensions

Executive directors are eligible to participate in the appropriate pension schemes applying in their home countries. Details are set out in the table below.

UK directors

UK directors are members of the regular BP pension scheme. 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.

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. Special early retirement terms apply to pre-1 December 2006 service for members with long service as at 1 December 2006.

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.

With the reduction in the annual allowance applicable to plans such as the BP pension scheme in 2011 the company reviewed the options available for employees who might wish to limit the increase in the value of their pension to remain within the new limit. To provide employees with flexibility, should they wish to limit the value of the increase in their pension to within the new limit, those impacted are able to elect a lower accrual rate and in addition receive a cash supplement so that the total cost to BP remains equivalent to the cost of providing 1/60th of basic salary. Some employees have had to cease pension accrual for future service to remain within the new annual allowance. For these employees the cash supplement is equal to 35% of basic salary.

Mr Conn has elected to cease to accrue pension benefits for future service in order to keep within the new annual allowance and has received a cash supplement of 35% of his basic salary from 1 April 2011. This is included in the remuneration table on page 141.

US directors

Mr Dudley and Dr Grote participate in the US BP retirement accumulation plan (US pension plan), which features a cash balance formula. Pension benefits are provided through a combination of tax-qualified and non-qualified benefit restoration plans, consistent with US tax regulations as applicable.

BP also provides a supplemental executive retirement benefits plan (supplemental plan), which is a non-qualified arrangement that became effective on 1 January 2002 for US employees with salary above a specified salary grade level. Mr Dudley and Dr Grote are eligible to participate under the supplemental plan. The benefit formula is a target of 1.3% of final average earnings (base pay plus bonus) for each year of service, inclusive of all other BP (US) qualified and non-qualified pension arrangements. This benefit is unfunded and therefore paid from corporate assets.

Mr Dudley retains the heritage Amoco retirement plan, which provides benefits on a final average pay formula of 1.67% of highest average earnings (base pay plus bonus in accordance with standard US practice) for each year of service, reduced by 1.5% of the primary social security benefit for each year of service. The highest benefit of the plans produced by the different formulas will be payable and this is currently the benefit determined under the Amoco heritage terms.

Their pension accrual for 2011, shown in the table below, takes into account the total amount that could be payable under relevant plans.

Other benefits

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.

Pensions (audited)

thousand

	Service at 31 Dec 2011	Accrued pension entitlement at 31 Dec 2011	Additional pension earned during the year ended 31 Dec 2011[a]	Transfer value of accrued benefit at 31 Dec 2010 (A)b	Transfer value of accrued benefit at 31 Dec 2011 (B)b	Amount of B-A less contributions made by the director in 2011
R W Dudley (US)	32 years	$948	$244	$10,336	$15,244	$4,908
I C Conn (UK)	26 years	£307	£20	£5,373	£6,582	£1,209
Dr B E Grote (US)	32 years	$1,328	$47	$16,501	$18,251	$1,750

a Additional pension earned during the year includes an inflation increase of 4.8% for UK directors and 3.6% for US directors.
b Transfer values have been calculated in accordance with guidance issued by the actuarial profession.

Share plans in detail

Performance share element of EDIP (audited)

	Performance period	Date of award of performance shares	Share element interests: Potential maximum performance shares[a]: At 1 Jan 2011	Awarded 2011	At 31 Dec 2011	Interests vested in 2011 and 2012: Number of ordinary shares vested[b]	Vesting date	Market price of each share at vesting £
R W Dudley[c]	2009-2011	06 May 2009	539,634		539,634	101,735	15 Feb 2012	4.98
	2010-2012	09 Feb 2010	581,082		581,082			
	2011-2013	09 Mar 2011[d]		1,330,332	1,330,332			
I C Conn	2008-2010	13 Feb 2008	578,376			0		
	2008-2011[e]	13 Feb 2008	133,452			155,695	22 Feb 2011	4.91
	2008-2013[e]	13 Feb 2008	133,452		133,452			
	2009-2011	11 Feb 2009	780,816		780,816	149,259	15 Feb 2012	4.98
	2010-2012	09 Feb 2010	656,813		656,813			
	2011-2013	09 Mar 2011[d]		623,025	623,025			
Dr B E Grote[c]	2008-2010	13 Feb 2008	581,748			0		
	2009-2011	11 Feb 2009	992,928		992,928	187,193	15 Feb 2012	4.98
	2010-2012	09 Feb 2010	801,894		801,894			
	2011-2013	09 Mar 2011[d]		785,394	785,394			
Former directors								
Dr A B Hayward	2008-2010	13 Feb 2008	845,319			0		
	2009-2011	11 Feb 2009	755,512		755,512[f]	144,422	15 Feb 2012	4.98
	2010-2012	09 Feb 2010	303,948		303,948[f]			
A G Inglis	2008-2010	13 Feb 2008	578,376			0		
	2009-2011	11 Feb 2009	520,544		520,544[f]	99,506	15 Feb 2012	4.98
	2010-2012	09 Feb 2010	218,938		218,938[f]			

a BP's performance is measured against the oil sector. For awards under the 2009-2011 plan, performance conditions are measured 50% on TSR against ExxonMobil, Shell, Total, ConocoPhillips and Chevron and 50% on a balanced scorecard of underlying performance. For the awards under the 2010-2012 plan, performance conditions are 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 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. 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 re-invested dividends on the shares vested.

c Dr Grote and Mr Dudley receive awards in the form of ADSs. The above numbers reflect calculated equivalents in ordinary shares.

d The market price of ordinary shares on 9 March 2011 was £4.85 and for ADSs was $47.41.

e Restricted award under share element of EDIP. As reported in the 2007 directors' remuneration report in February 2008, the committee awarded Mr Conn restricted shares, as set out above and includes re-invested dividends on the shares vested. The remaining award vests on the fifth anniversary of the award, dependent on the remuneration committee being satisfied as to their personal performance at the date of vesting. Any unvested tranche will lapse in the event of cessation of employment with the company.

f Potential maximum of performance shares reflect actual service during performance period on a pro-rated basis.

Deferred share element of EDIP (audited)

Name	Bonus year	Type	Performance period	Date of award of deferred shares[a]	Deferred share element interests: Potential maximum deferred shares: At 1 Jan 2011	Awarded 2011	At 31 Dec 2011	Interests vested in 2010 and 2011: Number of ordinary	Vesting date	Market price of each share at vesting

							shares vested	£
I C Conn	2010	Compulsory	2011-2013	09 Mar 2011	21,384	21,384		
		Voluntary	2011-2013	09 Mar 2011				
		Matching	2011-2013	09 Mar 2011	21,384	21,384		
Dr B E Grote [b]	2010	Compulsory	2011-2013	09 Mar 2011	26,604	26,604		
		Voluntary	2011-2013	09 Mar 2011	26,604	26,604		
		Matching	2011-2013	09 Mar 2011	53,208	53,208		

a The market price of ordinary shares on 9 March 2011 was £4.85 and for ADSs was $47.41.

b Dr Grote received awards in the form of ADSs. The above numbers reflect calculated equivalents in ordinary shares.

Share options (audited)

	Option type	At 1 Jan 2011	Granted	Exercised	At 31 Dec 2011	Option price	Market price at date of exercise	Date from which first exercisable	Expiry date
R W Dudley[a]	BP SOP	6,460			[b]	$49.65		23 Feb 2004	22 Feb 2011
	BP SOP	1,073			[b]	$43.82		17 Dec 2004	16 Dec 2011
	BP SOP	17,835			17,835	$48.99		18 Feb 2005	17 Feb 2012
	BP SOP	17,835			17,835	$38.10		17 Feb 2006	16 Feb 2013
I C Conn	SAYE	1,498		1 ,498		£4.41	£4.93[c]	01 Sep 2010	28 Feb 2011
	SAYE	617			617	£4.87		01 Sep 2011	29 Feb 2012
	SAYE	605			605	£4.20		01 Sep 2012	28 Feb 2013
	SAYE	3,017			3,017	£3.68		01 Sep 2016	28 Feb 2017
	EXEC	72,250			[b]	£5.67		23 Feb 2004	23 Feb 2011
	EXEC	130,000			130,000	£5.72		18 Feb 2005	18 Feb 2012
Dr B E Grote[a]	EDIP	58,333			[b]	$48.53		25 Feb 2005	25 Feb 2011

The closing market prices of an ordinary share and of an ADS on 31 December 2011 were £4.61 and $42.74 respectively.

During 2011, the highest market prices were £5.09 and $49.25 respectively and the lowest market prices were £3.63 and $35.22 respectively.

EDIP = Executive Directors Incentive Plan adopted by shareholders in 2010 as described on page 147.

EXEC = Executive Share Option Scheme. These options were granted to the relevant individuals prior to their appointments as directors and are not subject to performance conditions.

SAYE = Save As You Earn employee share scheme.

BP SOP = BP Share Option Plan. These options were granted to Mr Dudley prior to his appointment as a director and are not subject to performance conditions.

a Numbers shown are ADSs under option. One ADS is equivalent to six ordinary shares.

b Options lapsed.

c Options exercised on 22 February 2011. Closing market price for information. Shares were retained after exercise of options.

Service contracts

Service contracts have a notice period of one year and may be terminated by the company at any time with immediate effect on payment in lieu of notice equivalent to one year s salary or the amount of salary that would have been paid if the contract had been terminated on the expiry of the remainder of the notice period. Other than in the case of Dr Gilvary (who became a director on 1 January 2012), the service contracts are expressed to expire at a normal retirement age of 60 (subject to age discrimination).

Director	Contract date	Salary as at 1 Jan 2012
R W Dudley	6 Apr 2009	$1,700,000
I C Conn	22 Jul 2004	£730,000
Dr B Gilvary	22 Feb 2012	£690,000
Dr B E Grote	7 Aug 2000	$ 1,442,000

Mr Dudley s contract is with BP Corporation North America Inc. He is seconded to BP p.l.c. under a secondment agreement of 15 April 2009, which expires on 15 April 2012. Dr Grote s contract 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 contracts.

There are no other provisions for compensation payable on early termination of the above contracts. In the event of the early termination of any of the contracts by the company, other than for cause (or under a specific termination payment provision), the relevant director s then current salary and benefits would be taken into account in calculating any liability of the company. The committee will consider mitigation to reduce compensation to a departing director, when appropriate to do so.

Executive directors external appointments

The board encourages executive directors to broaden their knowledge and experience by taking up appointments outside the company. 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
I C Conn	Rolls-Royce	Senior independent director	£74,166
Dr B E Grote	Unilever	Audit committee member	Unilever PLC £33,500 Unilever NV 48,625

Past directors

Tony Hayward was engaged by BP to serve as a non-executive director of TNK-BP until 11 October 2011. For his service during 2011 he was paid $194,973.

Non-executive directors remuneration

Policy

The board sets the level of remuneration for all non-executive directors within a limit approved from time to time by shareholders. Key elements of BP s policy on non-executive director remuneration include:

- Remuneration should be sufficient to attract, motivate and retain world-class non-executive talent.
- Remuneration of non-executive directors is proposed by the chairman of the board and agreed by the board and should be proportional to their contribution towards the interests of the company.
- Remuneration practice should be consistent with recognized best practice standards for non-executive directors remuneration.
- Remuneration should be in the form of cash fees, payable monthly.
- Non-executive directors should not receive share options from the company.
- Non-executive directors are encouraged to establish a holding in BP shares of the equivalent value of one-year s base fee.

Process

BP reviews the quantum and structure of chairman of the board and non-executive remuneration on an annual basis. The chairman s remuneration is reviewed by the remuneration committee, who makes a recommendation to the board; the chairman does not vote on his own remuneration. Non-executive director remuneration is reviewed by the chairman, who makes a recommendation to the board; non-executive directors do not vote on their own remuneration.

Following the 2011 review of non-executive remuneration, it was concluded that in light of wider economic circumstances, an increase would not be appropriate and therefore no adjustment would be made to fee levels. It was agreed that the policy of annual review would continue and that the transatlantic attendance allowance be renamed the intercontinental travel allowance to better reflect when the allowance is awarded.

Fee structure

The table below shows the current fee structure for non-executive directors on 1 January 2012:

	£ thousand Fee level
Chairman[a]	750
Senior independent director[b]	120
Board member	75
Audit, Gulf of Mexico and safety, ethics and environment assurance committees chairmanship fees[c]	30
Remuneration committee chairmanship fee[c]	20
Committee membership fee[d]	5
Intercontinental travel allowance	5

a The chairman remains ineligible for committee chairmanship and membership fees or intercontinental attendance allowance. He has the use of a fully maintained office for company business, a chauffeured car and security advice in London. He receives secretarial support as appropriate to his needs in Sweden.

b The senior independent director is still eligible for committee chairmanship fees and intercontinental attendance allowance plus any committee membership fees.

c Committee chairmen do not receive an additional membership fee for the committee they chair.

d For members of the audit, Gulf of Mexico, SEEAC and remuneration committees.

Remuneration of non-executive directors in 2011 (audited)

£ thousand

	2011	2010
C-H Svanberg	**750**	750
P M Anderson	**128**	118
F L Bowman	**120**	17
A Burgmans	**100**	90

C B Carroll	**85**	90
Sir William Castell	**168**	147
G David	**128**[a]	135
I E L Davis	**160**	69
B R Nelson	**103**	17
F P Nhleko[b]	**113**	
Directors leaving the board in 2011		
D J Flint	**35**	108
Dr D S Julius	**32**[c]	100

a In addition, George David received a £28,000 fee for chairing the BP technical advisory council.

b Appointed on 1 February 2011.

c This figure excludes a superannuation gratuity of £1,543.

While fees were held at 2010 levels, in 2011 actual fees paid to non-executive directors were affected by changes in chairmanship and committee membership and the number of intercontinental meetings for which an attendance allowance was paid.

No share or share option awards were made to any non-executive director in respect of service on the board during 2011.

Non-executive directors have letters of appointment which recognize that, subject to the Articles of Association, their service is at the discretion of shareholders. All directors stand for re-election at each AGM.

Superannuation gratuities

Until 2002, BP maintained a long-standing practice whereby non-executive directors who retired from the board after at least six years service were eligible for consideration for a superannuation gratuity. The board was, and continues to be, authorized to make such payments under the company s Articles of Association and the amount of the payment is determined at the board s discretion, taking into consideration the director s period of service and other relevant factors.

In 2002, the board revised its policy with respect to superannuation gratuities so that:

- Non-executive directors appointed to the board after 1 July 2002 would not be eligible for consideration for such a payment.
- While non-executive directors in service at 1 July 2002 would remain eligible for consideration for a payment, service after that date would not be taken into account by the board in considering the amount of any such payment.

Dr DeAnne Julius who retired on 14 April 2011 was paid a superannuation gratuity of £1,543, in line with the policy arrangements agreed in 2002 and outlined above. With the retirement of Dr Julius from the board, no other non-executive directors are eligible for superannuation gratuities.

Past directors

Sir Ian Prosser (who retired as a non-executive director of BP in April 2010) was appointed as a director and non-executive chairman of BP Pension Trustees Limited on 29 September 2010. During 2011, he received £100,000 for this role.

Peter Sutherland (who was chairman of BP until 31 December 2009) continued his membership of the BP international advisory board after his retirement from the board of BP p.l.c. During 2011, he received 100,000 for this role.

This directors remuneration report was approved by the board and signed on its behalf by David J Jackson, Company Secretary on 6 March 2012.

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Additional information
for shareholders

Critical accounting policies

The significant accounting policies of the group are summarized in Financial statements Note 1 on pages 182-189.

Inherent in the application of many of the accounting policies used in preparing the financial statements is the need for BP management to make judgements, estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual outcomes could differ from the estimates and assumptions used. The following summary provides more information about the critical accounting judgements and estimates that could have a significant impact on the results of the group and should be read in conjunction with the information provided in the Notes on financial statements, including Note 1 Significant accounting policies.

The areas requiring the most significant judgement and estimation in the preparation of the consolidated financial statements are in relation to oil and natural gas accounting, including the estimation of reserves, the recoverability of asset carrying values, business combinations, taxation, derivative financial instruments, provisions and contingencies, and in particular, provisions and contingencies related to the Gulf of Mexico oil spill, and pensions and other post-retirement benefits.

Oil and natural gas accounting

The group follows the principles of the successful efforts method of accounting for its oil and natural gas exploration, appraisal and development expenditure. The group s accounting policy for oil and natural gas exploration, appraisal and development expenditure is provided in Financial statements Note 1 on page 184.

The accounting for oil and natural gas exploration, appraisal and development expenditure requires the use of various judgements and estimates in management s determination of the economic viability of a project based on a range of technical and commercial considerations, the establishment of development plans and timing, and estimates of future expenditure.

Exploration licence and leasehold property acquisition costs are capitalized within intangible assets and are reviewed at each reporting date to confirm that there is no indication that the carrying amount exceeds the recoverable amount. This review includes confirming that exploration drilling is still under way or firmly planned or that it has been determined, or work is under way to determine, that the discovery is economically viable based on a range of technical and commercial considerations and sufficient progress is being made on establishing development plans and timing. If no future activity is planned, the remaining balance of the licence and property acquisition costs is written off. Lower value licences are pooled and amortized on a straight-line basis over the estimated period of exploration.

For exploration wells and exploratory-type stratigraphic test wells, costs directly associated with the drilling of wells are initially capitalized within intangible assets, pending determination of whether potentially economic oil and gas reserves have been discovered by the drilling effort. These costs include employee remuneration, materials and fuel used, rig costs, delay rentals and payments made to contractors. The determination is usually made within one year after well completion, but can take longer, depending on the complexity of the geological structure. If the well did not encounter potentially economic oil and gas quantities, the well costs are expensed as a dry hole and are reported in exploration expense. Exploration wells that discover potentially economic quantities of oil and natural gas and are in areas where major capital expenditure (e.g. offshore platform or a pipeline) would be required before production could begin, and where the economic viability of that major capital expenditure depends on the successful completion of further exploration work in the area, remain capitalized on the balance sheet as long as additional exploration appraisal work is under way or firmly planned.

It is not unusual to have exploration wells and exploratory-type stratigraphic test wells remaining suspended on the balance sheet for several years while additional appraisal drilling and seismic work on the potential oil and natural gas field is performed or while the optimum development plans and timing are established.

All such carried costs are subject to regular technical, commercial and management review on at least an annual basis to confirm the continued intent to develop, or otherwise extract value from, the discovery. Where this is no longer the case, the costs are immediately expensed.

The determination of the group s estimated oil and gas reserves requires significant judgements and estimates to be applied and these are regularly reviewed and updated. Factors such as the availability of geological and engineering data, reservoir performance data, acquisition and divestment activity, drilling of new wells and commodity prices all impact on the determination of the group s estimates of its oil and gas reserves. BP bases its proved reserves estimates on the requirement of reasonable certainty with rigorous technical and commercial assessments based on conventional industry practice.

The estimation of oil and natural gas reserves and BP s process to manage reserves bookings is described in Exploration and Production Oil and gas disclosures on page 89, which is unaudited. Details on BP s proved reserves and production compliance and governance processes are provided on pages 90-91.

Estimates of oil and gas reserves are used to calculate depreciation, depletion and amortization charges for the group s oil and gas properties. The impact of changes in estimated proved reserves is dealt with prospectively by amortizing the remaining carrying value of the asset over the expected future production. As discussed below, oil and natural gas reserves also have a direct impact on the assessment of the recoverability of asset carrying values reported in the financial statements.

If proved reserves estimates are revised downwards, earnings could be affected by higher depreciation expense or an immediate write-down of the property s carrying value (see *discussion of recoverability of asset carrying values* below).

The 2011 movements in proved reserves are reflected in the tables showing movements in oil and gas reserves by region in Financial statements Supplementary information on oil and natural gas (unaudited) on pages 259-281. Information on the carrying amounts of the group s oil and gas properties, together with the amounts recognized in the income statement as depreciation, depletion and amortization is contained in Financial statements Note 15 and Note 9 respectively.

Recoverability of asset carrying values

BP assesses its fixed assets, including goodwill, for possible impairment if there are events or changes in circumstances that indicate that carrying values of the assets may not be recoverable and, as a result, charges for impairment are recognized in the group s results from time to time, with corresponding reductions in the carrying values of the group s assets. Such indicators include changes in the group s business plans, changes in commodity prices leading to sustained unprofitable performance, an increase in the discount rate, low plant utilization, evidence of physical damage and, for oil and natural gas properties, significant downward revisions of estimated volumes or increases in estimated future development expenditure. If there are low oil prices, natural gas prices, refining margins or marketing margins during an extended period, the group may need to recognize significant impairment charges.

The assessment for impairment entails comparing the carrying value of the asset or cash-generating unit with its recoverable amount, that is, the higher of fair value less costs to sell and value in use. Value in use is usually determined on the basis of discounted estimated future net cash flows. Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation on operating expenses, discount rates, production profiles and the outlook for global or regional market supply-and-demand conditions for crude oil, natural gas and refined products.

For oil and natural gas properties, the expected future cash flows are estimated using management s best estimate of future oil and natural gas prices and reserves volumes. Prices for oil and natural gas used for future cash flow calculations are based on market prices for the first five years and the group s long-term price assumptions thereafter. As at 31 December 2011, the group s long-term price assumptions were $90 per barrel for Brent and $6.50/mmBtu for Henry Hub (2010 $75 per barrel and $6.50/mmBtu). These long-term price assumptions are subject to periodic review and modification. The estimated future level of production is based on assumptions about future commodity prices, production and development costs, field decline rates, current fiscal regimes and other factors.

The future cash flows are adjusted for risks specific to the cash-generating unit and are discounted using a pre-tax discount rate. The discount rate is derived from the group s post-tax weighted average cost of capital and is adjusted where applicable to take into account any specific risks relating to the country where the cash-generating unit is located, although other rates may be used if appropriate to the specific circumstances. In 2011 the rates ranged from 12% to 14% nominal (2010 11% to 14% nominal). The rate applied in each country is reassessed each year.

Irrespective of whether there is any indication of impairment, BP is required to test annually for impairment of goodwill acquired in a business combination. The group carries goodwill of approximately $12.1 billion on its balance sheet (2010 $8.6 billion), principally relating to the Atlantic Richfield, Burmah Castrol, Devon Energy and Reliance transactions. In testing goodwill for impairment, the group uses a similar approach to that described above for asset impairment. If there are low oil prices or natural gas prices or refining margins or marketing margins for an extended period, the group may need to recognize significant goodwill impairment charges. In 2009, an impairment loss of $1.6 billion was recognized to write off all of the goodwill allocated to the US West Coast fuels value chain (FVC). The prevailing weak refining environment, together with a review of future margin expectations in the FVC, led to a reduction in the expected future cash flows.

Refer to *Oil and natural gas accounting* above for a discussion on the recoverability of intangible exploration and appraisal expenditure.

Details of impairment charges recognized in the income statement are provided in Financial statements Note 5 and details on the carrying amounts of assets are shown in Financial statements Note 21, Note 22 and Note 23.

Business combinations

Accounting for business combinations using the acquisition method requires the determination of the fair value of the consideration transferred, together with the fair value of the identifiable assets acquired and liabilities assumed at the acquisition date. Goodwill is measured as being the excess of the aggregate of the consideration transferred, the amount recognized for any minority interest and the acquisition-date fair values of any previously held interest in the acquiree over the fair value of the identifiable assets acquired and liabilities assumed at the acquisition date.

Judgement is required in determining whether a transaction meets the criteria to be treated as a business combination or not. Judgements and estimates are also required in order to determine the fair values of the assets acquired and the liabilities assumed, and the group uses all available information, including external valuations and appraisals where appropriate, to determine these fair values. If necessary, the group has up to one year from the acquisition date to finalize the determinations of fair value.

Details of the business combinations undertaken by the group in 2011 are provided in Financial statements Note 3 on page 194.

Taxation

The computation of the group s income tax expense and liability involves the interpretation of applicable tax laws and regulations in many jurisdictions throughout the world. The resolution of tax positions taken by the group, through negotiations with relevant tax authorities or through litigation, can take several years to complete and in some cases it is difficult to predict the ultimate outcome.

In addition, the group has carry-forward tax losses and tax credits in certain taxing jurisdictions that are available to offset against future taxable profit. However, deferred tax assets are recognized only to the extent that it is probable that taxable profit will be available against which the unused tax losses or tax credits can be utilized. Management judgement is exercised in assessing whether this is the case.

To the extent that actual outcomes differ from management s estimates, income tax charges or credits, and changes in deferred tax assets or liabilities, may arise in future periods. For more information see Financial statements Note 18 on page 210 and Note 43 on page 249.

Derivative financial instruments

The group uses derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates, interest rates and commodity prices as well as for trading purposes. In addition, derivatives embedded within other financial instruments or other host contracts are treated as separate derivatives when their risks and characteristics are not closely related to those of the host contract. All such derivatives are initially recognized at fair value on the date on which a derivative contract is entered into and are subsequently remeasured at fair value. Gains and losses arising from changes in the fair value of derivatives that are not designated as effective hedging instruments are recognized in the income statement.

In some cases the fair values of derivatives are estimated using internal models and other valuation methods due to the absence of quoted prices or other observable, market-corroborated data. This applies to the group s longer-term, structured derivative products and complex options, as well as to the majority of the group s natural gas embedded derivatives. The group s embedded derivatives arise primarily from long-term UK gas contracts that use pricing formulae not related to gas prices, for example, oil product and power prices. These contracts are valued using models with inputs that include price curves for each of the different products that are built up from active market pricing data and extrapolated to the expiry of the contracts using the maximum available external pricing information. Additionally, where limited data exists for certain products, prices are interpolated using historic and long-term pricing relationships. Price volatility is also an input for the models.

Changes in the key assumptions could have a material impact on the fair value gains and losses on derivatives and embedded derivatives recognized in the income statement. For more information see Financial statements Note 33 on page 224.

Details of the value-at-risk techniques used by the group to measure market risk exposure arising from its derivative trading positions is provided in Financial statements Note 26 on page 217. An analysis of the sensitivity of the fair value of the embedded derivatives to changes in the key assumptions is provided in Financial statements Note 26 on page 217.

Provisions and contingencies

The group holds provisions for the future decommissioning of oil and natural gas production facilities and pipelines at the end of their economic lives. The largest decommissioning obligations facing BP relate to the plugging and abandonment of wells and the removal and disposal of oil and natural gas platforms and pipelines around the world. The estimated discounted costs of performing this work are recognized as we drill the wells and install the facilities, reflecting our legal obligations at that time. A corresponding asset of an amount equivalent to the provision is also created within property, plant and equipment. This asset is depreciated over the expected life of the production facility or pipeline. Most of these decommissioning events are many years in the future and the precise requirements that will have to be met when the removal event actually occurs are uncertain. Decommissioning technologies and costs are constantly changing, as well as political, environmental, safety and public expectations. Consequently, the timing and amounts of future cash flows are subject to significant uncertainty. Any changes in the expected future costs are reflected in both the provision and the asset.

Decommissioning provisions associated with downstream and petrochemicals facilities are generally not recognized, as such potential obligations cannot be measured, given their indeterminate settlement dates. The group performs periodic reviews of its downstream and petrochemicals long-lived assets for any changes in facts and circumstances that might require the recognition of a decommissioning provision.

The timing and amount of future expenditures are reviewed annually, together with the interest rate used in discounting the cash flows. The interest rate used to determine the balance sheet obligation at the end of 2011 was 0.5% (2010 1.5%). The interest rate represents the real rate (i.e. excluding the impacts of inflation) on long-dated government bonds.

Other provisions and liabilities are recognized in the period when it becomes probable that there will be a future outflow of funds resulting from past operations or events and the amount of cash outflow can be reliably estimated. The timing of recognition and quantification of the liability require the application of judgement to existing facts and circumstances, which can be subject to change. Since the actual cash outflows can take place many years in the future, the carrying amounts of provisions and liabilities are reviewed regularly and adjusted to take account of changing facts and circumstances.

A change in estimate of a recognized provision or liability would result in a charge or credit to net income in the period in which the change occurs (with the exception of decommissioning costs as described above).

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 commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites. The provision for environmental liabilities is estimated based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, prices, discovery and analysis of site conditions and changes in clean-up technology.

The provision for environmental liabilities is reviewed at least annually. The interest rate used to determine the balance sheet obligation at 31 December 2011 was 0.5% (2010 1.5%).

Information about the group s provisions is provided in Financial statements Note 36.

As further described in Financial statements Note 43 on page 249, the group is subject to claims and actions. The facts and circumstances relating to particular cases are evaluated regularly in determining whether it is probable that there will be a future outflow of funds and, once established, whether a provision relating to a specific litigation should be established or revised. Accordingly, significant management judgement relating to provisions and contingent liabilities is required, since the outcome of litigation is difficult to predict.

Gulf of Mexico oil spill

Detailed information on the Gulf of Mexico oil spill, including the financial impacts, is provided in Financial statements Note 2 on pages 190-194.

As a consequence of the Gulf of Mexico oil spill, as described on pages 76-79, BP continues to incur costs and has also recognized liabilities for future costs. Liabilities of uncertain timing or amount and contingent liabilities have been accounted for and/or disclosed in accordance with IAS 37 Provisions, contingent liabilities and contingent assets . BP s rights and obligations in relation to the $20-billion trust fund which was established in 2010 are accounted for in accordance with IFRIC 5 Rights to interests arising from decommissioning, restoration and environmental rehabilitation funds .

The total amounts that will ultimately be paid by BP in relation to all obligations relating to the incident are subject to significant uncertainty and the ultimate exposure and cost to BP will be dependent on many factors (including, with respect to certain of the obligations, any determination of BP s culpability based on any findings of negligence, gross negligence or wilful misconduct). Furthermore, significant uncertainty exists in relation to the amount of claims that will become payable by BP, the amount of fines that will ultimately be levied on BP, the outcome of litigation and arbitration proceedings, the amount and timing of payments under any settlements, and any costs arising from any longer-term environmental consequences of the oil spill, which will also impact upon the ultimate cost for BP. Any further settlements which may be reached relating to the Deepwater Horizon oil spill could impact the amount and timing of any future payments. Although the provision recognized is the current best reliable estimate of expenditures required to settle certain present obligations at the end of the reporting period, there are future expenditures for which it is not possible to measure the obligation reliably as noted below under *Contingent liabilities.*

The magnitude and timing of possible obligations in relation to the Gulf of Mexico oil spill are subject to a very high degree of uncertainty as described further in Risk factors on pages 59-63. Furthermore, other material unanticipated obligations may arise in future in relation to the incident. Refer to Financial statements Note 43 on page 249 for further information.

Expenditure to be met from the $20-billion trust fund

In 2010, BP established the Deepwater Horizon Oil Spill Trust (the Trust) to be funded in the amount of $20 billion over the period to the fourth quarter of 2013, which is available to satisfy legitimate individual and business claims administered by the Gulf Coast Claims Facility (GCCF), state and local government claims resolved by BP, final judgments and settlements, state and local response costs, and natural resource damages and related costs. It is currently expected that the cost of the proposed settlement will be payable from the Trust. In 2010, BP contributed $5 billion to the fund, and further regular contributions totalling $5 billion were made in 2011. During 2011, BP also contributed the cash settlements received from MOEX, Weatherford and Anadarko amounting in total to $5.1 billion. A further cash settlement from Cameron was received in January 2012 and was also contributed to the trust fund. As a result of these accelerated contributions, it is now expected that the $20-billion commitment will have been paid in full by the end of 2012.

Fines, penalties and claims administration costs are not covered by the trust fund. BP s obligation to make contributions to the trust fund was recognized in full in the 2010 group income statement and the remaining liability to fund the Trust is included within other payables on the balance sheet after taking account of the time value of money. The establishment of the trust fund does not represent a cap or floor on BP s liabilities and BP does not admit to a liability of this amount.

An asset has been recognized representing BP s right to receive reimbursement from the trust fund. This is the portion of the estimated future expenditure provided for that will be settled by payments from the trust fund. We use the term "reimbursement asset" to describe this asset. BP will not actually receive any reimbursements from the trust fund, instead payments will be made directly to claimants from the trust fund, and BP will be released from its corresponding obligation.

Contingent liabilities relating to the Gulf of Mexico oil spill

BP has provided for its best estimate of certain claims under the Oil Pollution Act 1990 (OPA 90) that will be paid through the $20-billion trust fund, including the increased estimate of the cost of individual and business claims as a result of the proposed settlement announced on 3 March 2012 as described in Note 2 and Note 36. It is not possible, at this time, to measure reliably any other items that will be paid from the trust fund, namely any obligation in relation to Natural Resource Damages claims (except for the estimated costs of the assessment phase and the costs relating to emergency and early restoration agreements) and claims asserted in civil litigation, including any further litigation through potential opt-outs from the proposed settlement agreement with the Plaintiffs Steering Committee announced on 3 March 2012 (see page 76 for further information), nor is it practicable to estimate their magnitude or possible timing of payment. Although these items, which will be paid through the trust fund, have not been provided for at this time, BP s full obligation under the $20-billion trust fund was expensed in the income statement in 2010, taking account of the time value of money.

For those items not covered by the trust fund it is not possible to measure reliably any obligation in relation to other litigation or potential fines and penalties except, subject to certain assumptions, for those relating to the Clean Water Act. Therefore no amounts have been provided for these items as at 31 December 2011. There are a number of federal and state environmental and other provisions of law, other than the Clean Water Act, under which one or more governmental agencies could seek civil fines and penalties from BP. Given the large number of claims that may be asserted, it is not possible at this time to determine whether and to what extent any such claims would be successful or what penalties or fines would be assessed.

Pensions and other post-retirement benefits

Accounting for pensions and other post-retirement benefits involves judgement about uncertain events, including estimated retirement dates, salary levels at retirement, mortality rates, rates of return on plan assets, determination of discount rates for measuring plan obligations, assumptions for inflation rates, US healthcare cost trend rates and rates of utilization of healthcare services by US retirees.

These assumptions are based on the environment in each country. Determination of the projected benefit obligations for the group s defined benefit pension and post-retirement plans is important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the income statement. The assumptions used may vary from year to year, which will affect future results of operations. Any differences between these assumptions and the actual outcome also affect future results of operations.

Pension and other post-retirement benefit assumptions are reviewed by management at the end of each year. These assumptions are used to determine the projected benefit obligation at the year-end and hence the surpluses and deficits recorded on the group s balance sheet, and pension and other post-retirement benefit expense for the following year.

The pension and other post-retirement benefit assumptions at December 2011, 2010 and 2009 are provided in Financial statements Note 37 on page 234.

The assumed rate of investment return, discount rate, inflation rate and the US healthcare cost trend rate have a significant effect on the amounts reported. A sensitivity analysis of the impact of changes in these assumptions on the benefit expense and obligation is provided in Financial statements Note 37 on page 234.

In addition to the financial assumptions, we regularly review the demographic and mortality assumptions. Mortality assumptions reflect best practice in the countries in which we provide pensions and have been chosen with regard to the latest available published tables adjusted where appropriate to reflect the experience of the group and an extrapolation of past longevity improvements into the future. A sensitivity analysis of the impact of changes in the mortality assumptions on the benefit expense and obligation is provided in Financial statements Note 37 on page 234.

Actuarial gains and losses are recognized in full within other comprehensive income in the year in which they occur.

Property, plant and equipment

BP has freehold and leasehold interests in real estate in numerous countries, but no individual property is significant to the group as a whole. See Exploration and Production on page 80 for a description of the group s significant reserves and sources of crude oil and natural gas. Significant plans to construct, expand or improve specific facilities are described under each of the business headings within this section.

Share ownership

Directors and senior management

As at 1 March 2012, the following directors of BP p.l.c. held interests in BP ordinary shares of 25 cents each or their calculated equivalent as set out below:

Director	Ordinary shares	Performance shares[a]	Restricted shares[b]
C-H Svanberg	933,971		
R W Dudley	337,301[c]	1,911,414[c]	
P M Anderson	6,000[c]		
F L Bowman	12,720[c]		
A Burgmans	10,156		
C B Carroll	10,500[c]		
Sir William Castell	82,500		
I C Conn	497,501[d]	1,322,606	133,452[b]
G David	579,000[c]		
I E L Davis	10,391		
Professor Dame Ann Dowling			
Dr B Gilvary	331,088	45,000	269,145[e]
Dr B E Grote	1,484,603[f]	1,693,704[c]	
B R Nelson	11 ,040		
F P Nhleko			
A Shilston			

a Performance shares awarded under the BP Executive Directors Incentive Plan. 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.

b Restricted share award under the BP Executive Directors Incentive Plan. These shares will vest in 2013, subject to the director s continued service and satisfactory performance.

c Held as ADSs.

d Includes 48,024 shares held as ADSs.

e Held as restricted share units under the BP Deferred Annual Bonus Plan and the BP Executive Performance Plan.

f Held as ADSs, except for 94 shares held as ordinary shares.

As at 1 March 2012, the following directors of BP p.l.c. held options under the BP group share option schemes for ordinary shares or their calculated equivalent as set out below:

Director	Options
R W Dudley[a]	107,010
I C Conn	3,622
Dr B Gilvary	504,191
Dr B E Grote[a]	

a Held as ADSs.

There are no directors or members of senior management who own more than 1% of the ordinary shares outstanding. At 1 March 2012, all directors and senior management as a group held interests in 10,760,373 ordinary shares or their calculated equivalent, 5,536,676 performance shares or their calculated equivalent and 7,575,135 options for ordinary shares or their calculated equivalent under the BP group share options schemes.

Additional details regarding the options granted and performance shares awarded can be found in the Directors remuneration report on pages 139-151.

Employee share plans

The following table shows employee share options granted.

			Options thousands
	2011[a]	2010	2009
Employee share options granted during the year[b]	**152,473**	10,420	9,680

[a] 142,550,350 options were granted pursuant to the BP Plan 2011, adopted on 7 September 2011. For more information on the BP Plan 2011, see Financial statements Note 40 on page 246.
[b] For the options outstanding at 31 December 2011, the exercise price ranges and weighted average remaining contractual lives are shown in Financial statements Note 40 on page 246.

BP offers most of its employees the opportunity to acquire a shareholding in the company through savings-related and/or matching share plan arrangements. BP also uses performance plans and option plans (*see Financial statements Note 40 on page 246*) as elements of remuneration for executive directors and senior employees.

Shares acquired through the company s employee share plans rank pari passu with shares in issue and have no special rights, save as described below. For legal and practical reasons, the rules of these plans set out the consequences of a change of control of the company, and generally provide for options and conditional awards to vest on an accelerated basis.

Matching and saving plans

BP ShareMatch plans

These matching share plans give employees the opportunity to buy ordinary shares in BP p.l.c. and receive free matching shares in BP p.l.c., up to a predetermined limit. The plans are run in the UK and in more than 50 other countries. The UK plan is an approved HMRC plan and runs on a monthly basis. Under the UK plan, shares must be held in trust for at least three years to receive beneficial tax treatment. In other countries, the plan is run on an annual basis with shares being held in trust for three years. The plan is operated on a cash basis in those countries where there are regulatory restrictions preventing the holding of BP shares. When the employee leaves BP all shares must be removed from trust and units under the plan operated on a cash basis must be encashed.

Once shares have been awarded to an employee under the plan, the employee may instruct the trustee how to vote their shares.

BP ShareSave Plan

This is an approved HMRC plan which is open to all eligible UK employees. Participants can contribute up to a maximum of £250 per month from their net salary to a savings account over a three- or five-year contractual savings period. At the end of the savings period, they are entitled to purchase shares in BP p.l.c. at a preset price determined on the date when the invitations are sent to eligible employees. This price is usually set at a discount to the market price of a share of up to 20%. The option must be exercised within six months of maturity of the savings contract, otherwise it lapses. The plan is run in the UK and options are granted annually, usually in June. Participants leaving for a qualifying reason before the savings contract matured will have up to six months in which to use their savings to exercise their options on a pro-rated basis.

Local plans

In some countries, BP provides local scheme benefits, the rules and qualifications for which vary according to local circumstances. Certain US employees may participate in a defined contribution (401k) plan in which BP matches employee contributions up to certain limits. Participants may invest in several investment options including a BP Stock Fund that holds BP ADSs and a small percentage of cash. At 31 December 2011 the BP Stock Fund held 39,026,928 BP ADSs with a market value of $1,682 million (2010: 38,382,657 BP ADSs and $1,715 million). Participants in the fund as of the record date may direct the trustee how to vote their portion of the BP Stock Fund.

Cash-settled share-based payments

Grants are settled in cash where participants are located in a country whose regulatory environment prohibits the holding of BP shares.

Employee Share Ownership Plan Trusts (ESOPs)

ESOPs have been established to hold BP shares to satisfy any releases made to participants under the Executive Directors Incentive Plan, the Long-Term Performance Plan and the Share Option Plan. The ESOPs have waived their rights to dividends on shares held for future awards and are funded by the group. Pending vesting, the ESOPs have independent trustees that have the discretion in relation to the voting of such shares. Until such time as the company s own shares held by the ESOPs vest unconditionally in employees, the amount paid for those shares is deducted in arriving at shareholders equity (see *Financial statements -Note 39 on page 242).* Assets and liabilities of the ESOPs are recognized as assets and liabilities of the group.

At 31 December 2011, the ESOPs held 27,784,503 shares (2010 11,477,253 shares and 2009 18,062,246 shares) for potential future awards, which had a market value of $197 million (2010 $82 million and 2009 $174 million).

Pursuant to the various BP group share option schemes, the following options for ordinary shares of the company were outstanding at 17 February 2012:

Options outstanding (shares)	Expiry dates of options		Exercise price per share
334,424,461	2012-2021	$	5.66-11.92

More details on share options appear in Financial statements Note 40 on page 246.

Major shareholders

The disclosure of certain major and significant shareholdings in the share capital of the company is governed by the Companies Act 2006, the UK Financial Services Authority s Disclosure and Transparency Rules (DTR) and the US Securities Exchange Act of 1934.

Register of members holding BP ordinary shares as at 31 December 2011

Range of holdings	Number of ordinary shareholders	Percentage of total ordinary shareholders	Percentage of total ordinary share capital excluding shares held in treasury
1-200	59,824	19.65	0.02
201-1,000	112,279	36.87	0.31
1,001-10,000	119,628	39.28	1.88
10,001-100,000	11,107	3.65	1.17
100,001-1,000,000	923	0.30	1.81
Over 1,000,000[a]	755	0.25	94.81
Totals	304,516	100.00	100.00

a Includes JPMorgan Chase Bank, N.A. holding 26.50% of the total ordinary issued share capital (excluding shares held in treasury) as the approved depositary for ADSs, a breakdown of which is shown in the table below.

Register of holders of American depositary shares (ADSs) as at 31 December 2011[a]

Range of holdings	Number of ADS holders	Percentage of total ADS holders	Percentage of total ADSs
1-200	62,206	56.35	0.42
201-1,000	30,364	27.50	1.73
1,001-10,000	16,856	15.27	5.34
10,001-100,000	966	0.87	1.96
100,001-1,000,000	9	0.01	0.15
Over 1,000,000[b]	1	0.00	90.40
Totals	110,402	100.00	100.00

a One ADS represents six 25 cent ordinary shares.

b One holder of ADSs represents 792,991 underlying shareholders.

As at 31 December 2011, there were also 1,591 preference shareholders. Preference shareholders represented 0.44% and ordinary shareholders represented 99.56% of the total issued nominal share capital of the company (excluding shares held in treasury) as at that date.

In accordance with DTR 5, we have received notification that as at 31 December 2011 BlackRock, Inc. held 5.69% and Legal & General Group Plc held 3.90% of the voting rights of the issued share capital of the company. As at 17 February 2012 BlackRock, Inc. held 5.37% and Legal & General Group Plc held 3.99% of the voting rights of the issued share capital of the company.

Under the US Securities Exchange Act of 1934 we have received notification of the following interests as at 17 February 2012:

Holder	Holding of ordinary shares	Percentage of ordinary share capital excluding shares held in treasury
JPMorgan Chase Bank, depositary for ADSs, through its nominee Guaranty Nominees Limited	5,031,905,448	26.51
BlackRock, Inc.	1,019,731,492	5.37
Legal & General Group plc	758,363,148	4.00

The company s major shareholders do not have different voting rights.

On 17 May 2011, BP announced that the Rosneft Share Swap Agreement, originally announced on 14 January 2011, had terminated. For further information see Legal proceedings on page 166.

The company has also been notified of the following interests in preference shares as at 17 February 2012:

Holder	Holding of 8% cumulative first preference shares	Percentage of class
The National Farmers Union Mutual Insurance Society	945,000	13.07
M & G Investment Management Ltd.	528,150	7.30
Duncan Lawrie Ltd.	426,876	5.90
Smith & Williamson Investment Management Ltd.	407,250	5.63
Barclays Wealth	370,931	5.13

Holder	Holding of 9% cumulative second preference shares	Percentage of class
The National Farmers Union Mutual Insurance Society	987,000	18.03
M & G Investment Management Ltd.	644,450	11.77
Royal London Asset Management Ltd.	438,000	8.00

Smith & Williamson Investment Management Ltd.	405,500	7.41
Ruffer LLP	294,000	5.37

Lazard Asset Management Limited disposed of its interests in 374,000 8% cumulative first preference shares and 404,500 9% cumulative second preference shares during 2011.

Gartmore Investment Management Limited disposed of its interest in 394,538 8% cumulative first preference shares and 500,000 9% cumulative second preference shares during 2010.

As at 17 February 2012, the total preference shares in issue comprised only 0.44% of the company s total issued nominal share capital (excluding shares held in treasury), the rest being ordinary shares.

Called-up share capital

Details of the allotted, called-up and fully-paid share capital at 31 December 2011 are set out in Financial statements Note 38 on page 241.

At the AGM on 14 April 2011, authorization was given to the directors to allot shares up to an aggregate nominal amount equal to $3,133 million. Authority was also given to the directors to allot shares for cash and to dispose of treasury shares, other than by way of rights issue, up to a maximum of $235 million, without having to offer such shares to existing shareholders. These authorities are given for the period until the next AGM in 2012 or 14 July 2012, whichever is the earlier. These authorities are renewed annually at the AGM.

Dividends

When dividends are paid on its ordinary shares, BP s policy is to pay interim dividends on a quarterly basis.

BP policy is also to announce dividends for ordinary shares in US dollars and state an equivalent sterling dividend. Dividends on BP ordinary shares will be paid in sterling and on BP ADSs in US dollars. The rate of exchange used to determine the sterling amount equivalent is the average of the market exchange rates in London over the four business days prior to the sterling equivalent announcement date. The directors may choose to declare dividends in any currency provided that a sterling equivalent is announced, but it is not the company s intention to change its current policy of announcing dividends on ordinary shares in US dollars.

Information regarding dividends announced and paid by the company on ordinary shares and preference shares is provided in Financial statements Note 19 on page 212.

A Scrip Dividend Programme (Programme) was introduced in 2011 which enables BP ordinary shareholders and ADS holders to elect to receive new fully paid ordinary shares in BP (or ADSs in the case of ADS holders) instead of cash. The operation of the Programme is always subject to the directors decision to make the scrip offer available in respect of any particular dividend. Should the directors decide not to offer the scrip in respect of any particular dividend, cash will automatically be paid instead.

Future dividends will be dependent on future earnings, the financial condition of the group, the Risk factors set out on pages 59-63 and other matters that may affect the business of the group set out in Our strategy on pages 37-41 and in Liquidity and capital resources on page 103.

The following table shows dividends announced and paid by the company per ADS for each of the past five years.

Dividends per ADS		March	June	September	December	Total
2007	UK pence	31.5	30.9	31.7	31.8	125.9
	US cents	61.95	61.95	64.95	64.95	253.8
	Canadian cents	73.3	69.5	67.8	63.6	274.2
2008	UK pence	40.9	41.0	42.2	52.2	176.3
	US cents	81.15	81.15	84.0	84.0	330.3
	Canadian cents[a]	80.8	82.5	85.8	108.6	357.7
2009	UK pence	58.91	57.50	51.02	51.07	218.5
	US cents	84	84	84	84	336
2010	UK pence	52.07				52.07
	US cents	84				84
2011	**UK pence**	**26.02**	**25.68**	**25.90**	**26.82**	**104.42**
	US cents	**42**	**42**	**42**	**42**	**168**

a BP shares were de-listed from the Toronto Stock Exchange on 15 August 2008 and the last dividend payment in Canadian dollars was made on 8 December 2008.

Legal proceedings

Proceedings relating to the Deepwater Horizon oil spill

BP p.l.c., BP Exploration & Production Inc. (BP E&P) and various other BP entities (collectively referred to as BP) are among the companies named as defendants in approximately 600 private civil lawsuits resulting from the 20 April 2010 explosions and fire on the semi-submersible rig Deepwater Horizon and resulting oil spill (the Incident) and further actions are likely to be brought. BP E&P is lease operator of Mississippi Canyon, Block 252 in the Gulf of Mexico (Macondo), where the Deepwater Horizon was deployed at the time of the Incident. The other working interest owners at the time of the Incident were Anadarko Petroleum Company (Anadarko) and MOEX Offshore 2007 LLC (MOEX). The Deepwater Horizon, which was owned and operated by certain affiliates of Transocean Ltd. (Transocean), sank on 22 April 2010. The pending lawsuits and/or claims arising from the Incident have been brought in US federal and state courts. Plaintiffs include individuals, corporations, insurers, and governmental entities and many of the lawsuits purport to be class actions. The lawsuits assert, among others, claims for personal injury in connection with the Incident itself and the response to it, wrongful death, commercial and economic injury, breach of contract and violations of statutes. The lawsuits seek various remedies including compensation to injured workers and families of deceased workers, recovery for commercial losses and property damage, claims for environmental damage, remediation costs, claims for unpaid wages, injunctive and declaratory relief, treble damages and punitive damages. Purported classes of claimants include residents of the states of Louisiana, Mississippi, Alabama, Florida, Texas, Tennessee, Kentucky, Georgia and South Carolina, property owners and rental agents, fishermen and persons dependent on the fishing industry, charter boat owners and deck hands, marina owners, gasoline distributors, shipping interests, restaurant and hotel owners, cruise lines and others who are property and/or business owners alleged to have suffered economic loss. Among other claims arising from the spill response efforts, lawsuits have been filed claiming that additional payments are due by BP under certain Master Vessel Charter Agreements entered into in the course of the Vessels of Opportunity Program implemented as part of the response to the Incident.

Shareholder derivative lawsuits related to the Incident have also been filed in US federal and state courts against various current and former officers and directors of BP alleging, among other things, breach of fiduciary duty, gross mismanagement, abuse of control and waste of corporate assets. On 15 September 2011, the judge in the federal multi-district litigation proceeding in Houston granted BP s motion to dismiss the consolidated shareholder derivative litigation pending there on the grounds that the courts of England are the appropriate forum for the litigation. On 8 December 2011, a final judgment was entered dismissing the shareholder derivative case, and on 3 January 2012, one of the derivative plaintiffs filed a notice of appeal to the US Court of Appeals for the Fifth Circuit.

On 13 February 2012, the judge in the federal multi-district litigation proceeding in Houston issued two decisions on the defendants motions to dismiss the two consolidated securities fraud complaints filed on behalf of purported classes of BP ordinary shareholders and ADS holders. In those decisions the court dismissed all of the claims of the ordinary shareholders, dismissed the claims of the lead class of ADS holders against most of the individual defendants while holding that a subset of the claims against two individual defendants and the corporate defendants could proceed, and dismissed all of the claims of a smaller purported subclass with leave to re-plead in 20 days.

Purported class action lawsuits have been filed in US federal courts against BP entities and various current and former officers and directors alleging, among other things, securities fraud claims, violations of the Employee Retirement Income Security Act (ERISA) and contractual and quasi-contractual claims related to the cancellation of the dividend on 16 June 2010. In addition, BP has been named in several lawsuits alleging claims under the Racketeer-Influenced and Corrupt Organizations Act (RICO). In August 2010, many of the lawsuits pending in federal court were consolidated by the Federal Judicial Panel on Multidistrict Litigation into two multi-district litigation proceedings, one in federal court in Houston for the securities, derivative, ERISA and dividend cases and another in federal court in New Orleans for the remaining cases.

On 1 June 2010, the US Department of Justice (DoJ) announced that it is conducting an investigation into the Incident encompassing possible violations of US civil or criminal laws. The types of enforcement action that might be pursued and the nature of the remedies that might be sought will depend on the judgement and discretion of the prosecutors and regulatory authorities and their assessment as to whether BP has violated any applicable laws and its culpability following their investigations. Such enforcement actions could include criminal proceedings against BP and/or employees of the group. Prosecutors have broad discretion in identifying what, if any, charges to pursue, but such charges could include, among others, criminal environmental, criminal securities, manslaughter and obstruction-related offences. The United States filed a civil complaint in the multi-district litigation proceeding in New Orleans against BP E&P and others on 15 December 2010 (DoJ Action). The complaint seeks a declaration of liability under the Oil Pollution Act of 1990 (OPA 90) and civil penalties under the Clean Water Act and sets forth a purported reservation of rights on behalf of the US to amend the complaint or file additional complaints seeking various remedies under various US federal laws and statutes. On 8 December 2011, the US brought a motion for partial summary judgment seeking, among other things, an order finding that BP, Transocean, and Anadarko are strictly liable for a civil penalty under Section 311(b)(7)(A) of the Clean Water Act. This motion remains pending.

On 18 February 2011, Transocean filed a third-party complaint against BP, the US government, and other corporations involved in the Incident, naming those entities as formal parties in its Limitation of Liability action pending in federal court in New Orleans.

On 4 April 2011, BP initiated contractual out-of-court dispute resolution proceedings against Anadarko and MOEX, claiming that they have breached the parties contract by failing to reimburse BP for their working-interest share of Incident-related costs. On 19 April 2011, Anadarko filed a cross-claim against BP, alleging gross negligence and 15 other counts under state and federal laws. Anadarko sought a declaration that it was excused from its contractual obligation to pay Incident-related costs. Anadarko also sought damages from alleged economic losses and contribution or indemnity for claims filed against it by other parties. On 20 May 2011, BP and MOEX announced a settlement agreement of all claims between them, including a cross-claim brought by MOEX on 19 April 2011 similar to the Anadarko claim. Under the settlement agreement, MOEX has paid BP $1.065 billion, which BP has applied towards the $20-billion Trust and has also agreed to transfer all of its 10% interest in the MC252 lease to BP. On 17 October 2011, BP and Anadarko announced that they had reached a final agreement to settle all claims between the companies related to the Incident, including mutual releases of all claims between BP and Anadarko that are subject to the contractual out-of-court dispute resolution proceedings or the federal multi-district litigation proceeding in New Orleans. Under the settlement agreement, Anadarko has paid BP $4 billion, which BP has applied towards the $20-billion Trust, and has also agreed to transfer all of its 25% interest in the MC252 lease to BP. The settlement agreement also grants Anadarko the opportunity for a 12.5% participation in certain future recoveries from third parties and certain insurance proceeds in the event that such recoveries and proceeds exceed $1.5 billion in aggregate. Any such payments to Anadarko are capped at a total of $1 billion. BP has agreed to indemnify Anadarko and MOEX for certain claims arising from the Incident (excluding civil, criminal or administrative fines and penalties, claims for punitive damages, and certain other claims). The settlement agreements with Anadarko and MOEX are not an admission of liability by any party regarding the Incident.

On 20 April 2011, Transocean filed claims in its Limitation of Liability action alleging that BP had breached BP America Production Company s contract with Transocean Holdings LLC by BP not agreeing to indemnify Transocean against liability related to the Incident and by not paying certain invoices. Transocean also asserted claims against BP under state law, maritime law, and OPA 90 for contribution. On 1 November 2011, Transocean filed a motion for partial summary judgment on certain claims filed in the Limitation Action and the DoJ Action between BP and Transocean. Transocean s motion sought an order which would bar BP s contribution claims against Transocean and require BP to defend and indemnify Transocean against all pollution claims, including those resulting from any gross negligence, and from civil fines and penalties sought by the government. On 7 December 2011, BP filed a cross-motion for summary judgment seeking an order that BP is not required to indemnify Transocean for any civil fines and penalties sought by the government or for punitive damages.

On 26 January 2012, the judge ruled on BP s and Transocean s indemnity motions, holding that BP is required to indemnify Transocean for third-party claims for compensatory damages resulting from pollution originating beneath the surface of the water, regardless of whether the claim results from Transocean s strict liability, negligence, or gross negligence. The court, however, ruled that BP does not owe Transocean indemnity for such claims to the extent Transocean is held liable for punitive damages or for civil penalties under the Clean Water Act, or if Transocean acted with intentional or wilful misconduct in excess of gross negligence. The court further held that BP s obligation to defend Transocean for third-party claims does not require BP to fund Transocean s defence of third-party claims at this time, nor does it include Transocean s expenses in proving its right to indemnity. The court deferred a final ruling on the question of whether Transocean breached its drilling contract with BP so as to invalidate the contract s indemnity clause.

On 22 February 2012, the judge ruled on motions filed in the DoJ Action by the US, Anadarko, and Transocean seeking early rulings regarding the liability of BP, Anadarko, and Transocean under OPA 90 and the Clean Water Act, but limited the order to addressing the discharge of hydrocarbons occurring under the surface of the water. Regarding OPA 90, the judge held that BP and Anadarko are responsible parties under OPA 90 with regard to the subsurface discharge. The judge ruled that BP and Anadarko have joint and several liability under OPA 90 for removal costs and damages for such discharge, but did not rule on whether such liability under OPA 90 is unlimited. While the judge held that Transocean is not a responsible party under OPA 90 for subsurface discharge, the judge left open the question of whether Transocean may be liable under OPA 90 for removal costs for such discharge as the owner/operator of the Deepwater Horizon. Regarding the Clean Water Act, the judge held that the subsurface discharge was from the Macondo well, rather than from the Deepwater Horizon, and that BP and Anadarko are liable for civil penalties under Section 311 of the Clean Water Act as owners of the well. The judge left open the question of whether Transocean may be liable under the Clean Water Act as an operator of the Macondo well.

On 20 April 2011, Halliburton Energy Services, Inc. (Halliburton), filed claims in Transocean s Limitation of Liability action seeking indemnification from BP for claims brought against Halliburton in that action, and Cameron International Corporation (Cameron) asserted claims against BP for contribution under state law, maritime law, and OPA 90, as well as for contribution on the basis of comparative fault. Halliburton also asserted a claim for negligence, gross negligence and wilful misconduct against BP and others. On 19 April 2011, Halliburton filed a separate lawsuit in Texas state court seeking indemnification from BP E&P for certain tort and pollution-related liabilities resulting from the Incident. On 3 May 2011, BP E&P removed Halliburton s case to federal court, and on 9 August 2011, the action was transferred to the federal multi-district litigation proceedings pending in New Orleans.

Subsequently, on 30 November 2011, Halliburton filed a motion for summary judgment in the federal multi-district litigation proceedings pending in New Orleans. Halliburton s motion seeks an order stating that Halliburton is entitled to full and complete indemnity, including payment of defence costs, from BP for claims related to the Incident and denying BP s claims seeking contribution against Halliburton. On 21 December 2011, BP filed a cross-motion for partial summary judgment seeking an order that BP has no contractual obligation to indemnify Halliburton for fines, penalties, or punitive damages resulting from the Incident.

On 31 January 2012, the judge ruled on BP s and Halliburton s indemnity motions, holding that BP is required to indemnify Halliburton for third-party claims for compensatory damages resulting from pollution that did not originate from property or equipment of Halliburton located above the surface of the land or water, regardless of whether the claims result from Halliburton s gross negligence. The court, however, ruled that BP does not owe Halliburton indemnity to the extent that Halliburton is held

liable for punitive damages or for civil penalties under the Clean Water Act. The court further held that BP s obligation to defend Halliburton for third-party claims does not require BP to fund Halliburton s defence of third-party claims at this time, nor does it include Halliburton s expenses in proving its right to indemnity. The court deferred ruling on whether BP is required to indemnify Halliburton for any penalties or fines under the Outer Continental Shelf Lands Act. It also deferred ruling on whether Halliburton acted so as to invalidate the indemnity by breaching its contract with BP, by committing fraud, or by committing another act that materially increased the risk to BP or prejudiced the rights of BP as an indemnitor.

On 1 September 2011, Halliburton filed an additional lawsuit against BP in Texas state court. Its complaint alleges that BP did not identify the existence of a purported hydrocarbon zone at the Macondo well to Halliburton in connection with Halliburton s cement work performed before the Incident and that BP has concealed the existence of this purported hydrocarbon zone following the Incident. Halliburton claims that the alleged failure to identify this information has harmed its business ventures and reputation and resulted in lost profits and other damages. On 16 September 2011, BP removed the action to federal court, where it was stayed pending a decision by the Judicial Panel on Multidistrict Litigation on transfer of the action to the multi-district litigation proceeding in New Orleans. On 1 September 2011, Halliburton also moved to amend its claims in Transocean s Limitation of Liability action to add claims for fraud based on similar factual allegations to those included in its 1 September 2011 lawsuit against BP in Texas state court. On 11 October 2011, the magistrate judge in the federal multi-district litigation proceeding in New Orleans denied Halliburton s motion to amend its claims, and Halliburton s motion to review the order was denied by the judge on 19 December 2011.

On 20 April 2011, BP asserted claims against Cameron, Halliburton, and Transocean in the Limitation of Liability action. BP s claims against Transocean include breach of contract, unseaworthiness of the Deepwater Horizon vessel, negligence (or gross negligence and/or gross fault as may be established at trial based upon the evidence), contribution and subrogation for costs (including those arising from litigation claims) resulting from the Incident, as well as a declaratory claim that Transocean is wholly or partly at fault for the Incident and responsible for its proportionate share of the costs and damages. BP asserted claims against Halliburton for fraud and fraudulent concealment based on Halliburton s misrepresentations to BP concerning, among other things, the stability testing on the foamed cement used at the Macondo well; for negligence (or, if established by the evidence at trial, gross negligence) based on Halliburton s performance of its professional services, including cementing and mud logging services; and for contribution and subrogation for amounts that BP has paid in responding to the Incident, as well as in OPA assessments and in payments to plaintiffs. BP filed a similar complaint in federal court in the Southern District of Texas, Houston Division, against Halliburton, and the action was transferred on 4 May 2011 to the federal multi-district litigation proceeding pending in New Orleans.

On 20 April 2011, BP filed claims against Cameron, Halliburton, and Transocean in the DoJ Action, seeking contribution for any assessments against BP under OPA 90 based on those entities fault. On 20 June 2011, Cameron and Halliburton moved to dismiss BP s claims against them in the DoJ Action. BP s claim against Cameron has been resolved pursuant to settlement, but Halliburton s motion remains pending.

On 16 December 2011, BP and Cameron announced their agreement to settle all claims between the companies related to the Incident, including mutual releases of claims between BP and Cameron that are subject to the federal multi-district litigation proceeding in New Orleans. Under the settlement agreement, Cameron has paid BP $250 million in cash in January 2012, which BP has applied towards the $20-billion Trust. BP has agreed to indemnify Cameron for compensatory claims arising from the Incident, including claims brought relating to pollution damage or any damage to natural resources, but excluding civil, criminal or administrative fines and penalties, claims for punitive damages, and certain other claims.

On 20 May 2011, Dril-Quip, Inc. and M-I L.L.C. (M-I) filed claims against BP in Transocean s Limitation of Liability action, each claiming a right to contribution from BP for damages assessed against them as a result of the Incident, based on allegations of negligence. M-I also claimed a right to indemnity for such damages based on its well services contracts with BP. On 20 June 2011, BP filed counter-complaints against Dril-Quip, Inc. and M-I, asking for contribution and subrogation based on those entities fault in connection with the Incident and under OPA 90, and seeking declaratory judgment that Dril-Quip, Inc. and M-I caused or contributed to, and are responsible in whole or in part for damages incurred by BP in relation to, the Incident. On 20 January 2012, the court granted Dril-Quip, Inc. s motion for summary judgment, dismissing with prejudice all claims asserted against Dril-Quip in the federal multi-district litigation proceeding in New Orleans.

On 21 January 2012, BP and M-I entered into an agreement settling all claims between the companies related to the Incident, including mutual releases of claims between BP and M-I that are subject to the federal multi-district litigation proceeding in New Orleans. Under the settlement agreement, M-I has agreed to indemnify BP for personal injury and death claims brought by M-I employees. BP has agreed to indemnify M-I for claims resulting from the Incident, but excluding certain claims.

On 30 May 2011, Transocean filed claims against BP in the DoJ Action alleging that BP America Production Company had breached its contract with Transocean Holdings LLC by not agreeing to indemnify Transocean against liability related to the Incident. Transocean also asserted claims against BP under state law, maritime law, and OPA 90 for contribution. On 20 June 2011, Cameron filed similar claims against BP in the DoJ Action.

On 26 August 2011, the judge in the federal multi-district litigation proceeding in New Orleans granted in part BP s motion to dismiss a master complaint raising claims for economic loss by private plaintiffs, dismissing plaintiffs state law claims and limiting the types of maritime law claims plaintiffs may pursue, but also held that certain classes of claimants may seek punitive damages under general maritime law. The judge did not, however, lift an earlier stay on the underlying individual complaints raising those claims or otherwise apply his dismissal of the master complaint to those individual complaints.

On 14 September 2011, the BOEMRE issued its report (BOEMRE Report) regarding the causes of the 20 April 2010 Macondo well blowout. The BOEMRE Report states that decisions by BP, Halliburton and Transocean increased the risk or failed to fully consider or mitigate the risk of a blowout on 20 April 2010. The BOEMRE Report also states that BP, and Transocean and Halliburton, violated certain regulations related to offshore drilling. In itself, the BOEMRE Report does not constitute the initiation of enforcement proceedings relating to any violation. On 12 October 2011, the U.S. Department of the Interior Bureau of Safety and Environmental Enforcement issued to BP E&P, Transocean, and Halliburton Notification of Incidents of Noncompliance (INCs). The notification issued to BP E&P is for a number of alleged regulatory violations concerning Macondo well operations. The Department of Interior has indicated that this list of violations may be supplemented as additional evidence is reviewed, and on 7 December 2011, the Bureau of Safety and Environmental Enforcement issued to BP E&P a second INC. This notification was issued to BP for five alleged violations related to drilling and abandonment operations at the Macondo well. BP has filed an administrative appeal with respect to the first and second INCs. BP has also filed a joint stay of proceedings with the Department of Interior with respect to the 12 October 2011 INCs and plans to file a joint stay regarding the 7 December 2011 INCs.

On 30 September 2011, the judge in the federal multi-district litigation proceeding in New Orleans granted in part BP s motion to dismiss a master complaint asserting personal injury claims on behalf of persons exposed to crude oil or chemical dispersants, dismissing plaintiffs state law claims, claims by seamen for punitive damages, claims for medical monitoring damages by asymptomatic plaintiffs, claims for battery and nuisance under maritime law, and claims alleging negligence per se. As with his other rulings on motions to dismiss master complaints, the judge did not lift an earlier stay on the underlying individual complaints raising those claims or otherwise apply his dismissal of the master complaint to those individual complaints.

A Trial of Liability, Limitation, Exoneration, and Fault Allocation was originally scheduled to begin in the federal multi-district litigation proceeding in New Orleans in February 2012. The court s pre-trial order issued 14 September 2011 provided for the trial to proceed in three phases and to include issues asserted in or relevant to the claims, counterclaims, cross-claims, third-party claims, and comparative fault defences raised in Transocean s Limitation of Liability Action.

On 18 October 2011, Cameron filed a petition for writ of mandamus with US Court of Appeals for the Fifth Circuit seeking an order vacating the trial plan for the 27 February 2012 trial and requiring that all claims against Cameron in that proceeding be tried before a jury. On 26 December 2011, the Court of Appeals denied the application for mandamus.

The State of Alabama has filed a lawsuit seeking damages for alleged economic and environmental harms, including natural resource damages, civil penalties under state law, declaratory and injunctive relief, and punitive damages as a result of the Incident. The State of Louisiana has filed a lawsuit to declare various BP entities (as well as other entities) liable for removal costs and damages, including natural resource damages under federal and state law, to recover civil penalties, attorney s fees, and response costs under state law, and to recover for alleged negligence, nuisance, trespass, fraudulent concealment and negligent misrepresentation of material facts regarding safety procedures and BP s (and other defendants) ability to manage the oil spill, unjust enrichment from economic and other damages to the State of Louisiana and its citizens, and punitive damages. The Louisiana Department of Environmental Quality has issued an administrative order seeking environmental civil penalties and other relief under state law. On 23 September 2011, BP removed this matter to federal district court. Several local governments in the State of Louisiana have filed suits under state wildlife statutes seeking penalties for damage to wildlife as a result of the spill. On 10 December 2010, the Mississippi Department of Environmental Quality issued a Complaint and Notice of Violation alleging violations of several state environmental statutes.

On 14 November 2011, the judge in the federal multi-district litigation proceeding in New Orleans granted in part BP s motion to dismiss the complaints filed by the States of Alabama and Louisiana. The judge s order dismissed the States claims brought under state law, including claims for civil penalties and the State of Louisiana s request for a declaratory judgment under the Louisiana Oil Spill Prevention and Response Act, holding that those claims were pre-empted by federal law. It also dismissed the State of Louisiana s claims of nuisance and trespass under general maritime law. The judge s order further held that the States have stated claims for negligence and products liability under general maritime law, that the States have sufficiently alleged presentment of their claims under OPA 90, and that the States may seek punitive damages under general maritime law. On 9 December 2011, the judge in the federal multi-district litigation proceeding in New Orleans granted in part BP s motion to dismiss a master complaint brought on behalf of local government entities. The judge s order dismissed plaintiffs state law claims and limited the types of maritime law claims plaintiffs may pursue, but also held that the plaintiffs have sufficiently alleged presentment of their claims under OPA 90 and that certain local government entity claimants may seek punitive damages under general maritime law. The judge did not, however, lift an earlier stay on the underlying individual complaints raising those claims or otherwise apply his dismissal of the master complaint to those individual complaints.

On 9 December 2011 and 28 December 2011, the judge in the federal multi-district litigation proceeding in New Orleans also granted BP s motions to dismiss complaints filed by the District Attorneys of 11 parishes in the State of Louisiana seeking penalties for damage to wildlife, holding that those claims are pre-empted by the Clean Water Act. Many of the parishes have filed notices of appeal to the U.S. Court of Appeals for the Fifth Circuit.

On 3 March 2012, BP announced a settlement with the Plaintiffs Steering Committee (PSC) in the federal Multi-District Litigation proceedings pending in New Orleans (MDL 2179) to resolve the substantial majority of legitimate private economic loss and medical claims stemming from the Incident. The agreement in principle is subject to final written agreement and court approvals.

The proposed settlement is comprised of two separate agreements. The first of these resolves economic loss claims and the other resolves medical claims. The proposed agreement to resolve economic loss claims includes a $2.3 billion BP commitment to help resolve economic loss claims related to the Gulf seafood industry and a fund to support continued advertising that promotes Gulf Coast tourism. It also resolves claims for additional payments under certain Master Vessel Charter Agreements entered into in the course of the Vessels of Opportunity Program implemented as part of the response to the Incident.

The proposed agreement to resolve medical claims involves payments based on a matrix for certain currently manifested physical conditions, as well as a 21-year medical consultation programme for qualifying class members. It also provides that class members claiming later-manifested physical conditions may pursue their claims through a mediation/litigation process. Consistent with its commitment to the Gulf, BP has also agreed to provide $105 million to improve the availability, scope and quality of healthcare in Gulf communities. This healthcare outreach programme would be available to all individuals in those communities, regardless of whether they are class members.

Each proposed agreement provides that class members would be compensated for their claims on a claims-made basis, according to agreed compensation protocols in separate court-supervised claims processes. The compensation protocols under the proposed economic loss settlement agreement include a risk transfer premium (RTP). The RTP is an agreed factor to be used in calculating certain types of damages, including potential future damages that are not currently known, relating to the Incident.

BP estimates the cost of the proposed settlement would be approximately $7.8 billion (including the $2.3 billion commitment to help resolve economic loss claims related to the Gulf seafood industry). While this is BP s reliable best estimate of the cost of the proposed settlement, it is possible that the actual cost could be higher or lower than this estimate depending on the outcomes of the court-supervised claims processes. In accordance with its normal procedures, BP will re-evaluate the assumptions underlying this estimate on a quarterly basis as more information, including the outcomes of the court-supervised claims processes, becomes available. (For more information, see Financial statements Note 36.)

At this time, BP expects all settlements under these agreements to be paid from the Trust. Other costs to be paid from the Trust include state and local government claims, state and local response costs, natural resource damages and related claims, and final judgments and settlements. It is not possible at this time to determine whether the Trust will be sufficient to satisfy all of these claims as well as those under the proposed settlement. Should the Trust not be sufficient, payments under the proposed settlement would be made by BP directly.

The proposed economic loss settlement provides for a transition from the Gulf Coast Claims Facility (GCCF) to a new court-supervised claims programme, to administer payments made to qualifying class members. A court-supervised transitional claims process will be in operation while the infrastructure for the new settlement claims process is put in place. During this transitional period, the processing of claims that have been submitted to the GCCF will continue, and new claimants may submit their claims. BP has agreed not to wait for final approval of the economic loss settlement before claims are paid. The economic loss claims process will continue under court supervision before final approval of the settlement, first under the transitional claims process, and then through the settlement claims process established by the proposed economic loss settlement.

Under the proposed settlement, class members would release and dismiss their claims against BP. The proposed settlement also provides that, to the extent permitted by law, BP will assign to the PSC certain of its claims, rights and recoveries against Transocean and Halliburton for damages with protections such that Transocean and Halliburton cannot pass those damages through to BP.

The proposed settlement is subject to reaching definitive and fully-documented agreements within 45 days of 2 March 2012, and if those agreements are not reached, either party has the right to terminate the proposed settlement. Once definitive agreements have been reached, BP and the PSC will seek the court s preliminary approval of the settlement. Under US federal law, there is an established procedure for determining the fairness, reasonableness and adequacy of class action settlements. Pursuant to this procedure, and subject to the court granting preliminary approval of both agreements, there would be an extensive outreach programme to the public to explain settlement agreements and class members rights, including the right to "opt out" of the classes, and the processes for making claims. The court would then conduct fairness hearings at which class members and various other parties would have an opportunity to be heard and present evidence and decide whether or not to approve each proposed settlement agreement. Should the number of class members opting out exceed an agreed and court-approved threshold, BP will have the right to terminate the proposed settlement.

The proposed settlement does not include claims made against BP by the DoJ or other federal agencies (including under the Clean Water Act and for Natural Resource Damages under the Oil Pollution Act) or by the states and local governments. Also excluded are certain other claims against BP, such as securities and shareholder claims pending in MDL 2185, and claims based solely on the deepwater drilling moratorium and/or the related permitting process.

The court has subsequently ordered that the first phase of the trial be adjourned. The court will schedule a status conference to discuss issues raised by the proposed settlement and to set a new trial date.

On 15 September 2010, three Mexican states bordering the Gulf of Mexico (Veracruz, Quintana Roo, and Tamaulipas) filed lawsuits in federal court in Texas against several BP entities. These lawsuits allege that the Incident harmed their tourism, fishing, and commercial shipping industries (resulting in, among other things, diminished tax revenue), damaged natural resources and the environment, and caused the states to incur expenses in preparing a response to the Incident.

On 9 December 2011, the judge in the federal multi-district litigation proceeding in New Orleans granted in part BP s motion to dismiss the three Mexican states complaints, dismissing their claims under OPA 90 and for nuisance and negligence per se, and preserving their claims for negligence and gross negligence only to the extent there has been a physical injury to a proprietary interest of the states. On 5 April 2011, the State of Yucatan submitted a claim to the GCCF alleging potential damage to its natural resources and environment, and seeking to recover the cost of assessing the alleged damage. BP anticipates further claims from the Mexican federal government.

Citizens groups have also filed either lawsuits or notices of intent to file lawsuits seeking civil penalties and injunctive relief under the Clean Water Act and other environmental statutes. On 16 June 2011, the judge in the federal multi-district litigation proceeding in New Orleans granted BP s motion to dismiss a master complaint raising claims for injunctive relief under various federal environmental statutes brought by various citizens groups and others. The judge did not, however, lift an earlier stay on the underlying individual complaints raising those claims for injunctive relief or otherwise apply his dismissal of the master complaint to those individual complaints. In addition, a different set of environmental groups filed a motion to reconsider dismissal of their Endangered Species Act claims on 14 July 2011. That motion remains pending. On 31 January 2012, the court, on motion by the Center for Biological Diversity, entered final judgment on the basis of the 16 June 2011 order with respect to two actions brought against BP by that plaintiff. On 2 February 2012, the Center for Biological Diversity filed a notice of appeal of both actions.

On 15 July 2011, the judge granted BP s motion to dismiss a master complaint raising RICO claims against BP. The court s order dismissed the claims of the plaintiffs in four RICO cases encompassed by the master complaint.

The DoJ announced on 7 March 2011 that it created a unified task force of federal agencies, led by the DoJ Criminal Division, to investigate the Incident. Other US federal agencies may commence investigations relating to the Incident. The SEC and DoJ are investigating securities matters arising in relation to the Incident.

On 21 April 2011, BP entered a framework agreement with natural resource trustees for the US and five Gulf coast states, providing for up to $1 billion to be spent on early restoration projects to address natural resource injuries resulting from the Incident. Funding for these projects will come from the $20-billion Trust fund.

BP s potential liabilities resulting from threatened, pending and potential future claims, lawsuits and enforcement actions relating to the Incident, 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 are expected to have a material adverse impact on the group s business, competitive position, cash flows, prospects, liquidity, shareholder returns and/or implementation of its strategic agenda, particularly in the US. These potential liabilities may continue to have a material adverse effect on the group s results and financial condition. *See Financial statements Note 2 on pages 190-194 for information regarding the financial impact of the Incident.*

Investigations and reports relating to the Deepwater Horizon oil spill

BP is subject to a number of investigations related to the Incident by numerous agencies of the US government. The related published reports are available on the websites of the agencies and commissions referred to below.

On 11 January 2011, the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (National Commission), established by President Obama, published its report on the causes of the Incident and its recommendations for policy and regulatory changes for offshore drilling. On 17 February 2011, the National Commission s Chief Counsel published a separate report on his investigation that provides additional information regarding the causes of the Incident.

In a report dated 20 March 2011, with an Addendum dated 30 April 2011, the Joint Investigation Team (JIT) for the Marine Board of Investigation established by the US Coast Guard and Bureau of Ocean Energy Management (BOEMRE) issued the Final Report of the Forensic Examination of the Deepwater Horizon Blowout Preventer (BOP) prepared by Det Norske Veritas (BOP Report). The BOP Report concludes that the position of the drill pipe against the blind shear rams prevented the BOP from functioning as intended. Subsequently, BP helped to sponsor additional BOP testing conducted by Det Norske Veritas under court auspices, which concluded on 21 June 2011. BP continues to review the BOP Report and is in the process of evaluating the data obtained from the additional testing.

On 22 April 2011, the US Coast Guard issued its report (Maritime Report) focused upon the maritime aspects of the Incident. The Maritime Report criticizes Transocean s maintenance operations and safety culture, while also criticizing the Republic of the Marshall Islands the flag state responsible for certifying Transocean s Deepwater Horizon vessel.

The US Chemical Safety and Hazard Investigation Board (CSB) is also conducting an investigation of the Incident that is focused on the explosions and fire, and not the resulting oil spill or response efforts. The CSB is expected to issue a single investigation report in 2012 that will seek to identify the alleged root cause(s) of the Incident, and recommend improvements to BP and industry practices and to regulatory programmes to prevent recurrence and mitigate potential consequences.

Also, at the request of the Department of the Interior, the National Academy of Engineering/National Research Council established a Committee (Committee) to examine the performance of the technologies and practices involved in the probable causes of the Incident and to identify and recommend technologies, practices, standards and other measures to avoid similar future events. On 17 November 2010, the Committee publicly released its interim report setting forth the Committee s preliminary findings and observations on various actions and decisions including well design, cementing operations, well monitoring, and well control actions. The interim report also considers management, oversight, and regulation of offshore operations. On 14 December 2011, the Committee published its final report, including findings and recommendations. A second, unrelated National Academies Committee will be looking at the methodologies available for assessing spill impacts on ecosystem services in the Gulf of Mexico, with a final report expected in late 2012 or early 2013, and a third National Academies Committee will be studying methods for assessing the effectiveness of safety and environmental management systems (SEMS) established by offshore oil and gas operators.

On 10 March 2011, the Flow Rate Technical Group (FRTG), Department of the Interior, issued its final report titled "Assessment of Flow Rate Estimates for the Deepwater Horizon/Macondo Well Oil Spill." The report provides a summary of the strengths and limitations of the different methods used by the US government to estimate the flow rate and a range of estimates from 13,000 b/d to over 100,000 b/d. The report concludes that the most accurate estimate was 53,000 b/d just prior to shut in, with an uncertainty on that value of ±10% based on FRTG collective experience and judgement, and, based on modelling, the flow on day one of the Incident was 62,000 b/d.

On 18 March 2011, the US Coast Guard ISPR team released its final report capturing lessons learned from the Incident as well as making recommendations on how to improve future oil spill response and recovery efforts.

Additionally, since April 2010, BP representatives have testified multiple times before the US Congress regarding the Incident. BP has provided documents and written information in response to requests from Members, committees and subcommittees of the US Congress.

Other legal proceedings

The US Federal Energy Regulatory Commission (FERC) and the US Commodity Futures Trading Commission (CFTC) are currently investigating several BP entities regarding trading in the next-day natural gas market at Houston Ship Channel during September, October and November 2008. The FERC Office of Enforcement staff notified BP on 12 November 2010 of their preliminary conclusions relating to alleged market manipulation in violation of 18 C.F.R. Sec. 1c.1. On 30 November 2010, CFTC Enforcement staff also provided BP with a notice of intent to recommend charges based on the same conduct alleging that BP engaged in attempted market manipulation in violation of Section 6(c), 6(d), and 9(a)(2) of the Commodity Exchange Act. On 23 December 2010, BP submitted responses to the FERC and CFTC November 2010 notices providing a detailed response that it did not engage in any inappropriate or unlawful activity. On 28 July 2011, the FERC staff issued a Notice of Alleged Violations stating that it had preliminarily determined that several BP entities fraudulently traded physical natural gas in the Houston Ship Channel and Katy markets and trading points to increase the value of their financial swing spread positions. Other investigations into BP s trading activities continue to be conducted from time to time.

On 23 March 2005, an explosion and fire occurred in the isomerization unit of BP Products North America s (BP Products) Texas City refinery as the unit was coming out of planned maintenance. Fifteen workers died in the incident and many others were injured. BP Products has resolved all civil injury claims arising from the March 2005 incident.

In March 2007, the US Chemical Safety and Hazard Investigation Board (CSB) issued a report on the incident. The report contained recommendations to the Texas City refinery and to the board of directors of BP. In May 2007, BP responded to the CSB s recommendations. BP and the CSB will continue to discuss BP s responses with the objective of the CSB s agreeing to close out its recommendations.

On 25 October 2007, the DoJ announced that it had entered into a criminal plea agreement with BP Products related to the March 2005 explosion and fire. On 4 February 2008, BP Products pleaded guilty, pursuant to the plea agreement, to one felony violation of the risk management planning regulations promulgated under the US Clean Air Act (CAA) and on 12 March 2009, the court accepted the plea agreement. In connection with the plea agreement, BP Products paid a $50-million criminal fine and was sentenced to three years probation which is set to expire on 12 March 2012. Compliance with a 2005 US Occupational Safety and Health Administration (OSHA) settlement agreement (2005 Agreement) and a 2006 agreed order entered into by BP Products with the Texas Commission on Environmental Quality (TCEQ) are conditions of probation.

The Texas Office of Attorney General, on behalf of the Texas Commission on Environmental Quality (TCEQ), has filed a petition against BP Products asserting certain air emissions and reporting violations at the Texas City refinery from 2005 to 2010. BP Products settled this lawsuit by an Agreed Final Judgment entered by the court on 20 December 2011.

The Texas Attorney General filed a separate petition against BP Products asserting emissions violations relating to a 6 April 2010 flaring event. This lawsuit was also settled by the Agreed Final Judgment mentioned in the preceding paragraph. This emissions event is also the subject of a number of civil suits by many area workers and residents alleging personal injury and property damages and seeking substantial damages. In addition, this emissions event is the subject of a federal governmental investigation.

In September 2009, BP Products filed a petition to clarify specific required actions and deadlines under the 2005 Agreement with OSHA. That agreement resolved citations issued in connection with the March 2005 Texas City refinery explosion. OSHA denied BP Products petition.

In October 2009 OSHA issued citations to the Texas City refinery seeking a total of $87.4 million in civil penalties for alleged violations of the 2005 Agreement and alleged process safety management violations.

A settlement agreement between BP Products and OSHA in August 2010 (2010 Agreement) resolved the petition filed by BP Products in September 2009 and the alleged violations of the 2005 Agreement. BP Products has paid a penalty of $50.6 million in that matter and agreed to perform certain abatement actions. Compliance with the 2010 Agreement (which is set to expire on 12 March 2012) is also a condition of probation due to the linkage between this 2010 Agreement and the 2005 Agreement.

On 6 May 2010, certain persons qualifying under the US Crime Victims Rights Act as victims in relation to the Texas City plea agreement requested that the federal court revoke BP Products probation based on alleged violations of the Court s conditions of probation. The alleged violations of probation relate to the alleged failure to comply with the 2005 Agreement.

The OSHA process safety management citations issued in October 2009 were not resolved by the August 2010 settlement agreement. The proposed penalties in that matter are $30.7 million. The matter is currently before the OSH Review Commission which has assigned an Administrative Law Judge for purposes of mediation. These citations do not allege violations of the 2005 Agreement.

A shareholder derivative action was filed against several current and former BP officers and directors based on alleged violations of the US Clean Air Act (CAA) and Occupational Safety and Health Administration (OSHA) regulations at the Texas City refinery subsequent to the March 2005 explosion and fire. An investigation by a special committee of BP s board into the shareholder allegations has been completed and the committee has recommended that the allegations do not warrant action by BP against the officers and directors. BP filed a motion to dismiss the shareholder derivative action and a plea to the jurisdiction. On 16 June 2011, the court granted BP s plea to the jurisdiction and dismissed the action in its entirety. The shareholder has appealed the dismissal and the appeal is pending.

In March and August 2006, oil leaked from oil transit pipelines operated by BP Exploration (Alaska) Inc. (BPXA) at the Prudhoe Bay unit on the North Slope of Alaska. Several legal proceedings resulted from these events. On 29 November 2007, BPXA entered into a criminal plea agreement with the DoJ relating to these leaks. BPXA s guilty plea, to a misdemeanour violation of the US Water Pollution Control Act, included a term of three years probation. On 29 November 2009, a spill of approximately 360 barrels of crude oil and produced water was discovered beneath a line running from a well pad to the Lisburne Processing Center in Prudhoe Bay, Alaska. On 17 November 2010, the US Probation Officer filed a petition in federal district court to revoke BPXA s probation based on allegations that the Lisburne event was a criminal violation of state and federal law and therefore BPXA was in violation of its probation obligations. BPXA contested the petition at an evidentiary hearing that was completed on 7 December 2011 in U.S. District Court in Anchorage, Alaska. On 27 December 2011, the Court issued a decision and order finding that BPXA did not violate the terms of its probation, dismissing the government s petition and terminating BPXA s probation.

On 12 May 2008, a BP p.l.c. shareholder filed a consolidated complaint alleging violations of federal securities law on behalf of a putative class of BP p.l.c. shareholders against BP p.l.c., BPXA, BP America, and four officers of the companies, based on alleged misrepresentations concerning the integrity of the Prudhoe Bay pipeline before its shutdown on 6 August 2006. On 8 February 2010, the Ninth Circuit Court of Appeals accepted BP s appeal from a decision of the lower court granting in part and denying in part BP s motion to dismiss the lawsuit. On 29 June 2011, the Ninth Circuit ruled in BP s favour that the filing of a trust related agreement with the SEC containing contractual obligations on the part of BP was not a misrepresentation which violated federal securities laws. The BP p.l.c. shareholder has filed an amended complaint, in response to which BP filed a new motion to dismiss, which is pending. On 31 March 2009, the United States filed a complaint seeking civil penalties and damages relating to the events at Prudhoe Bay. The complaint also involved claims related to asbestos handling, allegations of non-compliance at multiple facilities for failure to comply with EPA s spill prevention plan regulations, and for non-compliance with US Department of Transportation orders and regulations. The parties settled the dispute and on 13 July 2011 the Court entered a Consent Agreement in which BPXA agreed to pay a $25-million penalty and to perform certain injunctive measures over the next three

years with respect to pipeline inspection and maintenance. On 31 March 2009, the State of Alaska filed a complaint seeking civil penalties and damages relating to these events. The complaint alleges that the two releases and BPXA s corrosion management practices violated various statutory, contractual and common law duties to the State, resulting in penalty liability, damages for lost royalties and taxes, and liability for punitive damages. In December 2011, the State of Alaska and BPXA entered into a Dispute Resolution Agreement concerning this matter that will result in arbitration of the amount of the State s lost royalty income and payment by BPXA of the additional amount of $10 million on account of other claims in the complaint.

Approximately 200 lawsuits were filed in state and federal courts in Alaska seeking compensatory and punitive damages arising out of the Exxon Valdez oil spill in Prince William Sound in March 1989. Most of those suits named Exxon (now ExxonMobil), Alyeska Pipeline Service Company (Alyeska), which operates the oil terminal at Valdez, and the other oil companies that own Alyeska. Alyeska initially responded to the spill until the response was taken over by Exxon. BP owns a 46.9% interest (reduced during 2001 from 50% by a sale of 3.1% to Phillips) in Alyeska through a subsidiary of BP America Inc. and briefly indirectly owned a further 20% interest in Alyeska following BP s combination with Atlantic Richfield. Alyeska and its owners have settled all the claims against them under these lawsuits. Exxon has indicated that it may file a claim for contribution against Alyeska for a portion of the costs and damages that it has incurred. If any claims are asserted by Exxon that affect Alyeska and its owners, BP will defend the claims vigorously.

Since 1987, Atlantic Richfield Company (Atlantic Richfield), a subsidiary of BP, has been named as a co-defendant in numerous lawsuits brought in the US alleging injury to persons and property caused by lead pigment in paint. The majority of the lawsuits have been abandoned or dismissed against Atlantic Richfield. Atlantic Richfield is named in these lawsuits as alleged successor to International Smelting and Refining and another company that manufactured lead pigment during the period 1920-1946. Plaintiffs include individuals and governmental entities. Several of the lawsuits purport to be class actions. The lawsuits seek various remedies including compensation to lead-poisoned children, cost to find and remove lead paint from buildings, medical monitoring and screening programmes, public warning and education of lead hazards, reimbursement of government healthcare costs and special education for lead-poisoned citizens and punitive damages. No lawsuit against Atlantic Richfield has been settled nor has Atlantic Richfield been subject to a final adverse judgment in any proceeding. The amounts claimed and, if such suits were successful, the costs of implementing the remedies sought in the various cases could be substantial. While it is not possible to predict the outcome of these legal actions, Atlantic Richfield believes that it has valid defences. It intends to defend such actions vigorously and believes that the incurrence of liability is remote. Consequently, BP believes that the impact of these lawsuits on the group s results, financial position or liquidity will not be material.

On 8 March 2010, OSHA issued citations to BP s Toledo refinery alleging violations of the Process Safety Management Standard, with penalties of approximately $3 million. These citations resulted from an inspection conducted pursuant to OSHA s Petroleum Refinery Process Safety Management National Emphasis Program. BP Products has contested the citations, and the matter is currently scheduled for trial before the OSH Review Commission in June 2012.

In April 2009, Kenneth Abbott, as relator, filed a US False Claims Act lawsuit against BP, alleging that BP violated federal regulations, and made false statements in connection with its compliance with those regulations, by failing to have necessary documentation for the Atlantis subsea and other systems. BP is the operator and 56% interest owner of the Atlantis unit in production in the Gulf of Mexico. That complaint was unsealed in May 2010 and served on BP in June 2010. Abbott seeks damages measured by the value, net of royalties, of all past and future production from the Atlantis platform, trebled, plus penalties. In September 2010, Kenneth Abbott and Food & Water Watch filed an amended complaint in the False Claims Act lawsuit seeking an injunction shutting down the Atlantis platform. The court denied BP s motion to dismiss the complaint in March 2011. Separately, also in March 2011, BOEMRE issued its investigation report of the Abbott Atlantis allegations, which concluded that Mr Abbott s allegations that Atlantis operations personnel lacked access to critical, engineer-approved drawings were without merit and that his allegations about false submissions by BP to BOEMRE were unfounded. Trial is scheduled to begin on 10 April 2012.

BP Products US refineries are subject to a 2001 consent decree with the EPA that resolved alleged violations of the CAA, and implementation of the decree s requirements continues. A 2009 amendment to the decree resolves remaining alleged air violations at the Texas City refinery through the payment of a $12-million civil fine, a $6-million supplemental environmental project and enhanced CAA compliance measures estimated to cost approximately $150 million. The fine has been paid, and BP Products is implementing the other provisions.

On 30 September 2010, the EPA and BP Products lodged a civil consent decree with the federal court in Houston. Following a public comment period, the federal court approved the settlement on 30 December 2010. The decree resolves allegations of civil violations of the risk management planning regulations promulgated under the CAA that are alleged to have occurred in 2004 and 2005 at the Texas City refinery. BP Products has paid the $15-million civil penalty and the Texas City refinery is implementing requirements to enhance reporting to the EPA regarding employee training, equipment inspection and incident investigation.

Various environmental groups and the EPA have challenged certain aspects of the air permits issued by the Indiana Department of Environmental Management (IDEM) for upgrades to the Whiting refinery. In response to these challenges, the IDEM has reviewed the permits and responded formally to the EPA. BP is in discussions with the EPA, the IDEM and certain environmental groups over these and other CAA issues relating to the Whiting refinery. BP has also been in settlement discussions with EPA to resolve alleged CAA violations at the Toledo, Carson and Cherry Point refineries.

An application was brought in the English High Court on 1 February 2011 by Alfa Petroleum Holdings Limited and OGIP Ventures Limited against BP International Limited and BP Russian Investments Limited alleging breach of a Shareholders Agreement on the part of BP and seeking an interim injunction restraining BP from taking steps to conclude, implement or perform the transactions with Rosneft Oil Company, originally announced on 14 January 2011, relating to oil and gas exploration, production, refining and marketing in Russia (the Arctic Opportunity). Those transactions included the issue or transfer of shares between Rosneft Oil Company and any BP group company (pursuant to the Rosneft Share Swap Agreement). The court granted an interim order restraining BP from taking any further steps in relation to the Rosneft transactions pending an expedited UNCITRAL arbitration procedure in accordance with the Shareholders Agreement between the parties. The arbitration has commenced and the interim injunction was continued by the arbitration panel.

On 17 May 2011, BP announced that both the Rosneft Share Swap Agreement and the Arctic Opportunity, originally announced on 14 January 2011, had terminated. This termination was as a result of the deadline for the satisfaction of conditions precedent having expired following delays resulting from the interim orders referred to above. These interim orders did not address the question of whether or not BP breached the Shareholders Agreement. The arbitration proceedings, which are subject to strict confidentiality obligations, are ongoing.

Five minority shareholders of OAO TNK-BP Holding (TBH) have filed two civil actions in Tyumen, Siberia, against BP Russia Investments Limited and BP p.l.c. and against two of the BP nominated directors of TBH. These two actions sought to recover alleged losses to TBH of $13 billion and $2.7 billion respectively. On 11 November 2011, the Tyumen Court dismissed both claims fully on their merits. The shareholders appealed both of these decisions to the Omsk Appellate court. On 26 January 2012, the Appellate court upheld the Tyumen Court s dismissal of the claim in relation to the BP nominated directors of TBH. The Omsk Appellate court subsequently confirmed the Tyumen court of first instance s dismissal of the minority suits against BP Russia Investments Limited and BP p.l.c. BP believes the allegations made are wholly without merit. No losses have been incurred and BP believes the likelihood of the claims being ultimately successful is remote. Consequently no amounts have been provided and the claim is not disclosed as a contingent liability.

On 9 February 2011, Apache Canada Ltd (Apache) commenced an arbitration against BP Canada Energy. Apache alleges that various properties/sites in respect of which it acquired interests from BP Canada Energy pursuant to the parties Purchase and Sale Agreement signed in July 2010 will require work to bring the properties/sites into compliance with applicable environmental laws, and Apache claims that the purchase price should be adjusted for its estimated possible costs. BP Canada Energy denies such costs will arise or require any adjustment to the purchase price. The parties have appointed the arbitrator, and currently the hearing on the merits is scheduled to commence during the second quarter of 2012.

On 24 January 2012, the Republic of Bolivia issued a press statement declaring its intent to nationalize Pan American Energy s interests in the Caipipendi Operations Contract. No formal nationalization process has yet commenced. Pan American Energy and its shareholders BP and Bridas intend to vigorously defend their legal interests under the Caipipendi Operations Contract and available Bilateral Investment Treaties.

Relationships with suppliers and contractors

Essential contracts

BP has contractual and other arrangements with numerous third parties in support of its business activities. This report does not contain information about any of these third parties as none of our arrangements with them are considered to be essential to the business of BP.

Suppliers and contractors

Our processes are designed to enable us to choose suppliers carefully on merit, avoiding conflicts of interest and inappropriate gifts and entertainment. We expect suppliers to comply with legal requirements and we seek to do business with suppliers who act in line with BP s commitments to compliance and ethics, as outlined in our code of conduct. We engage with suppliers in a variety of ways, including performance review meetings to identify mutually advantageous ways to improve performance.

Creditor payment policy and practice

Statutory regulations issued under the UK Companies Act 2006 require companies to make a statement of their policy and practice in respect of the payment of trade creditors. In view of the international nature of the group s operations there is no specific group-wide policy in respect of payments to suppliers. Relationships with suppliers are, however, governed by the group s policy commitment to long-term relationships founded on trust and mutual advantage. Within this overall policy, individual operating companies are responsible for agreeing terms and conditions for their business transactions and ensuring that suppliers are aware of the terms of payment.

Share prices and listings

Markets and market prices

The primary market for BP s ordinary shares is the London Stock Exchange (LSE). BP s ordinary shares are a constituent element of the Financial Times Stock Exchange 100 Index. BP s ordinary shares are also traded on the Frankfurt Stock Exchange in Germany.

Trading of BP s shares on the LSE is primarily through the use of the Stock Exchange Electronic Trading Service (SETS), introduced in 1997 for the largest companies in terms of market capitalization whose primary listing is the LSE. Under SETS, buy and sell orders at specific prices may be sent electronically to the exchange by any firm that is a member of the LSE, on behalf of a client or on behalf of itself acting as a principal. The orders are then anonymously displayed in the order book. When there is a match on a buy and a sell order, the trade is executed and automatically reported to the LSE. Trading is continuous from 8.00 a.m. to 4.30 p.m. UK time but, in the event of a 20% movement in the share price either way, the LSE may impose a temporary halt in the trading of that company s shares in the order book to allow the market to re-establish equilibrium. Dealings in ordinary shares may also take place between an investor and a market-maker, via a member firm, outside the electronic order book.

In the US, the company s securities are traded on the New York Stock Exchange (NYSE) in the form of ADSs, for which JPMorgan Chase Bank, N.A. is the depositary (the Depositary) and transfer agent. The Depositary s principal office is 1 Chase Manhattan Plaza, N.A., Floor 21, New York, NY 10005-1401, US. Each ADS represents six ordinary shares. ADSs are listed on the New York Stock Exchange. ADSs are evidenced by American depositary receipts (ADRs), which may be issued in either certificated or book entry form.

The following table sets forth for the periods indicated the highest and lowest middle market quotations for BP s ordinary shares and ADSs for the periods shown. These are derived from the highest and lowest sales prices as reported on the LSE and NYSE, respectively.

	Pence	Dollars

		Ordinary shares		American depositary shares[a]	
		High	Low	High	Low
Year ended 31 December					
2007		640.00	504.50	79.77	58.62
2008		657.25	370.00	77.69	37.57
2009		613.40	400.00	60.00	33.71
2010		658.20	296.00	62.38	26.75
2011		**514.90**	**361.25**	**49.50**	**33.63**
Year ended 31 December					
2010:	First quarter	640.10	555.00	62.38	52.00
	Second quarter	658.20	296.00	60.98	26.75
	Third quarter	438.25	312.65	41.59	28.79
	Fourth quarter	479.00	418.25	44.83	39.58
2011:	First quarter	**514.90**	**431.00**	**49.50**	**42.51**
	Second quarter	**480.23**	**425.00**	**47.45**	**41.26**
	Third quarter	**483.04**	**361.25**	**47.09**	**35.10**
	Fourth quarter	**477.54**	**363.95**	**45.83**	**33.63**
2012:	First quarter (to 17 February)	**501.37**	**455.05**	**47.67**	**42.85**
Month of					
September 2011		**426.04**	**361.25**	**39.72**	**35.10**
October 2011		**477.54**	**363.95**	**45.83**	**33.63**
November 2011		**466.05**	**416.99**	**44.89**	**39.41**
December 2011		**471.45**	**433.00**	**44.26**	**40.40**
January 2012		**487.60**	**455.05**	**46.03**	**42.85**
February 2012 (to 17 February)		**501.37**	**473.05**	**47.67**	**45.23**

a One ADS is equivalent to six 25 cent ordinary shares.

Market prices for the ordinary shares on the LSE and in after-hours trading off the LSE, in each case while the NYSE is open, and the market prices for ADSs on the NYSE, are closely related due to arbitrage among the various markets, although differences may exist from time to time due to various factors, including UK stamp duty reserve tax.

On 17 February 2012, 838,650,908 ADSs (equivalent to approximately 5,031,905,448 ordinary shares or some 26.51% of the total issued share capital, excluding shares held in treasury) were outstanding and were held by approximately 109,640 ADS holders. Of these, about 108,369 had registered addresses in the US at that date. One of the registered holders of ADSs represents some 811,108 underlying holders.

On 17 February 2012, there were approximately 303,020 holders of record of ordinary shares. Of these holders, around 1,585 had registered addresses in the US and held a total of some 4,331,996 ordinary shares.

Since certain of the ordinary shares and ADSs were held by brokers and other nominees, the number of holders of record in the US may not be representative of the number of beneficial holders or of their country of residence.

Material contracts

On 6 August 2010, BP entered into a trust agreement with John S Martin, Jr and Kent D Syverud, as individual trustees, and Citigroup Trust-Delaware, N.A., as corporate trustee (the Trust Agreement) which established the Deepwater Horizon Oil Spill Trust (the Trust) to be funded in the amount of $20 billion (the trust fund) over the period to the fourth quarter of 2013. The trust fund is available to satisfy legitimate individual and business claims administered by the Gulf Coast Claims Facility (GCCF), state and local government claims resolved by BP, final judgments and settlements, state and local response costs, and natural resource damages and related costs. Fines, penalties and claims administration costs are not covered by the trust fund. Under the terms of the Trust Agreement, BP has no right to access the funds once they have been contributed to the trust fund. BP will receive funds from the trust fund only upon its expiration, if there are any funds remaining at that point. BP has the authority under the Trust Agreement to present certain resolved claims, including natural resource damages claims and state and local response claims, to the Trust for payment, by providing the trustees with all the required documents establishing that such claims are valid under the Trust Agreement. However, any such payments can only be made on the authority of the trustee and any funds distributed are paid directly to the claimants, not to BP. The Trust Agreement is governed by the laws of the State of Delaware.

On 30 September 2010, BP entered a pledge and collateral agreement in favour of John S Martin, Jr and Kent D Syverud (the Pledge Agreement), which pledged certain Gulf of Mexico assets as collateral for the trust fund funding obligation. The pledged collateral consists of an overriding royalty interest in oil and gas production of BP s Thunder Horse, Atlantis, Mad Dog, Great White and Mars, Ursa and Na Kika assets in the Gulf of Mexico. A wholly-owned company called Verano Collateral Holdings LLC (Verano) has been created to hold the overriding royalty interest, which was capped at $1.25 billion per quarter and $17 billion in total. Verano pledged the overriding royalty interest to the Trust as collateral for BP s remaining contribution obligations to the Trust. An event of default under the Pledge Agreement arose if BP failed to make any contribution under the Trust Agreement when due or otherwise failed to observe certain other obligations, subject to specified cure periods. Following an event of default, the trustees were entitled to exercise all remedies as secured parties in respect of the collateral, including receipt of royalty interests from the pledged assets, having all or part of the limited liability company interests registered in the trustees name and selling the collateral at public or private sale. The Pledge Agreement was governed by the laws of the State of Texas. On 9 November 2011 the Pledge Agreement and the related overriding royalty interest conveyance and mortgage were amended and restated (such documents collectively referred to as the Amended and Restated Pledge Agreement) to change the overriding royalty interest effective as of 1 October 2011 to $14.7 billion. Beginning on 2 January 2012, and on the first business day of each subsequent

calendar quarter, the overriding royalty interest is recalculated as the remaining outstanding contributions owed by BP to the Trust as of that date multiplied by a factor of 1.45. On 2 January 2012 the overriding royalty interest was recalculated as $7.1 billion. The Amended and Restated Pledge Agreement also changed the definition of an event of default to be a failure by BP to make required payments pursuant to the terms of the Trust Agreement.

Exchange controls

There are currently no UK foreign exchange controls or restrictions on remittances of dividends on the ordinary shares or on the conduct of the company s operations.

There are no limitations, either under the laws of the UK or under the company s Articles of Association, restricting the right of non-resident or foreign owners to hold or vote BP ordinary or preference shares in the company.

Taxation

This section describes the material US federal income tax and UK taxation consequences of owning ordinary shares or ADSs to a US holder who holds the ordinary shares or ADSs as capital assets for tax purposes. It does not apply, however, to members of special classes of holders subject to special rules and holders that, directly or indirectly, hold 10% or more of the company s voting stock. In addition, if a partnership holds the shares or ADSs, the US federal income tax treatment of a partner will generally depend on the status of the partner and the tax treatment of the partnership and may not be described fully below.

A US holder is any beneficial owner of ordinary shares or ADSs that is for US federal income tax purposes (i) a citizen or resident of the US, (ii) a US domestic corporation, (iii) an estate whose income is subject to US federal income taxation regardless of its source, or (iv) a trust if a US court can exercise primary supervision over the trust s administration and one or more US persons are authorized to control all substantial decisions of the trust.

This section is based on the Internal Revenue Code of 1986, as amended, its legislative history, existing and proposed regulations thereunder, published rulings and court decisions, and the taxation laws of the UK, all as currently in effect, as well as the income tax convention between the US and the UK that entered into force on 31 March 2003 (the Treaty). These laws are subject to change, possibly on a retroactive basis. This section is further based in part on the representations of the Depositary and assumes that each obligation in the Deposit Agreement and any related agreement will be performed in accordance with its terms.

For purposes of the Treaty and the estate and gift tax Convention (the Estate Tax Convention ,) and for US federal income tax and UK taxation purposes, a holder of ADRs evidencing ADSs will be treated as the owner of the company s ordinary shares represented by those ADRs. Exchanges of ordinary shares for ADRs and ADRs for ordinary shares generally will not be subject to US federal income tax or to UK taxation other than stamp duty or stamp duty reserve tax, as described below.

Investors should consult their own tax adviser regarding the US federal, state and local, UK and other tax consequences of owning and disposing of ordinary shares and ADSs in their particular circumstances, and in particular whether they are eligible for the benefits of the Treaty.

Taxation of dividends

UK taxation

Under current UK taxation law, no withholding tax will be deducted from dividends paid by the company, including dividends paid to US holders. A shareholder that is a company resident for tax purposes in the UK or trading in the UK through a permanent establishment generally will not be taxable in the UK on a dividend it receives from the company. A shareholder who is an individual resident for tax purposes in the UK is subject to UK tax but entitled to a tax credit on cash dividends paid on ordinary shares or ADSs of the company equal to one-ninth of the cash dividend.

US federal income taxation

A US holder is subject to US federal income taxation on the gross amount of any dividend paid by the company out of its current or accumulated earnings and profits (as determined for US federal income tax purposes). Dividends paid to a non-corporate US holder in taxable years beginning before 1 January 2013 that constitute qualified dividend income will be taxable to the holder at a maximum tax rate of 15%, provided that the holder has a holding period in the ordinary shares or ADSs of more than 60 days during the 121-day period beginning 60 days before the ex-dividend date and meets other holding period requirements. Dividends paid by the company with respect to the shares or ADSs will generally be qualified dividend income.

As noted above in UK taxation, a US holder will not be subject to UK withholding tax. A US holder will include in gross income for US federal income tax purposes the amount of the dividend actually received from the company, and the receipt of a dividend will not entitle the US holder to a foreign tax credit.

For US federal income tax purposes, a dividend must be included in income when the US holder, in the case of ordinary shares, or the Depositary, in the case of ADSs, actually or constructively receives the dividend and will not be eligible for the dividends-received deduction generally allowed to US corporations in respect of dividends received from other US corporations. Dividends will be income from sources outside the US and generally will be passive category income or, in the case of certain US holders, general category income , each of which is treated separately for purposes of computing a US holder s foreign tax credit limitation.

The amount of the dividend distribution on the ordinary shares or ADSs that is paid in pounds sterling will be the US dollar value of the pounds sterling payments made, determined at the spot pounds sterling/US dollar rate on the date the dividend distribution is includible in income, regardless of whether the payment is, in fact, converted into US dollars. Generally, any gain or loss resulting from currency exchange fluctuations during the period from the date the pounds sterling dividend payment is includible in income to the date the payment is converted into US dollars will be treated as ordinary income or loss and will not be eligible for the 15% tax rate on qualified dividend income. The gain or loss generally will be income or loss from sources within the US for foreign tax credit limitation purposes.

Distributions in excess of the company s earnings and profits, as determined for US federal income tax purposes, will be treated as a return of capital to the extent of the US holder s basis in the ordinary shares or ADSs and thereafter as capital gain, subject to taxation as described in Taxation of capital gains US federal income taxation section below.

In addition, the taxation of dividends may be subject to the rules for passive foreign investment companies (PFIC), described below under Taxation of capital gains US federal income taxation . Distributions made by a PFIC do not constitute qualified dividend income and are not eligible for the 15% tax rate.

Taxation of capital gains

UK taxation

A US holder may be liable for both UK and US tax in respect of a gain on the disposal of ordinary shares or ADSs if the US holder is (i) a citizen of the US resident or ordinarily resident in the UK, (ii) a US domestic corporation resident in the UK by reason of its business being managed or controlled in the UK or (iii) a citizen of the US or a corporation that carries on a trade or profession or vocation in the UK through a branch or agency or, in respect of corporations for accounting periods beginning on or after 1 January 2003, through a permanent establishment, and that have used, held, or acquired the ordinary shares or ADSs for the purposes of such trade, profession or vocation of such branch, agency or permanent establishment. However, such persons may be entitled to a tax credit against their US federal income tax liability for the amount of UK capital gains tax or UK corporation tax on chargeable gains (as the case may be) that is paid in respect of such gain.

Under the Treaty, capital gains on dispositions of ordinary shares or ADSs generally will be subject to tax only in the jurisdiction of residence of the relevant holder as determined under both the laws of the UK and the US and as required by the terms of the Treaty.

Under the Treaty, individuals who are residents of either the UK or the US and who have been residents of the other jurisdiction (the US or the UK, as the case may be) at any time during the six years immediately preceding the relevant disposal of ordinary shares or ADSs may be subject to tax with respect to capital gains arising from a disposition of ordinary shares or ADSs of the company not only in the jurisdiction of which the holder is resident at the time of the disposition but also in the other jurisdiction.

US federal income taxation

A US holder who sells or otherwise disposes of ordinary shares or ADSs will recognize a capital gain or loss for US federal income tax purposes equal to the difference between the US dollar value of the amount realized and the holder s tax basis, determined in US dollars, in the ordinary shares or ADSs. Any capital gain of a non-corporate US holder is generally taxed at preferential rates if the holder s holding period for such ordinary shares or ADSs exceeds one year. The gain or loss will generally be income or loss from sources within the US for foreign tax credit limitation purposes. The deductibility of capital losses is subject to limitations.

We do not believe that ordinary shares or ADSs will be treated as stock of a passive foreign investment company, or PFIC, for US federal income tax purposes, but this conclusion is a factual determination that is made annually and thus is subject to change. If we are treated as a PFIC, unless a US holder elects to be taxed annually on a mark-to-market basis with respect to ordinary shares or ADSs, any gain realized on the sale or other disposition of ordinary shares or ADSs would in general not be treated as capital gain. Instead, a US holder would be treated as if he or she had realized such gain rateably over the holding period for ordinary shares or ADSs and would be taxed at the highest tax rate in effect for each such year to which the gain was allocated, in addition to which an interest charge in respect of the tax attributable to each such year would apply. Certain excess distributions would be similarly treated if we were treated as a PFIC.

Additional tax considerations

Scrip Dividend Programme

The company has introduced an optional Scrip Dividend Programme, wherein holders of ordinary shares or ADSs may elect to receive any dividends in the form of new, fully-paid ordinary shares or ADSs of the company, instead of cash. Please consult your tax adviser for the consequences to you.

UK inheritance tax

The Estate Tax Convention applies to inheritance tax. ADSs held by an individual who is domiciled for the purposes of the Estate Tax Convention in the US and is not for the purposes of the Estate Tax Convention a national of the UK will not be subject to UK inheritance tax on the individual s death or on transfer during the individual s lifetime unless, among other things, the ADSs are part of the business property of a permanent establishment situated in the UK used for the performance of independent personal services. In the exceptional case where ADSs are subject to both inheritance tax and US federal gift or estate tax, the Estate Tax Convention generally provides for tax payable in the US to be credited against tax payable in the UK or for tax paid in the UK to be credited against tax payable in the US, based on priority rules set forth in the Estate Tax Convention.

UK stamp duty and stamp duty reserve tax

The statements below relate to what is understood to be the current practice of HM Revenue & Customs in the UK under existing law.

Provided that any instrument of transfer is not executed in the UK and remains at all times outside the UK and the transfer does not relate to any matter or thing done or to be done in the UK, no UK stamp duty is payable on the acquisition or transfer of ADSs. Neither will an agreement to transfer ADSs in the form of ADRs give rise to a liability to stamp duty reserve tax.

Purchases of ordinary shares, as opposed to ADSs, through the CREST system of paperless share transfers will be subject to stamp duty reserve tax at 0.5%. The charge will arise as soon as there is an agreement for the transfer of the shares (or, in the case of a conditional agreement, when the condition is fulfilled). The stamp duty reserve tax will apply to agreements to transfer ordinary shares even if the agreement is made outside the UK between two non-residents. Purchases of ordinary shares outside the CREST system are subject either to stamp duty at a rate of £5 per £1,000 (or part, unless the stamp duty is less than £5, when no stamp duty is charged), or stamp duty reserve tax at 0.5%. Stamp duty and stamp duty reserve tax are generally the liability of the purchaser.

A subsequent transfer of ordinary shares to the Depositary s nominee will give rise to further stamp duty at the rate of £1.50 per £100 (or part) or stamp duty reserve tax at the rate of 1.5% of the value of the ordinary shares at the time of the transfer. An ADR holder electing to receive ADSs instead of a cash dividend will be responsible for the stamp duty reserve tax due on issue of shares to the Depositary s nominee and calculated at the rate of 1.5% on the issue price of the shares. It is understood that HM Revenue & Customs practice is to calculate the issue price by reference to the total cash receipt to which a US holder would

have been entitled had the election to receive ADSs instead of a cash dividend not been made. ADR holders electing to receive ADSs instead of the cash dividend authorize the Depositary to sell sufficient shares to cover this liability.

Documents on display

BP Annual Report and Form 20-F 2011 is also available online at *bp.com/annualreport.* Shareholders may obtain a hard copy of BP s complete audited financial statements, free of charge, by contacting BP Distribution Services at +44 (0)870 241 3269 or through an email request addressed to *bpdistributionservices@bp.com* (UK and Rest of World) or from Precision IR at + 1 888 301 2505 or through an email request addressed to *bpreports@precisionir.com* (US and Canada).

The company is subject to the information requirements of the US Securities Exchange Act of 1934 applicable to foreign private issuers. In accordance with these requirements, the company files its Annual Report on Form
20-F and other related documents with the SEC. It is possible to read and copy documents that have been filed with the SEC at the SEC s public reference room located at 100 F Street NE, Washington, DC 20549, US. You may also call the SEC at +1 800-SEC-0330. In addition, BP s SEC filings are available to the public at the SEC s website. BP discloses on its website at *bp.com/NYSEcorporategovernancerules,* and in this report (see *Corporate governance practices (Form 20-F Item 16G) on page* 134) significant ways (if any) in which its corporate governance practices differ from those mandated for US companies under NYSE listing standards.

Purchases of equity securities by the issuer and affiliated purchasers

At the AGM on 14 April 2011, authorization was given to repurchase up to 1.9 billion ordinary shares in the period to the next AGM in 2012 or 14 July 2012, the latest date by which an AGM must be held. This authorization is renewed annually at the AGM. No repurchases of shares were made in the period 1 January 2011 to 17 February 2012.

The following table provides details of ordinary share purchases made by Employee Share Ownership Plan Trusts (ESOPs) and other purchases of ordinary shares and ADSs made to satisfy the requirements of certain employee share-based payment plans.

	Total number of shares purchased	Average paid per share $	Total number of shares purchased as part of publicity announced programmes	Maximum number of shares that may yet be purchased under the programme[a]
2011				
January	**12,692,114**	**8.01**		
February	**1,660,496**	**7.77**		
March	**65**	**7.53**		
April	**1,159,235**	**7.69**		
May	**50,550**	**7.43**		
June	**253,500**	**7.01**		
July	**35,224**	**7.35**		
August	**903,513**	**6.57**		
September	**1,202,286**	**6.07**		
October	**1,682,852**	**6.18**		
November	**513,392**	**7.26**		
December	**42,034,522**	**7.09**		
2012				
January	**Nil**			
February (to 17 February)	**792**	**7.90**		

a No shares were repurchased pursuant to a publicly announced plan. Transactions represent the purchase of ordinary shares by ESOPs and other purchases of ordinary shares and ADSs made to satisfy requirements of certain employee share-based payment plans.

Fees and charges payable by a holder of ADSs

The Depositary collects fees for delivery and surrender of ADSs directly from investors depositing shares or surrendering ADSs for the purpose of withdrawal or from intermediaries acting for them. The Depositary collects fees for making distributions to investors by deducting those fees from the amounts distributed or by selling a portion of the distributable property to pay the fees.

The charges of the Depositary payable by investors are as follows:

Type of service	Depositary actions	Fee
Depositing or substituting the underlying shares	Issuance of ADSs against the deposit of shares, including deposits and issuances in respect of: Share distributions, stock splits, rights, merger. Exchange of securities or other transactions or event or other distribution affecting the ADSs or deposited securities.	$5.00 per 100 ADSs (or portion thereof) evidenced by the new ADSs delivered.
Selling or exercising rights	Distribution or sale of securities, the fee being in an amount equal to the fee for the execution and delivery of ADSs that would have been charged as a result of the deposit of such securities.	$5.00 per 100 ADSs (or portion thereof).
Withdrawing an underlying share	Acceptance of ADSs surrendered for withdrawal of deposited securities.	$5.00 for each 100 ADSs (or portion thereof) evidenced by the ADSs surrendered.
Expenses of the Depositary	Expenses incurred on behalf of holders in connection with: Stock transfer or other taxes and governmental charges. Cable, telex, electronic and facsimile transmission/ delivery. Transfer or registration fees, if applicable, for the registration of transfers of underlying shares. Expenses of the Depositary in connection with the conversion of foreign currency into US dollars (which are paid out of such foreign currency).	Expenses payable at the sole discretion of the Depositary by billing holders or by deducting charges from one or more cash dividends or other cash distributions.

Fees and payments made by the Depositary to the issuer

The Depositary has agreed to reimburse certain company expenses related to the company s ADS programme and incurred by the company in connection with the programme. The Depositary reimbursed to the company, or paid amounts on the company s behalf to third parties, or waived its fees and expenses, of $3,330,826 for the year ended 31 December 2011.

The table below sets out the types of expenses that the Depositary has agreed to reimburse and the fees it has agreed to waive for standard costs associated with the administration of the ADS programme relating to the year ended 31 December 2011. The Depositary has also paid certain expenses directly to third parties on behalf of the company.

Category of expense reimbursed, waived or paid directly to third parties	Amount reimbursed, waived or paid directly to third parties for the year ended 31 December 2011
NYSE listing fees reimbursed	$500,000
Service fees and out of pocket expenses waived[a]	$1,940,127
Broker fees reimbursed[b]	$798,177
Other third-party mailing costs reimbursed[c]	$76,736
Legal advice reimbursed[d]	$2,918
Other third-party expenses paid directly	$12,868
Total	$3,330,826

a Includes fees in relation to transfer agent costs and costs of the BP Scrip Dividend Programme operated by JPMorgan Chase Bank, N.A.

b Broker reimbursements are fees payable to Broadridge for the distribution of hard copy material to ADR beneficial holders in the Depositary Trust Company. Corporate materials include information related to shareholders meetings and related voting instructions. These fees are SEC approved.

c Payment of fees to Precision IR for proxy solicitation and investor support.

d Reimbursement for legal advice from Ziegler, Ziegler & Associates.

Under certain circumstances, including removal of the Depositary or termination of the ADR programme by the company, the company is required to repay the Depositary amounts reimbursed and/or expenses paid to or on behalf of the company during the 12-month period prior to notice of removal or termination.

Related-party transactions

Transactions between the group and its significant jointly controlled entities and associates are summarized in Financial statements Note 24 on page 215 and Note 25 on page 216. In the ordinary course of its business, the group enters into transactions with various organizations with which certain of its directors or executive officers are associated. Except as described in this report, the group did not have material transactions or transactions of an unusual nature with, and did not make loans to, related parties in the period commencing 1 January 2011 to 28 February 2012.

Administration

If you have any queries about the administration of shareholdings, such as change of address, change of ownership, dividend payments, the Scrip Dividend Programme or to change the way you receive your company documents (such as the *BP Annual Report and Form 20-F, BP Summary Review and Notice of BP Annual General Meeting*) please contact the BP Registrar or BP ADS Depositary.

Ordinary and preference shareholders BP Registrar

Equiniti

Aspect House, Spencer Road, Lancing, West Sussex BN99 6DA, UK

Freephone in UK 0800 701107 or +44 (0)121 415 7005 from outside the UK

Textphone 0871 384 2255; fax +44 (0)871 384 2100

Please note that any numbers quoted with the prefix 0871 will be charged at 8p per minute from a BT landline. Other network providers costs may vary.

ADS holders BP ADS Depositary

JPMorgan Chase Bank, N.A.

PO Box 64504, St Paul, MN 55164-0504, US

Toll-free in US and Canada +1 877 638 5672 or +1 651 306 4383 from outside the US and Canada

For the hearing impaired +1 651 453 2133

Annual general meeting

The 2012 AGM will be held on Thursday, 12 April 2012 at 11.30 a.m. at ExCeL London, One Western Gateway, Royal Victoria Dock, London E16 1XL. A separate notice convening the meeting is distributed to shareholders, which includes an explanation of the items of business to be considered at the meeting.

All resolutions of which notice has been given will be decided on a poll.

Ernst & Young LLP have expressed their willingness to continue in office as auditors and a resolution for their reappointment is included in *Notice of BP Annual General Meeting 2012.*

By order of the board

David J Jackson

Company Secretary

6 March 2012

BP p.l.c.

Registered in England and Wales No. 102498

Exhibits

The following documents are filed in the Securities and Exchange Commission (SEC) EDGAR system, as part of this Annual Report on Form 20-F, and can be viewed on the SEC s website.

Exhibit 1	Memorandum and Articles of Association of BP p.l.c.*
Exhibit 4.1	The BP Executive Directors Incentive Plan*
Exhibit 4.2	BP Plan 2011
Exhibit 4.3	BP Share Value Plan 2012
Exhibit 4.4	Amended Director s Service Contract and Secondment Agreement for R W Dudley*
Exhibit 4.5	Amended Director s Service Contract and Secondment Agreement for Dr B E Grote
Exhibit 4.6	Director s Service Contract for I C Conn**
Exhibit 4.7	Director s Service Contract for Dr B Gilvary
Exhibit 7	Computation of Ratio of Earnings to Fixed Charges (Unaudited)
Exhibit 8	Subsidiaries (included as Note 45 to the Financial Statements)
Exhibit 10.1	Trust Agreement dated as of 6 August 2010 among BP Exploration & Production Inc., John S Martin, Jr and Kent D Syverud, as individual trustees, and Citigroup Trust-Delaware, N.A., as corporate trustee, as amended by an Addendum, dated 6 August 2010*
Exhibit 10.2	Amended and Restated Pledge and Collateral Agreement dated as of 9 November 2011 by BP Exploration & Production Inc. in favor of John S Martin, Jr and Kent D Syverud, as individual trustees
Exhibit 11	Code of Ethics***
Exhibit 12	Rule 13a 14(a) Certifications
Exhibit 13	Rule 13a 14(b) Certifications#

* Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2010.
** Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2004.
*** Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2009.
\# Furnished only.
Included only in the annual report filed in the Securities and Exchange Commission EDGAR system.

The total amount of long-term securities of the Registrant and its subsidiaries authorized under any one instrument does not exceed 10% of the total assets of BP p.l.c. and its subsidiaries on a consolidated basis. The company agrees to furnish copies of any or all such instruments to the SEC on request.

Consolidated financial statements of the BP group

Notes on financial statements

Supplementary information on oil and natural gas (unaudited)

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Report of Independent Registered Public Accounting Firm on the Annual Report on Form 20-F

The Board of Directors and Shareholders of BP p.l.c.

We have audited the accompanying group balance sheets of BP p.l.c. as of 31 December 2011 and 2010, and the related group income statement, group statement of comprehensive income, group statement of changes in equity and group cash flow statement for each of the three years in the period ended 31 December 2011. These financial statements are the responsibility of the company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the group financial position of BP p.l.c. at 31 December 2011 and 2010, and the group results of operations and cash flows for each of the three years in the period ended 31 December 2011, in accordance with International Financial Reporting Standards as adopted by the European Union and International Financial Reporting Standards as issued by the International Accounting Standards Board.

In forming our opinion we have considered the adequacy of the disclosures made in Notes 2, 36 and 43 to the financial statements concerning the provisions, future expenditures for which reliable estimates cannot be made and other contingencies related to the Gulf of Mexico oil spill significant event. The total amounts that will ultimately be paid by BP in relation to all obligations relating to the incident are subject to significant uncertainty and the ultimate exposure and cost to BP will be dependent on many factors, including any determination of BP s culpability based on any findings of negligence, gross negligence or wilful misconduct. Actual costs could ultimately be significantly higher or lower than those recorded in relation to all obligations relating to the oil spill. Our opinion is not qualified in respect of these matters.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), BP p.l.c. s internal control over financial reporting as of 31 December 2011, based on criteria established in the Internal Control: Revised Guidance for Directors on the Combined Code (Turnbull) as issued by the Institute of Chartered Accountants in England and Wales (the Turnbull criteria) and our report dated 6 March 2012 expressed an unqualified opinion thereon.

/s/ERNST & YOUNG LLP

Ernst & Young LLP

London, England

6 March 2012

Report of Independent Registered Public Accounting Firm on the Annual Report on Form 20-F

The Board of Directors and Shareholders of BP p.l.c.

We have audited BP p.l.c. s internal control over financial reporting as of 31 December 2011, based on criteria established in Internal Control: Revised Guidance for Directors on the Combined Code (Turnbull) as issued by the Institute of Chartered Accountants in England and Wales (the Turnbull criteria). BP p.l.c. s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s report on internal control over financial reporting on page 135. Our responsibility is to express an opinion on the company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, BP p.l.c. maintained, in all material respects, effective internal control over financial reporting as of 31 December 2011, based on the Turnbull criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the group balance sheets of BP p.l.c. as of 31 December 2011 and 2010, and the related group income statement, group statement of comprehensive income, group statement of changes in equity and group cash flow statement for each of the three years in the period ended 31 December 2011, and our report dated 6 March 2012 expressed an unqualified opinion thereon.

/s/ERNST & YOUNG LLP

Ernst & Young LLP

London, England

6 March 2012

Consent of independent registered public accounting firm

We consent to the incorporation by reference of our reports dated 6 March 2012 with respect to the consolidated financial statements of BP p.l.c., and the effectiveness of internal control over financial reporting of BP p.l.c., included in this Annual Report (Form 20-F) for the year ended 31 December 2011 in the following registration statements:

Registration Statement on Form F-3 (File No. 333-157906) of BP Capital Markets p.l.c. and BP p.l.c.; and

Registration Statements on Form S-8 (File Nos. 333-149778, 333-119934, 333-103923, 333-79399, 333-67206, 333-102583, 333-103924, 333-123482, 333-123483, 333-131583, 333-146868, 333-146870, 333-146873, 333-131584, 333-132619, 333-173136, 333-177423 and 333-179406) of BP p.l.c.

/s/ERNST & YOUNG LLP

Ernst & Young LLP

London, England

6 March 2012

Group income statement

For the year ended 31 December $ million

	Note	2011	2010	2009
Sales and other operating revenues	6	**375,517**	297,107	239,272
Earnings from jointly controlled entities after interest and tax	24	**1,304**	1,175	1,286
Earnings from associates after interest and tax	25	**4,916**	3,582	2,615
Interest and other income	7	**596**	681	792
Gains on sale of businesses and fixed assets	5	**4,130**	6,383	2,173
Total revenues and other income		**386,463**	308,928	246,138
Purchases	28	**285,618**	216,211	163,772
Production and manufacturing expenses[a]		**24,145**	64,615	23,202
Production and similar taxes	8	**8,280**	5,244	3,752
Depreciation, depletion and amortization	9	**11,135**	11,164	12,106
Impairment and losses on sale of businesses and fixed assets	5	**2,058**	1,689	2,333
Exploration expense	15	**1,520**	843	1,116
Distribution and administration expenses	11	**13,958**	12,555	14,038
Fair value (gain) loss on embedded derivatives	33	**(68)**	309	(607)
Profit (loss) before interest and taxation		**39,817**	(3,702)	26,426
Finance costs[a]	17	**1,246**	1,170	1,110
Net finance expense (income) relating to pensions and other post-retirement benefits	37	**(263)**	(47)	192
Profit (loss) before taxation		**38,834**	(4,825)	25,124
Taxation[a]	18	**12,737**	(1,501)	8,365
Profit (loss) for the year		**26,097**	(3,324)	16,759
Attributable to				
BP shareholders	39	**25,700**	(3,719)	16,578
Minority interest	39	**397**	395	181
		26,097	(3,324)	16,759
Earnings per share cents				
Profit (loss) for the year attributable to BP shareholders				
Basic	20	**135.93**	(19.81)	88.49
Diluted	20	**134.29**	(19.81)	87.54

a See Note 2 for information on the impact of the Gulf of Mexico oil spill on the income statement line items in 2011 and 2010.

Group statement of comprehensive income

For the year ended 31 December — $ million

	Note	2011	2010	2009
Profit (loss) for the year		**26,097**	(3,324)	16,759
Currency translation differences		**(531)**	259	1,826
Exchange (gains) or losses on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets		**19**	(20)	(27)
Actuarial loss relating to pensions and other post-retirement benefits	37	**(5,960)**	(320)	(682)
Available-for-sale investments marked to market		**(71)**	(191)	705
Available-for-sale investments recycled to the income statement		**(3)**	(150)	2
Cash flow hedges marked to market		**44**	(65)	652
Cash flow hedges recycled to the income statement		**(195)**	(25)	366
Cash flow hedges recycled to the balance sheet		**(13)**	53	136
Share of equity-accounted entities other comprehensive income, net of tax		**(57)**		
Taxation	18, 39	**1,659**	(137)	525
Other comprehensive income		**(5,108)**	(596)	3,503
Total comprehensive income		**20,989**	(3,920)	20,262
Attributable to				
BP shareholders	39	**20,605**	(4,318)	20,137
Minority interest	39	**384**	398	125
		20,989	(3,920)	20,262

Group statement of changes in equity[a]

$ million

	Share capital and capital reserves	Own shares and treasury shares	Foreign currency translation reserve	Fair value reserves	Share-based payment reserve	Profit and loss account	BP shareholders equity	Minority interest	Total equity
At 1 January 2011	**43,448**	**(21,211)**	**4,937**	**469**	**1,586**	**65,758**	**94,987**	**904**	**95,891**
Profit for the year						**25,700**	**25,700**	**397**	**26,097**
Other comprehensive income			**(515)**	**(202)**		**(4,378)**	**(5,095)**	**(13)**	**(5,108)**
Total comprehensive income			**(515)**	**(202)**		**21,322**	**20,605**	**384**	**20,989**
Dividends						**(4,072)**	**(4,072)**	**(245)**	**(4,317)**
Share-based payments (net of tax)	**6**	**(112)**			**(4)**	**102**	**(8)**		**(8)**
Transactions involving minority interests						**(47)**	**(47)**	**(26)**	**(73)**
At 31 December 2011	**43,454**	**(21,323)**	**4,422**	**267**	**1,582**	**83,063**	**111,465**	**1,017**	**112,482**
At 1 January 2010	43,304	(21,517)	4,811	776	1,584	72,655	101,613	500	102,113
Profit (loss) for the year						(3,719)	(3,719)	395	(3,324)
Other comprehensive income			126	(307)		(418)	(599)	3	(596)
Total comprehensive income			126	(307)		(4,137)	(4,318)	398	(3,920)
Dividends						(2,627)	(2,627)	(315)	(2,942)
Share-based payments (net of tax)	144	306			2	(113)	339		339
Transactions involving minority interests						(20)	(20)	321	301
At 31 December 2010	43,448	(21,211)	4,937	469	1,586	65,758	94,987	904	95,891
At 1 January 2009	43,217	(21,839)	2,353	(803)	1,295	67,080	91,303	806	92,109
Profit for the year						16,578	16,578	181	16,759
Other comprehensive income			2,458	1,579		(478)	3,559	(56)	3,503
Total comprehensive income			2,458	1,579		16,100	20,137	125	20,262
Dividends						(10,483)	(10,483)	(416)	(10,899)

Share-based payments (net of tax)	87	322			289	23	721		721
Changes in associates equity						(43)	(43)		(43)
Transactions involving minority interests						(22)	(22)	(15)	(37)
At 31 December 2009	43,304	(21,517)	4,811	776	1,584	72,655	101,613	500	102,113

a See Note 39 for further information.

Consolidated financial statements of the BP group

Group balance sheet

At 31 December $ million

	Note	2011	2010a
Non-current assets			
Property, plant and equipment	21	**119,214**	110,163
Goodwill	22	**12,100**	8,598
Intangible assets	23	**21,102**	14,298
Investments in jointly controlled entities	24	**15,518**	14,927
Investments in associates	25	**13,291**	13,335
Other investments	27	**2,117**	1,191
Fixed assets		**183,342**	162,512
Loans		**884**	894
Trade and other receivables	29	**4,337**	6,298
Derivative financial instruments	33	**5,038**	4,210
Prepayments		**1,255**	1,432
Deferred tax assets	18	**611**	528
Defined benefit pension plan surpluses	37	**17**	2,176
		195,484	178,050
Current assets			
Loans		**244**	247
Inventories	28	**25,661**	26,218
Trade and other receivables	29	**43,526**	36,549
Derivative financial instruments	33	**3,857**	4,356
Prepayments		**1,286**	1,574
Current tax receivable		**235**	693
Other investments	27	**288**	1,532
Cash and cash equivalents	30	**14,067**	18,556
		89,164	89,725
Assets classified as held for sale	4	**8,420**	4,487
		97,584	94,212
Total assets		**293,068**	272,262
Current liabilities			
Trade and other payables	32	**52,405**	46,329
Derivative financial instruments	33	**3,220**	3,856
Accruals		**5,932**	5,612
Finance debt	34	**9,044**	14,626
Current tax payable		**1,941**	2,920
Provisions	36	**11,238**	9,489
		83,780	82,832
Liabilities directly associated with assets classified as held for sale	4	**538**	1,047
		84,318	83,879
Non-current liabilities			
Other payables	32	**3,437**	14,285
Derivative financial instruments	33	**3,773**	3,677
Accruals		**389**	637
Finance debt	34	**35,169**	30,710
Deferred tax liabilities	18	**15,078**	10,908
Provisions	36	**26,404**	22,418
Defined benefit pension plan and other post-retirement benefit plan deficits	37	**12,018**	9,857
		96,268	92,492
Total liabilities		**180,586**	176,371
Net assets		**112,482**	95,891
Equity			
BP shareholders equity	39	**111,465**	94,987
Minority interest	39	**1,017**	904
Total equity	39	**112,482**	95,891

a Adjusted following the termination of the Pan American Energy LLC sale agreement, as described in Note 4.

C-H Svanberg Chairman

R W Dudley Group Chief Executive

6 March 2012

Group cash flow statement

For the year ended 31 December $ million

	Note	2011	2010	2009
Operating activities				
Profit (loss) before taxation		**38,834**	(4,825)	25,124
Adjustments to reconcile profit (loss) before taxation to net cash provided by operating activities				
Exploration expenditure written off	15	**1,024**	375	593
Depreciation, depletion and amortization	9	**11,135**	11,164	12,106
Impairment and (gain) loss on sale of businesses and fixed assets	5	**(2,072)**	(4,694)	160
Earnings from jointly controlled entities and associates		**(6,220)**	(4,757)	(3,901)
Dividends received from jointly controlled entities and associates		**5,381**	3,277	3,003
Interest receivable		**(198)**	(277)	(258)
Interest received		**216**	205	203
Finance costs	17	**1,246**	1,170	1,110
Interest paid		**(1,110)**	(912)	(909)
Net finance expense (income) relating to pensions and other post-retirement benefits	37	**(263)**	(47)	192
Share-based payments		**(88)**	197	450
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans		**(1,004)**	(959)	(887)
Net charge for provisions, less payments		**2,976**	19,217	650
(Increase) decrease in inventories		**(3,988)**	(3,895)	(5,363)
(Increase) decrease in other current and non-current assets		**(9,913)**	(15,620)	7,595
Increase (decrease) in other current and non-current liabilities		**(5,767)**	20,607	(5,828)
Income taxes paid		**(8,035)**	(6,610)	(6,324)
Net cash provided by operating activities		**22,154**	13,616	27,716
Investing activities				
Capital expenditure		**(17,845)**	(18,421)	(20,650)
Acquisitions, net of cash acquired		**(10,909)**	(2,468)	1
Investment in jointly controlled entities		**(857)**	(461)	(578)
Investment in associates		**(55)**	(65)	(164)
Proceeds from disposals of fixed assets	5	**3,500**	7,492	1,715
Proceeds from disposals of businesses, net of cash disposed[a]	5	**(768)**	9,462	966
Proceeds from loan repayments		**301**	501	530
Other				47
Net cash used in investing activities		**(26,633)**	(3,960)	(18,133)
Financing activities				
Net issue of shares		**74**	169	207
Proceeds from long-term financing		**11,600**	11,934	11,567
Repayments of long-term financing		**(9,102)**	(4,702)	(6,021)
Net increase (decrease) in short-term debt		**2,227**	(3,619)	(4,405)
Dividends paid				
BP shareholders		**(4,072)**	(2,627)	(10,483)
Minority interest		**(245)**	(315)	(416)
Net cash provided by (used in) financing activities		**482**	840	(9,551)
Currency translation differences relating to cash and cash equivalents		**(492)**	(279)	110
Increase (decrease) in cash and cash equivalents		**(4,489)**	10,217	142
Cash and cash equivalents at beginning of year		**18,556**	8,339	8,197
Cash and cash equivalents at end of year		**14,067**	18,556	8,339

a 2010 included a deposit received in advance of $3,530 million in respect of the expected sale of our interest in Pan American Energy LLC; 2011 includes the repayment of the same amount following the termination of the sale agreement as described in Note 4.

Notes on financial statements

1. Significant accounting policies

Authorization of financial statements and statement of compliance with International Financial Reporting Standards

The consolidated financial statements of the BP group for the year ended 31 December 2011 were approved and signed by the chairman and group chief executive on 6 March 2012 having been duly authorized to do so by the board of directors. BP p.l.c. is a public limited company incorporated and domiciled in England and Wales. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB), IFRS as adopted by the European Union (EU) and in accordance with the provisions of the Companies Act 2006. IFRS as adopted by the EU differs in certain respects from IFRS as issued by the IASB, however, the differences have no impact on the group s consolidated financial statements for the years presented. The significant accounting policies of the group are set out below.

Basis of preparation

The consolidated financial statements have been prepared in accordance with IFRS and IFRS Interpretations Committee (IFRIC) interpretations issued and effective for the year ended 31 December 2011, or issued and early adopted. The standards and interpretations adopted in the year are described further on page 188.

The accounting policies that follow have been consistently applied to all years presented. The group balance sheet as at 1 January 2010 is not presented as it is not affected by the retrospective adoption of any new accounting policies during the year, nor any other retrospective restatements or reclassifications.

The consolidated financial statements are presented in US dollars and all values are rounded to the nearest million dollars ($ million), except where otherwise indicated.

For further information regarding the key judgements and estimates made by management in applying the group s accounting policies, refer to Critical accounting policies on pages 154 to 157, which forms part of these financial statements.

Basis of consolidation

The group financial statements consolidate the financial statements of BP p.l.c. and the entities it controls (its subsidiaries) drawn up to 31 December each year. Control comprises the power to govern the financial and operating policies of the investee so as to obtain benefit from its activities and is achieved through direct and indirect ownership of voting rights; currently exercisable or convertible potential voting rights; or by way of contractual agreement. Subsidiaries are consolidated from the date of their acquisition, being the date on which the group obtains control, and continue to be consolidated until the date that such control ceases. The financial statements of subsidiaries are prepared for the same reporting year as the parent company, using consistent accounting policies. Intercompany balances and transactions, including unrealized profits arising from intragroup transactions, have been eliminated. Unrealized losses are eliminated unless the transaction provides evidence of an impairment of the asset transferred. Minority interests represent the equity in subsidiaries that is not attributable, directly or indirectly, to the group.

Segmental reporting

The group s operating segments are established on the basis of those components of the group that are evaluated regularly by the chief operating decision maker in deciding how to allocate resources and in assessing performance. During the second quarter of 2010 a separate organization was created within the group to deal with the ongoing response to the Gulf of Mexico oil spill. This organization reports directly to the group chief executive officer and its costs are excluded from the results of the existing operating segments. Under IFRS its costs are therefore presented as a reconciling item between the sum of the results of the reportable segments and the group results.

The accounting policies of the operating segments are the same as the group s accounting policies described in this note, except that IFRS requires that the measure of profit or loss disclosed for each operating segment is the measure that is provided regularly to the chief operating decision maker. For BP, this measure of profit or loss is replacement cost profit before interest and tax which reflects the replacement cost of supplies by excluding from profit inventory holding gains and losses. Replacement cost profit for the group is not a recognized measure under generally accepted accounting practice (GAAP). For further information see Note 6.

Interests in joint ventures

A joint venture is a contractual arrangement whereby two or more parties (venturers) undertake an economic activity that is subject to joint control. Joint control exists only when the strategic financial and operating decisions relating to the activity require the unanimous consent of the venturers. A jointly controlled entity is a joint venture that involves the establishment of a company, partnership or other entity to engage in economic activity that the group jointly controls with its fellow venturers.

The results, assets and liabilities of a jointly controlled entity are incorporated in these financial statements using the equity method of accounting. Under the equity method, the investment in a jointly controlled entity is carried in the balance sheet at cost, plus post-acquisition changes in the group share of net assets of the jointly controlled entity, less distributions received and less any impairment in value of the investment. Loans advanced to jointly controlled entities that have the characteristics of equity financing are also included in the investment on the group balance sheet. The group income statement reflects the group s share of the results after tax of the jointly controlled entity.

Financial statements of jointly controlled entities are prepared for the same reporting year as the group. Where necessary, adjustments are made to those financial statements to bring the accounting policies used into line with those of the group.

Unrealized gains on transactions between the group and its jointly controlled entities are eliminated to the extent of the group s interest in the jointly controlled entities. Unrealized losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred.

The group assesses investments in jointly controlled entities for impairment whenever events or changes in circumstances indicate that the carrying value may not be recoverable. If any such indication of impairment exists, the carrying amount of the investment is compared with its recoverable amount, being the higher of its fair value less costs to sell and value in use. Where the carrying amount exceeds the recoverable amount, the investment is written down to its recoverable amount.

The group ceases to use the equity method of accounting on the date from which it no longer has joint control or significant influence over the joint venture or associate respectively, or when the interest becomes held for sale.

Certain of the group s activities, particularly in the Exploration and Production segment, are conducted through joint ventures where the venturers have a direct ownership interest in, and jointly control, the assets of the venture. BP recognizes, on a line-by-line basis in the consolidated financial statements, its share of the assets, liabilities and expenses of these jointly controlled assets incurred jointly with the other partners, along with the group s income from the sale of its share of the output and any liabilities and expenses that the group has incurred in relation to the venture.

Interests in associates

An associate is an entity over which the group is in a position to exercise significant influence through participation in the financial and operating policy decisions of the investee, but which is not a subsidiary or a jointly controlled entity. The results, assets and liabilities of an associate are incorporated in these financial statements using the equity method of accounting as described above for jointly controlled entities.

1. Significant accounting policies continued

Foreign currency translation

The functional currency is the currency of the primary economic environment in which an entity operates and is normally the currency in which the entity primarily generates and expends cash.

In individual companies, transactions in foreign currencies are initially recorded in the functional currency by applying the rate of exchange ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated into the functional currency at the rate of exchange ruling at the balance sheet date. Any resulting exchange differences are included in the income statement. Non-monetary assets and liabilities, other than those measured at fair value, are not retranslated subsequent to initial recognition.

In the consolidated financial statements, the assets and liabilities of non-US dollar functional currency subsidiaries, jointly controlled entities and associates, including related goodwill, are translated into US dollars at the rate of exchange ruling at the balance sheet date. The results and cash flows of non-US dollar functional currency subsidiaries, jointly controlled entities and associates are translated into US dollars using average rates of exchange. Exchange adjustments arising when the opening net assets and the profits for the year retained by non-US dollar functional currency subsidiaries, jointly controlled entities and associates are translated into US dollars are taken to a separate component of equity and reported in the statement of comprehensive income. Exchange gains and losses arising on long-term intragroup foreign currency borrowings used to finance the group s non-US dollar investments are also taken to other comprehensive income. On disposal or partial disposal of a non-US dollar functional currency subsidiary, jointly controlled entity or associate, the deferred cumulative amount of exchange gains and losses recognized in equity relating to that particular non-US dollar operation is reclassified to income statement.

Business combinations and goodwill

A business combination is a transaction or other event in which an acquirer obtains control of one or more businesses. A business is an integrated set of activities and assets that is capable of being conducted and managed for the purpose of providing a return in the form of dividends or lower costs or other economic benefits directly to investors or other owners or participants. A business consists of inputs and processes applied to those inputs that have the ability to create outputs.

Business combinations are accounted for using the acquisition method. The identifiable assets acquired and liabilities assumed are measured at their fair values at the acquisition date. The cost of an acquisition is measured as the aggregate of the consideration transferred, measured at acquisition-date fair value, and the amount of any minority interest in the acquiree. Minority interests are stated either at fair value or at the proportionate share of the recognized amounts of the acquiree s identifiable net assets. Acquisition costs incurred are expensed and included in distribution and administration expenses.

Goodwill is initially measured as the excess of the aggregate of the consideration transferred, the amount recognized for any minority interest and the acquisition-date fair values of any previously held interest in the acquiree over the fair value of the identifiable assets acquired and liabilities assumed at the acquisition date.

At the acquisition date, any goodwill acquired is allocated to each of the cash-generating units, or groups of cash-generating units, expected to benefit from the combination s synergies.

Following initial recognition, goodwill is measured at cost less any accumulated impairment losses. Goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate that the carrying value may be impaired. Impairment is determined by assessing the recoverable amount of the cash-generating unit to which the goodwill relates. Where the recoverable amount of the cash-generating unit is less than the carrying amount, an impairment loss is recognized. An impairment loss recognized for goodwill is not reversed in a subsequent period.

Goodwill arising on business combinations prior to 1 January 2003 is stated at the previous carrying amount, less subsequent impairments, under UK generally accepted accounting practice.

Goodwill may also arise upon investments in jointly controlled entities and associates, being the surplus of the cost of investment over the group s share of the net fair value of the identifiable assets. Such goodwill is recorded within investments in jointly controlled entities and associates, and any impairment of the investment is included within the earnings from jointly controlled entities and associates.

Non-current assets held for sale

Non-current assets and disposal groups classified as held for sale are measured at the lower of carrying amount and fair value less costs to sell.

Non-current assets and disposal groups are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is regarded as met only when the sale is highly probable and the asset or disposal group is available for immediate sale in its present condition subject only to terms that are usual and customary for sales of such assets. Management must be committed to the sale, which should be expected to qualify for recognition as a completed sale within one year from the date of classification as held for sale.

Property, plant and equipment and intangible assets once classified as held for sale are not depreciated. The group ceases to use the equity method of accounting on the date from which an interest in a jointly controlled entity or an interest in an associate becomes held for sale.

If a non-current asset or disposal group has been classified as held for sale, but subsequently ceases to meet the criteria to be classified as held for sale, the group ceases to classify the asset or disposal group as held for sale. Non-current assets and disposal groups that cease to be classified as held for sale are measured at the lower of carrying amount before the asset or disposal group was classified as held for sale (adjusted for any depreciation, amortization or revaluation that would have been recognized had the asset or disposal group not been classified as held for sale) and its recoverable amount at the date of the subsequent decision not to sell. Except for any interests in equity-accounted entities that cease to be classified as held for sale, any adjustment to the carrying amount is recognized in profit or loss in the period in which the asset ceases to be classified as held for sale. When an interest in an equity-accounted entity ceases to be classified as held for sale, it is accounted for using the equity method as from the date of its classification as held for sale and the financial statements for the periods since classification as held for sale are amended accordingly.

Intangible assets

Intangible assets, other than goodwill, include expenditure on the exploration for and evaluation of oil and natural gas resources, computer software, patents, licences and trademarks and are stated at the amount initially recognized, less accumulated amortization and accumulated impairment losses. For information on accounting for expenditures on the exploration for and evaluation of oil and gas resources, see the accounting policy for oil and natural gas exploration, appraisal and development expenditure below.

Intangible assets acquired separately from a business are carried initially at cost. The initial cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. An intangible asset acquired as part of a business combination is measured at fair value at the date of acquisition and is recognized separately from goodwill if the asset is separable or arises from contractual or other legal rights.

Intangible assets with a finite life are amortized on a straight-line basis over their expected useful lives. For patents, licences and trademarks, expected useful life is the shorter of the duration of the legal agreement and economic useful life, and can range from three to 15 years. Computer software costs generally have a useful life of three to five years.

The expected useful lives of assets are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

The carrying value of intangible assets is reviewed for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable.

1. Significant accounting policies continued

Oil and natural gas exploration, appraisal and development expenditure

Oil and natural gas exploration, appraisal and development expenditure is accounted for using the principles of the successful efforts method of accounting.

Licence and property acquisition costs

Exploration licence and leasehold property acquisition costs are capitalized within intangible assets and are reviewed at each reporting date to confirm that there is no indication that the carrying amount exceeds the recoverable amount. This review includes confirming that exploration drilling is still under way or firmly planned or that it has been determined, or work is under way to determine, that the discovery is economically viable based on a range of technical and commercial considerations and sufficient progress is being made on establishing development plans and timing. If no future activity is planned, the remaining balance of the licence and property acquisition costs is written off. Lower value licences are pooled and amortized on a straight-line basis over the estimated period of exploration. Upon recognition of proved reserves and internal approval for development, the relevant expenditure is transferred to property, plant and equipment.

Exploration and appraisal expenditure

Geological and geophysical exploration costs are charged against income as incurred. Costs directly associated with an exploration well are initially capitalized as an intangible asset until the drilling of the well is complete and the results have been evaluated. These costs include employee remuneration, materials and fuel used, rig costs and payments made to contractors. If potentially commercial quantities of hydrocarbons are not found, the exploration well is written off as a dry hole. If hydrocarbons are found and, subject to further appraisal activity, are likely to be capable of commercial development, the costs continue to be carried as an asset.

Costs directly associated with appraisal activity, undertaken to determine the size, characteristics and commercial potential of a reservoir following the initial discovery of hydrocarbons, including the costs of appraisal wells where hydrocarbons were not found, are initially capitalized as an intangible asset.

All such carried costs are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off. When proved reserves of oil and natural gas are determined and development is approved by management, the relevant expenditure is transferred to property, plant and equipment.

Development expenditure

Expenditure on the construction, installation and completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including service and unsuccessful development or delineation wells, is capitalized within property, plant and equipment and is depreciated from the commencement of production as described below in the accounting policy for property, plant and equipment.

Property, plant and equipment

Property, plant and equipment is stated at cost, less accumulated depreciation and accumulated impairment losses.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of any decommissioning obligation, if any, and, for qualifying assets, borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. The capitalized value of a finance lease is also included within property, plant and equipment. Exchanges of assets are measured at fair value unless the exchange transaction lacks commercial substance or the fair value of neither the asset received nor the asset given up is reliably measurable. The cost of the acquired asset is measured at the fair value of the asset given up, unless the fair value of the asset received is more clearly evident. Where fair value is not used, the cost of the acquired asset is measured at the carrying amount of the asset given up. The gain or loss on derecognition of the asset given up is recognized in profit or loss.

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

Oil and natural gas properties, including related pipelines, are depreciated using a unit-of-production method. The cost of producing wells is amortized over proved developed reserves. Licence acquisition, common facilities and future decommissioning costs are amortized over total proved reserves. The unit-of-production rate for the amortization of common facilities costs takes into account expenditures incurred to date, together with the future capital expenditure expected to be incurred in relation to these common facilities.

Other property, plant and equipment is depreciated on a straight line basis over its expected useful life. The useful lives of the group s other property, plant and equipment are as follows:

Land improvements	15 to 25 years
Buildings	20 to 50 years
Refineries	20 to 30 years
Petrochemicals	20 to 30 years
Pipelines	10 to 50 years
Service stations	15 years
Office equipment	3 to 7 years
Fixtures and fittings	5 to 15 years

The expected useful lives of property, plant and equipment are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

The carrying amount of property, plant and equipment is reviewed for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable.

An item of property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in the income statement in the period in which the item is derecognized.

Impairment of intangible assets and property, plant and equipment

The group assesses assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable, for example, low prices or margins for an extended period or, for oil and gas assets, significant downward revisions of estimated volumes or increases in estimated future development expenditure. If any such indication of impairment exists, the group makes an estimate of the asset s recoverable amount. Individual assets are grouped for impairment assessment purposes at the lowest level at which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. An asset group s recoverable amount is the higher of its fair value less costs to sell and its value in use. Where the carrying amount of an asset group exceeds its recoverable amount, the asset group is considered impaired and is written down to its recoverable amount. In assessing value in use, the estimated future cash flows are adjusted for the risks specific to the asset group and are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money.

An assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such an indication exists, the recoverable amount is estimated. A previously recognized impairment loss is reversed only if there has been a change in the estimates used to determine the asset s recoverable amount since the last impairment loss was recognized. If that is the case, the carrying amount of the asset is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depreciation, had no

1. Significant accounting policies continued

impairment loss been recognized for the asset in prior years. Such reversal is recognized in profit or loss. After such a reversal, the depreciation charge is adjusted in future periods to allocate the asset s revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.

Financial assets

Financial assets are classified as loans and receivables; available-for-sale financial assets; financial assets at fair value through profit or loss; or as derivatives designated as hedging instruments in an effective hedge, as appropriate. Financial assets include cash and cash equivalents, trade receivables, other receivables, loans, other investments, and derivative financial instruments. The group determines the classification of its financial assets at initial recognition. Financial assets are recognized initially at fair value, normally being the transaction price plus, in the case of financial assets not at fair value through profit or loss, directly attributable transaction costs.

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

Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Such assets are carried at amortized cost using the effective interest method if the time value of money is significant. Gains and losses are recognized in income when the loans and receivables are derecognized or impaired, as well as through the amortization process. This category of financial assets includes trade and other receivables.

Available-for-sale financial assets

Available-for-sale financial assets are those non-derivative financial assets that are not classified as loans and receivables. After initial recognition, available-for-sale financial assets are measured at fair value, with gains or losses recognized within other comprehensive income. Accumulated changes in fair value are recorded as a separate component of equity until the investment is derecognized or impaired.

The fair value of quoted investments is determined by reference to bid prices at the close of business on the balance sheet date. Where there is no active market, fair value is determined using valuation techniques. Where fair value cannot be reliably measured, assets are carried at cost.

Financial assets at fair value through profit or loss

Derivatives, other than those designated as effective hedging instruments, are classified as held for trading and are included in this category. These assets are carried on the balance sheet at fair value with gains or losses recognized in the income statement.

Derivatives designated as hedging instruments in an effective hedge

Such derivatives are carried on the balance sheet at fair value. The treatment of gains and losses arising from revaluation is described below in the accounting policy for derivative financial instruments and hedging activities.

Impairment of financial assets

The group assesses at each balance sheet date whether a financial asset or group of financial assets is impaired.

Loans and receivables

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

Available-for-sale financial assets

If an available-for-sale financial asset is impaired, the cumulative loss previously recognized in equity is transferred to the income statement. Any subsequent recovery in the fair value of the asset is recognized within other comprehensive income.

If there is objective evidence that an impairment loss on an unquoted equity instrument that is carried at cost has been incurred, the amount of the loss is measured as the difference between the asset s carrying amount and the present value of estimated future cash flows discounted at the current market rate of return for a similar financial asset.

Inventories

Inventories, other than inventory held for trading purposes, are stated at the lower of cost and net realizable value. Cost is determined by the first-in first-out method and comprises direct purchase costs, cost of production, transportation and manufacturing expenses. Net realizable value is determined by reference to prices existing at the balance sheet date.

Inventories held for trading purposes are stated at fair value less costs to sell and any changes in net realizable value are recognized in the income statement.

Supplies are valued at cost to the group mainly using the average method or net realizable value, whichever is the lower.

Financial liabilities

Financial liabilities are classified as financial liabilities at fair value through profit or loss; derivatives designated as hedging instruments in an effective hedge; or as financial liabilities measured at amortized cost, as appropriate. Financial liabilities include trade and other payables, accruals, most items of finance debt and derivative financial instruments. The group determines the classification of its financial liabilities at initial recognition. The measurement of financial liabilities depends on their classification, as follows:

Financial liabilities at fair value through profit or loss

Derivatives, other than those designated as effective hedging instruments, are classified as held for trading and are included in this category. These liabilities are carried on the balance sheet at fair value with gains or losses recognized in the income statement.

Derivatives designated as hedging instruments in an effective hedge

Such derivatives are carried on the balance sheet at fair value. The treatment of gains and losses arising from revaluation is described below in the accounting policy for derivative financial instruments and hedging activities.

Financial liabilities measured at amortized cost

All other financial liabilities are initially recognized at fair value. For interest-bearing loans and borrowings this is the fair value of the proceeds received net of issue costs associated with the borrowing.

After initial recognition, other financial liabilities are subsequently measured at amortized cost using the effective interest method. Amortized cost is calculated by taking into account any issue costs, and any discount or premium on settlement. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognized respectively in interest and other income and finance costs.

This category of financial liabilities includes trade and other payables and finance debt.

1. Significant accounting policies continued

Leases

Finance leases, which transfer to the group substantially all the risks and benefits incidental to ownership of the leased item, are capitalized at the commencement of the lease term at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Finance charges are allocated to each period so as to achieve a constant rate of interest on the remaining balance of the liability and are charged directly against income.

Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term. Operating lease payments are recognized as an expense in the income statement on a straight-line basis over the lease term. For both finance and operating leases, contingent rents are recognized in the income statement in the period in which they are incurred.

Derivative financial instruments and hedging activities

The group uses derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates, interest rates and commodity prices as well as for trading purposes. Such derivative financial instruments are initially recognized at fair value on the date on which a derivative contract is entered into and are subsequently remeasured at fair value. Derivatives are carried as assets when the fair value is positive and as liabilities when the fair value is negative.

Contracts to buy or sell a non-financial item that can be settled net in cash or another financial instrument, or by exchanging financial instruments as if the contracts were financial instruments, with the exception of contracts that were entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the group s expected purchase, sale or usage requirements, are accounted for as financial instruments.

Gains or losses arising from changes in the fair value of derivatives that are not designated as effective hedging instruments are recognized in the income statement.

For the purpose of hedge accounting, hedges are classified as:

- Fair value hedges when hedging exposure to changes in the fair value of a recognized asset or liability.
- Cash flow hedges when hedging exposure to variability in cash flows that is either attributable to a particular risk associated with a recognized asset or liability or a highly probable forecast transaction.

Hedge relationships are formally designated and documented at inception, together with the risk management objective and strategy for undertaking the hedge. The documentation includes identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged, and how the entity will assess the hedging instrument effectiveness in offsetting the exposure to changes in the hedged item s fair value or cash flows attributable to the hedged item. Such hedges are expected at inception to be highly effective in achieving offsetting changes in fair value or cash flows. Hedges meeting the criteria for hedge accounting are accounted for as follows:

Fair value hedges

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

The group applies fair value hedge accounting for hedging fixed interest rate risk on borrowings. The gain or loss relating to the effective portion of the interest rate swap is recognized in the income statement within finance costs, offsetting the amortization of the interest on the underlying borrowings.

If the criteria for hedge accounting are no longer met, or if the group revokes the designation, the adjustment to the carrying amount of a hedged item for which the effective interest method is used is amortized to profit or loss over the period to maturity.

Cash flow hedges

For cash flow hedges, the effective portion of the gain or loss on the hedging instrument is recognized within other comprehensive income, while the ineffective portion is recognized in profit or loss. Amounts taken to other comprehensive income are transferred to the income statement when the hedged transaction affects profit or loss. The gain or loss relating to the effective portion of interest rate swaps hedging variable rate borrowings is recognized in the income statement within finance costs.

Where the hedged item is the cost of a non-financial asset or liability, such as a forecast transaction for the purchase of property, plant and equipment, the amounts recognized within other comprehensive income are transferred to the initial carrying amount of the non-financial asset or liability.

If the hedging instrument expires or is sold, terminated or exercised without replacement or rollover, or if its designation as a hedge is revoked, amounts previously recognized within other comprehensive income remain in equity until the forecast transaction occurs and are transferred to the income statement or to the initial carrying amount of a non-financial asset or liability as above. If a forecast transaction is no longer expected to occur, amounts previously recognized in equity are reclassified to the income statement.

Embedded derivatives

Derivatives embedded in other financial instruments or other host contracts are treated as separate derivatives when their risks and characteristics are not closely related to those of the host contract. Contracts are assessed for embedded derivatives when the group becomes a party to them, including at the date of a business combination. Embedded derivatives are measured at fair value at each balance sheet date. Any gains or losses arising from changes in fair value are taken directly to the income statement.

Provisions, contingencies and reimbursement assets

Provisions are recognized when the group has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where appropriate, the future cash flow estimates are adjusted to reflect risks specific to the liability.

If the effect of the time value of money is material, provisions are determined by discounting the expected future cash flows at a pre-tax risk-free rate that reflects current market assessments of the time value of money. Where discounting is used, the increase in the provision due to the passage of time is recognized within finance costs. Provisions are split between amounts expected to be settled within 12 months of the balance sheet date (current) and amounts expected to be settled later (non-current). Contingent liabilities are possible obligations whose existence will only be confirmed by future events not wholly within the control of the group, or present obligations where it is not probable that an outflow of resources will be required or the amount of the obligation cannot be measured with sufficient reliability.

Contingent liabilities are not recognized in the financial statements but are disclosed unless the possibility of an outflow of economic resources is considered remote.

Where the group makes contributions into a separately administered fund for restoration, environmental or other obligations, which it does not control, and the group s right to the assets in the fund is restricted, the obligation to contribute to the fund is recognized as a liability where it is probable that such additional contributions will be made. The group recognizes a reimbursement asset separately, being the lower of the amount of the associated restoration, environmental or other provision and the group s share of the fair value of the net assets of the fund available to contributors.

1. Significant accounting policies continued

Decommissioning

Liabilities for decommissioning costs are recognized when the group has an obligation to dismantle and remove a facility or an item of plant and to restore the site on which it is located, and when a reliable estimate of that liability can be made. Where an obligation exists for a new facility, such as oil and natural gas production or transportation facilities, this liability will be recognized on construction or installation. An obligation for decommissioning may also crystallize during the period of operation of a facility through a change in legislation or through a decision to terminate operations. The amount recognized is the present value of the estimated future expenditure determined in accordance with local conditions and requirements.

A corresponding item of property, plant and equipment of an amount equivalent to the provision is also recognized. This is subsequently depreciated as part of the asset.

Other than the unwinding discount on the provision, any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding item of property, plant and equipment. Such changes include foreign exchange gains and losses arising on the retranslation of the liability into the functional currency of the reporting entity, when it is known that the liability will be settled in a foreign currency.

Environmental expenditures and liabilities

Environmental expenditures that relate to current or future revenues are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations and do not contribute to current or future earnings are expensed.

Liabilities for environmental costs are recognized when a clean-up is probable and the associated costs can be reliably estimated. Generally, the timing of recognition of these provisions coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The amount recognized is the best estimate of the expenditure required. Where the liability will not be settled for a number of years, the amount recognized is the present value of the estimated future expenditure.

Employee benefits

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

Share-based payments

Equity-settled transactions

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

No expense is recognized for awards that do not ultimately vest, except for awards where vesting is conditional upon a market condition, which are treated as vesting irrespective of whether or not the market condition is satisfied, provided that all other performance conditions are satisfied.

At each balance sheet date before vesting, the cumulative expense is calculated, representing the extent to which the vesting period has expired and management s best estimate of the achievement or otherwise of non-market conditions and the number of equity instruments that will ultimately vest or, in the case of an instrument subject to a market condition, be treated as vesting as described above. The movement in cumulative expense since the previous balance sheet date is recognized in the income statement, with a corresponding entry in equity.

When the terms of an equity-settled award are modified or a new award is designated as replacing a cancelled or settled award, the cost based on the original award terms continues to be recognized over the original vesting period. In addition, an expense is recognized over the remainder of the new vesting period for the incremental fair value of any modification, based on the difference between the fair value of the original award and the fair value of the modified award, both as measured on the date of the modification. No reduction is recognized if this difference is negative.

When an equity-settled award is cancelled, it is treated as if it had vested on the date of cancellation and any cost not yet recognized in the income statement for the award is expensed immediately.

Cash-settled transactions

The cost of cash-settled transactions is measured at fair value and recognized as an expense over the vesting period, with a corresponding liability recognized on the balance sheet.

Pensions and other post-retirement benefits

The cost of providing benefits under the defined benefit plans is determined separately for each plan using the projected unit credit method, which attributes entitlement to benefits to the current period (to determine current service cost) and to the current and prior periods (to determine the present value of the defined benefit obligation). Past service costs are recognized immediately when the company becomes committed to a change in pension plan design. When a settlement (eliminating all obligations for benefits already accrued) or a curtailment (reducing future obligations as a result of a material reduction in the scheme membership or a reduction in future entitlement) occurs, the obligation and related plan assets are remeasured using current actuarial assumptions and the resultant gain or loss is recognized in the income statement during the period in which the settlement or curtailment occurs.

The interest element of the defined benefit cost represents the change in present value of scheme obligations resulting from the passage of time, and is determined by applying the discount rate to the opening present value of the benefit obligation, taking into account material changes in the obligation during the year. The expected return on plan assets is based on an assessment made at the beginning of the year of long-term market returns on plan assets, adjusted for the forecasts of contributions received and benefits paid during the year. The difference between the expected return on plan assets and the interest cost is recognized in the income statement as other finance income or expense.

Actuarial gains and losses are recognized in full within other comprehensive income in the year in which they occur.

The defined benefit pension plan surplus or deficit in the balance sheet comprises the total for each plan of the present value of the defined benefit obligation (using a discount rate based on high quality corporate bonds), less the fair value of plan assets out of which the obligations are to be settled directly. Fair value is based on market price information and, in the case of quoted securities, is the published bid price.

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

1. Significant accounting policies continued

Corporate taxes

Income tax expense represents the sum of the tax currently payable and deferred tax. Interest and penalties relating to tax are also included in income tax expense.

The tax currently payable is based on the taxable profits for the period. Taxable profit differs from net profit as reported in the income statement because it excludes items of income or expense that are taxable or deductible in other periods and it further excludes items that are never taxable or deductible. The group s liability for current tax is calculated using tax rates and laws that have been enacted or substantively enacted by the balance sheet date.

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

Deferred tax liabilities are recognized for all taxable temporary differences except:

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

Deferred tax assets are recognized for all deductible temporary differences, carry-forward of unused tax credits and unused tax losses, to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax credits and unused tax losses can be utilized:

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

The carrying amount of deferred tax assets is reviewed at each balance sheet date and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred income tax asset to be utilized.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply to the year when the asset is realized or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the balance sheet date.

Tax relating to items recognized in other comprehensive income is recognized in other comprehensive income and tax relating to items recognized directly in equity is recognized directly in equity and not in the income statement.

Customs duties and sales taxes

Revenues, expenses and assets are recognized net of the amount of customs duties or sales tax except:

- Where the customs duty or sales tax incurred on a purchase of goods and services is not recoverable from the taxation authority, in which case the customs duty or sales tax is recognized as part of the cost of acquisition of the asset or as part of the expense item as applicable.
- Receivables and payables are stated with the amount of customs duty or sales tax included.

The net amount of sales tax recoverable from, or payable to, the taxation authority is included within receivables or payables in the balance sheet.

Own equity instruments

The group s holdings in its own equity instruments, including ordinary shares held by Employee Share Ownership Plan Trusts (ESOPs), are classified as treasury shares , or own shares for the ESOPs, and are shown as deductions from shareholders equity at cost. Consideration received for the sale of such shares is also recognized in equity, with any difference between the proceeds from sale and the original cost being taken to the profit and loss account reserve. No gain or loss is recognized in the income statement on the purchase, sale, issue or cancellation of equity shares.

Revenue

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

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

Physical exchanges are reported net, as are sales and purchases made with a common counterparty, as part of an arrangement similar to a physical exchange. Similarly, where the group acts as agent on behalf of a third party to procure or market energy commodities, any associated fee income is recognized but no purchase or sale is recorded. Additionally, where forward sale and purchase contracts for oil, natural gas or power have been determined to be for trading purposes, the associated sales and purchases are reported net within sales and other operating revenues whether or not physical delivery has occurred.

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

Interest income is recognized as the interest accrues (using the effective interest rate that is the rate that exactly discounts estimated future cash receipts through the expected life of the financial instrument to the net carrying amount of the financial asset).

Dividend income from investments is recognized when the shareholders right to receive the payment is established.

Research

Research costs are expensed as incurred.

Finance costs

Finance costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use. All other finance costs are recognized in the income statement in the period in which they are incurred.

Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities as well as the disclosure of contingent assets and liabilities at the balance sheet date and the reported amounts of revenues and expenses during the reporting period. Actual outcomes could differ from those estimates.

Impact of new International Financial Reporting Standards

Adopted for 2011

There are no new or amended standards or interpretations adopted with effect from 1 January 2011 that have a significant impact on the financial statements.

1. Significant accounting policies continued

Not yet adopted

The following pronouncements from the IASB will become effective for future financial reporting periods and have not yet been adopted by the group.

Interests in other entities and related disclosures

In May 2011, the IASB issued three new standards relating to interests in other entities and related disclosures. The new standards are IFRS 10 Consolidated Financial Statements , IFRS 11 Joint Arrangements and IFRS 12 Disclosure of Interests in Other Entities . In addition, the IASB issued amendments to IAS 27 Consolidated and Separate Financial Statements (now renamed IAS 27 Separate Financial Statements) and IAS 28 Investments in Associates (now renamed IAS 28 Investments in Associates and Joint Ventures).

IFRS 10 introduces a single consolidation model that identifies control as the basis for consolidation. The new model applies to all types of entities, including structured entities. Under the new model, an investor controls an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee.

IFRS 11 establishes a principle that applies to the accounting for all joint arrangements, whereby parties to the arrangement account for their underlying contractual rights and obligations relating to the joint arrangement. IFRS 11 identifies two types of joint arrangements. A joint venture is defined as a joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement. A joint operation is defined as a joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement. Investments in joint ventures will be accounted for using the equity method. Investments in joint operations will be accounted for by recognizing the group s assets, liabilities, revenue and expenses relating to the joint operation.

IFRS 12 combines all the disclosure requirements for an entity s interests in subsidiaries, joint arrangements, associates and structured entities into one comprehensive disclosure standard.

These new and amended standards are effective for annual periods beginning on or after 1 January 2013 and BP intends to adopt them from this date. The evaluation of the effect of adoption of these standards has not yet been completed. It is expected that the main impact of this suite of new standards is that certain of the group s existing jointly controlled entities, which are currently equity accounted, will fall under the definition of a joint operation under IFRS 11 and thus we will be required to cease equity accounting and instead recognize the group s assets, liabilities, revenue and expenses relating to these arrangements. This new suite of standards has not yet been adopted by the EU.

Other new standards not yet adopted

As part of the IASB s project to replace IAS 39 Financial Instruments: Recognition and Measurement , in November 2009 the IASB issued the first phase of IFRS 9 Financial Instruments , dealing with the classification and measurement of financial assets. In October 2010, the IASB updated IFRS 9 by incorporating the requirements for the accounting for financial liabilities. The remaining phases of IFRS 9 (covering impairment and hedge accounting) are still to be completed. In December 2011, the IASB decided that IFRS 9 will be effective for annual periods beginning on or after 1 January 2015, rather than 1 January 2013 as originally indicated. BP has not yet decided the date of adoption for the group and has not yet completed its evaluation of the effect of adoption. The new standard has not yet been adopted by the EU.

In May 2011, the IASB issued a new standard, IFRS 13 Fair value measurement . The new standard defines fair value, sets out a framework for measuring fair value and the required disclosures about fair value measurements. IFRS 13 does not require fair value measurements in

addition to those already required or permitted by other IFRSs, rather it prescribes how fair value should be measured if another IFRS requires it. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date i.e. it is an exit price. IFRS 13 is effective for annual periods beginning on or after 1 January 2013 and BP intends to adopt it from this date. The evaluation of the effect of adoption of IFRS 13 has not yet been completed.

In June 2011, the IASB issued an amended version of IAS 19 Employee Benefits , which brings in various changes relating to the recognition and measurement of termination benefits and post-employment defined benefit expense, and to the disclosures for all employee benefits. The main impact for BP will be that the expense for defined benefit pension and other post-retirement benefit plans will include a net interest income or expense, which will be calculated by applying the discount rate used for measuring the obligation and applying that to the net defined benefit asset or liability. This means that the expected return on assets credited to profit or loss (currently calculated based on the expected long-term return on pension assets) will now be based on a lower corporate bond rate, the same rate that is used to discount the pension liability. The amended IAS 19 is effective for annual periods beginning on or after 1 January 2013 and BP intends to adopt this new standard with effect from that date. The evaluation of the effect of adoption of the amended standard has not yet been completed, however, based upon our analysis to date, we expect the change to result in a significantly higher net charge to the income statement once adopted.

In June 2011, the IASB issued amendments to IAS 1 Presentation of Financial Statements on the presentation of other comprehensive income (OCI). The amendments require that those items of OCI that could be reclassified to profit or loss at a future date be presented separately from those items that will never be reclassified to profit or loss. These amendments to IAS 1 are effective for annual periods beginning on or after 1 July 2012. BP intends to adopt the amendments with effect from 1 January 2013. The adoption of the amended standard is expected to only have a presentational impact on the group s financial statements, with no effect on the reported income or net assets of the group.

In December 2011, the IASB issued amendments to IFRS 7 Disclosures Offsetting Financial Assets and Financial Liabilities and amendments to IAS 32 Offsetting Financial Assets and Financial Liabilities . These amendments introduce new disclosure requirements about the effects of offsetting financial assets and financial liabilities and related arrangements on an entity s financial position. The amendments to IFRS 7 are effective for annual periods beginning on or after 1 January 2013, with the amendments to IAS 32 effective for annual periods beginning on or after 1 January 2014. BP intends to adopt these amendments with effect from 1 January 2013 and 1 January 2014 respectively. The evaluation of the effect of adoption of these amendments has not yet been completed.

In October 2010, the IASB issued amendments to IFRS 7 Financial Instruments: Disclosures Transfers of Financial Assets . The amendments address the disclosures of transfers of financial assets. These amendments to IFRS 7 are effective for periods beginning on or after 1 July 2011. BP intends to adopt the amendments with effect from 1 January 2012. The extent to which BP will be required to amend its disclosures in the light of these new requirements is currently being evaluated.

With the exception of the amendments to IFRS 7 regarding the disclosures of transfers of financial assets, the EU has not yet adopted any of the above-mentioned other new standards that have been issued but not yet adopted by the group.

There are no other standards and interpretations in issue but not yet adopted that the directors anticipate will have a material effect on the reported income or net assets of the group.

2. Significant event Gulf of Mexico oil spill

As a consequence of the Gulf of Mexico oil spill, as described on pages 76 to 79, BP continues to incur costs and has also recognized liabilities for future costs. Liabilities of uncertain timing or amount and contingent liabilities have been accounted for and/or disclosed in accordance with IAS 37 Provisions, contingent liabilities and contingent assets . These are discussed in further detail in Note 36 for provisions and Note 43 for contingent liabilities. BP s rights and obligations in relation to the $20-billion trust fund which was established in 2010 are accounted for in accordance with IFRIC 5 Rights to interests arising from decommissioning, restoration and environmental rehabilitation funds . Key aspects of the accounting for the oil spill are summarized below.

The financial impacts of the Gulf of Mexico oil spill on the income statement, balance sheet and cash flow statement of the group are shown in the table below. Amounts related to the trust fund are separately identified.

$ million

		2011		2010
	Total	**Of which: amount related to the trust fund**	Total	Of which: amount related to the trust fund
Income statement				
Production and manufacturing expenses	**(3,800)**	**(3,995)**	40,858	7,261
Profit (loss) before interest and taxation	**3,800**	**3,995**	(40,858)	(7,261)
Finance costs	**58**	**52**	77	73
Profit (loss) before taxation	**3,742**	**3,943**	(40,935)	(7,334)
Less: Taxation	**(1,387)**		12,894	
Profit (loss) for the period	**2,355**	**3,943**	(28,041)	(7,334)
Balance sheet				
Current assets				
Trade and other receivables	**8,487**	**8,233**	5,943	5,943
Current liabilities				
Trade and other payables	**(5,425)**	**(4,872)**	(6,587)	(5,002)
Provisions	**(9,437)**		(7,938)	
Net current liabilities	**(6,375)**	**3,361**	(8,582)	941
Non-current assets				
Other receivables	**1,642**	**1,642**	3,601	3,601
Non-current liabilities				
Other payables			(9,899)	(9,899)
Provisions	**(5,896)**		(8,397)	
Deferred tax	**7,775**		11,255	
Net non-current liabilities	**3,521**	**1,642**	(3,440)	(6,298)
Net assets	**(2,854)**	**5,003**	(12,022)	(5,357)
Cash flow statement				
Profit (loss) before taxation	**3,742**	**3,943**	(40,935)	(7,334)
Finance costs	**58**	**52**	77	73
Net charge for provisions, less payments	**2,699**		19,354	
(Increase) decrease in other current and non-current assets	**(4,292)**	**(4,038)**	(12,567)	(12,567)
Increase (decrease) in other current and non-current liabilities	**(11,113)**	**(10,097)**	16,413	14,828
Pre-tax cash flows	**(8,906)**	**(10,140)**	(17,658)	(5,000)

Adjusting event after the reporting period: Settlement with the Plaintiffs Steering Committee, subject to final written agreement and court approvals, to resolve economic loss and medical claims

Subsequent to BP releasing its preliminary announcement of the fourth quarter 2011 results on 7 February 2012, BP announced on 3 March 2012 that it had reached a proposed settlement with the Plaintiffs Steering Committee (PSC), subject to final written agreement and court approvals, to resolve the substantial majority of legitimate economic loss and medical claims stemming from the Deepwater Horizon accident and oil spill. The PSC acts on behalf of individual and business plaintiffs in the Multi-District Litigation proceedings pending in New Orleans (MDL 2179). Under the proposed settlement, class members would release and dismiss their claims against BP. The proposed settlement is not an admission of liability by BP. The proposed settlement is an adjusting event after the reporting period and therefore has been reflected in the financial statements for 2011 included in this report.

The proposed settlement has not resulted in any increase in the $37.2 billion net pre-tax charge previously recorded in the financial statements. BP estimates that the cost of the proposed settlement, which covers Individual and Business Claims and associated costs that are expected to be paid from the $20-billion trust fund, would be approximately $7.8 billion. This represents an increase of $2.1 billion in the provision compared to the amount reflected in the fourth quarter 2011 preliminary results announcement, with no net impact to either the income statement or cash flow statement, since it is expected to be payable from the trust fund see below for information on accounting for the trust fund. The increase in provision of $2.1 billion has been recognized along with a corresponding increase of $2.1 billion in the reimbursement asset. The amount that can further be provided with no net impact to the income statement is therefore reduced from approximately $5.5 billion to approximately $3.4 billion. While this is BP s reliable best estimate of the cost of the proposed settlement, it is possible that the actual cost could be higher or lower than this estimate depending on the outcomes of the court-supervised claims processes. It is not possible at this time to determine whether the $20-billion trust fund will be sufficient to cover the total amounts payable under the proposed settlement and other claims covered by the trust fund.

The proposed settlement is comprised of two separate agreements; one to resolve economic loss claims and another to resolve medical claims. Each proposed agreement provides that the class members would be compensated for their claims on a claims-made basis according to agreed compensation protocols in separate court-supervised claims processes. The proposed settlement contains a commitment of $2.3 billion in respect of the Gulf seafood industry.

2. Significant event Gulf of Mexico oil spill continued

The proposed economic loss settlement provides for a transition from the Gulf Coast Claims Facility (GCCF). A court-supervised transitional claims process for economic loss claims will be in operation while the infrastructure for the new settlement claims process is put in place. During this transitional period, the processing of claims that have been submitted to the GCCF will continue, and new claimants may submit their claims.

Costs of the proposed settlement will be paid either from the $20-billion Trust or, should the Trust not be sufficient, directly by BP. At this time BP expects all claims to be paid from the Trust.

The proposed settlement does not include claims against BP made by the United States Department of Justice or other federal agencies (including under the Clean Water Act and for Natural Resource Damages under the Oil Pollution Act) or by the states and local governments. The proposed settlement also excludes certain other claims against BP, such as securities and shareholder claims pending in MDL 2185, and claims based solely on the deepwater drilling moratorium and/or the related permitting process.

The proposed settlement also provides that, to the extent permitted by law, BP will assign to the PSC certain of its claims, rights and recoveries against Transocean and Halliburton for damages with protections such that Transocean and Halliburton cannot pass those damages through to BP.

The proposed settlement is subject to reaching definitive and fully documented agreements within 45 days of 2 March 2012. If those agreements are not reached, either party has the right to terminate the proposed settlement. Once there are definitive and fully documented agreements, BP and the PSC would then seek the court s preliminary approval of the settlement. Under US federal law, there is an established procedure for determining the fairness, reasonableness and adequacy of class action settlements. Pursuant to this procedure and subject to the court granting preliminary approval of both agreements, there would be an extensive outreach programme to the public to explain the settlement agreements, class members rights, including the right to opt out of the classes, and the process of making claims. The court would then conduct fairness hearings at which class members and various other parties would have an opportunity to be heard and present evidence. The court would then decide whether or not to approve each proposed settlement agreement.

For further details of the proposed settlement see Legal proceedings on pages 160 to 164.

Trust fund

In 2010, BP established the Deepwater Horizon Oil Spill Trust (the Trust) to be funded in the amount of $20 billion (the trust fund) over the period to the fourth quarter of 2013, which is available to satisfy legitimate individual and business claims administered by the Gulf Coast Claims Facility (GCCF), state and local government claims resolved by BP, final judgments and settlements, state and local response costs, and natural resource damages and related costs. In 2010, BP contributed $5 billion to the fund, and further regular contributions totalling $5 billion were made in 2011. During 2011, BP also contributed the cash settlements received from MOEX, Weatherford and Anadarko, amounting in total to $5.1 billion. A further cash settlement from Cameron was received in January 2012 and was also contributed to the trust fund. As a result of these accelerated contributions, it is now expected that the $20-billion commitment will have been paid in full by the end of 2012. The income statement charge for 2010 included $20 billion in relation to the trust fund, adjusted to take account of the time value of money. Fines, penalties and claims administration costs are not covered by the trust fund. The establishment of the trust fund does not represent a cap or floor on BP s liabilities and BP does not admit to a liability of this amount.

Under the terms of the Trust agreement, BP has no right to access the funds once they have been contributed to the trust fund and BP has no decision-making role in connection with the payment by the trust fund of individual and business claims resolved by the GCCF and the new court-supervised claims processes referred to below. BP will receive funds from the trust fund only upon its expiration, if there are any funds remaining at that point. Any amount remaining in the trust fund when the trustees determine that all claims have been settled would be returned to BP. However, it is not possible to reliably estimate the number or total amount of the claims that will be settled from the trust fund, and therefore it is not possible to reliably measure the fair value of BP s residual interest in it. The carrying amount of BP s residual interest is, consequently, nil. BP has the authority under the Trust agreement to present certain resolved claims, including natural resource damages claims and state and local response claims, to the Trust for payment, by providing the trustees with all the required documents establishing that such claims are valid under the Trust agreement. However, any such payments can only be made on the authority of the Trustee and any funds distributed are paid directly to the claimants, not to BP. BP will not settle any such items directly or receive reimbursement from the trust fund for such items.

The proposed settlement with the PSC announced on 3 March 2012 provides for a transition from the GCCF. A court-supervised transitional claims process for economic loss claims will be in operation while the infrastructure for the new settlement claims process is put in place. During this transitional period, the processing of claims that have been submitted to the GCCF will continue, and new claimants may submit their claims. BP has agreed not to wait for final approval of the economic loss settlement before claims are paid. The economic loss claims process will continue under court supervision before final approval of the settlement, first under the transitional claims process, and then through the settlement claims process established by the proposed economic loss settlement.

The Trust will remain in place, unaffected by the proposed settlement and the transition from the GCCF to the new court-supervised claims processes.

BP s obligation to make contributions to the trust fund was recognized in full in 2010, amounting to $20 billion on an undiscounted basis as it is committed to making these contributions. On initial recognition the discounted amount recognized was $19,580 million. After BP s contributions of $15,140 million to the trust fund during 2010 and 2011, and adjustments for discounting, the remaining liability as at 31 December 2011 was $4,872 million. This liability is recorded within current other payables on the balance sheet, and is expected to be paid in full before the end of 2012.

The table below shows movements in the funding obligation during the period to 31 December 2011.

		$ million
	2011	2010
At 1 January	**14,901**	
Trust fund liability initially recognized discounted		19,580
Unwinding of discount	**52**	73
Change in discounting	**43**	240
Contributions	**(10,140)**	(5,000)
Other	**16**	8
At 31 December	**4,872**	14,901
Of which current	**4,872**	5,002
non-current		9,899

An asset has been recognized representing BP s right to receive reimbursement from the trust fund. This is the portion of the estimated future expenditure provided for that will be settled by payments from the trust fund. We use the term reimbursement asset to describe this asset. BP will not actually receive any reimbursements from the trust fund, instead payments will be made directly to claimants from the trust fund, and BP will be released from its corresponding obligation.

Notes on financial statements

2. Significant event Gulf of Mexico oil spill continued

The portion of the provision recognized during the year for items that will be covered by the trust fund, including the increased estimate of the cost of individual and business claims as a result of the proposed settlement with the PSC announced on 3 March 2012, was $4,038 million (2010 $12,567 million) and payments of $3,707 million (2010 $3,023 million) were made during the year from the trust fund. The remaining reimbursement asset as at 31 December 2011 was $9,875 million and is recorded within other receivables on the balance sheet. The amount of the reimbursement asset is equal to the amount of provisions as at 31 December 2011 that will be covered by the trust fund see Note 36 in the table under Provisions relating to the Gulf of Mexico oil spill.

Movements in the reimbursement asset are presented in the table below.

		$ million
	2011	2010
At 1 January	**9,544**	
Increase in provision for items covered by the trust fund	**4,038**	12,567
Amounts paid directly by the trust fund	**(3,707)**	(3,023)
At 31 December	**9,875**	9,544
Of which current	**8,233**	5,943
non-current	**1,642**	3,601

The amount charged or credited in the income statement, before finance costs, related to the trust fund comprises:

		$ million
	2011	2010
Trust fund liability discounted		19,580
Change in discounting relating to trust fund liability	**43**	240
Recognition of reimbursement asset	**(4,038)**	(12,567)
Other		8
Total (credit) charge relating to the trust fund	**(3,995)**	7,261

As noted above, the obligation to fund the $20-billion trust fund was recognized in full in 2010, on a discounted basis. In addition, a reimbursement asset of $12,567 million was recognized, reflecting the portion of provisions recognized in 2010 that will be covered by the trust fund. Any new provisions, or increases in provisions, that are covered by the trust fund (up to the amount of $20 billion) have no net income statement effect as a reimbursement asset is also recognized, as described above. During 2011, a further $4,038 million was recognized for new or increased provisions for items covered by the trust fund with a corresponding increase in the reimbursement asset, resulting in no net income statement effect. The cumulative charges for provisions, and the associated reimbursement asset, recognized during 2010 and 2011 amounted to $16,605 million. Thus, a further $3,395 million could be provided in subsequent periods for items covered by the trust fund with no net impact on the income statement. Such future increases in amounts provided could arise from adjustments to existing provisions, or from the initial recognition of provisions for items that currently cannot be estimated reliably, namely final judgments and settlements and natural resource damages and related costs.

It is not possible at this time to conclude as to whether the $20-billion fund will be sufficient to satisfy all claims under the Oil Pollution Act of 1990 (OPA 90) that will ultimately be paid. Further information on those items that currently cannot be reliably estimated is provided under Provisions and contingencies and in Note 43.

The Trust agreement does not require BP to make further contributions to the trust fund in excess of the agreed $20 billion should this be insufficient to cover all claims administered by the GCCF and the new court-supervised claims processes, or to settle other items that are covered by the trust fund, as described above. Should the $20-billion trust fund not be sufficient, BP would commence settling legitimate claims and other costs by making payments directly to claimants. In this case, increases in estimated future expenditure above $20 billion would be recognized as provisions with a corresponding charge in the income statement. The provisions would be utilized and derecognized at the point that BP made the payments.

BP pledged certain Gulf of Mexico assets as collateral for the trust fund funding obligation under an agreement entered into in September 2010. In November 2011, the agreement was amended and restated to change the way the overriding royalty interest is determined. For further information see Material contracts on page 168. The pledged collateral consists of an overriding royalty interest in oil and gas production of BP s Thunder Horse, Atlantis, Mad Dog, Great White and Mars, Ursa and Na Kika assets in the Gulf of Mexico. A wholly owned company called Verano Collateral Holdings LLC (Verano) has been created to hold the overriding royalty interest, which is capped at an amount equal to the product of (i) the outstanding funding obligation as calculated at the start of each calendar quarter, from and after 1 October 2011, and (ii) a factor of 1.45 (resulting in an amount of $14.7 billion at 1 October 2011, which remained unchanged at 31 December 2011). Verano has pledged the overriding royalty interest to the Trust as collateral for BP s remaining contribution obligations to the Trust, amounting to $4.9 billion at the end of 2011. On 2 January 2012 the overriding royalty interest was recalculated as $7.1 billion. There has been no change in operatorship or the marketing of the production from the assets and there is no effect on the other partners interests in the assets. For financial reporting purposes Verano is a consolidated entity of BP and there is no impact on the consolidated financial statements from the pledge of the overriding royalty interest.

Provisions and contingencies

At 31 December 2011 BP has recorded certain provisions and disclosed certain contingent liabilities as a consequence of the Gulf of Mexico oil spill. These are described below under *Oil Pollution Act of 1990* and *Other items.*

Oil Pollution Act of 1990 (OPA 90)

The claims against BP under the OPA 90 and for personal injury fall into three categories: (i) claims by individuals and businesses for removal costs, damage to real or personal property, lost profits or impairment of earning capacity, loss of subsistence use of natural resources and for personal injury (Individual and Business Claims); (ii) claims by state and local government entities for removal costs, physical damage to real or personal property, loss of government revenue and increased public services costs ("State and Local Claims"); and (iii) claims by the United States, a State trustee, an Indian tribe trustee, or a foreign trustee for natural resource damages ("Natural Resource Damages claims"). In addition, BP faces civil litigation in which claims for liability under OPA 90 along with other causes of actions, including personal injury claims, are asserted by individuals, businesses and government entities.

A provision has been recorded for Individual and Business Claims and State and Local Claims. The proposed settlement with the PSC, subject to final written agreement and court approvals, announced on 3 March 2012 relates to Individual and Business Claims. A provision has also been recorded for claims administration costs, natural resource damage assessment costs and costs relating to emergency and early natural resource damages restoration agreements.

2. Significant event   Gulf of Mexico oil spill continued

BP considers that it is not possible to measure reliably any other obligation in relation to Natural Resource Damages claims under OPA 90 or litigation for violations of OPA 90 (other than as included within the proposed settlement). These items are therefore disclosed as contingent liabilities.

The $20-billion trust fund described above is available to satisfy the OPA 90 claims and litigation referred to above, however claims administration costs associated with the existing GCCF organization are borne separately by BP. The administration costs of processing claims made under the proposed settlement agreement with the PSC are expected to be paid from the trust fund. However, at this time, the provision for these costs is shown as payable from outside the trust fund as the proposed settlement agreement is subject to final written agreement and court approvals. BP s rights and obligations in relation to the trust fund have been recognized and $20 billion, adjusted to take account of the time value of money, was charged to the income statement in 2010.

Other items

Provisions at 31 December 2011 also include amounts in relation to completing the oil spill response, BP s commitment to a 10-year research programme in the Gulf of Mexico, estimated penalties for liability under Clean Water Act Section 311 and estimated legal fees. These are not covered by the trust fund.

The provision does not reflect any amounts in relation to fines and penalties except for those relating to the Clean Water Act, as it is not possible to estimate reliably either the amount or timing of such additional items. BP also considers that it is not possible to measure reliably any obligation in relation to litigation other than as included within the proposed settlement with the PSC. These items are therefore disclosed as contingent liabilities.

Further information on provisions is provided below and in Note 36. Further information on contingent liabilities is provided in Note 43.

A provision has been recognized for estimated future expenditure relating to the incident, for items that can be measured reliably at this time, including the increased estimate of the cost of Individual and Business Claims as a result of the proposed settlement with the PSC as described above, in accordance with BP s accounting policy for provisions, as set out in Note 1.

The total amount recognized as a provision during the year was $5,183 million, including $4,038 million for items covered by the trust fund and $1,145 million for other items (2010 $30,261 million, including $12,567 million for items covered by the trust fund and $17,694 million for other items). After deducting amounts utilized during the year totalling $6,208 million, including payments from the trust fund of $3,707 million and payments made directly by BP of $2,501 million (2010 $13,935 million, including payments from the trust fund of $3,023 million and payments made directly by BP of $10,912 million), and after adjustments for discounting, the remaining provision as at 31 December 2011 was $15,333 million (2010 $16,335 million).

Movements in the provision are presented in the table below.

		$ million
	2011	2010
At 1 January	**16,335**	
Increase in provision items not covered by the trust fund	**1,145**	17,694
items covered by the trust fund	**4,038**	12,567
Unwinding of discount	**6**	4
Change in discount rate	**17**	5
Utilization paid by BP	**(2,501)**	(10,912)
paid by the trust fund	**(3,707)**	(3,023)
At 31 December	**15,333**	16,335
Of which current	**9,437**	7,938
non-current	**5,896**	8,397

The total amounts that will ultimately be paid by BP in relation to all obligations relating to the incident are subject to significant uncertainty and the ultimate exposure and cost to BP will be dependent on many factors (including, with respect to certain of the obligations, any determination of BP s culpability based on any findings of negligence, gross negligence or wilful misconduct). Significant uncertainty exists in relation to the amount of claims that will become payable by BP, the amount of fines that will ultimately be levied on BP, the outcome of litigation and arbitration proceedings, the amount and timing of payments under any settlements, and any costs arising from any longer-term environmental consequences of the oil spill, which will also impact upon the ultimate cost for BP. BP is ready to settle any remaining matters on fair and reasonable terms, but will continue to prepare vigorously for trial. Any settlements which may be reached relating to the Deepwater Horizon oil spill could impact the amount and timing of any future payments. Although the provision recognized is the current best reliable estimate of expenditures required to settle certain present obligations at the end of the reporting period, there are future expenditures for which it is not possible to measure the obligation reliably as noted above.

Impact upon the group income statement

The group income statement for 2011 includes a pre-tax credit of $3,742 million (2010 pre-tax charge of $40,935 million) in relation to the Gulf of Mexico oil spill. The amount charged to date comprises costs incurred up to 31 December 2011, settlements agreed with our co-owners of the Macondo well and other third parties, estimated obligations for future costs that can be estimated reliably at this time and rights and obligations relating to the trust fund. Finance costs of $58 million (2010 $77 million) reflect the unwinding of the discount on the trust fund liability and provisions.

The amount of the provision recognized during the year can be reconciled to the income statement amount as follows:

		$ million
	2011	2010
Increase in provision	**5,183**	30,261
Change in discount rate relating to provisions	**17**	5
Costs charged directly to the income statement	**512**	3,339
Trust fund liability discounted		19,580
Change in discounting relating to trust fund liability	**43**	240
Recognition of reimbursement asset	**(4,038)**	(12,567)
Settlements credited to the income statement	**(5,517)**	
(Profit) loss before interest and taxation	**(3,800)**	40,858

Costs charged directly to the income statement relate to expenditure prior to the establishment of a provision at the end of the second quarter 2010 and ongoing operating costs of the Gulf Coast Restoration Organization (GCRO). The accounting associated with the recognition of the trust fund liability and the expenditure which will be settled from the trust fund is described above.

2. Significant event Gulf of Mexico oil spill continued

The total amount in the income statement is analysed in the table below. Costs charged directly to the income statement in 2010 in relation to spill response, environmental and litigation and claims are those that arose prior to recording a provision at the end of the second quarter of that year.

		$ million
	2011	2010
Trust fund liability discounted		19,580
Change in discounting relating to trust fund liability	**43**	240
Recognition of reimbursement asset	**(4,038)**	(12,567)
Other		8
Total (credit) charge relating to the trust fund	**(3,995)**	7,261
Spill response amount provided	**586**	10,883
costs charged directly to the income statement	**85**	2,745
Total charge relating to spill response	**671**	13,628
Environmental amount provided	**1,167**	929
change in discount rate relating to provisions	**17**	5
costs charged directly to the income statement		70
Total charge relating to environmental	**1,184**	1,004
Litigation and claims amount provided	**3,430**	14,939
costs charged directly to the income statement		184
Total charge relating to litigation and claims	**3,430**	15,123
Clean Water Act penalties amount provided		3,510
Other costs charged directly to the income statement	**427**	332
Settlements credited to the income statement	**(5,517)**	
(Profit) loss before interest and taxation	**(3,800)**	40,858
Finance costs	**58**	77
(Profit) loss before taxation	**(3,742)**	40,935

The total amounts that will ultimately be paid by BP in relation to all obligations relating to the incident are subject to significant uncertainty as described above under Provisions and contingencies.

Pre-tax cash flows amounted to $8,906 million (2010 $17,658 million) and the impact on net cash provided by operating activities, on a post-tax basis, amounted to $6,813 million (2010 $16,019 million).

3. Business combinations

Business combinations in 2011

BP undertook a number of business combinations in 2011. Total consideration paid in cash amounted to $11.3 billion, offset by cash acquired of $0.4 billion. In addition, the fair value of contingent consideration payable amounted to $0.1 billion.

On 30 August 2011, BP acquired from Reliance Industries Limited (Reliance) a 30% interest in 21 oil and gas production-sharing agreements (PSAs) operated by Reliance in India for $7,026 million. This includes the producing KG D6 block.

In addition, on 17 November 2011, the companies formed a 50:50 joint venture for the sourcing and marketing of gas in India.

This transaction provides BP with access to an emerging market with growth in energy demand; it builds BP s business in natural gas and it represents an important partnership with a leading national energy business.

The transaction has been accounted for as a business combination using the acquisition method. Measurement period adjustments to the acquisition-date fair values of the identifiable assets and liabilities acquired, and contingent consideration payable, were recognized between the date of acquisition and 31 December 2011. These adjustments reflected new information obtained, including further understanding of the acquired assets and potential development options, and amounted to an overall decrease of $785 million in the net fair value of the identifiable assets and liabilities acquired, an increase of $854 million in the goodwill arising on acquisition and the recognition of $69 million of contingent consideration.

Goodwill of $2,523 million arose on acquisition, attributed to market access and other benefits arising from the business combination. It is currently uncertain as to whether goodwill recognized for accounting purposes will be deductible for income tax purposes in India, as jurisprudence in this area is currently evolving.

The provisional fair values of the identifiable assets and liabilities acquired, as at the date of acquisition, are as shown in the table below.

	$ million
Assets	
Property, plant and equipment	**1,860**
Intangible assets	**2,970**
Inventories	**55**
Prepayments	**5**
Liabilities	
Trade and other payables	**(145)**
Provisions	**(242)**
	4,503
Goodwill arising on acquisition	**2,523**
Total consideration	**7,026**

The consideration for the transaction included $6,957 million in cash. In addition, contingent consideration of up to $1,800 million, dependent upon exploration success in certain of the interests resulting in the development of commercial discoveries, was agreed. The fair value of contingent consideration recognized as at the acquisition date amounted to $69 million.

3. Business combinations continued

The acquisition-date fair values of the assets and liabilities acquired and the fair value of contingent consideration to be paid are provisional. As we gain further understanding of the acquired properties and development options, these fair values may be further adjusted to reflect information which may be obtained in respect of the acquired assets and liabilities.

An analysis of the cash flows relating to the acquisition is provided below.

	$ million
Transaction costs of the acquisition (included in cash flows from operating activities)	**13**
Cash consideration paid (included in cash flows from investing activities)	**6,957**
Total net cash outflow for the acquisition	**6,970**

Transaction costs of $13 million have been charged within production and manufacturing expenses in the group income statement.

From the date of acquisition to 31 December 2011, the acquired activities contributed revenues of $268 million and profit of $49 million to the group. If the business combination had taken place on 1 January 2011, it is estimated that the acquired activities would have contributed revenues of $884 million and profit of $219 million to the group.

In addition to the Reliance transaction described above, BP undertook a number of other business combinations in 2011. These included the completion of the final part of the transaction with Devon Energy (Devon), the acquisition of Devon s equity stake in a number of assets in Brazil for consideration of $3.6 billion (see below). Additionally, BP s Alternative Energy business acquired Companhia Nacional de Açúcar e Álcool (CNAA) in Brazil for consideration of $0.7 billion and increased its share in the Brazilian biofuels company, Tropical BioEnergia S.A., to 100% by acquiring the remaining 50% for consideration of $71 million. There were a number of other individually insignificant business combinations.

Business combinations in 2010

BP undertook a number of business combinations in 2010 for a total consideration of $3.6 billion, of which $3 billion comprised cash consideration. The most significant acquisition was a transaction in the Exploration and Production segment with Devon, undertaken in a number of stages during 2010 and 2011. This transaction strengthens BP s position in the Gulf of Mexico, enhances interests in Azerbaijan and facilitates the development of Canadian assets.

On 27 April 2010, BP acquired 100% of Devon s Gulf of Mexico deepwater properties for $1.8 billion. This included a number of exploration properties, Devon s interest in the major Paleogene discovery Kaskida (giving BP a 100% interest in the project), four producing assets and one non-producing asset. As part of the transaction, BP sold to Devon a 50% stake in its Kirby oil sands interests in Alberta, Canada for $500 million and Devon committed to fund an additional $150 million of capital costs on BP s behalf by issuing a promissory note to BP. In addition, the companies formed a 50:50 joint venture, operated by Devon, to pursue the development of the interest. On 16 August 2010, the group acquired Devon s 3.29% (after pre-emption exercised by some of the partners) interest in the BP-operated Azeri-Chirag-Gunashli (ACG) development in the Azerbaijan sector of the Caspian Sea for $1.1 billion, increasing BP s interest to 37.43%.

The business combination was accounted for using the acquisition method. Goodwill of $332 million was recognized on the 2010 part of the Devon transaction. As part of the Devon transaction, the gain on the disposal of the group s 50% interest in the Kirby oil sands in Alberta, Canada amounted to $633 million.

The final part of the Devon transaction, the acquisition of 100% of Devon s equity stake in a number of entities holding all of Devon s assets in Brazil for consideration of $3.6 billion, completed in May 2011. The acquisition-date fair values are provisional. Goodwill of $966 million was recognized in 2011 for this part of the transaction.

In addition to the Devon transaction, BP undertook a number of other minor business combinations in 2010, the most significant of which was the acquisition by BP s Alternative Energy business of Verenium Corporation s lignocellulosic biofuels business, for consideration of $98 million.

Business combinations in 2009

BP did not undertake any significant business combinations in 2009.

4. Non-current assets held for sale

As a result of the group s disposal programme following the Gulf of Mexico oil spill, various assets, and associated liabilities, have been presented as held for sale in the group balance sheet at 31 December 2011. The carrying amount of the assets held for sale is $8,420 million, with associated liabilities of $538 million. Included within these amounts are the following items, all of which relate to the Exploration and Production segment, unless otherwise stated.

On 18 October 2010, BP announced that it had reached agreement to sell its upstream and midstream assets in Vietnam, together with its upstream businesses and associated interests in Venezuela, to TNK-BP for $1.8 billion in cash, subject to post-closing adjustments. The sale of the Venezuelan business and the upstream and certain midstream assets in Vietnam completed during 2011. BP is in ongoing negotiations and expects to complete a sale of its equity-accounted investment in the Phu My 3 plant facility in 2012, subject to the satisfaction of regulatory and other approvals and conditions. The investment in the Phu My 3 plant facility has been classified as held for sale in the group balance sheet at 31 December 2011.

On 1 December 2011, BP announced that it had agreed to sell its Canadian natural gas liquids (NGL) business to Plains Midstream Canada ULC (Plains Midstream), a wholly-owned subsidiary of Plains All American Pipeline, L.P. Plains Midstream will pay BP a total of $1.67 billion in cash, subject to post-closing adjustments, for the business. The assets, and associated liabilities, of this business have been classified as held for sale in the group balance sheet at 31 December 2011. Completion of the transaction is subject to closing conditions including the receipt of all necessary governmental and regulatory approvals. The sale is expected to be completed in the first half of 2012.

Within the Refining and Marketing segment, BP intends to divest the Texas City refinery and related assets, and the southern part of its US West Coast fuels value chain, including the Carson refinery. The non-current assets, together with the inventories, of these businesses have been classified as held for sale in the group balance sheet at 31 December 2011. BP intends to complete the sales in 2012.

Impairment losses amounting to $398 million (2010 $192 million) have been recognized in relation to certain assets classified as held for sale. See Note 5 for further information.

Non-current assets classified as held for sale are not depreciated. It is estimated that the benefit arising from the absence of depreciation for the assets noted above amounted to approximately $166 million (2010 $162 million).

Deposits of $30 million ($6,197 million at 31 December 2010) received in advance of completion of certain of these transactions have been classified as finance debt on the group balance sheet at 31 December 2011 and of this, none (2010 $4,780 million) has been secured on the assets held for sale.

The majority of the transactions noted above are subject to post-closing adjustments, which may include adjustments for working capital and adjustments for profits attributable to the purchaser between the agreed effective date and the closing date of the transaction. Such post-closing adjustments may result in the final amounts received by BP from the purchasers differing from the disposal proceeds noted above.

The major classes of assets and liabilities reclassified as held for sale as at 31 December are as follows:

		$ million
	2011	2010a
Assets		
Property, plant and equipment	**4,772**	2,971
Goodwill	**8**	87
Intangible assets	**20**	135
Investments in jointly controlled entities	**122**	467
Investments in associates	**38**	333
Loans		12
Inventories	**3,167**	92
Cash		34
Other current assets	**293**	356
Assets classified as held for sale	**8,420**	4,487
Liabilities		
Trade and other payables	**300**	597
Provisions	**98**	383
Deferred tax liabilities	**140**	67
Liabilities directly associated with assets classified as held for sale	**538**	1,047

a On 28 November 2010, BP announced that it had reached agreement to sell its interests in Pan American Energy LLC (PAE) to Bridas Corporation (Bridas) for $7.06 billion in cash. PAE is an Argentina-based oil and gas company owned by BP (60%) and Bridas (40%). On 5 November 2011, BP received from Bridas a notice of termination of the agreement. As a result of Bridas s decision and action, the share purchase agreement governing this transaction was terminated. BP s interest in PAE was classified as held for sale in the group balance sheet from the date the sale was originally agreed in 2010, and equity accounting for PAE was discontinued from that date. Following the termination of the sale agreement, BP s interest in PAE no longer meets the criteria to be classified as held for sale. Under IFRS, equity accounting is reinstated and prior periods are adjusted when a jointly controlled entity ceases to be classified as held for sale. Consequently, BP s investment in PAE at 31 December 2010 of $2,641 million has been reclassified in the group balance sheet from assets classified as held for sale to investments in jointly controlled entities. BP s share of PAE s profit for 2011 has been recognized in full in the group income statement; the 2010 income statement has not been adjusted as the amount is insignificant. Comparative financial information for 2010 presented in the table above has been adjusted to exclude PAE. For further information on the termination of this agreement see page 85.

There were no accumulated foreign exchange gains or losses recognized directly in equity relating to the assets held for sale at 31 December 2011 (2010 nil).

5. Disposals and impairment

			$ million
	2011	2010	2009
Proceeds from disposals of fixed assets	**3,500**	7,492	1,715
Proceeds from disposals of businesses, net of cash disposed	**(768)**	9,462	966
	2,732	16,954	2,681
By business			
Exploration and Production	**1,080**	14,392	940
Refining and Marketing	**721**	1,840	1,294
Other businesses and corporate	**931**	722	447
	2,732	16,954	2,681

Included in proceeds from disposal for 2010 are deposits of $6,197 million received from counterparties in respect of disposal transactions in the Exploration and Production segment not completed at 31 December 2010, of which $30 million related to transactions still not completed at 31 December 2011. This included a deposit of $3,530 million received in advance of the expected sale of our interest in Pan American Energy LLC. 2011 proceeds from disposal included the repayment of the same amount following the termination of the sale agreement as described in Note 4. No disposal deposits were received in 2011 or 2009 for expected transactions which had not completed by the end of those years. For further information on disposal transactions not yet completed see Note 4.

Deferred consideration relating to disposals of businesses and fixed assets at 31 December 2011 amounted to $117 million receivable within one year (2010 $562 million and 2009 $807 million) and $111 million receivable after one year (2010 $271 million and 2009 $691 million).

			$ million
	2011	2010	2009
Gains on sale of businesses and fixed assets			
Exploration and Production	**3,477**	5,267	1,717
Refining and Marketing	**317**	999	384
Other businesses and corporate	**336**	117	72
	4,130	6,383	2,173

			$ million
	2011	2010	2009
Losses on sale of businesses and fixed assets			
Exploration and Production	**49**	196	28
Refining and Marketing	**52**	119	154
Other businesses and corporate	**3**	6	21
	104	321	203
Impairment losses			
Exploration and Production	**1,443**	1,259	118
Refining and Marketing	**599**	144	1,834
Other businesses and corporate	**58**	113	189
	2,100	1,516	2,141
Impairment reversals			
Exploration and Production	**(146)**		(3)
Refining and Marketing		(141)	
Other businesses and corporate		(7)	(8)
	(146)	(148)	(11)
Impairment and losses on sale of businesses and fixed assets	**2,058**	1,689	2,333

Disposals

As part of the response to the consequences of the Gulf of Mexico oil spill, the group announced plans to deliver up to $30 billion of disposal proceeds by the end of 2011. This target has now been increased to $38 billion of disposal proceeds by the end of 2013. Prior to this, in the normal course of business, the group has sold interests in exploration and production properties, service stations and pipeline interests as well as non-core businesses. The group has also disposed of other assets in the past, such as refineries, when this has met strategic objectives.

See Note 4 for further information relating to assets and associated liabilities held for sale at 31 December 2011.

Exploration and Production

In 2011, the major disposal transactions were the sale of our interests in Colombia to Ecopetrol and Talisman, the sale of our upstream and midstream assets in Vietnam and our investments in equity-accounted entities in Venezuela to TNK-BP, and the sale of our assets in Pakistan to United Energy Group. In addition, we also completed the disposal of half of the 3.29% interest in the Azeri-Chirag-Gunashli development in Azerbaijan to SOCAR and a number of interests in the Gulf of Mexico to Marubeni Group. All of these transactions resulted in gains.

In 2010, the major transactions were the sale of Permian Basin assets in the US, upstream gas assets in Canada and exploration concessions in Egypt to Apache Corporation. In addition, we sold 50% of our interests in Kirby oil sands in Canada to Devon Energy as part of a business combination described in Note 3. All of these transactions resulted in gains.

In 2009, the major transactions were the sale of BP West Java Limited in Indonesia, the sale of our 49.9% interest in Kazakhstan Pipeline Ventures LLC and the sale of our 46% stake in LukArco, all of which resulted in gains. We also exchanged interests in a number of fields in the North Sea with BG Group plc.

5. Disposals and impairment continued

Refining and Marketing

In 2011, gains on disposal resulted from our disposal of the fuels marketing business in Namibia, Malawi, Zambia and Tanzania to Puma Energy, certain non-strategic pipelines and terminals in the US and other assets in the segment. Losses resulted from the disposal of a number of assets in the segment portfolio.

In 2010, gains resulted from our disposals of the 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. Losses resulted from the disposal of a number of assets in the segment portfolio.

In 2009, gains on disposal mainly resulted from the disposal of our ground fuels marketing business in Greece and retail churn in the US, Europe and Australasia. Losses resulted from the disposal of company-owned and company-operated retail sites in the US, retail churn and disposals of assets elsewhere in the segment portfolio. Retail churn is the overall process of acquiring and disposing of retail sites by which the group aims to improve the quality and mix of its portfolio of service stations.

Other businesses and corporate

In 2011, we disposed of our aluminium business in the US which resulted in a gain. We also contributed Mehoopany and Flat Ridge 2 wind energy development assets in exchange for cash and 50% equity interests in the jointly controlled entities Mehoopany Wind Holdings LLC and Flat Ridge 2 Wind Holdings LLC.

In 2010, we disposed of our 35% interest in K-Power, a gas-fired power asset in South Korea, and contributed our Cedar Creek 2 wind energy development asset in exchange for a 50% equity interest in a jointly controlled entity, Cedar Creek II Holdings LLC (Cedar Creek 2) and cash. In addition, there was a return of capital in the jointly controlled entities Fowler II Holdings LLC and Cedar Creek II Holdings LLC which did not change our percentage interest in either entity.

During 2009, we disposed of our wind energy business in India and contributed our Fowler 2 wind energy development asset in the US in exchange for a 50% equity interest in a jointly controlled entity, Fowler II Holdings LLC. In addition, there was a return of capital in the jointly controlled entity Fowler Ridge Wind Farm LLC which did not change our percentage interest in the entity.

Summarized financial information relating to the sale of businesses is shown in the table below. Information relating to sales of fixed assets is excluded from the table.

$ million

	2011	2010	2009
Non-current assets	**2,085**	2,319	536
Current assets	**1,008**	310	444
Non-current liabilities	**(212)**	(303)	(146)
Current liabilities	**(611)**	(124)	(152)
Total carrying amount of net assets disposed	**2,270**	2,202	682
Recycling of foreign exchange on disposal	**8**	(52)	(27)
Costs on disposal	**17**	18	3
	2,295	2,168	658
Profit on sale of businesses[a]	**2,232**	1,968	314
Total consideration	**4,527**	4,136	972
Consideration received (receivable)[b]	**11**	20	(6)
Proceeds from the sale of businesses related to completed transactions	**4,538**	4,156	966
Deposits received (repaid) related to assets classified as held for sale[c]	**(3,530)**	5,306	_
Disposals completed in relation to which deposits had been received in prior year	**(1,776)**		
Proceeds from the sale of businesses[d]	**(768)**	9,462	966

a Of which $278 million gain was not recognized in the income statement in 2011 as it represented an unrealized gain on the sale of business assets in Vietnam to our associate TNK-BP.

b Consideration received from prior year business disposals or not yet received from current year disposals.

c 2010 included a deposit received in advance of $3,530 million in respect of the expected sale of our interest in Pan American Energy LLC; 2011 includes the repayment of the same amount following the termination of the sale agreement as described in Note 4.

d Net of cash and cash equivalents disposed of $14 million (2010 $55 million and 2009 $91 million).

Impairment

In assessing whether a write-down is required in the carrying value of a potentially impaired intangible asset, item of property, plant and equipment or an equity-accounted investment, the asset s carrying value is compared with its recoverable amount. The recoverable amount is the higher of the asset s fair value less costs to sell and value in use. Unless indicated otherwise, the recoverable amount used in assessing the impairment losses described below is value in use. The group estimates value in use using a discounted cash flow model. The future cash flows are adjusted for risks specific to the asset and are discounted using a pre-tax discount rate. This discount rate is derived from the group s post-tax weighted average cost of capital and is adjusted where applicable to take into account any specific risks relating to the country where the cash-generating unit is located, although other rates may be used if appropriate to the specific circumstances. In 2011 the rates used ranged from 12-14% (2010 11-14%). The rate applied in each country is reassessed each year. In certain circumstances an impairment assessment may be carried out using fair value less costs to sell as the recoverable amount when, for example, a recent market transaction for a similar asset has taken place. For impairments of available-for-sale financial assets that are quoted investments, the fair value is determined by reference to bid prices at the close of business at the balance sheet date. Any cumulative loss previously recognized in other comprehensive income is transferred to the income statement.

5. Disposals and impairment continued

Exploration and Production

During 2011, the Exploration and Production segment recognized impairment losses of $1,443 million. The main elements were a $555-million impairment loss relating to a number of our interests in the Gulf of Mexico, caused by an increase in the decommissioning provision as a result of further assessments of the regulations relating to idle infrastructure and a decrease in our assumption of the discount rate for provisions; the $393-million write-down of our interest in the Fayetteville shale gas asset in the US, triggered by a decrease in value by reference to a sale transaction by a partner of its interest in the same asset; and the $153-million write-down of our interest in the proposed Denali gas pipeline in Alaska, resulting from a decision not to proceed with the project. There were several other impairment losses amounting to $342 million in total that were not individually significant. These impairment losses were partly offset by reversals of impairment of certain of our interests in the Gulf of Mexico and Egypt amounting to $146 million in total, triggered by an increase in our assumption of long-term oil prices.

During 2010, the Exploration and Production segment recognized impairment losses of $1,259 million. The main elements were the $501-million write-down of assets in the Gulf of Mexico, triggered by an increase in the decommissioning provision as a result of new regulations in the US relating to idle infrastructure; impairments of oil and gas properties in the Gulf of Mexico and onshore North America of $310 million and $80 million respectively, as a result of decisions to dispose of assets at a price lower than the assets carrying values; a $341-million write-down of accumulated costs in Sakhalin, Russia, triggered by a change in the outlook on the future recoverability of the investment; and several other individually insignificant impairment losses amounting to $27 million in total.

During 2009, the Exploration and Production segment recognized impairment losses of $118 million. The main elements were the write-down of our $42-million investment in the East Shmidt interest in Russia, triggered by a decision to not proceed to development; a $62-million charge associated with our nErgize gas scheduling system; and several other individually insignificant impairment losses amounting to $14 million.

Refining and Marketing

During 2011, the Refining and Marketing segment recognized impairment losses of $599 million. Impairment losses of $398 million related to assets classified as held for sale. Other impairment losses were also recognized relating to retail churn in Europe and other minor asset disposals amounting to $201 million in total.

During 2010, the Refining and Marketing segment recognized impairment losses amounting to $144 million relating to retail churn in Europe and other minor asset disposals. These losses were largely offset by the reversal of a previously recognized impairment loss of $141 million relating to the investment in our jointly controlled entity China American Petrochemical Company resulting from a change in market conditions.

During 2009, an impairment loss of $1,579 million was recognized against the goodwill allocated to the US West Coast fuels value chain (FVC). The goodwill was originally recognized at the time of the ARCO acquisition in 2000. The prevailing weak refining environment, together with a review of future margin expectations in the FVC, led to a reduction in the expected future cash flows. Other impairment losses were also recognized by the segment on a number of assets which amounted to $255 million.

Other businesses and corporate

During 2011, 2010 and 2009, Other businesses and corporate recognized impairment losses totalling $58 million, $113 million and $189 million respectively related to various assets in the Alternative Energy business.

6. Segmental analysis

The group s organizational structure reflects the various activities in which BP is engaged. In 2011, BP had two reportable segments: Exploration and Production and Refining and Marketing. BP s activities in low-carbon energy are managed through our Alternative Energy business, which is reported in Other businesses and corporate. The group is managed on an integrated basis.

Exploration and Production s activities include oil and natural gas exploration, field development and production; midstream transportation, storage and processing; and the marketing and trading of natural gas, including liquefied natural gas (LNG), together with power and natural gas liquids (NGLs).

At the end of 2010, BP announced its decision to reorganize its Exploration and Production segment to create three functional divisions Exploration, Developments and Production, integrated through a Strategy and Integration organization. This structure was established in March 2011 but this has not affected the group s reportable segments and Exploration and Production continues to be reported as a single operating segment.

From 1 January 2012, the group s investment in TNK-BP will be reported as a separate operating segment, rather than within the Exploration and Production segment, reflecting the way in which the investment is now managed.

Refining and Marketing s activities include the refining, manufacturing, marketing, transportation, and supply and trading of crude oil, petroleum, petrochemicals products and related services to wholesale and retail customers.

Other businesses and corporate comprises the Alternative Energy business, Shipping, Treasury (which in the segmental analysis includes all of the group s cash, cash equivalents and associated interest income), and corporate activities worldwide. It also included the group s aluminium business until its disposal during 2011. The Alternative Energy business is an operating segment that has been aggregated with the other activities within Other businesses and corporate as it does not meet the materiality thresholds for separate segment reporting.

In 2010, following the Gulf of Mexico incident, we established the Gulf Coast Restoration Organization (GCRO) and equipped it with dedicated resources and capabilities to manage all aspects of our response to the incident. This organization reports directly to the group chief executive and is overseen by a board committee, however it is not an operating segment.

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

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

All surpluses and deficits recognized on the group balance sheet in respect of pension and other post-retirement benefit plans are allocated to Other businesses and corporate. However, the periodic expense relating to these plans is allocated to the other operating segments based upon the business in which the employees work.

Certain financial information is provided separately for the US as this is an individually material country for BP, and for the UK as this is BP s country of domicile.

a Inventory holding gains and losses represent the difference between the cost of sales calculated using the 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.

6. Segmental analysis continued

$ million

By business	Exploration and Production	Refining and Marketing	Other businesses and corporate	Gulf of Mexico oil spill response	Consolidation adjustment and eliminations	Total group
						2011
Segment revenues						
Sales and other operating revenues	**75,475**	**344,116**	**2,957**		**(47,031)**	**375,517**
Less: sales between businesses	**(44,766)**	**(1,396)**	**(869)**		**47,031**	
Third party sales and other operating revenues	**30,709**	**342,720**	**2,088**			**375,517**
Equity-accounted earnings	**5,466**	**787**	**(33)**			**6,220**
Interest revenues	**(4)**	**25**	**146**			**167**
Segment results						
Replacement cost profit (loss) before interest and taxation	**30,500**	**5,474**	**(2,478)**	**3,800**	**(113)**	**37,183**
Inventory holding gains[a]	**132**	**2,487**	**15**			**2,634**
Profit (loss) before interest and taxation	**30,632**	**7,961**	**(2,463)**	**3,800**	**(113)**	**39,817**
Finance costs						**(1,246)**
Net finance income relating to pensions and other post-retirement benefits						**263**
Profit before taxation						**38,834**
Other income statement items						
Depreciation, depletion and amortization	**8,693**	**2,117**	**325**			**11,135**
Impairment losses	**1,443**	**599**	**58**			**2,100**
Impairment reversals	**(146)**					**(146)**
Fair value (gain) loss on embedded derivatives	**(191)**		**123**			**(68)**
Charges for provisions, net of write-back of unused provisions, including change in discount rate	**213**	**371**	**942**	**5,200**		**6,726**
Segment assets						
Equity-accounted investments	**21,054**	**6,731**	**1,024**			**28,809**
Additions to non-current assets	**34,527**	**4,128**	**1,864**			**40,519**
Additions to other investments						**25**
Element of acquisitions not related to non-current assets						**(1,089)**
Additions to decommissioning asset						**(7,937)**
Capital expenditure and acquisitions	**25,535**	**4,130**	**1,853**			**31,518**

a See explanation of inventory holding gains and losses on page 200.

6. Segmental analysis continued

$ million

By business	Exploration and Production	Refining and Marketing	Other businesses and corporate	Gulf of Mexico oil spill response	Consolidation adjustment and eliminations	Total group
						2010
Segment revenues						
Sales and other operating revenues	66,266	266,751	3,328		(39,238)	297,107
Less: sales between businesses	(37,049)	(1,358)	(831)		39,238	
Third party sales and other operating revenues	29,217	265,393	2,497			297,107
Equity-accounted earnings	3,979	755	23			4,757
Interest revenues	83	46	109			238
Segment results						
Replacement cost profit (loss) before interest and taxation	30,886	5,555	(1,516)	(40,858)	447	(5,486)
Inventory holding gains[a]	84	1,684	16			1,784
Profit (loss) before interest and taxation	30,970	7,239	(1,500)	(40,858)	447	(3,702)
Finance costs						(1,170)
Net finance income relating to pensions and other post-retirement benefits						47
Loss before taxation						(4,825)
Other income statement items						
Depreciation, depletion and amortization	8,616	2,258	290			11,164
Impairment losses	1,259	144	113			1,516
Impairment reversals		(141)	(7)			(148)
Fair value loss on embedded derivatives	309					309
Charges for provisions, net of write-back of unused provisions, including change in discount rate	303	275	206	30,266		31,050
Segment assets						
Equity-accounted investments[b]	20,379	7,043	840			28,262
Additions to non-current assets	20,113	4,030	1,226			25,369
Additions to other investments						20
Element of acquisitions not related to non-current assets						(401)
Additions to decommissioning asset						(1,972)
Capital expenditure and acquisitions	17,753	4,029	1,234			23,016

a See explanation of inventory holding gains and losses on page 200.
b Includes BP s investment in Pan American Energy LLC following the termination of the sale agreement and the reinstatement of equity accounting. See Note 4 for further information.

6. Segmental analysis continued

$ million

By business	Exploration and Production	Refining and Marketing	Other businesses and corporate	Consolidation adjustment and eliminations	Total group
					2009
Segment revenues					
Sales and other operating revenues	57,626	213,050	2,843	(34,247)	239,272
Less: sales between businesses	(32,540)	(821)	(886)	34,247	
Third party sales and other operating revenues	25,086	212,229	1,957		239,272
Equity-accounted earnings	3,309	558	34		3,901
Interest revenues	98	32	95		225
Segment results					
Replacement cost profit (loss) before interest and taxation	24,800	743	(2,322)	(717)	22,504
Inventory holding gains[a]	142	3,774	6		3,922
Profit (loss) before interest and taxation	24,942	4,517	(2,316)	(717)	26,426
Finance costs					(1,110)
Net finance expense relating to pensions and other post-retirement benefits					(192)
Profit before taxation					25,124
Other income statement items					
Depreciation, depletion and amortization	9,557	2,236	313		12,106
Impairment losses	118	1,834	189		2,141
Impairment reversals	(3)		(8)		(11)
Fair value (gain) loss on embedded derivatives	(664)	57			(607)
Charges for provisions, net of write-back of unused provisions, including change in discount rate	307	756	488		1,551
Segment assets					
Equity-accounted investments	20,289	6,882	1,088		28,259
Additions to non-current assets	15,855	4,083	1,297		21,235
Additions to other investments					19
Element of acquisitions not related to non-current assets					(7)
Additions to decommissioning asset					(938)
Capital expenditure and acquisitions	14,896	4,114	1,299		20,309

a See explanation of inventory holding gains and losses on page 200.

Notes on financial statements

6. Segmental analysis continued

$ million

By geographical area	US	Non-US	2011 Total
Revenues			
Third party sales and other operating revenues[a]	**131,488**	**244,029**	**375,517**
Results			
Replacement cost profit before interest and taxation	**10,202**	**26,981**	**37,183**
Non-current assets			
Other non-current assets[b c]	**68,707**	**113,773**	**182,480**
Other investments			**2,117**
Loans			**884**
Other receivables			**4,337**
Derivative financial instruments			**5,038**
Deferred tax assets			**611**
Defined benefit pension plan surpluses			**17**
Total non-current assets			**195,484**
Capital expenditure and acquisitions	**8,830**	**22,688**	**31,518**

a Non-US region includes UK $75,816 million.

b Non-US region includes UK $18,363 million.

c Excluding financial instruments, deferred tax assets and post-retirement benefit plan surpluses.

$ million

By geographical area	US	Non-US	2010 Total
Revenues			
Third party sales and other operating revenues[a]	101,768	195,339	297,107
Results			
Replacement cost profit (loss) before interest and taxation	(30,087)	24,601	(5,486)
Non-current assets			
Other non-current assets[b c d]	67,498	95,255	162,753
Other investments			1,191
Loans			894
Other receivables			6,298
Derivative financial instruments			4,210
Deferred tax assets			528
Defined benefit pension plan surpluses			2,176
Total non-current assets			178,050
Capital expenditure and acquisitions	10,370	12,646	23,016

a Non-US region includes UK $62,794 million.

b Non-US region includes UK $16,650 million.

c Excluding financial instruments, deferred tax assets and post-retirement benefit plan surpluses.

d Includes BP s investment in Pan American Energy LLC following the termination of the sale agreement and the reinstatement of equity accounting. See Note 4 for further information.

$ million

By geographical area	US	Non-US	2009 Total
Revenues			
Third party sales and other operating revenues[a]	83,982	155,290	239,272

Results			
Replacement cost profit before interest and taxation	2,806	19,698	22,504
Non-current assets			
Other non-current assets[b c]	64,529	93,580	158,109
Other investments			1,567
Loans			1,039
Other receivables			1,729
Derivative financial instruments			3,965
Deferred tax assets			516
Defined benefit pension plan surpluses			1,390
Total non-current assets			168,315
Capital expenditure and acquisitions	9,865	10,444	20,309

a Non-US region includes UK $51,172 million.

b Non-US region includes UK $16,713 million.

c Excluding financial instruments, deferred tax assets and post-retirement benefit plan surpluses.

7. Interest and other income

	2011	2010	2009
			$ million
Interest income			
Interest income from available-for-sale financial assets[a]	**21**	23	15
Interest income from loans and receivables[a]	**101**	88	69
Interest from loans to equity-accounted entities	**32**	36	53
Other interest	**13**	91	88
	167	238	225
Other income			
Dividend income from available-for-sale financial assets[a]	**29**	37	32
Other income	**400**	406	535
	429	443	567
	596	681	792

[a] Total interest and other income related to financial instruments amounted to $151 million (2010 $148 million and 2009 $116 million).

8. Production and similar taxes

	2011	2010	2009
			$ million
US	**1,854**	1,093	649
Non-US	**6,426**	4,151	3,103
	8,280	5,244	3,752

9. Depreciation, depletion and amortization

By business	2011	2010	2009
			$ million
Exploration and Production			
US	**3,201**	3,751	4,150
Non-US	**5,492**	4,865	5,407
	8,693	8,616	9,557
Refining and Marketing			
US	**840**	955	919
Non-US[a]	**1,277**	1,303	1,317
	2,117	2,258	2,236
Other businesses and corporate			
US	**151**	140	136
Non-US	**174**	150	177
	325	290	313
By geographical area			
US	**4,192**	4,846	5,205
Non-US	**6,943**	6,318	6,901
	11,135	11,164	12,106

a Non-US area includes the UK-based international activities of Refining and Marketing.

10. Impairment review of goodwill

$ million

Goodwill at 31 December	2011	2010
Exploration and Production	**7,931**	4,450
Refining and Marketing	**4,014**	4,074
Other businesses and corporate	**155**	74
	12,100	8,598

Goodwill acquired through business combinations has been allocated to groups of cash-generating units that are expected to benefit from the synergies of the acquisition. For Exploration and Production, goodwill is held at the segment level; previously it was allocated to each geographic region (UK, US and Rest of World) (see below). For Refining and Marketing, goodwill has been allocated to the Rhine fuels value chain (FVC), Lubricants and Other.

In assessing whether goodwill has been impaired, the carrying amount of the cash-generating unit (including goodwill) is compared with the recoverable amount of the cash-generating unit. The recoverable amount is the higher of fair value less costs to sell and value in use. In the absence of any information about the fair value of a cash-generating unit, the recoverable amount is deemed to be the value in use.

The group calculates the value in use using a discounted cash flow model. The future cash flows are adjusted for risks specific to the cash-generating unit and are discounted using a pre-tax discount rate. The discount rate is derived from the group s post-tax weighted average cost of capital and is adjusted where applicable to take into account any specific risks relating to the country where the cash-generating unit is located. The rate to be applied to each country is reassessed each year. Discount rates of 12% and 14% have been used for goodwill impairment calculations performed in 2011 (2010 12% and 14%).

The business segment plans, which are approved on an annual basis by senior management, are the primary source of information for the determination of value in use. They contain forecasts for oil and natural gas production, refinery throughputs, sales volumes for various types of refined products (e.g. gasoline and lubricants), revenues, costs and capital expenditure. As an initial step in the preparation of these plans, various environmental assumptions, such as oil prices, natural gas prices, refining margins, refined product margins and cost inflation rates, are set by senior management. These environmental assumptions take account of existing prices, global supply-demand equilibrium for oil and natural gas, other macroeconomic factors and historical trends and variability.

Exploration and Production

$ million

	2011				2010
	Total	UK	US	Rest of world	Total
Goodwill	**7,931**	341	3,479	630	4,450
Excess of recoverable amount over carrying amount	**49,247**	7,556	18,968	41,714	n/a

The value in use is based on the cash flows expected to be generated by the projected oil or natural gas production profiles up to the expected dates of cessation of production of each producing field. As the production profile and related cash flows can be estimated from BP s past experience, management believes that the cash flows generated over the estimated life of field is the appropriate basis upon which to assess goodwill and individual assets for impairment. The date of cessation of production depends on the interaction of a number of variables, such as the recoverable quantities of hydrocarbons, the production profile of the hydrocarbons, the cost of the development of the infrastructure necessary to recover the hydrocarbons, the production costs, the contractual duration of the production concession and the selling price of the hydrocarbons produced. As each producing field has specific reservoir characteristics and economic circumstances, the cash flows of the fields are computed using appropriate individual economic models and key assumptions agreed by BP s management for the purpose. Capital expenditure and operating costs for the first four years and expected hydrocarbon production profiles up to 2020 are derived from the business segment plan. Estimated production quantities and cash flows up to the date of cessation of production on a field-by-field basis are developed to be consistent with this. The production profiles used are consistent with the resource volumes approved as part of BP s centrally-controlled process for the estimation of proved reserves and total resources.

Prior to 2011, goodwill in the Exploration and Production segment was allocated to each geographic region, that is UK, US and Rest of World, and impairment reviews of goodwill were performed at this level. Following a reorganization of the Exploration and Production segment, the group has revised the way goodwill is monitored for internal management purposes. Given the global nature of our upstream business, the impairment review of goodwill is now performed at the Exploration and Production segment level. Consistent with prior years, the 2011 review for impairment was carried out during the fourth quarter.

The table above shows the carrying amount of the goodwill for the segment and the excess of the recoverable amount over the carrying amount (the headroom). Consistent with prior periods, midstream and intangible oil and gas assets were excluded from the headroom calculation.

The Brent oil price assumption used in the impairment review of goodwill is shown in the table below.

						2011
	2012	**2013**	**2014**	**2015**	**2016**	**2017 and thereafter**
Brent oil price ($/bbl)	**106**	**101**	**97**	**94**	**92**	**90**

						2010
	2011	2012	2013	2014	2015	2016 and thereafter
Brent oil price ($/bbl)	85	88	89	89	90	75

Key assumptions for oil and gas prices for the first five years were derived from forward price curves in the fourth quarter. Prices in 2017 and beyond were determined using long-term views of global supply and demand, building upon past experience of the industry and consistent with external sources. These prices were adjusted to arrive at appropriate consistent price assumptions for different qualities of oil and gas, or where appropriate, contracted oil and gas prices were applied.

10. Impairment review of goodwill continued

The key assumptions required for the value-in-use estimation are the oil and natural gas prices, production volumes and the discount rate. To test the sensitivity of the headroom to changes in production volumes and oil and natural gas prices, management has developed rules of thumb for key assumptions. Applying these gives an indication of the impact on the headroom of possible changes in the key assumptions. Due to the non-linear relationship of different variables, the calculations were performed using a number of simplified assumptions, therefore a detailed calculation at any given price may produce a different result.

It was estimated that if the oil price assumption was around 25% lower than the current assumption for 2017 and beyond, this would cause the recoverable amount to be equal to the carrying amount of goodwill and related non-current assets of the segment. It was estimated that no reasonably possible change in the long-term price of natural gas would cause the headroom to be reduced to zero.

Estimated production volumes are based on detailed data for the fields and take into account development plans for the fields agreed by management as part of the long-term planning process. In 2011, it was estimated that, if all our production were to be reduced by 10% for the whole of the next 15 years, this would not be sufficient to reduce the excess of recoverable amount over the carrying amount to zero. Consequently, management believes no reasonably possible change in the production assumption would cause the carrying amount to exceed the recoverable amount.

Management also believes that currently there is no reasonably possible change in discount rate that would cause the carrying amount to exceed the recoverable amount.

Refining and Marketing

								$ million
				2011				2010
	Rhine FVC	**Lubricants**	**Other**	**Total**	Rhine FVC	Lubricants	Other	Total
Goodwill	**618**	**3,284**	**112**	**4,014**	629	3,285	160	4,074
Excess of recoverable amount over carrying amount	**2,264**	**n/a**	**n/a**	**n/a**	4,091	n/a	n/a	n/a

Cash flows for each cash-generating unit are derived from the business segment plans, which cover a period of two to five years. To determine the value in use for each of the cash-generating units, cash flows for a period of 10 years are discounted and aggregated with a terminal value.

Rhine FVC

The key assumptions to which the calculation of value in use for the Rhine FVC is most sensitive are refinery gross margins, throughput volumes and discount rate. Gross margin assumptions used in the Rhine FVC plan are consistent with those used to develop the regional Refining Marker Margin (RMM). The regional RMM is a margin measure based upon product yields and a marker crude oil deemed appropriate for the region. The average values assigned to the regional RMM and refinery throughput volume over the plan period are $11.35 per barrel and 257 million barrels per year (2010 $11.05 per barrel and 248 million barrels per year). These values reflect past experience and are consistent with external sources. Cash flows beyond the five-year plan period are extrapolated using a nominal 4% growth rate (2010 cash flows beyond the five-year plan period were extrapolated using a nominal 4% growth rate).

	2011
Sensitivity analysis	
Sensitivity of value in use to a change in refinery margins of $1 per barrel ($ billion)	**1.5**
Adverse change in refinery margins to reduce recoverable amount to carrying amount ($ per barrel)	**1.5**
Sensitivity of value in use to a 5% change in throughput volume ($ billion)	**0.9**
Adverse change in throughput volume to reduce recoverable amount to carrying amount (million barrels per year)	**31**
Sensitivity of value in use to a change in the discount rate of 1% ($ billion)	**0.7**
Discount rate to reduce recoverable amount to carrying amount	**16%**

Lubricants

As permitted by IAS 36, the detailed calculations of the Lubricants unit s recoverable amount performed in the most recent detailed calculation in 2009 were used for the 2011 impairment test as the criteria in that standard were considered satisfied: the headroom was substantial in 2009; there have been no significant changes in the assets and liabilities; and the likelihood that the recoverable amount would be less than the carrying amount at the time of the test was remote.

The key assumptions to which the calculation of value in use for the Lubricants unit is most sensitive are operating unit margins, sales volumes and discount rate. The values assigned to these key assumptions reflect past experience. No reasonably possible changes in any of these key assumptions would cause the unit s carrying amount to exceed its recoverable amount. Cash flows beyond the two-year plan period were extrapolated using a nominal 3% growth rate.

11. Distribution and administration expenses

$ million

	2011	2010	2009
Distribution	**12,416**	11,393	12,798
Administration	**1,542**	1,162	1,240
	13,958	12,555	14,038

12. Currency exchange gains and losses

			$ million
	2011	2010	2009
Currency exchange (gains) losses (credited) charged to the income statement[a]	**(70)**	218	193

a Excludes exchange gains and losses arising on financial instruments measured at fair value through profit or loss.

13. Research and development

			$ million
	2011	2010	2009
Expenditure on research and development	**636**	780	587

In addition to the expenditure on research and development presented in the table above, BP also made donations to external organizations for research purposes, including the Gulf of Mexico Research Initiative as described on page 79. These donations are not included in the amounts reported above.

14. Operating leases

In the case of an operating lease entered into by BP as the operator of a jointly controlled asset, the amounts shown in the tables below represent the net operating lease expense and net future minimum lease payments. These net amounts are after deducting amounts reimbursed, or to be reimbursed, by joint venture partners, whether the joint venture partners have co-signed the lease or not. Where BP is not the operator of a jointly controlled asset, BP s share of the lease expense and future minimum lease payments is included in the amounts shown, whether BP has co-signed the lease or not.

The table below shows the expense for the year in respect of operating leases.

			$ million
	2011	2010	2009
Minimum lease payments	**4,866**	5,371	4,109
Contingent rentals	**(97)**	(60)	(9)
Sub-lease rentals	**(153)**	(121)	(133)
	4,616	5,190	3,967

The future minimum lease payments at 31 December, before deducting related rental income from operating sub-leases of $566 million (2010 $365 million), are shown in the table below. This does not include future contingent rentals. Where the lease rentals are dependent on a variable factor, the future minimum lease payments are based on the factor as at inception of the lease.

		$ million
Future minimum lease payments	**2011**	2010
Payable within		
1 year	**4,182**	3,521
2 to 5 years	**8,346**	6,798
Thereafter	**3,544**	3,654
	16,072	13,973

The group enters into operating leases of ships, plant and machinery, commercial vehicles and land and buildings. Typical durations of the leases are as follows:

	Years
Ships	up to 15
Plant and machinery	up to 10
Commercial vehicles	up to 15
Land and buildings	up to 40

The group has entered into a number of structured operating leases for ships and in most cases the lease rental payments vary with market interest rates. The variable portion of the lease payments above or below the amount based on the market interest rate prevailing at inception of the lease is treated as contingent rental expense. The group also routinely enters into bareboat charters, time-charters and spot-charters for ships on standard industry terms.

The most significant items of plant and machinery hired under operating leases are drilling rigs used in the Exploration and Production segment. At 31 December 2011 the future minimum lease payments relating to drilling rigs amounted to $6,292 million (2010 $4,515 million). In some cases, drilling rig lease rental rates are adjusted periodically to market rates that are influenced by oil prices and may be significantly different from the rates at the inception of the lease. Differences between the rate paid and rate at inception of the lease are treated as contingent rental expense.

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

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

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

The following financial information represents the amounts included within the group totals relating to activity associated with the exploration for and evaluation of oil and natural gas resources. All such activity is recorded within the Exploration and Production segment.

			$ million
	2011	2010	2009
Exploration and evaluation costs			
Exploration expenditure written off	**1,024**	375	593
Other exploration costs	**496**	468	523
Exploration expense for the year	**1,520**	843	1,116
Intangible assets exploration and appraisal expenditure	**19,887**	13,126	10,388
Liabilities	**306**	157	
Net assets	**19,581**	12,969	10,388
Capital expenditure	**8,911**	6,422	2,715
Net cash used in operating activities	**496**	468	523
Net cash used in investing activities	**8,556**	6,428	3,306

16. Auditor s remuneration

			$ million
Fees Ernst & Young	**2011**	2010	2009
Fees payable to the company s auditors for the audit of the company s accounts[a]	**15**	13	13
Fees payable to the company s auditors and its associates for other services			
Audit of the company s subsidiaries pursuant to legislation	**19**	22	22
Other services pursuant to legislation	**10**	12	11
	44	47	46
Tax services	**2**	2	1
Services relating to corporate finance transactions	**4**	1	
All other services	**4**	4	6
Audit fees in respect of the BP pension plans	**1**	1	1
	55	55	54

a Fees in respect of the audit of the accounts of BP p.l.c. including the group s consolidated financial statements.

2011 includes $1 million of additional fees for 2010 and 2010 includes $1 million of additional fees for 2009. Auditor s remuneration is included in the income statement within distribution and administration expenses.

The tax services relate to income tax and indirect tax compliance, employee tax services and tax advisory services.

The audit committee has established pre-approval policies and procedures for the engagement of Ernst & Young to render audit and certain assurance and tax services. The audit fees payable to Ernst & Young are reviewed by the audit committee in the context of other global companies for cost-effectiveness. Ernst & Young performed further assurance and tax services that were not prohibited by regulatory or other professional requirements and were pre-approved by the committee. Ernst & Young is engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit nature. Tax services were awarded either through a full competitive tender process or following an assessment of the expertise of Ernst & Young compared with that of other potential service providers. These services are for a fixed term.

Under SEC regulations, the remuneration of the auditor of $55 million (2010 $55 million and 2009 $54 million) is required to be presented as follows: audit $44 million (2010 $47 million and 2009 $46 million); other audit-related services $1 million (2010 $1 million and 2009 $2 million); tax $2 million (2010 $2 million and 2009 $1 million); and fees for all other services $8 million (2010 $5 million and 2009 $5 million).

17. Finance costs

			$ million
	2011	2010	2009
Interest payable	**1,135**	955	906
Capitalized at 2.63% (2010 2.75% and 2009 2.75%)[a]	**(347)**	(254)	(188)
Unwinding of discount on provisions[b]	**243**	234	247
Unwinding of discount on other payables[b]	**215**	235	145
	1,246	1,170	1,110

a Tax relief on capitalized interest is $107 million (2010 $71 million and 2009 $63 million).
b Unwinding of discount on provisions relating to the Gulf of Mexico oil spill was $6 million (2010 $4 million and 2009 nil) and unwinding of discount on other payables relating to the Gulf of Mexico oil spill was $52 million (2010 $73 million and 2009 nil). See Note 2 for further information on the financial impacts of the Gulf of Mexico oil spill.

18. Taxation

Tax on profit

$ million

	2011	2010	2009
Current tax			
Charge for the year	**7,477**	6,766	6,045
Adjustment in respect of prior years	**111**	(74)	(300)
	7,588	6,692	5,745
Deferred tax			
Origination and reversal of temporary differences in the current year	**5,664**	(8,157)	2,131
Adjustment in respect of prior years	**(515)**	(36)	489
	5,149	(8,193)	2,620
Tax charge (credit) on profit (loss)	**12,737**	(1,501)	8,365

Tax included in other comprehensive income[a]

$ million

	2011	2010	2009
Current tax	**(10)**	(107)	
Deferred tax	**(1,649)**	244	(525)
	(1,659)	137	(525)

[a] See Note 39 for further information.

Tax included directly in equity

$ million

	2011	2010	2009
Current tax		(37)	
Deferred tax	**(7)**	64	(65)
	(7)	27	(65)

Reconciliation of the effective tax rate

The following table provides a reconciliation of the UK statutory corporation tax rate to the effective tax rate of the group on profit or loss before taxation. With effect from 1 April 2011 the UK statutory corporation tax rate reduced from 28% to 26%.

For 2010, the items presented in the reconciliation are distorted as a result of the overall tax credit for the year and the loss before taxation. In order to provide a more meaningful analysis of the effective tax rate for 2010, the table also presents separate reconciliations for the group excluding the impacts of the Gulf of Mexico oil spill, and for the impacts of the Gulf of Mexico oil spill in isolation. For 2011, the effective tax rate is not impacted significantly by the Gulf of Mexico oil spill.

$ million

	2011	2010 excluding impacts of Gulf of Mexico oil spill	2010 impacts of Gulf of Mexico oil spill	2010	2009
Profit (loss) before taxation	**38,834**	36,110	(40,935)	(4,825)	25,124
Tax charge (credit) on profit (loss)	**12,737**	11,393	(12,894)	(1,501)	8,365
Effective tax rate	**33%**	32%	31%	31%	33%
					% of profit or loss before taxation
UK statutory corporation tax rate	**26**	28	28	28	28
Increase (decrease) resulting from:					
UK supplementary and overseas taxes at higher/lower rates	**14**	9	7	(4)	8

Tax reported in equity-accounted entities	**(3)**	(3)		23	(3)
Adjustments in respect of prior years	**(1)**			2	1
Current year losses unrelieved				1	
Goodwill impairment					2
Tax incentives for investment	**(1)**	(1)		9	(2)
Gulf of Mexico oil spill non-deductible costs			(4)	(30)	
Permanent differences relating to disposals	**(2)**	(1)		5	
Other				(3)	(1)
Effective tax rate	**33**	32	31	31	33

18. Taxation continued

Deferred tax

$ million

	Income statement 2011	Income statement 2010	Income statement 2009	Balance sheet 2011	Balance sheet 2010
Deferred tax liability					
Depreciation	**4,511**	1,565	1,983	**33,038**	27,309
Pension plan surpluses		38	(6)		469
Other taxable temporary differences	**129**	1,178	978	**5,683**	5,538
	4,640	2,781	2,955	**38,721**	33,316
Deferred tax asset					
Pension plan and other post-retirement benefit plan deficits	**388**	179	180	**(2,872)**	(2,155)
Decommissioning, environmental and other provisions	**(1,324)**	(8,151)	86	**(14,565)**	(13,296)
Derivative financial instruments	**24**	(56)	80	**(274)**	(298)
Tax credits	**(401)**	(1,088)	(516)	**(2,549)**	(2,118)
Loss carry forward	**(218)**	24	402	**(1,295)**	(943)
Other deductible temporary differences	**2,040**	(1,882)	(567)	**(2,699)**	(4,126)
	509	(10,974)	(335)	**(24,254)**	(22,936)
Net deferred tax charge (credit) and net deferred tax liability	**5,149**	(8,193)	2,620	**14,467**	10,380
Of which deferred tax liabilities				**15,078**	10,908
deferred tax assets				**611**	528

$ million

Analysis of movements during the year	2011	2010
At 1 January	**10,380**	18,146
Exchange adjustments	**55**	3
Charge (credit) for the year on profit	**5,149**	(8,193)
Charge (credit) for the year in other comprehensive income	**(1,649)**	244
Charge (credit) for the year in equity	**(7)**	64
Acquisitions	**692**	187
Reclassified as assets held for sale	**(140)**	(67)
Deletions	**(13)**	(4)
At 31 December	**14,467**	10,380

Deferred tax assets are recognized to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax credits and unused tax losses can be utilized.

At 31 December 2011, the group had approximately $4.6 billion (2010 $3.9 billion) of carry-forward tax losses that would be available to offset against future taxable profit. A deferred tax asset has been recognized in respect of $3.8 billion of losses (2010 $3.0 billion). No deferred tax asset has been recognized in respect of $0.8 billion of losses (2010 $0.9 billion). In 2011, a current tax benefit of $0.1 billion arose relating to losses utilized on which a deferred tax asset had not previously been recognized (2010 nil). Substantially all the tax losses have no fixed expiry date.

At 31 December 2011, the group had approximately $18.2 billion of unused tax credits predominantly in the UK and US (2010 $13.9 billion). At 31 December 2011 there is a deferred tax asset of $2.5 billion in respect of unused tax credits (2010 $2.1 billion). No deferred tax asset has been recognized in respect of $15.7 billion of tax credits (2010 $11.8 billion). In 2011, a current tax benefit of $0.1 billion arose relating to tax credits utilized on which a deferred tax asset had not previously been recognized (2010 $0.3 billion).

The UK tax credits, arising in UK branches overseas with no deferred tax asset, amounting to $13.0 billion (2010 $9.9 billion) do not have a fixed expiry date. In addition there are also temporary differences in overseas branches of UK companies with no deferred tax asset recognized. At 31 December 2011 the unrecognized deferred tax amounted to $0.9 billion (2010 $0.9 billion). These credits and temporary differences arise in UK branches predominantly based in high tax rate jurisdictions and so are unlikely to have value in the future as UK taxes on these overseas branches are largely mitigated by the double tax relief on the local foreign tax.

The US tax credits with no deferred tax asset amounting to $2.7 billion (2010 $1.9 billion) expire 10 years after generation, and the majority expire in the period 2014-2021.

The group recognized significant costs in 2010 in relation to the Gulf of Mexico oil spill and in 2011 has recognized certain recoveries relating to the incident as well as further costs. Tax has been calculated on the expenditures that are expected to qualify for tax relief, and on the recoveries, at the US statutory tax rate. A deferred tax asset has been recognized in respect of provisions for future expenditure that are expected to qualify for tax relief. This is included under the heading decommissioning, environmental and other provisions.

The other major components of temporary differences at the end of 2011 relate to tax depreciation, provisions, including items relating to the Gulf of Mexico oil spill, US inventory holding gains (classified as other taxable temporary differences) and pension plan and other post-retirement benefit plan deficits.

At 31 December 2011, there were no material temporary differences associated with investments in subsidiaries and equity-accounted entities for which deferred tax liabilities have not been recognized.

In 2011, the enactment of a 12% increase in the UK supplementary charge on oil and gas production activities in the North Sea increased the deferred tax charge in the income statement by $713 million of which $683 million relates to the revaluation of the opening deferred tax balance.

Also in 2011, the enactment of a 2% reduction in the rate of UK corporation tax to 25% with effect from 1 April 2012 on profits arising from activities outside the North Sea reduced the deferred tax charge in the income statement by $120 million. In 2010 the enactment of a 1% reduction in the rate of UK corporation tax to 27% with effect from 1 April 2011 similarly reduced the deferred tax charge in the income statement by $86 million.

In 2012, legislation to restrict relief for UK decommissioning expenditure from 62% to 50% is expected to be enacted. New legislation is also likely to be introduced in Australia which would bring BP s North West Shelf activities into the charge to Petroleum Resource Rent Tax (PRRT) from July 2012. The impacts of both of these changes are currently being assessed.

Notes on financial statements

19. Dividends

The quarterly dividend expected to be paid on 30 March 2012 in respect of the fourth quarter 2011 is 8 cents per ordinary share ($0.48 per American Depositary Share (ADS)). The corresponding amount in sterling will be announced on 19 March 2012. A scrip dividend alternative is available, allowing shareholders to elect to receive their dividend in the form of new ordinary shares and ADS holders in the form of new ADSs.

On 1 February 2011 BP announced the resumption of quarterly dividend payments with a fourth-quarter 2010 dividend of 7 cents per share. The resumption came after the suspension of dividends for the first three quarters of 2010 in light of the Gulf of Mexico oil spill and commitments to fund the $20-billion Trust.

	Pence per share			Cents per share			$ million		
	2011	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Dividends announced and paid in cash									
Preference shares							**2**	2	2
Ordinary shares									
March	**4.3372**	8.679	9.818	**7**	14	14	**808**	2,625	2,619
June	**4.2809**		9.584	**7**		14	**794**		2,619
September	**4.3160**		8.503	**7**		14	**1,224**		2,620
December	**4.4694**		8.512	**7**		14	**1,244**		2,623
	17.4035	8.679	36.417	**28**	14	56	**4,072**	2,627	10,483
Dividend announced, payable in March 2012[a]				**8**			**1,517**		

a The amount in sterling will be announced on 19 March 2012.

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

	2011	2010	2009
Number of shares issued (thousand)	**165,601**		
Value of shares issued ($ million)	**1,219**		

The financial statements for the year ended 31 December 2011 do not reflect the dividend announced on 7 February 2012 and expected to be paid in March 2012; this will be treated as an appropriation of profit in the year ended 31 December 2012.

20. Earnings per ordinary share

	Cents per share		
	2011	2010	2009
Basic earnings per share	**135.93**	(19.81)	88.49
Diluted earnings per share	**134.29**	(19.81)	87.54

Basic earnings per ordinary share amounts are calculated by dividing the profit or loss for the year attributable to ordinary shareholders by the weighted average number of ordinary shares outstanding during the year. The average number of shares outstanding excludes treasury shares and the shares held by the Employee Share Ownership Plan Trusts (ESOPs) and includes certain shares that will be issuable in the future under employee share plans.

For the diluted earnings per share calculation, the weighted average number of shares outstanding during the year is adjusted for the number of shares that are potentially issuable in connection with employee share-based payment plans using the treasury stock method. If the inclusion of potentially issuable shares would decrease the loss per share, the potentially issuable shares are excluded from the diluted earnings per share calculation.

			$ million
	2011	2010	2009
Profit (loss) attributable to BP shareholders	**25,700**	(3,719)	16,578
Less: dividend requirements on preference shares	**2**	2	2
Profit (loss) for the year attributable to BP ordinary shareholders	**25,698**	(3,721)	16,576

			Shares thousand
	2011	2010	2009
Basic weighted average number of ordinary shares	**18,904,812**	18,785,912	18,732,459
Potential dilutive effect of ordinary shares issuable under employee share schemes	**231,388**	211,895	203,232
	19,136,200	18,997,807	18,935,691

The number of ordinary shares outstanding at 31 December 2011, excluding treasury shares and the shares held by the ESOPs, and including certain shares that will be issuable in the future under employee share plans was 18,977,213,826. Between 31 December 2011 and 17 February 2012, the latest practicable date before the completion of these financial statements, there was a net increase of 379,374 in the number of ordinary shares outstanding as a result of share issues in relation to employee share plans. The number of potential ordinary shares issuable through the exercise of employee share plans was 254,106,576 at 31 December 2011. There has been a decrease of 53,225,107 in the number of potential ordinary shares between 31 December 2011 and 17 February 2012.

21. Property, plant and equipment

$ million

	Land and land improvements	Buildings	Oil and gas properties	Plant, machinery and equipment	Fixtures, fittings and office equipment	Transportation	Oil depots, storage tanks and service stations	Total
Cost								
At 1 January 2011	**3,560**	**2,835**	**160,184**	**42,827**	**2,965**	**12,216**	**9,652**	**234,239**
Exchange adjustments	**(73)**	**(73)**		**(294)**	**(35)**	**(12)**	**(225)**	**(712)**
Additions	**39**	**46**	**18,515**	**3,782**	**370**	**655**	**512**	**23,919**
Acquisitions	**62**	**134**	**2,100**	**567**	**4**			**2,867**
Transfers			**1,013**					**1,013**
Reclassified as assets held for sale	**(325)**		**(832)**	**(9,931)**				**(11,088)**
Deletions	**(164)**	**(96)**	**(5,106)**	**(1,242)**	**(209)**	**(106)**	**(1,328)**	**(8,251)**
At 31 December 2011	**3,099**	**2,846**	**175,874**	**35,709**	**3,095**	**12,753**	**8,611**	**241,987**
Depreciation								
At 1 January 2011	**572**	**1,384**	**88,047**	**19,183**	**1,876**	**7,940**	**5,074**	**124,076**
Exchange adjustments	**(10)**	**(36)**		**(108)**	**(34)**	**(6)**	**(113)**	**(307)**
Charge for the year	**36**	**111**	**8,116**	**1,411**	**278**	**252**	**567**	**10,771**
Impairment losses	**133**	**4**	**1,239**	**245**		**42**	**46**	**1,709**
Impairment reversals			**(146)**					**(146)**
Reclassified as assets held for sale	**(115)**		**(680)**	**(5,761)**				**(6,556)**
Deletions	**(106)**	**(91)**	**(4,582)**	**(704)**	**(209)**	**(79)**	**(1,003)**	**(6,774)**
At 31 December 2011	**510**	**1,372**	**91,994**	**14,266**	**1,911**	**8,149**	**4,571**	**122,773**
Net book amount at 31 December 2011	**2,589**	**1,474**	**83,880**	**21,443**	**1,184**	**4,604**	**4,040**	**119,214**
Cost								
At 1 January 2010	3,786	2,918	157,197	41,599	3,022	12,441	10,295	231,258
Exchange adjustments	(85)	(68)	3	35	(41)	28	(72)	(200)
Additions	39	96	11,980	3,354	279	152	610	16,510
Acquisitions	2	3	1,931	41	5	15		1,997
Transfers			2,633					2,633
Reclassified as assets held for sale	(6)	(10)	(6,610)	(1,083)	(87)	(212)		(8,008)
Deletions	(176)	(104)	(6,950)	(1,119)	(213)	(208)	(1,181)	(9,951)
At 31 December 2010	3,560	2,835	160,184	42,827	2,965	12,216	9,652	234,239
Depreciation								
At 1 January 2010	571	1,389	86,975	18,903	1,893	7,852	5,400	122,983
Exchange adjustments	1	(46)		(19)	(25)	16	(13)	(86)
Charge for the year	34	82	8,024	1,492	291	268	606	10,797
Impairment losses	57	5	918	117	1		21	1,119
Reclassified as assets held for sale		(8)	(4,342)	(514)	(76)	(97)		(5,037)
Deletions	(91)	(38)	(3,528)	(796)	(208)	(99)	(940)	(5,700)
At 31 December 2010	572	1,384	88,047	19,183	1,876	7,940	5,074	124,076
Net book amount at 31 December 2010	2,988	1,451	72,137	23,644	1,089	4,276	4,578	110,163
Net book amount at 1 January 2010	3,215	1,529	70,222	22,696	1,129	4,589	4,895	108,275
Assets held under finance leases at net book amount included above								
At 31 December 2011		**10**	**213**	**326**		**7**	**18**	**574**
At 31 December 2010		14	236	386		7	18	661
Assets under construction included above								
At 31 December 2011								**26,443**
At 31 December 2010								23,055

22. Goodwill

$ million

	2011	2010
Cost		
At 1 January	**10,177**	10,199
Exchange adjustments	**(26)**	(154)
Acquisitions	**3,602**	335
Reclassified as assets held for sale	**(50)**	(87)
Deletions		(116)
At 31 December	**13,703**	10,177
Impairment losses		
At 1 January	**(1,579)**	(1,579)
Impairment losses for the year	**(66)**	
Reclassified as assets held for sale	**42**	
At 31 December	**(1,603)**	(1,579)
Net book amount at 31 December	**12,100**	8,598
Net book amount at 1 January	**8,598**	8,620

23. Intangible assets

$ million

			2011			2010
	Exploration and appraisal expenditure	Other intangibles	Total	Exploration and appraisal expenditure	Other intangibles	Total
Cost						
At 1 January	**13,476**	**3,403**	**16,879**	10,713	3,284	13,997
Exchange adjustments		**(21)**	**(21)**	6	(29)	(23)
Acquisitions	**5,563**	**176**	**5,739**	982	118	1,100
Additions	**3,348**	**352**	**3,700**	5,440	297	5,737
Transfers	**(1,013)**		**(1,013)**	(2,633)		(2,633)
Reclassified as assets held for sale		**(66)**	**(66)**	(134)	(4)	(138)
Deletions	**(704)**	**(370)**	**(1,074)**	(898)	(263)	(1,161)
At 31 December	**20,670**	**3,474**	**24,144**	13,476	3,403	16,879
Amortization						
At 1 January	**350**	**2,231**	**2,581**	325	2,124	2,449
Exchange adjustments		**(11)**	**(11)**		(11)	(11)
Charge for the year	**1,024**	**364**	**1,388**	375	367	742
Impairment losses	**7**	**79**	**86**			
Reclassified as assets held for sale		**(46)**	**(46)**		(3)	(3)
Deletions	**(598)**	**(358)**	**(956)**	(350)	(246)	(596)
At 31 December	**783**	**2,259**	**3,042**	350	2,231	2,581
Net book amount at 31 December	**19,887**	**1,215**	**21,102**	13,126	1,172	14,298
Net book amount at 1 January	**13,126**	**1,172**	**14,298**	10,388	1,160	11,548

24. Investments in jointly controlled entities

The significant jointly controlled entities of the BP group at 31 December 2011 are shown in Note 45. Summarized financial information for the group s share of jointly controlled entities is shown below. Balance sheet information shown below excludes data relating to jointly controlled entities reclassified as assets held for sale as at the end of the period. Income statement information shown below includes data relating to jointly controlled entities reclassified as assets held for sale for the period up until their date of reclassification as held for sale.

$ million

	2011	2010a	2009
Sales and other operating revenues	**15,720**	11,679	9,396
Profit before interest and taxation	**1,918**	1,730	1,815
Finance costs	**134**	122	155
Profit before taxation	**1,784**	1,608	1,660
Taxation	**480**	433	374
Profit for the year	**1,304**	1,175	1,286
Non-current assets	**16,495**	16,035	
Current assets	**4,613**	4,167	
Total assets	**21,108**	20,202	
Current liabilities	**2,553**	2,101	
Non-current liabilities	**3,980**	4,131	
Total liabilities	**6,533**	6,232	
	14,575	13,970	
Group investment in jointly controlled entities			
Group share of net assets (as above)	**14,575**	13,970	
Loans made by group companies to jointly controlled entities	**943**	957	
	15,518	14,927	

a 2010 information has been adjusted following the termination of the Pan American Energy LLC sale agreement. See Note 4 for further information.

Transactions between the group and its jointly controlled entities are summarized below.

$ million

Sales to jointly controlled entities		2011		2010		2009
Product	**Sales**	**Amount receivable at 31 December**	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
LNG, crude oil and oil products, natural gas, employee services	**5,095**	**1,616**	3,804	1,352	2,182	1,328

$ million

Purchases from jointly controlled entities		2011		2010		2009
Product	**Purchases**	**Amount payable at 31 Decembera**	Purchases	Amount payable at 31 Decembera	Purchases	Amount payable at 31 Decembera
LNG, crude oil and oil products, natural gas, refinery operating costs, plant processing fees	**7,798**	**369**	8,063	683	5,377	214

a In addition to the amounts shown above, there are amounts payable to jointly controlled entities of $2,256 million (2010 $2,583 million and 2009 $2,509 million) relating to BP s contribution on the establishment of the Sunrise Oil Sands joint venture.

The terms of the outstanding balances receivable from jointly controlled entities are typically 30 to 45 days, except for a receivable from Ruhr Oel of $605 million (2010 $585 million), part of which is a reimbursement balance relating to pensions that will be received over several years. The balances are unsecured and will be settled in cash. There are no significant provisions for doubtful debts relating to these balances and no significant expense recognized in the income statement in respect of bad or doubtful debts. Dividends receivable are not included in the above balances.

BP has commitments amounting to $4,155 million (2010 $3,389 million) in relation to contracts with jointly controlled entities for the purchase of LNG, crude oil and oil products, refinery operating costs and storage and handling services. See Note 44 for further information on capital commitments relating to BP s investments in jointly controlled entities.

25. Investments in associates

The significant associates of the BP group are shown in Note 45. The principal associate is TNK-BP. Summarized financial information for the group s share of associates is set out below. Balance sheet information shown below excludes data relating to associates reclassified as assets held for sale as at the end of the period. Income statement information shown below includes data relating to associates reclassified as assets held for sale for the period up until their date of reclassification as held for sale.

$ million

			2011			2010			2009
	TNK-BP	**Other**	**Total**	TNK-BP	Other	Total	TNK-BP	Other	Total
Sales and other operating revenues	**30,100**	**12,145**	**42,245**	22,323	10,031	32,354	17,377	8,301	25,678
Profit before interest and taxation	**5,992**	**958**	**6,950**	3,866	1,215	5,081	3,178	811	3,989
Finance costs	**132**	**13**	**145**	128	22	150	220	19	239
Profit before taxation	**5,860**	**945**	**6,805**	3,738	1,193	4,931	2,958	792	3,750
Taxation	**1,333**	**214**	**1,547**	913	228	1,141	871	125	996
Minority interest	**342**		**342**	208		208	139		139
Profit for the year	**4,185**	**731**	**4,916**	2,617	965	3,582	1,948	667	2,615
Non-current assets	**16,172**	**3,865**	**20,037**	14,686	4,024	18,710			
Current assets	**4,210**	**2,273**	**6,483**	4,500	1,989	6,489			
Total assets	**20,382**	**6,138**	**26,520**	19,186	6,013	25,199			
Current liabilities	**3,086**	**2,149**	**5,235**	3,284	1,888	5,172			
Non-current liabilities	**6,416**	**1,744**	**8,160**	5,283	1,914	7,197			
Total liabilities	**9,502**	**3,893**	**13,395**	8,567	3,802	12,369			
Minority interest	**867**		**867**	624		624			
	10,013	**2,245**	**12,258**	9,995	2,211	12,206			
Group investment in associates									
Group share of net assets (as above)	**10,013**	**2,245**	**12,258**	9,995	2,211	12,206			
Loans made by group companies to associates		**1,033**	**1,033**		1,129	1,129			
	10,013	**3,278**	**13,291**	9,995	3,340	13,335			

Transactions between the group and its associates are summarized below.

$ million

Sales to associates		**2011**		2010		2009
Product	**Sales**	**Amount receivable at 31 December**	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
LNG, crude oil and oil products, natural gas, employee services	**3,855**	**393**	3,561	330	2,801	320

$ million

Purchases from associates		**2011**		2010		2009
Product	**Purchases**	**Amount payable at 31 December**	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December
Crude oil and oil products, natural gas, transportation tariff	**8,159**	**815**	4,889	633	5,110	614

The terms of the outstanding balances receivable from associates are typically 30 to 45 days. The balances are unsecured and will be settled in cash. There are no significant provisions for doubtful debts relating to these balances and no significant expense recognized in the income statement in respect of bad or doubtful debts.

The amounts receivable and payable at 31 December 2011, as shown in the table above, exclude $220 million (2010 $299 million) due from and due to an intermediate associate which provides funding for our associate The Baku-Tbilisi-Ceyhan Pipeline Company. These balances are expected to be settled in cash throughout the period to 2015.

Dividends receivable at 31 December 2011 of $38 million (2010 $39 million) are also excluded from the table above.

BP has commitments amounting to $1,477 million (2010 $310 million) in relation to contracts with its associates for the purchase of crude oil and oil products, transportation and storage. See Note 44 for further information on capital commitments relating to BP s investments in associates.

On 18 October 2010, BP announced that it had reached agreement to sell assets in Vietnam, together with its upstream businesses and associated interests in Venezuela, to TNK-BP which is an associate and therefore a related party of the group. This transaction is part of the group s disposal programme and is the result of normal commercial negotiations. As at 31 December 2010, a deposit of $1 billion had been received from TNK-BP in advance of completion of this transaction and was reported within finance debt on the group balance sheet. This deposit was not reflected in the amount payable in the table above. The sale of the Venezuelan business and the sale of the upstream and certain midstream assets in Vietnam completed during 2011. Additional disposal proceeds of $0.7 billion were received upon completion of these transactions. The sale of the group s remaining equity-accounted investment in the Phu My 3 plant facility in Vietnam is expected to complete in 2012. See Note 4 for further information. A deposit of $30 million relating to the disposal of the Phu My 3 plant facility remains reported within finance debt on the group balance sheet at 31 December 2011.

26. Financial instruments and financial risk factors

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

$ million

At 31 December		Note	Loans and receivables	Available-for-sale financial assets	At fair value through profit or loss	Derivative hedging instruments	Financial liabilities measured at amortized cost	Total carrying amount 2011
Financial assets								
Other investments	equity shares	**27**		**1,128**				**1,128**
	other	**27**		**1,277**				**1,277**
Loans			**1,128**					**1,128**
Trade and other receivables		**29**	**36,879**					**36,879**
Derivative financial instruments		**33**			**7,188**	**1,707**		**8,895**
Cash and cash equivalents		**30**	**9,750**	**4,317**				**14,067**
Financial liabilities								
Trade and other payables		**32**					**(50,651)**	**(50,651)**
Derivative financial instruments		**33**			**(6,436)**	**(557)**		**(6,993)**
Accruals							**(6,321)**	**(6,321)**
Finance debt		**34**					**(44,183)**	**(44,183)**
			47,757	**6,722**	**752**	**1,150**	**(101,155)**	**(44,774)**

$ million

At 31 December		Note	Loans and receivables	Available-for-sale financial assets	At fair value through profit or loss	Derivative hedging instruments	Financial liabilities measured at amortized cost	Total carrying amount 2010
Financial assets								
Other investments	equity shares	27		1,191				1,191
	other	27		1,532				1,532
Loans			1,141					1,141
Trade and other receivables		29	32,380					32,380
Derivative financial instruments		33			7,222	1,344		8,566
Cash and cash equivalents		30	13,462	5,094				18,556
Financial liabilities								
Trade and other payables		32					(56,499)	(56,499)
Derivative financial instruments		33			(7,254)	(279)		(7,533)
Accruals							(6,249)	(6,249)
Finance debt		34					(39,139)	(39,139)
			46,983	7,817	(32)	1,065	(101,887)	(46,054)

The fair value of finance debt is shown in Note 34. For all other financial instruments, the carrying amount is either the fair value, or approximates the fair value.

Financial risk factors

The group is exposed to a number of different financial risks arising from natural business exposures as well as its use of financial instruments including: market risks relating to commodity prices, foreign currency exchange rates, interest rates and equity prices; credit risk; and liquidity risk.

The group financial risk committee (GFRC) advises the group chief financial officer (CFO) who oversees the management of these risks. The GFRC is chaired by the CFO and consists of a group of senior managers including the group treasurer and the heads of the group finance, tax and the integrated supply and trading functions. The purpose of the committee is to advise on financial risks and the appropriate financial risk governance framework for the group. The committee provides assurance to the CFO and the group chief executive (GCE), and via the GCE to the board, that the group s financial risk-taking activity is governed by appropriate policies and procedures and that financial risks are identified, measured and managed in accordance with group policies and group risk appetite.

The group s trading activities in the oil, natural gas and power markets are managed within the integrated supply and trading function, while the activities in the financial markets are managed by the integrated supply and trading function, on behalf of the treasury function. All derivative activity is carried out by specialist teams that have the appropriate skills, experience and supervision. These teams are subject to close financial and management control.

The integrated supply and trading function maintains formal governance processes that provide oversight of market risk associated with trading activity. These processes meet generally accepted industry practice and reflect the principles of the Group of Thirty Global Derivatives Study recommendations. A policy and risk committee monitors and validates limits and risk exposures, reviews incidents and validates risk-related policies, methodologies and procedures. A commitments committee approves value-at-risk delegations, the trading of new products, instruments and strategies and material commitments.

In addition, the integrated supply and trading function undertakes derivative activity for risk management purposes under a separate control framework as described more fully below.

26. Financial instruments and financial risk factors continued

(a) Market risk

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

The group measures market risk exposure arising from its trading positions using value-at-risk techniques. These techniques are based on Monte Carlo simulation and make a statistical assessment of the market risk arising from possible future changes in market prices over a one-day holding period. The calculation of the range of potential changes in fair value takes into account a snapshot of the end-of-day exposures and the history of one-day price movements, together with the correlation of these price movements. The value-at-risk measure is supplemented by stress testing.

The value-at-risk table does not incorporate any of the group s natural business exposures or any derivatives entered into to risk manage those exposures. Market risk exposure in respect of embedded derivatives is also not included in the value-at-risk table.

Value-at-risk limits are in place for each trading activity and for the group s trading activity in total. The board has delegated a limit of $100 million value at risk in support of this trading activity. The high and low values at risk indicated in the table below for each type of activity are independent of each other. Through the portfolio effect the high value at risk for the group as a whole is lower than the sum of the highs for the constituent parts. The potential movement in fair values is expressed to a 95% confidence interval. This means that, in statistical terms, one would expect to see a decrease in fair values greater than the trading value at risk on one occasion per month if the portfolio were left unchanged.

								$ million
Value at risk for 1 day at 95% confidence interval				**2011**				2010
	High	**Low**	**Average**	**Year end**	High	Low	Average	Year end
Group trading	**83**	**28**	**42**	**28**	70	15	34	33
Oil price trading	**84**	**23**	**39**	**27**	39	10	19	25
Gas and power trading	**20**	**6**	**11**	**7**	62	7	27	18

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

(i) Commodity price risk

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

As described above, the group also carries out risk management of certain natural business exposures using over-the-counter swaps and exchange futures contracts. Together with certain physical supply contracts that are classified as derivatives, these contracts fall outside of the value-at-risk framework. For these derivative contracts the sensitivity of the net fair value to an immediate 10% increase or decrease in all reference prices would have been $23 million at 31 December 2011 (2010 $104 million). This figure does not include any corresponding economic benefit or disbenefit that would arise from the natural business exposure which would be expected to offset the gain or loss on the over-the-counter swaps and exchange futures contracts mentioned above.

In addition, the group has embedded derivatives relating to certain natural gas contracts. The net fair value of these contracts was a liability of $1,417 million at 31 December 2011 (2010 liability of $1,607 million). Key information on the natural gas contracts is given below.

At 31 December	**2011**	2010

Remaining contract terms	**3 years and 5 months to 6 years and 9 months**	4 years and 5 months to 7 years and 9 months
Contractual/notional amount	**952 million therms**	1,688 million therms

For these embedded derivatives the sensitivity of the net fair value to an immediate 10% favourable or adverse change in the key assumptions is as follows.

								$ million
At 31 December				**2011**				2010
	Gas price	**Oil price**	**Power price**	**Discount rate**	Gas price	Oil price	Power price	Discount rate
Favourable 10% change	**100**	**74**	**4**	**5**	145	48	10	10
Unfavourable 10% change	**(109)**	**(77)**	**(4)**	**(5)**	(180)	(68)	(10)	(10)

26. Financial instruments and financial risk factors continued

The sensitivities for risk management activity and embedded derivatives are hypothetical and should not be considered to be predictive of future performance. In addition, for the purposes of this analysis, in the above table, the effect of a variation in a particular assumption on the fair value of the embedded derivatives is calculated independently of any change in another assumption. In reality, changes in one factor may contribute to changes in another, which may magnify or counteract the sensitivities. Furthermore, the estimated fair values as disclosed should not be considered indicative of future earnings on these contracts.

(ii) Foreign currency exchange risk

Where the group enters into foreign currency exchange contracts for entrepreneurial trading purposes the activity is controlled using trading value-at-risk techniques as explained above. This activity is included within oil price trading in the value-at-risk table above.

Since BP has global operations, fluctuations in foreign currency exchange rates can have significant effects on the group s reported results. The effects of most exchange rate fluctuations are absorbed in business operating results through changing cost competitiveness, lags in market adjustment to movements in rates and translation differences accounted for on specific transactions. For this reason, the total effect of exchange rate fluctuations is not identifiable separately in the group s reported results. The main underlying economic currency of the group s cash flows is the US dollar. This is because BP s major product, oil, is priced internationally in US dollars. BP s foreign currency exchange management policy is to minimize economic and material transactional exposures arising from currency movements against the US dollar. The group co-ordinates the handling of foreign currency exchange risks centrally, by netting off naturally-occurring opposite exposures wherever possible, and then dealing with any material residual foreign currency exchange risks.

The group manages these exposures by constantly reviewing the foreign currency economic value at risk and aims to manage such risk to keep the 12-month foreign currency value at risk below $200 million. At 31 December 2011, the foreign currency value at risk was $100 million (2010 $81 million). At no point over the past three years did the value at risk exceed the maximum risk limit. The most significant exposures relate to capital expenditure commitments and other UK and European operational requirements, for which a hedging programme is in place and hedge accounting is claimed as outlined in Note 33.

For highly probable forecast capital expenditures the group locks in the US dollar cost of non-US dollar supplies by using currency forwards and futures. The main exposures are sterling, euro, Norwegian krone, Australian dollar and Korean won and at 31 December 2011 open contracts were in place for $1,242 million sterling, $158 million euro, $118 million Norwegian krone, $210 million Australian dollar and $230 million Korean won capital expenditures maturing within five years, with over 69% of the deals maturing within two years (2010 $989 million sterling, $115 million euro, $212 million Norwegian krone and $143 million Australian dollar capital expenditures maturing within five years, with over 80% of the deals maturing within two years).

For other UK, European and Australian operational requirements the group uses cylinders and currency forwards to hedge the estimated exposures on a 12-month rolling basis. At 31 December 2011, the open positions relating to cylinders consisted of receive sterling, pay US dollar, purchased call and sold put options (cylinders) for $2,683 million (2010 $1,340 million); receive euro, pay US dollar cylinders for $1,304 million (2010 $650 million); receive Australian dollar, pay US dollar cylinders for $312 million (2010 $286 million). At 31 December 2011 there were no open positions relating to currency forwards (2010 buy sterling, sell US dollar currency forwards for $925 million; buy euro, sell US dollar currency forwards for $630 million; buy Canadian dollar, sell US dollar currency forwards for $162 million).

In addition, most of the group s borrowings are in US dollars or are hedged with respect to the US dollar. At 31 December 2011, the total foreign currency net borrowings not swapped into US dollars amounted to $371 million (2010 $278 million). Of this total, $129 million was denominated in currencies other than the functional currency of the individual operating unit being entirely Canadian dollars (2010 $125 million, being entirely Canadian dollars). It is estimated that a 10% change in the corresponding exchange rates would result in an exchange gain or loss in the income statement of $13 million (2010 $12 million).

(iii) Interest rate risk

Where the group enters into money market contracts for entrepreneurial trading purposes the activity is controlled using value-at-risk techniques as described above. This activity is included within oil price trading in the value-at-risk table above.

BP is also exposed to interest rate risk from the possibility that changes in interest rates will affect future cash flows or the fair values of its financial instruments, principally finance debt.

While the group issues debt in a variety of currencies based on market opportunities, it uses derivatives to swap the debt to a floating rate exposure, mainly to US dollar floating, but in certain defined circumstances maintains a US dollar fixed rate exposure for a proportion of debt. The proportion of floating rate debt net of interest rate swaps and excluding disposal deposits at 31 December 2011 was 65% of total finance debt outstanding (2010 62%). The weighted average interest rate on finance debt at 31 December 2011 is 2% (2010 2%) and the weighted average maturity of fixed rate debt is five years (2010 five years).

The group s earnings are sensitive to changes in interest rates on the floating rate element of the group s finance debt. If the interest rates applicable to floating rate instruments were to have increased by 1% on 1 January 2012, it is estimated that the group s profit before taxation for 2012 would decrease by approximately $289 million (2010 $241 million decrease in 2011). This assumes that the amount and mix of fixed and floating rate debt, including finance leases, remains unchanged from that in place at 31 December 2011 and that the change in interest rates is effective from the beginning of the year. Where the interest rate applicable to an instrument is reset during a quarter it is assumed that this occurs at the beginning of the quarter and remains unchanged for the rest of the year. In reality, the fixed/floating rate mix will fluctuate over the year and interest rates will change continually. Furthermore, the effect on earnings shown by this analysis does not consider the effect of any other changes in general economic activity that may accompany such an increase in interest rates.

(iv) Equity price risk

The group holds equity investments, typically made for strategic purposes, that are classified as non-current available-for-sale financial assets and are measured initially at fair value with changes in fair value recognized in other comprehensive income. Accumulated fair value changes are recycled to the income statement on disposal, or when the investment is impaired. No impairment losses have been recognized for the years presented relating to listed non-current available-for-sale investments. For further information see Note 27.

At 31 December 2011, it is estimated that an increase of 10% in quoted equity prices would result in an immediate credit to other comprehensive income of $87 million (2010 $95 million credit to other comprehensive income), while a decrease of 10% in quoted equity prices would result in an immediate charge to other comprehensive income of $87 million (2010 $95 million charge to other comprehensive income).

26. Financial instruments and financial risk factors continued

At 31 December 2011, 77% (2010 80%) of the carrying amount of non-current available-for-sale equity financial assets represented the group s stake in Rosneft, thus the group s exposure is concentrated on changes in the share price of this equity investment in particular.

(b) Credit risk

Credit risk is the risk that a customer or counterparty to a financial instrument will fail to perform or fail to pay amounts due causing financial loss to the group and arises from cash and cash equivalents, derivative financial instruments and deposits with financial institutions and principally from credit exposures to customers relating to outstanding receivables.

The group has a credit policy, approved by the CFO, that is designed to ensure that consistent processes are in place throughout the group to measure and control credit risk. Credit risk is considered as part of the risk-reward balance of doing business. On entering into any business contract the extent to which the arrangement exposes the group to credit risk is considered. Key requirements of the policy are formal delegated authorities to the sales and marketing teams to incur credit risk and to a specialized credit function to set counterparty limits; the establishment of credit systems and processes to ensure that counterparties are rated and limits set; and systems to monitor exposure against limits and report regularly on those exposures, and immediately on any excesses, and to track and report credit losses. The treasury function provides a similar credit risk management activity with respect to group-wide exposures to banks and other financial institutions.

The global credit environment exhibited deterioration in 2011, suffering not only from continuing economic and political uncertainties but also from key event risks, causing the group to further heighten awareness, discussion and co-ordination around the material credit risks arising from its activities.

Before trading with a new counterparty can start, its creditworthiness is assessed and a credit rating is allocated that indicates the probability of default, along with a credit exposure limit. The assessment process takes into account all available qualitative and quantitative information about the counterparty and the group, if any, to which the counterparty belongs. The counterparty s business activities, financial resources and business risk management processes are taken into account in the assessment, to the extent that this information is publicly available or otherwise disclosed to BP by the counterparty, together with external credit ratings. Creditworthiness continues to be evaluated after transactions have been initiated and a watchlist of higher-risk counterparties is maintained.

The group does not aim to remove credit risk but expects to experience a certain level of credit losses. The group attempts to mitigate credit risk by entering into contracts that permit netting and allow for termination of the contract on the occurrence of certain events of default. Depending on the creditworthiness of the counterparty, the group may require collateral or other credit enhancements such as cash deposits, letters of credit, trade credit insurance, liens, third-party guarantees and other forms of credit mitigation. Trade receivables and payables, and derivative assets and liabilities, are presented on a net basis where unconditional netting arrangements are in place with counterparties and where there is an intent to settle amounts due on a net basis. The maximum credit exposure associated with financial assets is equal to the carrying amount. Collateral received and recognized in the balance sheet at the year end was $273 million (2010 $313 million) and collateral held off balance sheet was $6 million (2010 $52 million). As at 31 December 2011, the group had in place other credit enhancements designed to mitigate approximately $8.6 billion of credit risk (2010 $7.0 billion). Credit exposure exists in relation to guarantees issued by group companies under which amounts outstanding at 31 December 2011 were $415 million (2010 $404 million) in respect of liabilities of jointly controlled entities and associates and $1,430 million (2010 $1,339 million) in respect of liabilities of other third parties.

Notwithstanding the processes described above, significant unexpected credit losses can occasionally occur. Exposure to unexpected losses increases with concentrations of credit risk that exist when a number of counterparties are involved in similar activities or operate in the same industry sector or geographical area, which may result in their ability to meet contractual obligations being impacted by changes in economic, political or other conditions. The group s principal customers, suppliers and financial institutions with which it conducts business are located throughout the world. In addition, these risks are managed by maintaining a group watchlist and aggregating multi-segment exposures to ensure that a material credit risk is not missed.

Reports are regularly prepared and presented to the GFRC that cover the group s overall credit exposure and expected loss trends, exposure by segment, and overall quality of the portfolio. The reports also include details of the largest counterparties by exposure level and expected loss, and details of counterparties on the group watchlist.

For the contracts comprising derivative financial instruments in an asset position at 31 December 2011, it is estimated that over 76% (2010 over 80%) of the unmitigated credit exposure is to counterparties of investment grade credit quality.

For cash and cash equivalents, the treasury function dynamically manages bank deposit limits to ensure cash is well-diversified and to reduce concentration risks. At 31 December 2011, 98% of the cash and cash equivalents balance was deposited with financial institutions rated at least A by Standard & Poor s and A2 by Moody s. Direct cash and cash equivalent exposures to Greek, Italian, Irish, Portuguese and Spanish financial institutions totalled less than 1% of total cash and cash equivalents.

Trade and other receivables of the group are analysed in the table below. By comparing the BP credit ratings to the equivalent external credit ratings, it is estimated that approximately 70-80% (2010 approximately 50-60%) of the unmitigated trade receivables portfolio exposure is of investment grade credit quality. With respect to the trade and other receivables that are neither impaired nor past due, there are no indications as of the reporting date that the debtors will not meet their payment obligations.

		$ million
Trade and other receivables at 31 December	**2011**	2010
Neither impaired nor past due	**34,563**	30,181
Impaired (net of valuation allowance)	**33**	67
Not impaired and past due in the following periods		
within 30 days	**1,263**	1,358
31 to 60 days	**250**	249
61 to 90 days	**132**	101
over 90 days	**638**	424
	36,879	32,380

26. Financial instruments and financial risk factors continued

The movement in the valuation allowance for trade receivables is set out below.

		$ million
	2011	2010
At 1 January	**428**	430
Exchange adjustments	**(16)**	(9)
Charge for the year	**115**	150
Utilization	**(124)**	(143)
Write-back	**(71)**	
At 31 December	**332**	428

(c) Liquidity risk

Liquidity risk is the risk that suitable sources of funding for the group s business activities may not be available. The group s liquidity is managed centrally with operating units forecasting their cash and currency requirements to the central treasury function. Unless restricted by local regulations, subsidiaries pool their cash surpluses to treasury, which will then arrange to fund other subsidiaries requirements, or invest any net surplus in the market or arrange for necessary external borrowings, while managing the group s overall net currency positions.

In managing its liquidity risk, the group has access to a wide range of funding at competitive rates through capital markets and banks. The group s treasury function centrally co-ordinates relationships with banks, borrowing requirements, foreign exchange requirements and cash management. The group believes it has access to sufficient funding through its own current cash holdings and future cash generation including disposal proceeds, the commercial paper markets and by using undrawn committed borrowing facilities to meet foreseeable liquidity requirements.

The group has 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 2011, the amount drawn down against the DIP was $11,582 million (2010 $12,272 million). In addition, the group has in place an unlimited US Shelf Registration under which it may raise debt with maturities of one month or longer.

The group has long-term debt ratings of A2 (stable outlook) assigned by Moody s consistently throughout the year, and A (stable outlook) assigned by Standard & Poor s since July 2011, strengthened from A (negative outlook) in force at the start of the year.

During 2011 $10.7 billion of long-term taxable bonds were issued with tenors of between 18 months and 10 years, and $0.8 billion of US Industrial/Municipal bonds were re-issued in term-out mode of between three and ten years. Flexible commercial paper is issued at competitive rates to meet short-term borrowing requirements as and when needed.

As a further liquidity measure, the group continues to maintain suitable levels of cash and cash equivalents, invested with highly rated banks or money market funds and readily accessible at immediate and short notice ($14.1 billion at the end of 2011; $18.6 billion at the end of 2010).

At 31 December 2011, the group had substantial amounts of undrawn borrowing facilities available, consisting of $6,925 million of standby facilities (of which $6,825 million is available to draw and repay until mid-March 2014, and the equivalent of $100 million is available to draw and repay in Chinese yuan with half expiring in mid-September 2012 and half in December 2012). These facilities were renegotiated during 2011 across 25 international banks, and borrowings under them would be at pre-agreed rates.

The group also has committed letter of credit (LC) facilities totalling $5,125 million with a number of banks for a one-year duration, allowing LCs to be issued to a maximum one-year duration. There were also uncommitted secured LC evergreen facilities in place at the year end for $2,160 million, secured against inventories or receivables when utilized.

The amounts shown for finance debt in the table below include expected interest payments on borrowings and the future minimum lease payments with respect to finance leases.

Current finance debt on the group balance sheet at 31 December 2011 includes $30 million (2010 $6,197 million) in respect of cash deposits received for disposals expected to complete in 2012, which will be considered extinguished on completion of the transactions. This amount is excluded from the table below.

The table also shows the timing of cash outflows relating to trade and other payables and accruals.

$ million

	2011			2010		
	Trade and other payables[a]	**Accruals**	**Finance debt**	Trade and other payables[a]	Accruals	Finance debt
Within one year	**47,678**	**5,933**	**10,024**	42,691	5,612	9,353
1 to 2 years	**1,605**	**137**	**7,866**	6,549	278	6,816
2 to 3 years	**569**	**55**	**7,311**	6,242	125	7,542
3 to 4 years	**449**	**26**	**5,487**	411	42	6,105
4 to 5 years	**259**	**49**	**4,634**	365	28	5,494
5 to 10 years	**31**	**82**	**12,381**	323	110	6,642
Over 10 years	**72**	**39**	**573**	25	54	724
	50,663	**6,321**	**48,276**	56,606	6,249	42,676

a Trade and other payables at 31 December 2011 includes the Gulf of Mexico oil spill trust fund liability which is payable as follows: $4,884 million within one year (2010 $5,008 million within one year, $5,000 million payable in 1 to 2 years and $5,000 million payable in 2 to 3 years).

26. Financial instruments and financial risk factors continued

The group manages liquidity risk associated with derivative contracts, other than derivative hedging instruments, based on the expected maturities of both derivative assets and liabilities as indicated in Note 33. Management does not currently anticipate any cash flows that could be of a significantly different amount, or could occur earlier than the expected maturity analysis provided.

The table below shows cash outflows for derivative hedging instruments based upon contractual payment dates. The amounts reflect the maturity profile of the fair value liability where the instruments will be settled net, and the gross settlement amount where the pay leg of a derivative will be settled separately from the receive leg, as in the case of cross-currency interest rate swaps hedging non-US dollar finance debt. The swaps are with high investment-grade counterparties and therefore the settlement day risk exposure is considered to be negligible. Not shown in the table are the gross settlement amounts for the receive leg of derivatives that are settled separately from the pay leg, which amount to $9,099 million at 31 December 2011 (2010 $6,725 million) to be received on the same day as the related cash outflows.

		$ million
	2011	2010
Within one year	**1,738**	986
1 to 2 years	**1,372**	1,682
2 to 3 years	**1,115**	1,358
3 to 4 years	**298**	1,124
4 to 5 years	**1,262**	295
5 to 10 years	**3,459**	947
	9,244	6,392

The group has issued third-party guarantees, as described above under credit risk. These amounts represent the maximum exposure of the group, substantially all of which could be called within one year.

27. Other investments

				$ million
		2011		2010
	Current	**Non-current**	Current	Non-current
Equity investments listed		**876**		953
unlisted		**252**		238
Repurchased gas pre-paid bonds	**288**	**989**	1,532	
	288	**2,117**	1,532	1,191

Equity investments have no fixed maturity date or coupon rate, and are classified as available-for-sale financial assets. As such they are recorded at fair value with the gain or loss arising as a result of changes in fair value recorded directly in other comprehensive income. Accumulated fair value changes are recycled to the income statement on disposal, or when the investment is impaired.

The fair value of listed investments has been determined by reference to quoted market bid prices and as such are in level 1 of the fair value hierarchy. Unlisted investments are stated at cost less accumulated impairment losses.

The most significant listed investment is the group s stake in Rosneft which had a fair value of $873 million at 31 December 2011 (2010 $948 million). The fair value loss arising on revaluation of this investment during 2011 has been recorded within other comprehensive income.

In 2011, impairment losses of $12 million were incurred relating to unlisted investments; there were no impairment losses relating to listed investments. In 2010, no impairment losses were incurred relating to either unlisted investments or listed investments.

BP has entered into long-term gas supply contracts which are backed by gas pre-paid bonds. In 2010, BP was unsuccessful in the remarketing of these bonds and repurchased them. The outstanding bonds associated with these long-term gas supply contracts held by BP are recorded within other investments, with the related liability recorded within other payables on the balance sheet. The fair value of the gas pre-paid bonds is the same as the carrying amount, as the bonds are based on floating rate interest with weekly market re-set, and as such are in Level 1 of the fair value hierarchy.

BP has no investments pledged as security for liabilities as at 31 December 2011. As at 31 December 2010, BP had pledged listed equity investments with a carrying value of $948 million as part of a financing arrangement. As BP had retained substantially all the risks and rewards associated with the shares, they continued to be reflected as an asset on the balance sheet, with a liability being reflected within finance debt. The terms of the arrangement meant that BP could request to have the shares returned at any time with 20 days notice, up to the date of maturity (in three tranches, up to December 2013), subject to repayment of the outstanding loan. The financing arrangement was terminated during 2011.

28. Inventories

		$ million
	2011	2010
Crude oil	**7,702**	8,969
Natural gas	**178**	112
Refined petroleum and petrochemical products	**14,909**	13,997
	22,789	23,078
Supplies	**2,057**	1,669
	24,846	24,747
Trading inventories	**815**	1,471
	25,661	26,218
Cost of inventories expensed in the income statement	**285,618**	216,211

29. Trade and other receivables

$ million

	2011		2010	
	Current	**Non-current**	Current	Non-current
Financial assets				
Trade receivables	**27,929**	**508**	24,255	
Amounts receivable from jointly controlled entities	**1,004**	**612**	751	601
Amounts receivable from associates	**492**	**159**	448	220
Other receivables	**5,429**	**746**	4,763	1,342
	34,854	**2,025**	30,217	2,163
Non-financial assets				
Gulf of Mexico oil spill trust fund reimbursement asset[a]	**8,233**	**1,642**	5,943	3,601
Other receivables	**439**	**670**	389	534
	8,672	**2,312**	6,332	4,135
	43,526	**4,337**	36,549	6,298

a See Note 2 for further information.

Trade and other receivables are predominantly non-interest bearing. See Note 26 for further information.

30. Cash and cash equivalents

$ million

	2011	2010
Cash at bank and in hand	**4,872**	8,209
Term bank deposits	**4,878**	5,253
Cash equivalents	**4,317**	5,094
	14,067	18,556

Cash and cash equivalents comprise cash in hand; current balances with banks and similar institutions; term deposits of three months or less with banks and similar institutions; and short-term highly liquid investments that are readily convertible to known amounts of cash, are subject to insignificant risk of changes in value and have a maturity of three months or less from the date of acquisition. The carrying amounts of cash at bank and in hand and term bank deposits approximate their fair values. All of the other cash equivalents are categorized within level 1 of the fair value hierarchy.

Cash and cash equivalents at 31 December 2011 includes $901 million (2010 $982 million) that is restricted. This relates principally to amounts required to cover initial margins on trading exchanges.

See Note 26 for further information.

31. Valuation and qualifying accounts

$ million

		2011		2010		2009
	Doubtful debts	**Fixed assets investments**	Doubtful debts	Fixed assets investments	Doubtful debts	Fixed assets investments
At 1 January	**428**	**540**	430	349	391	935
Charged to costs and expenses	**115**	**111**	150	376	157	66

Charged to other accounts[a]	**(16)**	**(3)**	(9)	(3)	12	6
Deductions	**(195)**	**(5)**	(143)	(182)	(130)	(658)
At 31 December	**332**	**643**	428	540	430	349

a Principally currency transactions.

Valuation and qualifying accounts are deducted in the balance sheet from the assets to which they apply.

32. Trade and other payables

$ million

	2011 Current	2011 Non-current	2010 Current	2010 Non-current
Financial liabilities				
Trade payables	**29,830**		27,510	
Amounts payable to jointly controlled entities	**1,578**	**1,047**	1,361	1,905
Amounts payable to associates	**876**	**159**	712	220
Gulf of Mexico oil spill trust fund liability[a]	**4,872**		5,002	9,899
Other payables	**10,510**	**1,779**	8,100	1,790
	47,666	**2,985**	42,685	13,814
Non-financial liabilities				
Other payables	**4,739**	**452**	3,644	471
	52,405	**3,437**	46,329	14,285

a See Note 2 for further information.

Trade and other payables are predominantly interest free, however the Gulf of Mexico oil spill trust fund liability is recorded on a discounted basis. See Note 26 for further information.

33. Derivative financial instruments

An outline of the group s financial risks and the objectives and policies pursued in relation to those risks is set out in Note 26.

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

IAS 39 prescribes strict criteria for hedge accounting, whether as a cash flow or fair value hedge or a hedge of a net investment in a foreign operation, and requires that any derivative that does not meet these criteria should be classified as held for trading and fair valued, with gains and losses recognized in the income statement.

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

$ million

	2011 Fair value asset	2011 Fair value liability	2010 Fair value asset	2010 Fair value liability
Derivatives held for trading				
Currency derivatives	**217**	**(217)**	194	(280)
Oil price derivatives	**823**	**(536)**	1,099	(877)
Natural gas price derivatives	**5,305**	**(3,603)**	5,350	(3,951)
Power price derivatives	**843**	**(663)**	561	(432)
	7,188	**(5,019)**	7,204	(5,540)
Embedded derivatives				
Commodity price contracts		**(1,417)**	18	(1,625)
Other embedded derivatives				(89)
		(1,417)	18	(1,714)
Cash flow hedges				

Currency forwards, futures and cylinders	**25**	**(159)**	134	(124)
Cross-currency interest rate swaps			101	(1)
	25	**(159)**	235	(125)
Fair value hedges				
Currency forwards, futures and swaps	**842**	**(398)**	772	(80)
Interest rate swaps	**840**		337	(74)
	1,682	**(398)**	1,109	(154)
	8,895	**(6,993)**	8,566	(7,533)
Of which current	**3,857**	**(3,220)**	4,356	(3,856)
non-current	**5,038**	**(3,773)**	4,210	(3,677)

33. Derivative financial instruments continued

Derivatives held for trading

The group maintains active trading positions in a variety of derivatives. The contracts may be entered into for risk management purposes, to satisfy supply requirements or for entrepreneurial trading. Certain contracts are classified as held for trading, regardless of their original business objective, and are recognized at fair value with changes in fair value recognized in the income statement. Trading activities are undertaken by using a range of contract types in combination to create incremental gains by arbitraging prices between markets, locations and time periods. The net of these exposures is monitored using market value-at-risk techniques as described in Note 26.

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

$ million

	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**2011 Total**
Currency derivatives	**194**	**18**	**5**				**217**
Oil price derivatives	**573**	**135**	**77**	**25**	**10**	**3**	**823**
Natural gas price derivatives	**2,493**	**1,160**	**597**	**346**	**207**	**502**	**5,305**
Power price derivatives	**498**	**160**	**101**	**54**	**30**		**843**
	3,758	**1,473**	**780**	**425**	**247**	**505**	**7,188**

$ million

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	2010 Total
Currency derivatives	124	41	18	11			194
Oil price derivatives	797	128	82	64	21	7	1,099
Natural gas price derivatives	2,591	1,100	652	375	231	401	5,350
Power price derivatives	389	125	35	11	1		561
	3,901	1,394	787	461	253	408	7,204

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

$ million

	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**2011 Total**
Currency derivatives	**(168)**	**(49)**					**(217)**
Oil price derivatives	**(483)**	**(37)**	**(7)**	**(4)**	**(3)**	**(2)**	**(536)**
Natural gas price derivatives	**(1,696)**	**(876)**	**(347)**	**(197)**	**(102)**	**(385)**	**(3,603)**
Power price derivatives	**(328)**	**(176)**	**(89)**	**(46)**	**(24)**		**(663)**
	(2,675)	**(1,138)**	**(443)**	**(247)**	**(129)**	**(387)**	**(5,019)**

$ million

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	2010 Total
Currency derivatives	(228)	(6)	(46)				(280)
Oil price derivatives	(794)	(76)	(6)	(1)			(877)
Natural gas price derivatives	(2,174)	(741)	(484)	(161)	(114)	(277)	(3,951)
Power price derivatives	(287)	(103)	(32)	(9)	(1)		(432)
	(3,483)	(926)	(568)	(171)	(115)	(277)	(5,540)

If at inception of a contract the valuation cannot be supported by observable market data, any gain or loss determined by the valuation methodology is not recognized in the income statement but is deferred on the balance sheet and is commonly known as day-one profit or loss . This deferred gain or loss is recognized in the income statement over the life of the contract until substantially all of the remaining contract term can be valued using observable market data at which point any remaining deferred gain or loss is recognized in the income statement. Changes in valuation from this initial valuation are recognized immediately through the income statement.

33. Derivative financial instruments continued

The following table shows the changes in the day-one profits and losses deferred on the balance sheet.

				$ million
		2011		2010
	Power price	**Natural gas price**	Oil price	Natural gas price
Fair value of contracts not recognized through the income statement at 1 January		**69**	21	33
Fair value of new contracts at inception not recognized in the income statement	**9**	**51**		39
Fair value recognized in the income statement		**(6)**	(21)	(3)
Fair value of contracts not recognized through profit at 31 December	**9**	**114**		69

The following table shows the fair value of derivative assets and derivative liabilities held for trading, analysed by maturity period and by methodology of fair value estimation.

IFRS 7 *Financial Instruments: Disclosures* sets out a fair value hierarchy which consists of three levels that describe the methodology of estimation as follows:

- Level 1 using quoted prices in active markets for identical assets or liabilities.
- Level 2 using inputs for the asset or liability, other than quoted prices, that are observable either directly (i.e. as prices) or indirectly (i.e. derived from prices).
- Level 3 using inputs for the asset or liability that are not based on observable market data such as prices based on internal models or other valuation methods.

This information is presented on a gross basis, that is, before netting by counterparty.

							$ million
							2011
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Fair value of derivative assets							
Level 1	**229**	**18**	**5**				**252**
Level 2	**7,225**	**2,725**	**1,123**	**269**	**81**	**8**	**11,431**
Level 3	**310**	**284**	**253**	**221**	**170**	**500**	**1,738**
	7,764	**3,027**	**1,381**	**490**	**251**	**508**	**13,421**
Less: netting by counterparty	**(4,006)**	**(1,554)**	**(601)**	**(65)**	**(4)**	**(3)**	**(6,233)**
	3,758	**1,473**	**780**	**425**	**247**	**505**	**7,188**
Fair value of derivative liabilities							
Level 1	**(168)**	**(49)**					**(217)**
Level 2	**(6,323)**	**(2,479)**	**(887)**	**(163)**	**(21)**	**(7)**	**(9,880)**
Level 3	**(190)**	**(164)**	**(157)**	**(149)**	**(112)**	**(383)**	**(1,155)**
	(6,681)	**(2,692)**	**(1,044)**	**(312)**	**(133)**	**(390)**	**(11,252)**
Less: netting by counterparty	**4,006**	**1,554**	**601**	**65**	**4**	**3**	**6,233**
	(2,675)	**(1,138)**	**(443)**	**(247)**	**(129)**	**(387)**	**(5,019)**
Net fair value	**1,083**	**335**	**337**	**178**	**118**	**118**	**2,169**

							$ million
							2010
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Fair value of derivative assets							
Level 1	122	36	12	5			175
Level 2	7,132	1,928	639	239	109		10,047
Level 3	341	314	296	267	165	410	1,793
	7,595	2,278	947	511	274	410	12,015
Less: netting by counterparty	(3,694)	(884)	(160)	(50)	(21)	(2)	(4,811)
	3,901	1,394	787	461	253	408	7,204

Fair value of derivative liabilities							
Level 1	(239)	(6)	(46)				(291)
Level 2	(6,733)	(1,685)	(617)	(107)	(44)		(9,186)
Level 3	(205)	(148)	(125)	(114)	(92)	(279)	(963)
	(7,177)	(1,839)	(788)	(221)	(136)	(279)	(10,440)
Less: netting by counterparty	3,694	884	160	50	21	2	4,811
	(3,483)	(955)	(628)	(171)	(115)	(277)	(5,629)
Net fair value	418	439	159	290	138	131	1,575

33. Derivative financial instruments continued

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

$ million

	Oil price	Natural gas price	Power price	Total
Net fair value of contracts at 1 January 2011	**164**	**667**	**(1)**	**830**
Gains (losses) recognized in the income statement	**69**	**129**	**11**	**209**
Settlements	**(71)**	**(110)**	**3**	**(178)**
Transfers out of level 3		**(278)**		**(278)**
Net fair value of contracts at 31 December 2011	**162**	**408**	**13**	**583**

$ million

	Oil price	Natural gas price	Power price	Total
Net fair value of contracts at 1 January 2010	215	72	(1)	286
Gains (losses) recognized in the income statement	21	637	(1)	657
Settlements	(54)	(11)	1	(64)
Transfers out of level 3	(18)	(38)		(56)
Transfers into level 3		4		4
Exchange adjustments		3		3
Net fair value of contracts at 31 December 2010	164	667	(1)	830

Transfers out of level 3 of the fair value hierarchy in 2011 relate primarily to the delivery dates for a number of natural gas forward contracts moving into a time period where market observable prices are available, and therefore being reclassified to level 2 of the fair value hierarchy.

The amount recognized in the income statement for the year relating to level 3 held for trading derivatives still held at 31 December 2011 was a $204 million gain (2010 $651 million gain relating to derivatives still held at 31 December 2010).

Gains and losses relating to derivative contracts are included either within sales and other operating revenues or within purchases in the income statement depending upon the nature of the activity and type of contract involved. The contract types treated in this way include futures, options, swaps and certain forward sales and forward purchases contracts, and relate to both currency and commodity trading activities. Gains or losses arise on contracts entered into for risk management purposes, optimization activity and entrepreneurial trading. They also arise on certain contracts that are for normal procurement or sales activity for the group but that are required to be fair valued under accounting standards. Also included within sales and other operating revenues are gains and losses on inventory held for trading purposes. The total amount relating to all of these items was a net loss of $934 million (2010 $1,738 million net gain and 2009 $4,046 million net gain).

Embedded derivatives

The group has embedded derivatives relating to certain natural gas contracts. Prior to the development of an active gas trading market, UK gas contracts were priced using a basket of available price indices, primarily relating to oil products, power and inflation. After the development of an active UK gas market, certain contracts were entered into or renegotiated using pricing formulae not directly related to gas prices, for example, oil product and power prices. In these circumstances, pricing formulae have been determined to be derivatives, embedded within the overall contractual arrangements that are not clearly and closely related to the underlying commodity. The resulting fair value relating to these contracts is recognized on the balance sheet with gains or losses recognized in the income statement.

All the commodity price embedded derivatives relate to natural gas contracts, are categorized in level 3 of the fair value hierarchy and are valued using inputs that include price curves for each of the different products that are built up from active market pricing data. Where necessary, these are extrapolated to the expiry of the contracts (the last of which is in 2018) using all available external pricing information. Additionally, where limited data exists for certain products, prices are interpolated using historic and long-term pricing relationships.

In addition, at 31 December 2010, BP was party to a collar-backed financing arrangement involving an available-for-sale investment held by the group. This arrangement contained an embedded derivative whose fair value was related to the equity price of the investment and was categorized in level 2 of the fair value hierarchy. The arrangement was terminated in 2011.

33. Derivative financial instruments continued

Embedded derivative assets and liabilities have the following fair values and maturities.

$ million

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total 2011
Liabilities commodity price contracts	**(347)**	**(319)**	**(306)**	**(236)**	**(134)**	**(75)**	**(1,417)**
Net fair value	**(347)**	**(319)**	**(306)**	**(236)**	**(134)**	**(75)**	**(1,417)**

$ million

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total 2010
Assets commodity price contracts	18						18
Liabilities commodity price contracts	(325)	(326)	(285)	(281)	(212)	(196)	(1,625)
other embedded derivatives		(29)	(60)				(89)
Net fair value	(307)	(355)	(345)	(281)	(212)	(196)	(1,696)

The following table shows the changes during the year in the net fair value of embedded derivatives, within level 3 of the fair value hierarchy.

$ million

	2011 Commodity price	2010 Commodity price
Net fair value of contracts at 1 January	**(1,607)**	(1,331)
Settlements	**301**	37
Losses recognized in the income statement	**(106)**	(350)
Exchange adjustments	**(5)**	37
Net fair value of contracts at 31 December	**(1,417)**	(1,607)

The amount recognized in the income statement for the year relating to level 3 embedded derivatives still held at 31 December 2011 was a $106 million loss (2010 $350 million loss relating to embedded derivatives still held at 31 December 2010).

The fair value gain (loss) on embedded derivatives is shown below.

$ million

	2011	2010	2009
Commodity price embedded derivatives	**190**	(309)	607
Other embedded derivatives	**(122)**		
Fair value gain (loss)	**68**	(309)	607

Cash flow hedges

At 31 December 2011, the group held currency forwards and futures contracts and cylinders that were being used to hedge the foreign currency risk of highly probable forecast transactions. Note 26 outlines the management of risk aspects for currency risk. For cash flow hedges the group only claims hedge accounting for the intrinsic value on the currency with any fair value attributable to time value taken immediately to the income statement. There were no highly probable transactions for which hedge accounting has been claimed that have not occurred and no significant element of hedge ineffectiveness requiring recognition in the income statement. For cash flow hedges the pre-tax amount removed from equity during the period and included in the income statement is a gain of $195 million (2010 gain of $25 million and 2009 loss of $366 million). The entire gain of $195 million is included in production and manufacturing expenses (2010 $25 million gain in production and manufacturing expense; 2009 $332 million loss in production and manufacturing expense and $34 million loss in finance costs). The amount removed from equity during the period and included in the carrying amount of non-financial assets was a gain of $13 million (2010 $53 million loss and 2009 $136 million loss).

The amounts retained in equity at 31 December 2011 consist of deferred losses of $78 million maturing in 2012, deferred losses of $39 million maturing in 2013 and deferred losses of $30 million maturing in 2014 and beyond.

Fair value hedges

At 31 December 2011, the group held interest rate and cross-currency interest rate swap contracts as fair value hedges of the interest rate risk on fixed rate debt issued by the group. The effectiveness of each hedge relationship is quantitatively assessed and demonstrated to continue to be highly effective. The gain on the hedging derivative instruments taken to the income statement in 2011 was $328 million (2010 $563 million gain and 2009 $98 million loss) offset by a loss on the fair value of the finance debt of $327 million (2010 $554 million loss and 2009 $117 million gain).

The interest rate and cross-currency interest rate swaps mature within one to 10 years, with an average maturity of four to five years (2010 four to five years) and are used to convert sterling, euro, Swiss franc, Australian dollar, Japanese yen and Hong Kong dollar denominated borrowings into US dollar floating rate debt. Note 26 outlines the group s approach to interest rate and currency risk management.

34. Finance debt

						$ million
			2011			2010
	Current	**Non-current**	**Total**	Current	Non-current	Total
Borrowings	**8,675**	**34,816**	**43,491**	8,312	30,017	38,329
Net obligations under finance leases	**339**	**353**	**692**	117	693	810
	9,014	**35,169**	**44,183**	8,429	30,710	39,139
Disposal deposits	**30**		**30**	6,197		6,197
	9,044	**35,169**	**44,213**	14,626	30,710	45,336

Current finance debt includes the portion of long-term borrowings and net obligations under finance leases that will mature in the next 12 months, amounting to $5,214 million (2010 $6,976 million).

The main elements of current borrowings are the current portion of long-term bonds of $4,875 million (2010 $6,859 million) and issued commercial paper of $3,635 million (2010 $1,025 million).

Deposits for disposal transactions expected to complete in 2012 of $30 million are also included in current finance debt (2010 $6,197 million for transactions expected to complete in 2011). This debt will be considered extinguished on completion of the transactions.

At 31 December 2011, $131 million (2010 $790 million) of finance debt was secured by the pledging of assets, and no finance debt was secured in connection with deposits received relating to certain disposal transactions expected to complete in subsequent periods (2010 $4,780 million). In addition, in connection with $2,344 million (2010 $4,588 million) of finance debt, BP has entered into crude oil sales contracts in respect of oil produced from certain fields in offshore Angola and Azerbaijan to provide security to the lending banks. The remainder of finance debt was unsecured.

The following table shows, by major currency, the group s finance debt at 31 December and the weighted average interest rates achieved at those dates through a combination of borrowings and derivative financial instruments entered into to manage interest rate and currency exposures. The disposal deposits noted above are excluded from this analysis.

			Fixed rate debt		Floating rate debt	Total
	Weighted average interest rate %	**Weighted average time for which rate is fixed Years**	**Amount $ million**	**Weighted average interest rate %**	**Amount $ million**	**Amount $ million**
						2011
US dollar	**4**	**5**	**15,016**	**1**	**27,285**	**42,301**
Euro	**5**	**3**	**25**	**3**	**1,575**	**1,600**
Other currencies	**4**	**12**	**240**	**3**	**42**	**282**
			15,281		**28,902**	**44,183**
						2010
US dollar	4	5	14,797	1	21,076	35,873
Euro	4	3	53	2	2,988	3,041
Other currencies	6	18	140	4	85	225
			14,990		24,149	39,139

The euro debt not swapped to US dollar is naturally hedged for the foreign currency risk by holding equivalent euro cash and cash equivalent amounts.

Finance leases

The group uses finance leases to acquire property, plant and equipment. These leases have terms of renewal but no purchase options and escalation clauses. Renewals are at the option of the lessee. The terms and conditions of these finance leases do not impose any significant financial restrictions on the group. Future minimum lease payments under finance leases are set out below.

		$ million
	2011	2010
Future minimum lease payments payable within		
1 year	**454**	153
2 to 5 years	**200**	535
Thereafter	**380**	438
	1,034	1,126
Less: finance charges	**342**	316
Net obligations	**692**	810
Of which payable within 1 year	**339**	117
payable within 2 to 5 years	**99**	404
payable thereafter	**254**	289

Notes on financial statements

34. Finance debt continued

Fair values

The estimated fair value of finance debt is shown in the table below together with the carrying amount as reflected in the balance sheet.

Long-term borrowings in the table below include the portion of debt that matures in the year from 31 December 2011, whereas in the balance sheet the amount would be reported within current finance debt. The disposal deposits noted above are excluded from this analysis.

The carrying amount of the group s short-term borrowings, comprising mainly commercial paper, approximates their fair value. The fair value of the group s long-term borrowings and finance lease obligations is estimated using quoted prices or, where these are not available, discounted cash flow analyses based on the group s current incremental borrowing rates for similar types and maturities of borrowing.

$ million

	2011		2010	
	Fair value	**Carrying amount**	Fair value	Carrying amount
Short-term borrowings	**3,800**	**3,800**	1,453	1,453
Long-term borrowings	**40,606**	**39,691**	37,258	36,876
Net obligations under finance leases	**776**	**692**	928	810
Total finance debt	**45,182**	**44,183**	39,639	39,139

35. Capital disclosures and analysis of changes in net debt

The group defines capital as total equity. The group s approach to managing capital is set out in its financial framework which BP continues to refine to support the pursuit of value growth for shareholders, while maintaining a secure financial base. We intend to maintain a significant liquidity buffer and to reduce our net debt ratio to the lower half of the 10-20% gearing range over time as our disposal programme progresses.

The group monitors capital on the basis of the net debt ratio, that is, the ratio of net debt to net debt plus equity. Net debt is calculated as gross finance debt, as shown in the balance sheet, plus the fair value of associated derivative financial instruments that are used to hedge foreign exchange and interest rate risks relating to finance debt, for which hedge accounting is applied, less cash and cash equivalents. Net debt and net debt ratio are non-GAAP measures. BP believes these measures provide useful information to investors. Net debt enables investors to see the economic effect of gross debt, related hedges and cash and cash equivalents in total. The net debt ratio enables investors to see how significant net debt is relative to equity from shareholders. The derivatives are reported on the balance sheet within the headings Derivative financial instruments . All components of equity are included in the denominator of the calculation. At 31 December 2011 the net debt ratio was 20.5% (2010 21.2%).

During 2011 and 2010, the company did not repurchase any of its own shares, other than to satisfy the requirements of certain employee share-based payment plans.

$ million

At 31 December	**2011**	2010
Gross debt	**44,213**	45,336
Less: Cash and cash equivalents	**14,067**	18,556
Less: Fair value asset of hedges related to finance debt	**1,133**	916
Net debt	**29,013**	25,864
Equity	**112,482**	95,891
Net debt ratio	**20.5%**	21.2%

An analysis of changes in net debt is provided below.

$ million

Movement in net debt	Finance debt[a] **2011**	Cash and cash equivalents **2011**	Net debt **2011**	Finance debt[a] 2010	Cash and cash equivalents 2010	Net debt 2010
At 1 January	**(44,420)**	**18,556**	**(25,864)**	(34,500)	8,339	(26,161)
Exchange adjustments	**30**	**(492)**	**(462)**	194	(279)	(85)
Net cash flow	**(4,725)**	**(3,997)**	**(8,722)**	(3,613)	10,496	6,883
Movement in finance debt relating to investing activities[b]	**6,167**		**6,167**	(6,197)		(6,197)
Other movements	**(132)**		**(132)**	(304)		(304)
At 31 December	**(43,080)**	**14,067**	**(29,013)**	(44,420)	18,556	(25,864)

a Including fair value of associated derivative financial instruments.
b See Note 34 for further information.

36. Provisions

$ million

	Decommissioning	Environmental	Spill response	Litigation and claims	Clean Water Act penalties	Other	Total
At 1 January 2011	**10,544**	**2,465**	**1,043**	**11,967**	**3,510**	**2,378**	**31,907**
Exchange adjustments	**(27)**	**(4)**		**(13)**		**(12)**	**(56)**
Acquisitions	**163**			**9**		**118**	**290**
New or increased provisions	**4,596**	**1,677**	**586**	**3,821**		**1,145**	**11,825**
Write-back of unused provisions	**(1)**	**(140)**		**(92)**		**(416)**	**(649)**
Unwinding of discount	**195**	**27**		**15**		**6**	**243**
Change in discount rate	**3,211**	**90**		**45**		**10**	**3,356**
Utilization	**(342)**	**(840)**	**(1,293)**	**(4,715)**		**(876)**	**(8,066)**
Reclassified as liabilities directly associated with assets held for sale	**(51)**						**(51)**
Deletions	**(1,048)**	**(11)**		**(61)**		**(37)**	**(1,157)**
At 31 December 2011	**17,240**	**3,264**	**336**	**10,976**	**3,510**	**2,316**	**37,642**
Of which current	**596**	**1,375**	**282**	**8,518**		**467**	**11,238**
non-current	**16,644**	**1,889**	**54**	**2,458**	**3,510**	**1,849**	**26,404**

$ million

	Decommissioning	Environmental	Spill response	Litigation and claims	Clean Water Act penalties	Other	Total
At 1 January 2010	9,020	1,719		1,076		2,815	14,630
Exchange adjustments	(114)			(7)		(50)	(171)
Acquisitions	188			2		15	205
New or increased provisions	1,800	1,290	10,883	15,171	3,510	808	33,462
Write-back of unused provisions	(12)	(120)		(51)		(466)	(649)
Unwinding of discount	168	29		18		19	234
Change in discount rate	444	22		9		(6)	469
Utilization	(164)	(460)	(9,840)	(4,250)		(755)	(15,469)
Reclassified as liabilities directly associated with assets held for sale	(381)	(1)				(1)	(383)
Deletions	(405)	(14)		(1)		(1)	(421)
At 31 December 2010	10,544	2,465	1,043	11,967	3,510	2,378	31,907
Of which current	432	635	982	7,011		429	9,489
non-current	10,112	1,830	61	4,956	3,510	1,949	22,418

The group makes full provision for the future cost of decommissioning oil and natural gas wells, facilities and related pipelines on a discounted basis upon installation. The provision for the costs of decommissioning these wells, production facilities and pipelines at the end of their economic lives has been estimated using existing technology, at current prices or future assumptions, depending on the expected timing of the activity, and discounted using a real discount rate of 0.5% (2010 1.5%). These costs are generally expected to be incurred over the next 30 years. While the provision is based on the best estimate of future costs and the economic lives of the facilities and pipelines, there is uncertainty regarding both the amount and timing of these costs.

Provisions for environmental remediation are made when a clean-up is probable and the amount of the obligation can be estimated reliably. Generally, this coincides with commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites. The provision for environmental liabilities has been estimated using existing technology, at current prices and discounted using a real discount rate of 0.5% (2010 1.5%). The majority of these costs are expected to be incurred over the next 10 years. The extent and cost of future remediation programmes are inherently difficult to estimate. They depend on the scale of any possible contamination, the timing and extent of corrective actions, and also the group s share of the liability.

The litigation category includes provisions for matters related to, for example, commercial disputes, product liability, and allegations of exposures of third parties to toxic substances. Included within the other category at 31 December 2011 are provisions for deferred employee compensation of $666 million (2010 $728 million). These provisions are discounted using either a nominal discount rate of 2.5% (2010 3.75%) or a real discount rate of 0.5% (2010 1.5%), as appropriate.

Provisions relating to the Gulf of Mexico oil spill

The Gulf of Mexico oil spill is described on pages 76 to 79 and in Note 2. Provisions relating to the Gulf of Mexico oil spill, included in the table above, are separately presented below:

$ million

	Environmental	Spill response	Litigation and claims	Clean Water Act penalties	Total
At 1 January 2011	**809**	**1,043**	**10,973**	**3,510**	**16,335**
New or increased provisions	**1,167**	**586**	**3,430**		**5,183**
Unwinding of discount	**6**				**6**
Change in discount rate	**17**				**17**
Utilization	**(482)**	**(1,293)**	**(4,433)**		**(6,208)**
At 31 December 2011	**1,517**	**336**	**9,970**	**3,510**	**15,333**
Of which current	**961**	**282**	**8,194**		**9,437**
non-current	**556**	**54**	**1,776**	**3,510**	**5,896**
Of which payable from the trust fund	**1,066**		**8,809**		**9,875**

Notes on financial statements

36. Provisions continued

					$ million
	Environmental	Spill response	Litigation and claims	Clean Water Act penalties	Total
At 1 January 2010					
New or increased provisions	929	10,883	14,939	3,510	30,261
Unwinding of discount	4				4
Change in discount rate	5				5
Utilization	(129)	(9,840)	(3,966)		(13,935)
At 31 December 2010	809	1,043	10,973	3,510	16,335
Of which current	314	982	6,642		7,938
non-current	495	61	4,331	3,510	8,397
Of which payable from the trust fund	382		9,162		9,544

As described in Note 2, BP has recorded provisions at 31 December 2011 relating to the Gulf of Mexico oil spill including amounts in relation to environmental expenditure, spill response costs, litigation and claims, and Clean Water Act penalties, each of which is described below. The total amounts that will ultimately be paid by BP are subject to significant uncertainty as described in Note 2.

Subsequent to BP releasing its preliminary announcement of the fourth quarter 2011 results on 7 February 2012, BP announced on 3 March 2012 that it had reached a proposed settlement with the Plaintiffs Steering Committee (PSC), subject to final written agreement and court approvals, to resolve the substantial majority of legitimate economic loss and medical claims stemming from the Deepwater Horizon accident and oil spill. The proposed settlement has been reflected in the financial statements for 2011 included in this report.

Certain items are subject to settlement discussions or may be subject to settlement discussions in the future. Any further settlements which may be reached relating to the Deepwater Horizon accident and oil spill could impact the amount and timing of any future payments.

Environmental

The amounts committed by BP for a 10-year research programme to study the impact of the incident on the marine and shoreline environment of the Gulf of Mexico have been provided for. BP s commitment is to provide $500 million of funding, and the remaining commitment, on a discounted basis, of $421 million was included in provisions at 31 December 2011. This amount is expected to be spent over the remaining life of the programme.

As a responsible party under the Oil Pollution Act of 1990 (OPA 90), BP faces claims by the United States, as well as by State, tribal, and foreign trustees, if any, for natural resource damages (Natural Resource Damages claims). These damages include, among other things, the reasonable costs of assessing the injury to natural resources as well as some emergency restoration projects which are expected to occur over the next two years. BP has been incurring natural resource damage assessment costs and a provision has been made for the estimated costs of the assessment phase. The assessment covers a large area of potential impact and will take some time to complete in order to determine both the severity and duration of the impact of the oil spill. The process of interpreting the large volume of data collected is expected to take at least several months and, in order to determine potential injuries to certain animal populations, data will need to be collected over one or more reproductive cycles. This expected assessment spend is based upon past experience as well as identified projects. During 2011, BP entered a framework agreement with natural resource trustees for the United States and five Gulf Coast states, providing for up to $1 billion to be spent on early restoration projects to address natural resource injuries resulting from the Gulf of Mexico oil spill. Funding for these projects will come from the $20-billion trust fund. The total amount provided for these items was $1,096 million at 31 December 2011. Until the size, location and duration of the impact is assessed, it is not possible to estimate reliably either the amounts or timing of the remaining Natural Resource Damages claims other than the emergency and early restoration agreements noted above, therefore no amounts have been provided for these items and they are disclosed as a contingent liability. See Note 43 for further information.

Spill response

Further amounts were provided relating to the spill response during 2011, totalling $0.6 billion. This primarily reflected increased costs of shoreline clean-up, patrolling and maintenance and vessel decontamination. The majority of the active clean-up of the shorelines had been completed by the end of the year.

Litigation and claims

Individual and Business Claims, and State and Local Claims under the Oil Pollution Act of 1990 (OPA 90) and claims for personal injury

BP faces claims under OPA 90 by individuals and businesses for removal costs, damage to real or personal property, lost profits or impairment of earning capacity, loss of subsistence use of natural resources and for personal injury (Individual and Business Claims) and by state and local government entities for removal costs, physical damage to real or personal property, loss of government revenue and increased public services costs (State and Local Claims).

The estimated future cost of settling Individual and Business Claims, State and Local Claims under OPA 90 and claims for personal injuries, both reported and unreported, has been provided for. Claims administration costs and legal fees have also been provided for.

Subsequent to BP releasing its preliminary announcement of the fourth quarter 2011 results on 7 February 2012, BP announced on 3 March 2012 that it had reached a proposed settlement with the PSC, subject to final written agreement and court approvals, to resolve the substantial majority of legitimate economic loss and medical claims stemming from the Deepwater Horizon accident and oil spill. The details of the proposed settlement agreement are explained in Legal proceedings on pages 160 to 164.

In 2010 and for the 2011 preliminary results, BP believed that the history of claims received, and settlements made, provided sufficient data to enable the company to use an approach based on a combination of actuarial methods and management judgements to estimate IBNR (Incurred But Not Reported) claims to determine a reliable best estimate of BP s exposure for claims not yet reported in relation to Individual and Business claims, and State and Local claims under OPA 90. The amount provided for these claims was determined in accordance with IFRS and represented BP s best estimate of the expenditure required to settle its obligations at the balance sheet date.

In estimating the amount of the provision, BP determined a range of possible outcomes for Individual and Business Claims, and State and Local Claims. As disclosed in the preliminary announcement of the fourth quarter 2011 results, BP had concluded that a reasonable range of possible outcomes for the amount of the provision as at 31 December 2011 was $4.1 billion to $8.3 billion. This range was for claims payable through the Gulf Coast Claims Facility and State and Local Claims only.

36. Provisions continued

Following the proposed settlement agreement entered into with the PSC, subject to final written agreement and court approvals, BP reviewed the amount of the provision for the items covered by the proposed settlement based upon information available at the time that the consolidated financial statements were approved. The provision for these items at 31 December 2011 is now $7.8 billion which represents a reliable best estimate of the liability under the proposed settlement agreement which, under accounting standards, is the amount that BP would rationally pay to settle the obligation. Substantially all of this amount is included as payable from the trust fund under Litigation and claims in the table above. Future claims administration costs are expected to be paid from the trust fund. However, at this time, the provision for these costs is shown as payable from outside the trust fund, consistent with how the administration costs associated with the GCCF were treated, as the proposed settlement is subject to final written agreement and court approvals. Further information on the proposed settlement with the PSC is included in Legal proceedings on pages 160 to 164.

The provision is in addition to the $6.3 billion of claims paid in total ($2.9 billion in 2011 and $3.4 billion in 2010). Of this total paid, $6.1 billion is included within utilization of provision in the table ($2.9 billion in 2011 and $3.2 billion in 2010), and the remaining $0.2 billion was a period expenditure prior to the recognition of the provision at the end of the second quarter 2010. Also included within the utilization of the provision of $4.4 billion (2010 $4.0 billion) under Litigation and claims in the table are amounts relating to claims administration costs, legal fees and other settlements. Of the total payments of $6.3 billion, $5.9 billion was paid out of the trust fund ($2.9 billion in 2011 and $3.0 billion in 2010) and $0.4 billion was paid by BP in 2010.

Many key assumptions underlie and influence the reliable best estimates of total expenditures derived for both categories of claims. The amount provided for Individual and Business Claims is based upon the expected terms of the proposed settlement with the PSC, which is subject to final written agreement and court approvals. Other key assumptions include the amounts that will ultimately be paid in relation to current claims, the number, type and amounts for claims not yet reported, the outcomes of any further litigation through potential opt-outs from the proposed settlement and the amount of administration and other costs associated with the proposed settlement. While BP has determined a reliable best estimate of the cost of the proposed settlement with the PSC, it is possible that the actual cost could be higher or lower than this estimate.

The outcomes of claims and litigation are likely to be paid out over many years to come. BP will re-evaluate the assumptions underlying this analysis on a quarterly basis as more information becomes available and the claims process matures.

BP also faces other litigation for which no reliable estimate of the cost can currently be made. Therefore no amounts have been provided for these items. See Note 43 for further information.

Clean Water Act penalties

A provision has been made for the estimated penalties for strict liability under Section 311 of the Clean Water Act. Such penalties are subject to a statutory maximum calculated as the product of a per-barrel maximum penalty rate and the number of barrels of oil spilled. Uncertainties currently exist in relation to both the per-barrel penalty rate that will ultimately be imposed and the volume of oil spilled.

A charge for potential Clean Water Act Section 311 penalties was first included in BP s second-quarter 2010 interim financial statements. At the time that charge was taken, the latest estimate from the intra-agency Flow Rate Technical Group created by the National Incident Commander in charge of the spill response was between 35,000 and 60,000 barrels per day. The mid-point of that range, 47,500 barrels per day, was used for the purposes of calculating the charge. For the purposes of calculating the amount of the oil flow that was discharged into the Gulf of Mexico, the amount of oil that had been or was projected to be captured in vessels on the surface was subtracted from the total estimated flow up until when the well was capped on 15 July 2010. The result of this calculation was an estimate that approximately 3.2 million barrels of oil had been discharged into the Gulf. This estimate of 3.2 million barrels was calculated using a total flow of 47,500 barrels per day multiplied by the 85 days from 22 April 2010 through 15 July 2010 less an estimate of the amount captured on the surface (then estimated at approximately 850,000 barrels).

This estimated discharge volume was then multiplied by $1,100 per barrel the maximum amount the statute allows in the absence of gross negligence or wilful misconduct for the purposes of estimating a potential penalty. This resulted in a provision of $3,510 million for potential penalties under Section 311.

In utilizing the $1,100 per-barrel input, BP took into account that the actual per-barrel penalty a court may impose, or that the Government might agree to in settlement, could be lower than $1,100 per barrel if it were determined that such a lower penalty was appropriate based on the factors a court is directed to consider in assessing a penalty. In particular, in determining the amount of a civil penalty, Section 311 directs a court to consider a number of enumerated factors, including the seriousness of the violation or violations, the economic benefit to the violator, if any, resulting from the violation, the degree of culpability involved, any other penalty for the same incident, any history of prior violations, the nature, extent, and degree of success of any efforts of the violator to minimize or mitigate the effects of the discharge, the economic impact of the penalty on the violator, and any other matters as justice may require. Civil penalties above $1,100 per barrel up to a statutory maximum of $4,300 per barrel of oil discharged would only be imposed if gross negligence or wilful misconduct were alleged and subsequently proven. BP expects to seek assessment of a penalty lower than $1,100 per barrel based on several of these factors. However, the $1,100 per-barrel rate was utilized for the purposes of calculating a charge after considering and weighing all possible outcomes and in light of: (i) BP s conclusion that it did not act with gross negligence or engage in wilful misconduct; and (ii) the uncertainty as to whether a court would assess a penalty below the $1,100 statutory maximum.

On 2 August 2010, the United States Department of Energy and the Flow Rate Technical Group had issued an estimate that 4.9 million barrels of oil had flowed from the Macondo well, and 4.05 million barrels had been discharged into the Gulf (the difference being the amount of oil captured by vessels on the surface as part of BP s well containment efforts).

It was and remains BP s view, that the 2 August 2010 Government estimate and other similar estimates are not reliable estimates because they are based on incomplete or inaccurate information, rest in large part on assumptions that have not been validated, and are subject to far greater uncertainties than have been acknowledged. As BP has publicly asserted, including at a 22 October 2010 meeting with the staff of the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, BP believes that the 2 August 2010 discharge estimate and similar estimates are overstated by a significant amount, and that the flow rate is potentially in the range of 20 50% lower. If the flow rate is 50% lower than the 2 August 2010 estimate, then the amount of oil that flowed from the Macondo well would be approximately 2.5 million barrels, and the amount discharged into the Gulf would be approximately 1.6 million barrels. If the flow rate is 20% lower than the 2 August 2010 estimate, then the amount of oil that flowed from the Macondo well would be approximately 3.9 million barrels and the amount discharged into the Gulf would be approximately 3.1 million barrels, which is not materially different from the amount we used for our original estimate at the second quarter of 2010.

Notes on financial statements

36. Provisions continued

Therefore, for the purposes of calculating a provision for fines and penalties under Section 311 of the Clean Water Act, BP has continued to use an estimate of 3.2 million barrels of oil discharged to the Gulf of Mexico as its current best estimate, as defined in paragraphs 36-40 of IAS 37 Provisions, contingent liabilities and contingent assets , of the amount which may be used in calculating the penalty under Section 311 of the Clean Water Act. This reflects an estimate of total flow from the well of approximately 4 million barrels, and an estimate of barrels captured by vessels on the surface, currently estimated at 811,000 barrels. In utilizing this estimate, BP has taken into consideration not only its own analysis of the flow and discharge issue, but also the analyses and conclusions of other parties, including the US government. The estimate of BP and of other parties as to how much oil was discharged to the Gulf of Mexico may change, perhaps materially, over time. Changes in estimates as to flow and discharge could affect the amount actually assessed for Clean Water Act fines and penalties. The year-end provision continued to be based on a per-barrel penalty of $1,100 for the reasons discussed above, including BP s continued conclusion that it did not act with gross negligence or engage in wilful misconduct.

The amount and timing of these costs will depend upon what is ultimately determined to be the volume of oil spilled and the per-barrel penalty rate that is imposed. It is not currently practicable to estimate the timing of expending these costs and the provision has been included within non-current liabilities on the balance sheet. No other amounts have been provided as at 31 December 2011 in relation to other potential fines and penalties because it is not possible to measure the obligation reliably. Fines and penalties are not covered by the trust fund.

37. Pensions and other post-retirement benefits

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

In particular, the primary pension arrangement in the UK is a funded final salary pension plan under which retired employees draw the majority of their benefit as an annuity. With effect from 1 April 2010, BP closed its UK plan to new joiners other than some of those joining the North Sea business. The plan remains open to ongoing accrual for those employees who had joined BP on or before 31 March 2010. The majority of new joiners in the UK have the option to join a defined contribution plan.

In the US, a range of retirement arrangements is provided. This includes a funded final salary pension plan for certain heritage employees and a cash balance arrangement for new hires. Retired US employees typically take their pension benefit in the form of a lump sum payment. US employees are also eligible to participate in a defined contribution (401k) plan in which employee contributions are matched with company contributions.

The level of contributions to funded defined benefit plans is the amount needed to provide adequate funds to meet pension obligations as they fall due. During 2011, contributions of $429 million (2010 $411 million and 2009 $9 million) and $777 million (2010 $694 million and 2009 $795 million) were made to the UK plans and US plans respectively. In addition, contributions of $223 million (2010 $188 million and 2009 $204 million) were made to other funded defined benefit plans. The aggregate level of contributions in 2012 is expected to be approximately $1,250 million, and includes contributions in all countries that we expect to be required to make by law or under contractual agreements as well as an allowance for discretionary funding.

Certain group companies, principally in the US, provide post-retirement healthcare and life insurance benefits to their retired employees and dependants. The entitlement to these benefits is usually based on the employee remaining in service until retirement age and completion of a minimum period of service.

The obligation and cost of providing pensions and other post-retirement benefits is assessed annually using the projected unit credit method. The date of the most recent actuarial review was 31 December 2011. The group s principal plans are subject to a formal actuarial valuation every three years in the UK, with valuations being required more frequently in many other countries. The most recent formal actuarial valuation of the UK pension plans was as at 31 December 2008.

The material financial assumptions used for estimating the benefit obligations of the various plans are set out below. The assumptions are reviewed by management at the end of each year, and are used to evaluate accrued pension and other post-retirement benefits at 31 December. The same assumptions are used to determine pension and other post-retirement benefit expense for the following year, that is, the assumptions at 31 December 2011 are used to determine the pension liabilities at that date and the pension expense for 2012.

						%
Financial assumptions	**2011**	2010	**2011**	2010	**2011**	2010

			UK 2009			US 2009			Other 2009
Discount rate for pension plan liabilities	**4.8**	5.5	5.8	**4.3**	4.7	5.4	**4.7**	5.3	5.8
Discount rate for other post-retirement benefit plans	**n/a**	n/a	n/a	**4.5**	5.3	5.8	**n/a**	n/a	n/a
Rate of increase in salaries	**5.1**	5.4	5.3	**3.7**	4.1	4.2	**3.7**	3.8	3.8
Rate of increase for pensions in payment	**3.2**	3.5	3.4				**1.7**	1.8	1.8
Rate of increase in deferred pensions	**3.2**	3.5	3.4				**1.2**	1.3	1.2
Inflation	**3.2**	3.5	3.4	**1.9**	2.3	2.4	**2.2**	2.3	2.3

Our discount rate assumptions are based on third-party AA corporate bond indices and for our largest plans in the UK, US and Germany we use yields that reflect the maturity profile of the expected benefit payments. The inflation rate assumptions for our UK and US plans are based on the difference between the yields on index-linked and fixed-interest long-term government bonds. In other countries we use either this approach, or the central bank inflation target, or advice from the local actuary depending on the information that is available to us. The inflation rate assumptions are used to determine the rate of increase for pensions in payment and the rate of increase in deferred pensions where there is such an increase.

37. Pensions and other post-retirement benefits continued

Our assumptions for the rate of increase in salaries are based on our inflation rate assumption plus an allowance for expected long-term real salary growth. These include allowance for promotion-related salary growth, of between 0.3% and 0.4% depending on country.

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

Mortality assumptions			UK			US			Germany
									Years
	2011	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Life expectancy at age 60 for a male currently aged 60	**27.6**	26.1	26.0	**24.8**	24.7	24.6	**23.5**	23.3	23.2
Life expectancy at age 60 for a male currently aged 40	**30.5**	29.1	29.0	**26.3**	26.2	26.1	**26.3**	26.2	26.1
Life expectancy at age 60 for a female currently aged 60	**29.3**	28.7	28.6	**26.4**	26.3	26.3	**28.0**	27.9	27.8
Life expectancy at age 60 for a female currently aged 40	**32.0**	31.6	31.5	**27.3**	27.2	27.2	**30.7**	30.6	30.4

Our assumption for future US healthcare cost trend rate for the first year after the reporting date reflects the rate of actual cost increases seen in recent years. The ultimate trend rate reflects our long-term expectations of the level at which cost inflation will stabilize based on past healthcare cost inflation seen over a longer period of time. The assumed future US healthcare cost trend rate assumptions are as follows:

			%
	2011	2010	2009
First year s US healthcare cost trend rate	**7.6**	7.8	8.0
Ultimate US healthcare cost trend rate	**5.0**	5.0	5.0
Year in which ultimate trend rate is reached	**2020**	2018	2016

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

A significant proportion of the assets are held in equities, owing to a higher expected level of return over the long term with an acceptable level of risk. In order to provide reasonable assurance that no single security or type of security has an unwarranted impact on the total portfolio, the investment portfolios are highly diversified. The long-term asset allocation policy for the major plans is as follows:

	UK	**US**	**Other**
Asset category	%	%	%
Total equity	**73**	**70**	**17-63**
Bonds/cash	**20**	**30**	**25-75**
Property/real estate	**7**		**0-10**

Some of the group s pension plans use derivative financial instruments as part of their asset mix and to manage the level of risk. The group s main pension plans do not invest directly in either securities or property/real estate of the company or of any subsidiary.

Return on asset assumptions reflect the group s expectations built up by asset class and by plan. The group s expectation is derived from a combination of historical returns over the long term and the forecasts of market professionals. Our assumption for return on equities is based on a long-term view, and the size of the resulting equity risk premium over government bond yields is reviewed each year for reasonableness. Our assumption for return on bonds reflects the portfolio mix of government fixed-interest, index-linked and corporate bonds.

37. Pensions and other post-retirement benefits continued

The expected long-term rates of return and market values of the various categories of assets held by the defined benefit plans at 31 December are set out below. The market values shown include the effects of derivative financial instruments. The amounts classified as equities include investments in companies listed on stock exchanges as well as unlisted investments. Movements in the value of plan assets during the year are shown in detail in the table on page 238.

		2011		2010		2009
	Expected long-term rate of return %	**Market value $ million**	Expected long-term rate of return %	Market value $ million	Expected long-term rate of return %	Market value $ million
UK pension plans						
Equities[a]	**8.0**	**17,202**	8.0	18,546	8.0	16,945
Bonds	**4.4**	**4,141**	5.0	3,866	5.3	3,701
Property/real estate	**6.5**	**1,710**	6.5	1,462	6.5	1,269
Cash	**1.7**	**534**	1.4	406	1.1	634
	7.0	**23,587**	7.2	24,280	7.3	22,549
US pension plans						
Equities[a]	**9.0**	**5,034**	9.1	5,058	9.0	4,326
Bonds	**4.0**	**2,022**	4.5	1,419	4.8	1,218
Property/real estate	**8.0**	**4**	8.0	7	8.0	8
Cash	**0.2**	**144**	0.3	165	0.9	271
	7.4	**7,204**	8.0	6,649	8.0	5,823
US other post-retirement benefit plans						
Equities					8.5	8
Bonds					4.8	4
Cash	**0.2**	**4**	0.3	8		
	0.2	**4**	0.3	8	7.6	12
Other plans						
Equities	**7.9**	**831**	8.0	1,182	8.6	1,091
Bonds	**3.3**	**1,951**	4.2	1,874	4.4	1,651
Property/real estate	**6.2**	**117**	6.3	83	6.5	82
Cash	**2.2**	**387**	2.7	155	2.0	245
	4.7	**3,286**	5.4	3,294	5.9	3,069

a The amounts classified as equities include investments in companies listed on stock exchanges as well as private equity investments which are substantially all unlisted. The market value of private equity investments at 31 December 2011 was $4,099 million (2010 $3,348 million and 2009 $2,956 million). The equity return assumption shown above is the weighted average of the assumed returns for listed and private equity investments in each fund. Comparative return assumptions for the US pension plans equities have been restated to reflect this. Equity return assumptions previously disclosed reflected the assumption for listed equities only.

37. Pensions and other post-retirement benefits continued

The assumed rate of investment return, discount rate, inflation, US healthcare cost trend rate and the mortality assumptions all have a significant effect on the amounts reported.

A one-percentage point change in the following assumptions for the group s plans would have had the effects shown in the table below. The effects shown for the expense in 2012 include current service cost and interest on plan liabilities.

	$ million	
	One percentage point	
	Increase	**Decrease**
Investment return		
Effect on pension and other post-retirement benefit expense in 2012	**(351)**	**351**
Discount rate		
Effect on pension and other post-retirement benefit expense in 2012	**(78)**	**101**
Effect on pension and other post-retirement benefit obligation at 31 December 2011	**(5,585)**	**7,285**
Inflation rate		
Effect on pension and other post-retirement benefit expense in 2012	**494**	**(381)**
Effect on pension and other post-retirement benefit obligation at 31 December 2011	**5,323**	**(4,301)**
US healthcare cost trend rate		
Effect on US other post-retirement benefit expense in 2012	**27**	**(22)**
Effect on US other post-retirement obligation at 31 December 2011	**350**	**(290)**

One additional year of longevity in the mortality assumptions would have the effects shown in the table below. The effect shown for the expense in 2012 includes current service cost and interest on plan liabilities.

				$ million
	UK pension plans	**US pension plans**	**US other post-retirement benefit plans**	**German pension plans**
One additional year s longevity				
Effect on pension and other post-retirement benefit expense in 2012	**44**	**5**	**4**	**9**
Effect on pension and other post-retirement benefit obligation at 31 December 2011	**609**	**111**	**73**	**166**

Notes on financial statements

37. Pensions and other post-retirement benefits continued

$ million

					2011
	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	383	280	53	133	849
Past service cost		184		7	191
Settlement, curtailment and special termination benefits	3			40	43
Payments to defined contribution plans	5	199		41	245
Total operating charge[b]	391	663	53	221	1,328
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	1,799	518		185	2,502
Interest on plan liabilities	(1,263)	(369)	(163)	(444)	(2,239)
Other finance income (expense)	536	149	(163)	(259)	263
Analysis of the amount recognized in other comprehensive income					
Actual return less expected return on pension plan assets	(1,990)	10	(1)	(61)	(2,042)
Change in assumptions underlying the present value of the plan liabilities	(2,680)	(512)	39	(642)	(3,795)
Experience gains and losses arising on the plan liabilities	(84)	(102)	89	(26)	(123)
Actuarial (loss) gain recognized in other comprehensive income	(4,754)	(604)	127	(729)	(5,960)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	22,363	7,988	3,157	8,404	41,912
Exchange adjustments	(137)			(326)	(463)
Current service cost[a]	383	280	53	133	849
Past service cost		184		7	191
Interest cost	1,263	369	163	444	2,239
Curtailment				(1)	(1)
Settlement				4	4
Special termination benefits[c]	3			37	40
Contributions by plan participants[d]	33			10	43
Benefit payments (funded plans)[e]	(993)	(750)	(3)	(226)	(1,972)
Benefit payments (unfunded plans)[e]	(4)	(68)	(181)	(405)	(658)
Disposals				(20)	(20)
Actuarial loss (gain) on obligation	2,764	614	(128)	668	3,918
Benefit obligation at 31 December[a f]	25,675	8,617	3,061	8,729	46,082
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	24,280	6,649	8	3,294	34,231
Exchange adjustments	29			(123)	(94)
Expected return on plan assets[a g]	1,799	518		185	2,502
Contributions by plan participants[d]	33			10	43
Contributions by employers (funded plans)	429	777		223	1,429
Benefit payments (funded plans)[e]	(993)	(750)	(3)	(226)	(1,972)
Disposals				(16)	(16)
Actuarial gain (loss) on plan assets[g]	(1,990)	10	(1)	(61)	(2,042)
Fair value of plan assets at 31 December	23,587	7,204	4	3,286	34,081
Deficit at 31 December	(2,088)	(1,413)	(3,057)	(5,443)	(12,001)
Represented by					
Asset recognized				17	17
Liability recognized	(2,088)	(1,413)	(3,057)	(5,460)	(12,018)
	(2,088)	(1,413)	(3,057)	(5,443)	(12,001)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	(1,852)	(784)	(41)	(492)	(3,169)
Unfunded	(236)	(629)	(3,016)	(4,951)	(8,832)
	(2,088)	(1,413)	(3,057)	(5,443)	(12,001)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(25,439)	(7,988)	(45)	(3,778)	(37,250)

Unfunded	**(236)**	**(629)**	**(3,016)**	**(4,951)**	**(8,832)**
	(25,675)	**(8,617)**	**(3,061)**	**(8,729)**	**(46,082)**

a The costs of managing the plan s investments are treated as being part of the investment return, the costs of administering our pension plan benefits are generally included in current service cost and the costs of administering our other post-retirement benefit plans are included in the benefit obligation.

b Included within production and manufacturing expenses and distribution and administration expenses.

c The charge for special termination benefits represents the increased liability arising as a result of early retirements occurring as part of restructuring programmes.

d Most of the contributions made by plan participants after 1 January 2010 into UK pension plans were made under salary sacrifice arrangements.

e The benefit payments amount shown above comprises $2,576 million benefits plus $54 million of plan expenses incurred in the administration of the benefit.

f The benefit obligation for other plans includes $3,909 million for the German plan, which is largely unfunded.

g The actual return on plan assets is made up of the sum of the expected return on plan assets and the actuarial gain on plan assets as disclosed above.

37. Pensions and other post-retirement benefits continued

$ million

	2010				
	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	393	241	48	120	802
Past service cost				3	3
Settlement, curtailment and special termination benefits	24			161	185
Payments to defined contribution plans	1	187		35	223
Total operating charge[b]	418	428	48	319	1,213
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	1,580	465	1	178	2,224
Interest on plan liabilities	(1,183)	(396)	(169)	(429)	(2,177)
Other finance income (expense)	397	69	(168)	(251)	47
Analysis of the amount recognized in other comprehensive income					
Actual return less expected return on pension plan assets	1,577	425	(1)	36	2,037
Change in assumptions underlying the present value of the plan liabilities	(1,144)	(498)	(132)	(489)	(2,263)
Experience gains and losses arising on the plan liabilities	12	(167)	(8)	69	(94)
Actuarial (loss) gain recognized in other comprehensive income	445	(240)	(141)	(384)	(320)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	21,425	7,519	2,996	8,133	40,073
Exchange adjustments	(835)			(269)	(1,104)
Current service cost[a]	393	241	48	120	802
Past service cost				3	3
Interest cost	1,183	396	169	429	2,177
Curtailment				4	4
Settlement	11			18	29
Special termination benefits[c]	13			139	152
Contributions by plan participants[d]	39			13	52
Benefit payments (funded plans)[e]	(952)	(758)	(4)	(192)	(1,906)
Benefit payments (unfunded plans)[e]	(3)	(75)	(192)	(387)	(657)
Acquisitions				2	2
Disposals	(43)			(29)	(72)
Actuarial (gain) loss on obligation	1,132	665	140	420	2,357
Benefit obligation at 31 December[a f]	22,363	7,988	3,157	8,404	41,912
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	22,549	5,823	12	3,069	31,453
Exchange adjustments	(881)			29	(852)
Expected return on plan assets[a g]	1,580	465	1	178	2,224
Contributions by plan participants[d]	39			13	52
Contributions by employers (funded plans)	411	694		187	1,292
Benefit payments (funded plans)[e]	(952)	(758)	(4)	(192)	(1,906)
Acquisitions				2	2
Disposals	(43)			(28)	(71)
Actuarial gain (loss) on plan assets[g]	1,577	425	(1)	36	2,037
Fair value of plan assets at 31 December	24,280	6,649	8	3,294	34,231
Surplus (deficit) at 31 December	1,917	(1,339)	(3,149)	(5,110)	(7,681)
Represented by					
Asset recognized	2,120			56	2,176
Liability recognized	(203)	(1,339)	(3,149)	(5,166)	(9,857)
	1,917	(1,339)	(3,149)	(5,110)	(7,681)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	2,115	(838)	(39)	(223)	1,015
Unfunded	(198)	(501)	(3,110)	(4,887)	(8,696)
	1,917	(1,339)	(3,149)	(5,110)	(7,681)

The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(22,165)	(7,487)	(47)	(3,517)	(33,216)
Unfunded	(198)	(501)	(3,110)	(4,887)	(8,696)
	(22,363)	(7,988)	(3,157)	(8,404)	(41,912)

a The costs of managing the plan s investments are treated as being part of the investment return, the costs of administering our pension plan benefits are generally included in current service cost and the costs of administering our other post-retirement benefit plans are included in the benefit obligation.

b Included within production and manufacturing expenses and distribution and administration expenses.

c The charge for special termination benefits represents the increased liability arising as a result of early retirements occurring as part of restructuring programmes.

d Most of the contributions made by plan participants after 1 January 2010 into UK pension plans were made under salary sacrifice arrangements.

e The benefit payments amount shown above comprises $2,507 million benefits plus $56 million of plan expenses incurred in the administration of the benefit.

f The benefit obligation for other plans includes $3,871 million for the German plan, which is largely unfunded.

g The actual return on plan assets is made up of the sum of the expected return on plan assets and the actuarial gain on plan assets as disclosed above.

Notes on financial statements

37. Pensions and other post-retirement benefits continued

$million

					2009
	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	311	243	48	117	719
Past service cost			(22)	1	(21)
Settlement, curtailment and special termination benefits	37			53	90
Payments to defined contribution plans		205		28	233
Total operating charge[b]	348	448	26	199	1,021
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	1,426	405	1	147	1,979
Interest on plan liabilities	(1,112)	(456)	(183)	(420)	(2,171)
Other finance income (expense)	314	(51)	(182)	(273)	(192)
Analysis of the amount recognized in other comprehensive income					
Actual return less expected return on pension plan assets	1,761	617	2	169	2,549
Change in assumptions underlying the present value of the plan liabilities	(2,217)	(501)	(50)	(42)	(2,810)
Experience gains and losses arising on the plan liabilities	(141)	(229)	71	(122)	(421)
Actuarial (loss) gain recognized in other comprehensive income	(597)	(113)	23	5	(682)

a The costs of managing the plan s investments are treated as being part of the investment return, the costs of administering our pension plan benefits are generally included in current service cost and the costs of administering our other post-retirement benefit plans are included in the benefit obligation.
b Included within production and manufacturing expenses and distribution and administration expenses.

At 31 December 2011, reimbursement balances due from or to other companies in respect of pensions amounted to $546 million reimbursement assets (2010 $483 million) and $13 million reimbursement liabilities (2010 $13 million). These balances are not included as part of the pension surpluses and deficits, but are reflected within other receivables and other payables in the group balance sheet.

$ million

	2011	2010	2009	2008	2007
History of surplus (deficit) and of experience gains and losses					
Benefit obligation at 31 December	**46,082**	41,912	40,073	34,847	43,100
Fair value of plan assets at 31 December	**34,081**	34,231	31,453	26,154	42,799
Deficit	**(12,001)**	(7,681)	(8,620)	(8,693)	(301)
Experience losses on plan liabilities	**(123)**	(94)	(421)	(178)	(200)
Actual return less expected return on pension plan assets	**(2,042)**	2,037	2,549	(10,253)	302
Actual return on plan assets	**460**	4,261	4,528	(7,331)	3,157
Actuarial (loss) gain recognized in other comprehensive income	**(5,960)**	(320)	(682)	(8,430)	1,717
Cumulative amount recognized in other comprehensive income	**(9,902)**	(3,942)	(3,622)	(2,940)	5,490

Estimated future benefit payments

The expected benefit payments, which reflect expected future service as appropriate, but exclude plan expenses, up until 2021 are as follows:

$ million

	UK pension	**US pension**	**US other post-retirement benefit**	**Other**	

	plans	plans	plans	plans	Total
2012	**998**	**743**	**181**	**619**	**2,541**
2013	**1,031**	**756**	**183**	**588**	**2,558**
2014	**1,068**	**766**	**186**	**592**	**2,612**
2015	**1,109**	**778**	**188**	**583**	**2,658**
2016	**1,154**	**776**	**190**	**567**	**2,687**
2017-2021	**6,476**	**3,721**	**955**	**2,728**	**13,880**

38. Called-up share capital

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

		2011		2010		2009
	Shares		Shares		Shares	
	thousand	**$ million**	thousand	$ million	thousand	$ million
8% cumulative first preference shares of £1 each[a]	**7,233**	**12**	7,233	12	7,233	12
9% cumulative second preference shares of £1 each[a]	**5,473**	**9**	5,473	9	5,473	9
		21		21		21
Ordinary shares of 25 cents each						
At 1 January	**20,647,160**	**5,162**	20,629,665	5,158	20,618,458	5,155
Issue of new shares for the scrip dividend programme	**165,601**	**41**				
Issue of new shares for employee share plans[b]	**649**		17,495	4	11,207	3
At 31 December	**20,813,410**	**5,203**	20,647,160	5,162	20,629,665	5,158
		5,224		5,183		5,179

a The nominal amount of 8% cumulative first preference shares and 9% cumulative second preference shares that can be in issue at any time shall not exceed £10,000,000 for each class of preference shares.
b The nominal value of new shares issued for the employee share plans in 2011 amounted to $162,000. Consideration received relating to the issue of new shares for employee share plans amounted to $4 million (2010 $138 million and 2009 $84 million).

Voting on substantive resolutions tabled at a general meeting is on a poll. On a poll, shareholders present in person or by proxy have two votes for every £5 in nominal amount of the first and second preference shares held and one vote for every ordinary share held. On a show-of-hands vote on other resolutions (procedural matters) at a general meeting, shareholders present in person or by proxy have one vote each.

In the event of the winding up of the company, preference shareholders would be entitled to a sum equal to the capital paid up on the preference shares, plus an amount in respect of accrued and unpaid dividends and a premium equal to the higher of (i) 10% of the capital paid up on the preference shares and (ii) the excess of the average market price of such shares on the London Stock Exchange during the previous six months over par value.

Treasury shares

		2011		2010		2009
	Shares	**Nominal value**	Shares	Nominal value	Shares	Nominal value
	thousand	**$ million**	thousand	$ million	thousand	$ million
At 1 January	**1,850,699**	**462**	1,869,777	467	1,888,151	472
Shares gifted to ESOPs					(1,265)	(1)
Shares transferred to ESOPs at market price			(7,125)	(2)		
Shares re-issued for employee share plans	**(13,191)**	**(3)**	(11,953)	(3)	(17,109)	(4)
At 31 December	**1,837,508**	**459**	1,850,699	462	1,869,777	467

For each year presented, the balance at 1 January represents the maximum number of shares held in treasury during the year, representing 9.0% (2010 9.1% and 2009 9.2%) of the called-up ordinary share capital of the company.

During 2011, the movement in treasury shares represented less than 0.1% (2010 less than 0.1% and 2009 less than 0.1%) of the ordinary share capital of the company.

39. Capital and reserves

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2011	**5,183**	**9,987**	**1,072**	**27,206**	**43,448**
Currency translation differences (including recycling)					
Actuarial loss relating to pensions and other post-retirement benefits					
Available-for-sale investments (including recycling)					
Cash flow hedges (including recycling)					
Share of equity-accounted entities other comprehensive income, net of tax					
Profit for the year					
Total comprehensive income					
Dividends	**41**	**(41)**			
Share-based payments[a]		**6**			**6**
Transactions involving minority interests					
At 31 December 2011	**5,224**	**9,952**	**1,072**	**27,206**	**43,454**
At 1 January 2010	5,179	9,847	1,072	27,206	43,304
Currency translation differences (including recycling)					
Actuarial loss relating to pensions and other post-retirement benefits					
Available-for-sale investments (including recycling)					
Cash flow hedges (including recycling)					
Profit (loss) for the year					
Total comprehensive income					
Dividends					
Share-based payments[a]	4	140			144
Transactions involving minority interests					
At 31 December 2010	5,183	9,987	1,072	27,206	43,448
At 1 January 2009	5,176	9,763	1,072	27,206	43,217
Currency translation differences (including recycling)					
Actuarial loss relating to pensions and other post-retirement benefits					
Available-for-sale investments (including recycling)					
Cash flow hedges (including recycling)					
Profit for the year					
Total comprehensive income					
Dividends					
Share-based payments[a]	3	84			87
Changes in associates equity					
Transactions involving minority interests					
At 31 December 2009	5,179	9,847	1,072	27,206	43,304

a Includes new share issues and movements in own shares and treasury shares where these relate to employee share-based payment plans.

$ million

Own shares	Treasury shares	Total own shares and treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Total fair value reserves	Share-based payment reserve	Profit and loss account	BP shareholders equity	Minority interest	Total equity
(126)	**(21,085)**	**(21,211)**	**4,937**	**463**	**6**	**469**	**1,586**	**65,758**	**94,987**	**904**	**95,891**
			(515)		**(1)**	**(1)**			**(516)**	**(10)**	**(526)**
								(4,321)	**(4,321)**	**(3)**	**(4,324)**
				(74)		**(74)**			**(74)**		**(74)**
					(127)	**(127)**			**(127)**		**(127)**
								(57)	**(57)**		**(57)**
								25,700	**25,700**	**397**	**26,097**
			(515)	**(74)**	**(128)**	**(202)**		**21,322**	**20,605**	**384**	**20,989**
								(4,072)	**(4,072)**	**(245)**	**(4,317)**
(262)	**150**	**(112)**					**(4)**	**102**	**(8)**		**(8)**
								(47)	**(47)**	**(26)**	**(73)**
(388)	**(20,935)**	**(21,323)**	**4,422**	**389**	**(122)**	**267**	**1,582**	**83,063**	**111,465**	**1,017**	**112,482**
(214)	(21,303)	(21,517)	4,811	754	22	776	1,584	72,655	101,613	500	102,113
			126		2	2			128	3	131
								(418)	(418)		(418)
				(291)		(291)			(291)		(291)
					(18)	(18)			(18)		(18)
								(3,719)	(3,719)	395	(3,324)
			126	(291)	(16)	(307)		(4,137)	(4,318)	398	(3,920)
								(2,627)	(2,627)	(315)	(2,942)
88	218	306					2	(113)	339		339
								(20)	(20)	321	301
(126)	(21,085)	(21,211)	4,937	463	6	469	1,586	65,758	94,987	904	95,891
(326)	(21,513)	(21,839)	2,353	63	(866)	(803)	1,295	67,080	91,303	806	92,109
			2,458	(2)	(37)	(39)			2,419	(56)	2,363
								(478)	(478)		(478)
				693		693			693		693
					925	925			925		925
								16,578	16,578	181	16,759
			2,458	691	888	1,579		16,100	20,137	125	20,262
								(10,483)	(10,483)	(416)	(10,899)
112	210	322					289	23	721		721
								(43)	(43)		(43)
								(22)	(22)	(15)	(37)
(214)	(21,303)	(21,517)	4,811	754	22	776	1,584	72,655	101,613	500	102,113

39. Capital and reserves continued

Share capital

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

Share premium account

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

Capital redemption reserve

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

Merger reserve

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

Own shares

Own shares represent BP shares held in Employee Share Ownership Plan Trusts (ESOPs) to meet the future requirements of the employee share-based payment plans, as discussed in Note 40. At 31 December 2011, a further 21,420,000 ordinary share equivalents were held by the group in the form of ADSs to meet the requirements of employee share-based payment plans in the US.

Treasury shares

Treasury shares represent BP shares repurchased and available for re-issue.

Foreign currency translation reserve

The foreign currency translation reserve is used to record exchange differences arising from the translation of the financial statements of foreign operations. Upon disposal of foreign operations, the related accumulated exchange differences are recycled to the income statement. This reserve is also used to record the effect of hedging net investments in foreign operations.

Available-for-sale investments

This reserve records the changes in fair value of available-for-sale investments. On disposal or impairment, the cumulative changes in fair value are recycled to the income statement.

Cash flow hedges

This reserve records the portion of the gain or loss on a hedging instrument in a cash flow hedge that is determined to be an effective hedge. When the hedged transaction occurs, the gain or loss on the hedging instrument is transferred out of equity to either profit or loss or the carrying value of assets, as appropriate. If the forecast transaction is no longer expected to occur the gain or loss recognized in equity is transferred to profit or loss.

Share-based payment reserve

This reserve represents cumulative amounts charged to profit in respect of employee share-based payment plans where the scheme has not yet been settled by means of an award of shares to an individual.

Profit and loss account

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

39. Capital and reserves continued

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

$ million

			2011
	Pre-tax	**Tax**	**Net of tax**
Currency translation differences (including recycling)	**(512)**	**(14)**	**(526)**
Actuarial loss relating to pensions and other post-retirement benefits	**(5,960)**	**1,636**	**(4,324)**
Available-for-sale investments (including recycling)	**(74)**		**(74)**
Cash flow hedges (including recycling)	**(164)**	**37**	**(127)**
Share of equity-accounted entities other comprehensive income	**(57)**		**(57)**
Other comprehensive income	**(6,767)**	**1,659**	**(5,108)**

$ million

			2010
	Pre-tax	Tax	Net of tax
Currency translation differences (including recycling)	239	(108)	131
Actuarial loss relating to pensions and other post-retirement benefits	(320)	(98)	(418)
Available-for-sale investments (including recycling)	(341)	50	(291)
Cash flow hedges (including recycling)	(37)	19	(18)
Other comprehensive income	(459)	(137)	(596)

$ million

			2009
	Pre-tax	Tax	Net of tax
Currency translation differences (including recycling)	1,799	564	2,363
Actuarial loss relating to pensions and other post-retirement benefits	(682)	204	(478)
Available-for-sale investments (including recycling)	707	(14)	693
Cash flow hedges (including recycling)	1,154	(229)	925
Other comprehensive income	2,978	525	3,503

40. Share-based payments

Effect of share-based payment transactions on the group s result and financial position

			$million
	2011	2010	2009
Total expense recognized for equity-settled share-based payment transactions	**579**	577	506
Total expense (credit) recognized for cash-settled share-based payment transactions	**5**	(1)	15
Total expense recognized for share-based payment transactions	**584**	576	521
Closing balance of liability for cash-settled share-based payment transactions	**12**	16	32
Total intrinsic value for vested cash-settled share-based payments	**1**	1	7

For ease of presentation, options and shares detailed in the tables within this note are stated as UK ordinary share equivalents in US dollars. US employees are granted American Depositary Shares (ADSs) or options over the company s ADSs (one ADS is equivalent to six ordinary shares). The main share-based payment plans that existed during the year are detailed below.

Plans for executive directors

For further information on the Executive Directors Incentive Plan (EDIP) see the Directors remuneration report on pages 139 to 151.

Plans for senior employees

The group operates a number of equity-settled share plans under which share units are granted to its senior leaders and certain other employees. These plans typically have a three-year performance or restricted period during which the units accrue net notional dividends which are treated as having been reinvested. Leaving employment will normally preclude the conversion of units into shares, but special arrangements apply for participants that leave for qualifying reasons. Grants are settled in cash where the regulatory environment prohibits participants to hold BP shares.

Performance unit plans

The number of units granted is related to the level of seniority of employees. The number of units converted to shares is determined by reference to performance measures over the three-year performance period. The main performance measure used is BP s total shareholder return (TSR) compared to the other oil majors. Plans included in this category are the Competitive Performance Plan (CPP) and, in part, the Performance Share Plan (PSP).

Restricted share unit plans

Share unit grants under BP s restricted plans typically take into account the employee s performance in either the current or the prior year, track record of delivery, business and leadership skills and potential. One restricted share unit plan for senior employees, used in special circumstances such as recruitment and retention, normally has no performance conditions. Plans included in this category are the Executive Performance Plan (EPP), the Restricted Share Plan (RSP), the Deferred Annual Bonus Plan (DAB) and, in part, the Performance Share Plan (PSP).

BP Share Option Plan (BPSOP)

Share options with an exercise price equivalent to the market price of a BP share immediately preceding the date of grant were granted to participants annually until 2006. These options are not subject to any performance conditions and are exercisable between the third and tenth anniversaries of the grant date.

BP Plan 2011

Share options with an exercise price equivalent to the market price of a BP share immediately preceding the date of grant were granted to participants in 2011. These options are not subject to any performance conditions and will be exercisable between the third and tenth anniversaries of the grant date.

Share Value Plan

In 2012, the group will launch a new performance plan known as the Share Value Plan (SVP) which will grant restricted share units with a three-year performance period. The number of units granted is dependent on grade and country of operation. The performance measures are grade specific and include individual rating, balanced scorecard and TSR criteria. For the 2012 performance year, no further grants will be made under DAB; and from 1 January 2012, no further grants will be made under CPP, EPP or PSP.

Other plans

For further information on BP s savings and matching plans, including the BP ShareMatch plans and the BP ShareSave Plan, see page 158.

40. Share-based payments continued

Share option transactions

Details of share option transactions for the year under the share options plans are as follows:

Share option transactions	2011 Number of options	2011 Weighted average exercise price $	2010 Number of options	2010 Weighted average exercise price $	2009 Number of options	2009 Weighted average exercise price $
Outstanding at 1 January	**263,306,722**	**8.75**	295,895,357	8.73	326,254,599	8.70
Granted[a]	**152,472,556**	**6.03**	10,420,287	6.08	9,679,836	6.55
Forfeited	**(9,058,406)**	**7.22**	(9,499,661)	7.88	(5,954,325)	8.81
Exercised	**(2,502,306)**	**7.64**	(31,839,034)	7.97	(21,293,871)	7.53
Expired	**(29,717,854)**	**8.26**	(1,670,227)	8.71	(12,790,882)	8.01
Outstanding at 31 December	**374,500,712**	**7.73**	263,306,722	8.75	295,895,357	8.73
Exercisable at 31 December	**209,776,014**	**9.01**	242,530,635	8.90	274,685,068	8.80

a Share options granted during 2011 include 142.5 million options awarded under the BP Plan 2011 with a fair value of $1.02 per option at the date of grant, determined using a binomial option pricing model including assumptions for share price volatility, dividends and cancellations.

The weighted average share price at the date of exercise was $7.71 (2010 $9.54 and 2009 $9.10).

For options outstanding at 31 December 2011, the exercise price ranges and weighted average remaining contractual lives were as shown below:

Range of exercise prices	Options outstanding[a] Number of shares	Options outstanding[a] Weighted average remaining life Years	Options outstanding[a] Weighted average exercise price $	Options exercisable Number of shares	Options exercisable Weighted average exercise price $
$5.66 $ 7.22	**199,571,741**	**7.51**	**6.11**	**37,283,772**	**6.37**
$7.23 $ 8.79	**81,608,110**	**1.21**	**8.13**	**81,608,110**	**8.13**
$8.80 $ 10.35	**22,264,187**	**2.73**	**9.83**	**19,827,458**	**9.92**
$10.36 $ 11.92	**71,056,674**	**3.81**	**11.14**	**71,056,674**	**11.14**
	374,500,712	**5.15**	**7.73**	**209,776,014**	**9.01**

a Included within options outstanding at 31 December 2011 are options granted under the BPSOP of 208 million options (2010 239 million options).

Fair values and associated details for restricted share units granted

For restricted share units granted in 2011, the number of units and weighted average fair value at the date of grant were as shown below:

Restricted share units granted in 2011	CPP	EPP	RSP	DAB	PSP
Number of restricted share units granted (million)	**1.4**	**8.9**	**20.0**	**17.5**	**19.2**
Weighted average fair value	**$11.99**	**$7.51**	**$6.86**	**$7.51**	**$7.51**
Fair value measurement basis	**Monte Carlo**	**Market value**	**Market value**	**Market value**	**Market value**

Restricted share units granted in 2010	CPP	EPP	RSP	DAB	PSP
Number of restricted share units granted (million)	1.3	7.6	21.4	24.5	16.0

Weighted average fair value	$19.81	$9.43	$6.78	$9.43	$9.43
Fair value measurement basis	Monte Carlo	Market value	Market value	Market value	Market value

Restricted share units granted in 2009	CPP	EPP	RSP	DAB	PSP
Number of restricted share units granted (million)	1.4	7.6	2.4	38.9	16.5
Weighted average fair value	$9.76	$6.56	$8.76	$6.56	$8.32
Fair value measurement basis	Monte Carlo	Market value	Market value	Market value	Monte Carlo

The group uses the observable market price for ordinary shares at the date of grant to determine the fair value of non-TSR restricted share units.

The group used a Monte Carlo simulation to determine the fair values of the TSR elements of the 2011, 2010 and 2009 CPP and EDIP grants and the 2009 PSP grant. In accordance with the plans rules, the model simulates BP s TSR and compares it against its principal strategic competitors over the three-year period of the plans. The model takes into account the historical dividends, share price volatilities and covariances of BP and each comparator company to produce a predicted distribution of relative share performance. This is applied to the reward criteria to give an expected value of the TSR element.

Accounting expense does not necessarily represent the actual value of share-based payments made to recipients, which are determined by the remuneration committee according to established criteria.

Employee Share Ownership Plan Trusts (ESOPs)

ESOPs have been established to acquire BP shares to satisfy any awards made to participants under the BP share plans as required. The ESOPs have waived their rights to dividends on shares held for future awards and are funded by the group. Until such time as the company s own shares held by the ESOPs vest unconditionally to employees, the amount paid for those shares is shown as a reduction in shareholders equity (see Note 39). Assets and liabilities of the ESOPs are recognized as assets and liabilities of the group.

At 31 December 2011, the ESOPs held 27,784,503 shares (2010 11,477,253 shares and 2009 18,062,246 shares) for potential future awards, which had a market value of $197 million (2010 $82 million and 2009 $174 million).

41. Employee costs and numbers

			$ million
Employee costs	**2011**	2010	2009
Wages and salaries[a]	**9,827**	9,242	9,702
Social security costs	**851**	789	780
Share-based payments	**584**	576	521
Pension and other post-retirement benefit costs	**1,065**	1,166	1,213
	12,327	11,773	12,216

Number of employees at 31 December	**2011**	2010	2009
Exploration and Production	**22,200**	21,100	21,500
Refining and Marketing[b]	**51,000**	52,300	51,600
Other businesses and corporate	**10,100**	6,200	7,200
Gulf Coast Restoration Organization	**100**	100	
	83,400	79,700	80,300
By geographical area			
US	**22,900**	22,100	22,800
Non-US[b]	**60,500**	57,600	57,500
	83,400	79,700	80,300

			2011			2010			2009
Average number of employees	**US**	**Non-US**	**Total**	US	Non-US	Total	US	Non-US	Total
Exploration and Production	**8,500**	**13,200**	**21,700**	8,100	13,500	21,600	7,900	13,800	21,700
Refining and Marketing	**12,300**	**39,200**	**51,500**	12,600	38,300	50,900	14,700	40,700	55,400
Other businesses and corporate	**1,700**	**6,500**	**8,200**	1,900	5,000	6,900	2,300	5,800	8,100
Gulf Coast Restoration Organization	**100**		**100**						
	22,600	**58,900**	**81,500**	22,600	56,800	79,400	24,900	60,300	85,200

a Includes termination payments of $126 million (2010 $166 million and 2009 $945 million).
b Includes 14,600 (2010 15,200 and 2009 13,900) service station staff.

42. Remuneration of directors and senior management

Remuneration of directors

			$ million
	2011	2010	2009
Total for all directors			
Emoluments	**10**	15	19
Gains made on exercise of share options		2	2
Amounts awarded under incentive schemes	**1**	4	2

Emoluments

These amounts comprise fees paid to the non-executive chairman and the non-executive directors and, for executive directors, salary and benefits earned during the relevant financial year, plus bonuses awarded for the year. There was no compensation for loss of office in 2011 (2010 $3 million and 2009 nil).

Pension contributions

During 2011 one executive director participated in a non-contributory pension plan established for UK employees by a separate trust fund to which contributions are made by BP based on actuarial advice. Two US executive directors participated in the US BP Retirement Accumulation Plan during 2011.

Office facilities for former chairmen and deputy chairmen

It is customary for the company to make available to former chairmen and deputy chairmen, who were previously employed executives, the use of office and basic secretarial facilities following their retirement. The cost involved in doing so is not significant.

Further information

Full details of individual directors remuneration are given in the directors remuneration report on pages 139 to 151.

Remuneration of directors and senior management

			$ million
Total for all senior management	**2011**	2010	2009
Total for all senior management			
Short-term employee benefits	**34**	25	36
Post-retirement benefits	**3**	3	3
Share-based payments	**27**	29	20

42. Remuneration of directors and senior management continued

Senior management, in addition to executive and non-executive directors, includes other senior managers who are members of the executive management team.

Short-term employee benefits

In addition to fees paid to the non-executive chairman and non-executive directors, these amounts comprise, for executive directors and senior managers, salary and benefits earned during the year, plus cash bonuses awarded for the year. Deferred annual bonus awards, to be settled in shares, are included in share-based payments. Short-term employee benefits includes compensation for loss of office of $9 million (2010 $3 million and 2009 $6 million).

Post-retirement benefits

The amounts represent the estimated cost to the group of providing defined benefit pensions and other post-retirement benefits to senior management in respect of the current year of service measured in accordance with IAS 19 Employee Benefits .

Share-based payments

This is the cost to the group of senior management s participation in share-based payment plans, as measured by the fair value of options and shares granted accounted for in accordance with IFRS 2 Share-based Payments . The main plans in which senior management have participated are the EDIP, DAB and RSP. For details of these plans refer to Note 40.

43. Contingent liabilities

Contingent liabilities relating to the Gulf of Mexico oil spill

As a consequence of the Gulf of Mexico oil spill, as described on pages 76 to 79, BP has incurred costs during the year and recognized provisions for certain future costs. Further information is provided in Note 2 and Note 36.

BP has provided for its best estimate of amounts expected to be paid from the $20-billion trust fund. This includes certain amounts expected to be paid pursuant to the Oil Pollution Act of 1990 (OPA 90), as well as the increased estimate of the cost of individual and business claims as a result of the proposed settlement with the PSC announced on 3 March 2012 as described in Note 2 and Note 36. It is not possible, at this time, to measure reliably any other items that will be paid from the trust fund, namely any obligation in relation to Natural Resource Damages claims other than the emergency and early restoration costs as described in Note 36, and claims asserted in civil litigation, including any further litigation through potential opt-outs from the proposed settlement agreement, nor is it practicable to estimate their magnitude or possible timing of payment.

Natural resource damages resulting from the oil spill are currently being assessed (see Note 36 for further information). BP and the federal and state trustees are collecting extensive data in order to assess the extent of damage to wildlife, shoreline, near shore and deepwater habitats, and recreational uses, among other things. Because the affected areas and their uses vary by seasons, we are continuing our work to complete a full assessment of the natural resource damages. In addition, as and when early restoration projects are undertaken, these projects could mitigate the total damages resulting from the incident. Accordingly, until the size, location and duration of the impact have been fully determined and the effects of early restoration projects are fully assessed, or other actions such as potential future settlement discussions occur, it is not possible to obtain a range of outcomes or to estimate reliably either the amounts (other than the amounts previously provided for emergency and early restoration projects) or timing of the remaining Natural Resource Damages claims.

BP is named as a defendant in approximately 600 civil lawsuits brought by individuals, corporations and governmental entities in US federal and state courts resulting from the Gulf of Mexico oil spill. Additional lawsuits are likely to be brought. The lawsuits assert, among others, claims for personal injury in connection with the incident itself and the response to it, and wrongful death, commercial or economic injury, securities and shareholder claims, breach of contract and violations of statutes. The lawsuits, many of which purport to be class actions, seek various remedies including compensation to injured workers and families of deceased workers, recovery for commercial losses and property damage, claims for environmental damage, remediation costs, injunctive relief, treble damages and punitive damages. Most of these lawsuits have been consolidated into one of two multi-district litigation (MDL) proceedings. On 3 March 2012, BP announced that it had reached a proposed settlement with the Plaintiffs Steering Committee (PSC), subject to final written agreement and court approvals, to resolve the substantial majority of legitimate economic loss and medical claims stemming from the Deepwater Horizon accident and oil spill. The PSC acts on behalf of individual and business plaintiffs in the MDL 2179 and the estimated cost of the proposed settlement has been reflected in the financial statements. While BP announced that it had reached a proposed settlement with the PSC, a trial of liability issues in the MDL 2179 is, at this time, still expected to go ahead. Damage issues will be scheduled for trial thereafter. Until further fact and expert disclosures occur, court rulings clarify the issues in dispute, liability and damage trial activity nears, or other actions such as possible settlements occur, it is not possible given these uncertainties to arrive at a range of outcomes or a reliable estimate of the liability other than the estimated cost of the proposed settlement with the PSC. See Legal proceedings on pages 160 to 164 for further information.

Therefore, with the exception of the estimated costs of the proposed settlement agreement with the PSC, no amounts have been provided for these items as of 31 December 2011. Although these items, which will be paid through the trust fund, have not been provided for at this time, BP s full obligation under the $20-billion trust fund has been expensed in the income statement, taking account of the time value of money. The aggregate of amounts paid and provided for items to be settled from the trust fund currently falls within the amount committed by BP to the trust fund.

For those items not covered by the trust fund it is not possible to measure reliably any obligation in relation to other litigation or potential fines and penalties except, subject to certain assumptions detailed in Note 36, for those relating to the Clean Water Act. There are a number of federal and state environmental and other provisions of law, other than the Clean Water Act, under which one or more governmental agencies could seek civil fines and penalties from BP. For example, a complaint filed by the United States sought to reserve the ability to seek penalties and other relief under a number of other laws. Given the large number of claims that may be asserted, it is not possible at this time to determine whether and to what extent any such claims would be successful or what penalties or fines would be assessed. Therefore no amounts have been provided for these items.

Under the settlement agreements with Anadarko and MOEX, BP has agreed to indemnify Anadarko and MOEX for certain claims arising from the accident (excluding civil, criminal or administrative fines and penalties, claims for punitive damages, and certain other claims). Under the settlement agreement entered into with M-I L.L.C. (M-I) (see Legal proceedings on pages 160 to 164), BP agreed to indemnify M-I for certain claims resulting from the accident. M-I was contracted by BP to provide specialized drilling mud and mud engineering services for the Macondo well. It is therefore possible that BP may face claims under these indemnities, but it is not currently possible to reliably measure any obligation in relation to such claims and therefore no amount has been provided as at 31 December 2011.

43. Contingent liabilities continued

The magnitude and timing of possible obligations in relation to the Gulf of Mexico oil spill are subject to a very high degree of uncertainty as described further in Risk factors on pages 59 to 63. Any such possible obligations are therefore contingent liabilities and, at present, it is not practicable to estimate their magnitude or possible timing of payment. Certain items are subject to settlement discussions or may be subject to settlement discussions in the future. Any settlements which may be reached relating to the Deepwater Horizon accident and oil spill could impact the amount and timing of any future payments. Furthermore, other material unanticipated obligations may arise in future in relation to the incident.

Other contingent liabilities

There were contingent liabilities at 31 December 2011 in respect of guarantees and indemnities entered into as part of the ordinary course of the group s business. No material losses are likely to arise from such contingent liabilities. Further information is included in Note 26.

Lawsuits arising out of the Exxon Valdez oil spill in Prince William Sound, Alaska, in March 1989 were filed against Exxon (now ExxonMobil), Alyeska Pipeline Service Company (Alyeska), which operates the oil terminal at Valdez, and the other oil companies that own Alyeska. Alyeska initially responded to the spill until the response was taken over by Exxon. BP owns a 46.9% interest (reduced during 2001 from 50% by a sale of 3.1% to Phillips) in Alyeska through a subsidiary of BP America Inc. and briefly indirectly owned a further 20% interest in Alyeska following BP s combination with Atlantic Richfield Company (Atlantic Richfield). Alyeska and its owners have settled all the claims against them under these lawsuits. Exxon has indicated that it may file a claim for contribution against Alyeska for a portion of the costs and damages that Exxon has incurred. BP will defend any such claims vigorously. It is not possible to estimate any financial effect.

In the normal course of the group s business, legal proceedings are pending or may be brought against BP group entities arising out of current and past operations, including matters related to commercial disputes, product liability, antitrust, premises-liability claims, general environmental claims and allegations of exposures of third parties to toxic substances, such as lead pigment in paint, asbestos and other chemicals. BP believes that the impact of these legal proceedings on the group s results of operations, liquidity or financial position will not be material.

With respect to lead pigment in paint in particular, Atlantic Richfield, a subsidiary of BP, has been named as a co-defendant in numerous lawsuits brought in the US alleging injury to persons and property. Although it is not possible to predict the outcome of the legal proceedings, Atlantic Richfield believes it has valid defences that render the incurrence of a liability remote; however, the amounts claimed and the costs of implementing the remedies sought in the various cases could be substantial. The majority of the lawsuits have been abandoned or dismissed against Atlantic Richfield. No lawsuit against Atlantic Richfield has been settled nor has Atlantic Richfield been subject to a final adverse judgment in any proceeding. Atlantic Richfield intends to defend such actions vigorously.

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

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

The group also has obligations to decommission oil and natural gas production facilities and related pipelines. Provision is made for the estimated costs of these activities, however there is uncertainty regarding both the amount and timing of these costs, given the long-term nature of these obligations. BP believes that the impact of any reasonably foreseeable changes to these provisions on the group s results of operations, financial position or liquidity will not be material.

The group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. This is because external insurance is not considered an economic means of financing losses for the group. Losses will therefore be borne as they arise rather than being spread over time through insurance premiums with attendant transaction costs. The position is reviewed periodically.

44. Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been placed at 31 December 2011 amounted to $12,517 million (2010 $11,279 million). In addition, at 31 December 2011, the group had contracts in place for future capital expenditure relating to investments in jointly controlled entities of $296 million (2010 $437 million) and investments in associates of $36 million (2010 $80 million).

BP s share of capital commitments of jointly controlled entities amounted to $1,244 million (2010 $1,117 million).

45. Subsidiaries, jointly controlled entities and associates

The more important subsidiaries, jointly controlled entities and associates of the group at 31 December 2011 and the group percentage of ordinary share capital or joint venture interest (to nearest whole number) are set out below. Those held directly by the parent company are marked with an asterisk (*), the percentage owned being that of the group unless otherwise indicated. A complete list of investments in subsidiaries, jointly controlled entities and associates will be attached to the parent company s annual return made to the Registrar of Companies.

Subsidiaries	%	Country of incorporation	Principal activities
International			
*BP Corporate Holdings	100	England & Wales	Investment holding
BP Europa SE	100	Germany	Refining and marketing and petrochemicals
BP Exploration Operating Company	100	England & Wales	Exploration and production
*BP Global Investments	100	England & Wales	Investment holding
*BP International	100	England & Wales	Integrated oil operations
BP Oil International	100	England & Wales	Integrated oil operations
*BP Shipping	100	England & Wales	Shipping
*Burmah Castrol	100	Scotland	Lubricants
Jupiter Insurance	100	Guernsey	Insurance
Algeria			
BP Amoco Exploration (In Amenas)	100	Scotland	Exploration and production
BP Exploration (El Djazair)	100	Bahamas	Exploration and production
Angola			
BP Exploration (Angola)	100	England & Wales	Exploration and production
Australia			
BP Australia Capital Markets	100	Australia	Finance
BP Developments Australia	100	Australia	Exploration and production
BP Finance Australia	100	Australia	Finance
BP Oil Australia	100	Australia	Integrated oil operations
Azerbaijan			
Amoco Caspian Sea Petroleum	100	British Virgin Islands	Exploration and production
BP Exploration (Caspian Sea)	100	England & Wales	Exploration and production
Brazil			
BP Energy do Brazil	100	Brazil	Exploration and production
Canada			
BP Canada Energy	100	Canada	Exploration and production
BP Canada Finance	100	Canada	Finance
Egypt			
BP Egypt Company	100	US	Exploration and production
India			
BP Exploration (Alpha)	100	England & Wales	Exploration and production
Indonesia			
BP Berau	100	US	Exploration and production
New Zealand			
BP Oil New Zealand	100	New Zealand	Marketing
Norway			
BP Norge	100	Norway	Exploration and production
Spain			
BP España	100	Spain	Refining and marketing
South Africa			
*BP Southern Africa	75	South Africa	Refining and marketing
Trinidad & Tobago			
BP Trinidad and Tobago	70	US	Exploration and production
UK			
BP Capital Markets	100	England & Wales	Finance
BP Oil UK	100	England & Wales	Marketing
Britoil	100	Scotland	Exploration and production

US			
*BP Holdings North America	100	England & Wales	Investment holding
Atlantic Richfield Company	100	US	
BP America	100	US	
BP America Production Company	100	US	
BP Amoco Chemical Company	100	US	
BP Company North America	100	US	
BP Corporation North America	100	US	Exploration and production, refining and marketing, pipelines and petrochemicals
BP Exploration & Production	100	US	
BP Exploration (Alaska)	100	US	
BP Products North America	100	US	
BP West Coast Products	100	US	
Standard Oil Company	100	US	
Verano Collateral Holdings	100	US	
BP Capital Markets America	100	US	Finance

45. Subsidiaries, jointly controlled entities and associates continued

Jointly controlled entities	%	Country of incorporation	Principal activities
Angola			
Angola LNG Supply Services	14	US	LNG processing and transportation
Argentina			
Pan American Energy[a]	60	US	Exploration and production
Canada			
Sunrise Oil Sands	50	Canada	Exploration and production
China			
Shanghai SECCO Petrochemical Company	50	China	Petrochemicals
Germany			
Ruhr Oel	50	Germany	Refining and petrochemicals
Trinidad & Tobago			
Atlantic 4 Holdings	38	US	LNG manufacture
Atlantic LNG 2/3 Company of Trinidad and Tobago	43	Trinidad & Tobago	LNG manufacture
Taiwan			
China American Petrochemical Company[a]	61	Taiwan	Petrochemicals
UK			
Vivergo Fuels	46	England & Wales	Biofuels
US			
BP-Husky Refining	50	US	Refining
Watson Cogeneration[a b]	51	US	Power generation

[a] The entity is not controlled by BP as certain key business decisions require joint approval of both BP and the minority partner. It is therefore classified as a jointly controlled entity rather than a subsidiary.

[b] As at 31 December 2011 the group s interests in Watson Cogeneration have been classified as assets held for sale. See Note 4 for further information.

Associates	%	Country of incorporation	Principal activities
Abu Dhabi			
Abu Dhabi Gas Liquefaction Company	10	United Arab Emirates	Crude oil production
Abu Dhabi Marine Areas	33	England & Wales	Crude oil production
Abu Dhabi Petroleum Company	24	England & Wales	Crude oil production
Azerbaijan			
The Baku-Tbilisi-Ceyhan Pipeline Company	30	Cayman Islands	Pipelines
South Caucasus Pipeline Company	26	Cayman Islands	Pipelines
Russia			
TNK-BP	50	British Virgin Islands	Integrated oil operations

46. Condensed consolidating information on certain US subsidiaries

BP p.l.c. fully and unconditionally guarantees the payment obligations of its 100%-owned subsidiary BP Exploration (Alaska) Inc. under the BP Prudhoe Bay Royalty Trust. The following financial information for BP p.l.c., BP Exploration (Alaska) Inc. and all other subsidiaries on a condensed consolidating basis is intended to provide investors with meaningful and comparable financial information about BP p.l.c. and its subsidiary issuers of registered securities and is provided pursuant to Rule 3-10 of Regulation S-X in lieu of the separate financial statements of each subsidiary issuer of public debt securities. Investments include the investments in subsidiaries recorded under the equity method for the purposes of the condensed consolidating financial information. Equity income of subsidiaries is the group s share of profit related to such investments. The eliminations and reclassifications column includes the necessary amounts to eliminate the intercompany balances and transactions between BP p.l.c., BP Exploration (Alaska) Inc. and other subsidiaries. The financial information presented in the following tables for BP Exploration (Alaska) Inc. for all years includes equity income arising from subsidiaries of BP Exploration (Alaska) Inc., some of which operate outside of Alaska and excludes the BP group s midstream operations in Alaska that are reported through different legal entities and that are included within the other subsidiaries column in these tables. BP p.l.c. also fully and unconditionally guarantees securities issued by BP Capital Markets p.l.c. and BP Capital Markets America Inc. These companies are 100%-owned finance subsidiaries of BP p.l.c.

Income statement

$ million

For the year ended 31 December					2011
	Issuer	**Guarantor**			
	BP Exploration (Alaska) Inc.	**BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Sales and other operating revenues	**6,159**		**375,517**	**(6,159)**	**375,517**
Earnings from jointly controlled entities after interest and tax			**1,304**		**1,304**
Earnings from associates after interest and tax			**4,916**		**4,916**
Equity-accounted income of subsidiaries after interest and tax	**313**	**26,158**		**(26,471)**	
Interest and other revenues	**10**	**242**	**664**	**(320)**	**596**
Gains on sale of businesses and fixed assets		**1**	**4,129**		**4,130**
Total revenues and other income	**6,482**	**26,401**	**386,530**	**(32,950)**	**386,463**
Purchases	**978**		**290,799**	**(6,159)**	**285,618**
Production and manufacturing expenses	**1,280**		**22,865**		**24,145**
Production and similar taxes	**1,684**		**6,596**		**8,280**
Depreciation, depletion and amortization	**335**		**10,800**		**11,135**
Impairment and losses on sale of businesses and fixed assets			**2,058**		**2,058**
Exploration expense	**4**		**1,516**		**1,520**
Distribution and administration expenses	**27**	**1,048**	**12,992**	**(109)**	**13,958**
Fair value gain on embedded derivatives			**(68)**		**(68)**
Profit before interest and taxation	**2,174**	**25,353**	**38,972**	**(26,682)**	**39,817**
Finance costs	**32**	**47**	**1,378**	**(211)**	**1,246**
Net finance (income) expense relating to pensions and other post-retirement benefits		**(533)**	**270**		**(263)**
Profit before taxation	**2,142**	**25,839**	**37,324**	**(26,471)**	**38,834**
Taxation	**729**	**139**	**11,869**		**12,737**
Profit for the year	**1,413**	**25,700**	**25,455**	**(26,471)**	**26,097**
Attributable to					
BP shareholders	**1,413**	**25,700**	**25,058**	**(26,471)**	**25,700**
Minority interest			**397**		**397**
	1,413	**25,700**	**25,455**	**(26,471)**	**26,097**

46. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

					$ million
For the year ended 31 December					2010
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	4,793		297,107	(4,793)	297,107
Earnings from jointly controlled entities after interest and tax			1,175		1,175
Earnings from associates after interest and tax			3,582		3,582
Equity-accounted income of subsidiaries after interest and tax	620	(3,567)		2,947	
Interest and other revenues		188	714	(221)	681
Gains on sale of businesses and fixed assets		260	6,376	(253)	6,383
Total revenues and other income	5,413	(3,119)	308,954	(2,320)	308,928
Purchases	637		220,367	(4,793)	216,211
Production and manufacturing expenses	966		63,649		64,615
Production and similar taxes	998		4,246		5,244
Depreciation, depletion and amortization	351		10,813		11,164
Impairment and losses on sale of businesses and fixed assets	1,524		1,689	(1,524)	1,689
Exploration expense			843		843
Distribution and administration expenses	16	673	11,975	(109)	12,555
Fair value loss on embedded derivatives			309		309
Profit (loss) before interest and taxation	921	(3,792)	(4,937)	4,106	(3,702)
Finance costs	2	31	1,249	(112)	1,170
Net finance (income) expense relating to pensions and other post-retirement benefits	4	(388)	337		(47)
Profit (loss) before taxation	915	(3,435)	(6,523)	4,218	(4,825)
Taxation	143	31	(1,675)		(1,501)
Profit (loss) for the year	772	(3,466)	(4,848)	4,218	(3,324)
Attributable to					
BP shareholders	772	(3,466)	(5,243)	4,218	(3,719)
Minority interest			395		395
	772	(3,466)	(4,848)	4,218	(3,324)

46. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

					$ million
For the year ended 31 December					2009
	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	4,189		239,272	(4,189)	239,272
Earnings from jointly controlled entities after interest and tax			1,286		1,286
Earnings from associates after interest and tax			2,615		2,615
Equity-accounted income of subsidiaries after interest and tax	838	17,315		(18,153)	
Interest and other revenues	17	144	832	(201)	792
Gains on sale of businesses and fixed assets		9	2,173	(9)	2,173
Total revenues and other income	5,044	17,468	246,178	(22,552)	246,138
Purchases	510		167,451	(4,189)	163,772
Production and manufacturing expenses	970		22,232		23,202
Production and similar taxes	602		3,150		3,752
Depreciation, depletion and amortization	424		11,682		12,106
Impairment and losses on sale of businesses and fixed assets			2,333		2,333
Exploration expense			1,116		1,116
Distribution and administration expenses	27	1,145	12,974	(108)	14,038
Fair value gain on embedded derivatives			(607)		(607)
Profit before interest and taxation	2,511	16,323	25,847	(18,255)	26,426
Finance costs	22	26	1,155	(93)	1,110
Net finance (income) expense relating to pensions and other post-retirement benefits	10	(310)	492		192
Profit before taxation	2,479	16,607	24,200	(18,162)	25,124
Taxation	583	20	7,762		8,365
Profit for the year	1,896	16,587	16,438	(18,162)	16,759
Attributable to					
BP shareholders	1,896	16,587	16,257	(18,162)	16,578
Minority interest			181		181
	1,896	16,587	16,438	(18,162)	16,759

Notes on financial statements

46. Condensed consolidating information on certain US subsidiaries continued

Balance Sheet

At 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	$ million 2011 BP group
Non-current assets					
Property, plant and equipment	**8,653**		**110,561**		**119,214**
Goodwill			**12,100**		**12,100**
Intangible assets	**456**		**20,646**		**21,102**
Investments in jointly controlled entities			**15,518**		**15,518**
Investments in associates		**2**	**13,289**		**13,291**
Other investments			**2,117**		**2,117**
Subsidiaries equity-accounted basis	**4,802**	**129,042**		**(133,844)**	
Fixed assets	**13,911**	**129,044**	**174,231**	**(133,844)**	**183,342**
Loans	**46**	**38**	**5,113**	**(4,313)**	**884**
Other receivables			**4,337**		**4,337**
Derivative financial instruments			**5,038**		**5,038**
Prepayments			**1,255**		**1,255**
Deferred tax assets			**611**		**611**
Defined benefit pension plan surpluses			**17**		**17**
	13,957	**129,082**	**190,602**	**(138,157)**	**195,484**
Current assets					
Loans			**244**		**244**
Inventories	**167**		**25,494**		**25,661**
Trade and other receivables	**4,109**	**17,698**	**49,753**	**(28,034)**	**43,526**
Derivative financial instruments			**3,857**		**3,857**
Prepayments	**7**		**1,279**		**1,286**
Current tax receivable			**235**		**235**
Other investments			**288**		**288**
Cash and cash equivalents	**(1)**		**14,068**		**14,067**
	4,282	**17,698**	**95,218**	**(28,034)**	**89,164**
Assets classified as held for sale			**8,420**		**8,420**
	4,282	**17,698**	**103,638**	**(28,034)**	**97,584**
Total assets	**18,239**	**146,780**	**294,240**	**(166,191)**	**293,068**
Current liabilities					
Trade and other payables	**5,035**	**2,390**	**73,014**	**(28,034)**	**52,405**
Derivative financial instruments			**3,220**		**3,220**
Accruals		**28**	**5,904**		**5,932**
Finance debt			**9,044**		**9,044**
Current tax payable	**287**		**1,654**		**1,941**
Provisions			**11,238**		**11,238**
	5,322	**2,418**	**104,074**	**(28,034)**	**83,780**
Liabilities directly associated with assets classified as held for sale			**538**		**538**
	5,322	**2,418**	**104,612**	**(28,034)**	**84,318**
Non-current liabilities					
Other payables	**9**	**4,264**	**3,477**	**(4,313)**	**3,437**
Derivative financial instruments			**3,773**		**3,773**
Accruals		**35**	**354**		**389**
Finance debt			**35,169**		**35,169**
Deferred tax liabilities	**1,966**		**13,112**		**15,078**
Provisions	**1,620**		**24,784**		**26,404**
Defined benefit pension plan and other post-retirement benefit plan deficits		**2,088**	**9,930**		**12,018**
	3,595	**6,387**	**90,599**	**(4,313)**	**96,268**
Total liabilities	**8,917**	**8,805**	**195,211**	**(32,347)**	**180,586**
Net assets	**9,322**	**137,975**	**99,029**	**(133,844)**	**112,482**
Equity					

BP shareholders equity	**9,322**	**137,975**	**98,012**	**(133,844)**	**111,465**
Minority interest			**1,017**		**1,017**
Total equity	**9,322**	**137,975**	**99,029**	**(133,844)**	**112,482**

46. Condensed consolidating information on certain US subsidiaries continued

Balance Sheet continued

At 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries[a]	Eliminations and reclassifications	$ million 2010 BP group[a]
Non-current assets					
Property, plant and equipment	7,679		102,484		110,163
Goodwill			8,598		8,598
Intangible assets	425		13,873		14,298
Investments in jointly controlled entities			14,927		14,927
Investments in associates		2	13,333		13,335
Other investments			1,191		1,191
Subsidiaries equity-accounted basis	4,489	112,227		(116,716)	
Fixed assets	12,593	112,229	154,406	(116,716)	162,512
Loans		38	5,161	(4,305)	894
Other receivables			6,298		6,298
Derivative financial instruments			4,210		4,210
Prepayments			1,432		1,432
Deferred tax assets			528		528
Defined benefit pension plan surpluses		1,870	306		2,176
	12,593	114,137	172,341	(121,021)	178,050
Current assets					
Loans			247		247
Inventories	244		25,974		26,218
Trade and other receivables	3,173	14,444	42,783	(23,851)	36,549
Derivative financial instruments			4,356		4,356
Prepayments	6		1,568		1,574
Current tax receivable			693		693
Other investments			1,532		1,532
Cash and cash equivalents	(1)	4	18,553		18,556
	3,422	14,448	95,706	(23,851)	89,725
Assets classified as held for sale			4,487		4,487
	3,422	14,448	100,193	(23,851)	94,212
Total assets	16,015	128,585	272,534	(144,872)	272,262
Current liabilities					
Trade and other payables	4,931	2,362	62,887	(23,851)	46,329
Derivative financial instruments			3,856		3,856
Accruals		23	5,589		5,612
Finance debt			14,626		14,626
Current tax payable	182		2,738		2,920
Provisions			9,489		9,489
	5,113	2,385	99,185	(23,851)	82,832
Liabilities directly associated with assets classified as held for sale			1,047		1,047
	5,113	2,385	100,232	(23,851)	83,879
Non-current liabilities					
Other payables	9	4,258	14,323	(4,305)	14,285
Derivative financial instruments			3,677		3,677
Accruals		35	602		637
Finance debt			30,710		30,710
Deferred tax liabilities	2,026	410	8,472		10,908
Provisions	958		21,460		22,418
Defined benefit pension plan and other post-retirement benefit plan deficits			9,857		9,857
	2,993	4,703	89,101	(4,305)	92,492
Total liabilities	8,106	7,088	189,333	(28,156)	176,371
Net assets	7,909	121,497	83,201	(116,716)	95,891
Equity					

BP shareholders equity	7,909	121,497	82,297	(116,716)	94,987
Minority interest			904		904
Total equity	7,909	121,497	83,201	(116,716)	95,891

a Adjusted following the termination of the Pan American Energy LLC sale agreement as described in Note 4.

Notes on financial statements

46. Condensed consolidating information on certain US subsidiaries continued

Cash flow statement

$ million

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					2011
Net cash provided by operating activities	**661**	**8,321**	**25,114**	**(11,942)**	**22,154**
Net cash used in investing activities	**(661)**	**(3,710)**	**(22,262)**		**(26,633)**
Net cash (used in) provided by financing activities		**(4,615)**	**(6,845)**	**11,942**	**482**
Currency translation differences relating to cash and cash equivalents			**(492)**		**(492)**
Decrease in cash and cash equivalents		**(4)**	**(4,485)**		**(4,489)**
Cash and cash equivalents at beginning of year	**(1)**	**4**	**18,553**		**18,556**
Cash and cash equivalents at end of year	**(1)**		**14,068**		**14,067**

$ million

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					2010
Net cash provided by (used in) operating activities	829	32,111	(4,584)	(14,740)	13,616
Net cash (used in) provided by investing activities	(752)	(29,325)	26,117		(3,960)
Net cash (used in) provided by financing activities	(56)	(2,810)	(11,034)	14,740	840
Currency translation differences relating to cash and cash equivalents			(279)		(279)
Increase (decrease) in cash and cash equivalents	21	(24)	10,220		10,217
Cash and cash equivalents at beginning of year	(22)	28	8,333		8,339
Cash and cash equivalents at end of year	(1)	4	18,553		18,556

$ million

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					2009
Net cash provided by operating activities	1,022	14,514	47,466	(35,286)	27,716
Net cash used in investing activities	(935)	(4,227)	(12,971)		(18,133)
Net cash used in financing activities	(99)	(10,270)	(34,468)	35,286	(9,551)
Currency translation differences relating to cash and cash equivalents			110		110
(Decrease) increase in cash and cash equivalents	(12)	17	137		142
Cash and cash equivalents at beginning of year	(10)	11	8,196		8,197
Cash and cash equivalents at end of year	(22)	28	8,333		8,339

Supplementary information on oil and natural gas (unaudited)

The regional analysis presented below is on a continent basis, with separate disclosure for countries that contain 15% or more of the total proved reserves (for subsidiaries plus equity-accounted entities), in accordance with SEC and FASB requirements.

Oil and gas reserves certain definitions

Unless the context indicates otherwise, the following terms have the meanings shown below:

Proved oil and gas reserves

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:
  (A) The area identified by drilling and limited by fluid contacts, if any; and
  (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.
(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
  (A) Successful testing by a pilot project in an area of the reservoir with properties no more favourable than in the reservoir as a whole, the operation of an installed programme in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or programme was based; and
  (B) The project has been approved for development by all necessary parties and entities, including governmental entities.
(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Undeveloped oil and gas reserves

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.
(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Developed oil and gas reserves

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

For details on BP s proved reserves and production compliance and governance processes, see pages 90 to 91.

Supplementary information on oil and natural gas (unaudited)

Oil and natural gas exploration and production activities

$ million

2011

	Europe		North America		South America	Africa		Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries[a]										
Capitalized costs at 31 December[b j]										
Gross capitalized costs										
Proved properties	37,491	8,994	73,626	182	7,471	29,358		14,833	3,370	175,325
Unproved properties	368	180	6,198	1,471	2,986	3,689		4,495	1,279	20,666
	37,859	9,174	79,824	1,653	10,457	33,047		19,328	4,649	195,991
Accumulated depreciation	26,953	3,715	36,009	139	3,839	14,595		6,235	1,294	92,779
Net capitalized costs	10,906	5,459	43,815	1,514	6,618	18,452		13,093	3,355	103,212
Costs incurred for the year ended 31 December[b j]										
Acquisition of properties[c k]										
Proved			1,178	8	237			1,733		3,156
Unproved		1	418		2,592	679		3,008		6,698
		1	1,596	8	2,829	679		4,741		9,854
Exploration and appraisal costs[d]	211	1	566	117	271	490	6	511	225	2,398
Development	1,361	889	3,016		405	2,933		1,340	251	10,195
Total costs	1,572	891	5,178	125	3,505	4,102	6	6,592	476	22,447
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	1,997		751	25	2,263	3,353		1,450	1,611	11,450
Sales between businesses	3,495	1,273	19,089	20	1,409	4,858		10,811	967	41,922
	5,492	1,273	19,840	45	3,672	8,211		12,261	2,578	53,372
Exploration expenditure	37	1	1,065	9	35	163	6	134	70	1,520
Production costs	1,372	230	3,402	66	503	1,146	4	787	194	7,704
Production taxes	72		1,854		278			5,956	147	8,307
Other costs (income)[f]	(1,357)	101	4,688	49	935	215	72	118	257	5,078
Depreciation, depletion and amortization	874	199	2,980	6	523	1,668		1,692	172	8,114
Impairments and (gains) losses on sale of businesses and fixed assets	26	(64)	(492)	15	(1,085)	18	(1)	(537)		(2,120)
	1,024	467	13,497	145	1,189	3,210	81	8,150	840	28,603
Profit (loss) before taxation[g]	4,468	806	6,343	(100)	2,483	5,001	(81)	4,111	1,738	24,769
Allocable taxes	2,483	384	2,152	(159)	1,205	2,184	(21)	1,001	677	9,906
Results of operations	1,985	422	4,191	59	1,278	2,817	(60)	3,110	1,061	14,863
Exploration and Production segment replacement cost profit before interest and tax										
Exploration and production activities subsidiaries (as above)	4,468	806	6,343	(100)	2,483	5,001	(81)	4,111	1,738	24,769
Midstream activities subsidiaries[h]	(118)	29	(157)	299	(58)	(4)	(1)	42	284	316
Equity-accounted entities[i]		12	10	58	598	69	4,095	573		5,415
Total replacement cost profit before interest and tax	4,350	847	6,196	257	3,023	5,066	4,013	4,726	2,022	30,500

a These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries. They do not include any costs relating to the Gulf of Mexico oil spill. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia and BP is also investing in the LNG business in Angola.

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

c Includes costs capitalized as a result of asset exchanges.

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

e Presented net of transportation costs, purchases and sales taxes.

f Includes property taxes, other government take and the fair value gain on embedded derivatives of $191 million. The UK region includes a $1,442 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme. The South America region includes 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 (see page 85).

g Excludes the unwinding of the discount on provisions and payables amounting to $352 million which is included in finance costs in the group income statement.

h Midstream activities exclude inventory holding gains and losses.

i The profits of equity-accounted entities are included after interest and tax.

j Excludes balances associated with assets held for sale.

k Excludes goodwill associated with business combinations.

Oil and natural gas exploration and production activities continued

$ million

2011

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Equity-accounted entities (BP share)[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties				168	6,562		16,214	3,571		26,515
Unproved properties				1,510	19		652	9		2,190
				1,678	6,581		16,866	3,580		28,705
Accumulated depreciation					2,644		6,978	3,017		12,639
Net capitalized costs				1,678	3,937		9,888	563		16,066
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved								46		46
Unproved					6		37			43
					6		37	46		89
Exploration and appraisal costs[d]					2		167	9		178
Development				251	587		1,862	435		3,135
Total costs				251	595		2,066	490		3,402
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties					2,381		7,380	3,828		13,589
Sales between businesses							5,149	23		5,172
					2,381		12,529	3,851		18,761
Exploration expenditure					10		72	1		83
Production costs					459		1,846	212		2,517
Production taxes					1,098		5,000	3,125		9,223
Other costs (income)					(239)		2	(1)		(238)
Depreciation, depletion and amortization					329		988	431		1,748
Impairments and (gains) losses on sale of businesses and fixed assets										
					1,657		7,908	3,768		13,333
Profit (loss) before taxation					724		4,621	83		5,428
Allocable taxes					294		806	19		1,119
Results of operations					430		3,815	64		4,309
Exploration and production activities equity-accounted entities after tax (as above)					430		3,815	64		4,309
Midstream and other activities after tax[f]		12	10	58	168	69	280	509		1,106
Total replacement cost profit after interest and tax		12	10	58	598	69	4,095	573		5,415

a These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. They do not include amounts relating to assets held for sale. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation as well as downstream activities of TNK-BP are excluded. The amounts reported for equity-accounted entities exclude the corresponding amounts for their equity-accounted entities.

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

c Includes costs capitalized as a result of asset exchanges.

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

e Presented net of transportation costs and sales taxes.

f Includes interest, minority interest and the net results of equity-accounted entities of equity-accounted entities, and excludes inventory holding gains and losses.

Supplementary information on oil and natural gas (unaudited)

Oil and natural gas exploration and production activities continued

$ million

										2010
	Europe		North America		South America	Africa		Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries[a]										
Capitalized costs at 31 December[b j]										
Gross capitalized costs										
Proved properties	36,161	7,846	67,724	278	6,047	27,014		11,497	3,088	159,655
Unproved properties	787	179	5,968	1,363	220	2,694		1,113	1,149	13,473
	36,948	8,025	73,692	1,641	6,267	29,708		12,610	4,237	173,128
Accumulated depreciation	27,688	3,515	33,972	216	3,282	13,893		4,569	1,205	88,340
Net capitalized costs	9,260	4,510	39,720	1,425	2,985	15,815		8,041	3,032	84,788
Costs incurred for the year ended 31 December[b j]										
Acquisition of properties[c]										
Proved			655	1				1,121		1,777
Unproved		519	1,599	1,200				151		3,469
		519	2,254	1,201				1,272		5,246
Exploration and appraisal costs[d]	401	13	1,096	78	68	607	7	316	120	2,706
Development	726	816	3,034	251	414	3,003		1,244	187	9,675
Total costs	1,127	1,348	6,384	1,530	482	3,610	7	2,832	307	17,627
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	1,472	58	1,148	90	1,896	3,158		1,272	1,398	10,492
Sales between businesses	3,405	1,134	18,819	453	1,574	4,353		6,697	929	37,364
	4,877	1,192	19,967	543	3,470	7,511		7,969	2,327	47,856
Exploration expenditure	82	(2)	465	25	9	189	7	51	17	843
Production costs	1,018	152	2,867	240	445	938	9	365	124	6,158
Production taxes	52		1,093	2	249			3,764	109	5,269
Other costs (income)[f]	(316)	76	3,502	129	209	130	76	90	195	4,091
Depreciation, depletion and amortization	897	209	3,477	95	575	1,771		829	168	8,021
Impairments and (gains) losses on sale of businesses and fixed assets	(1)		(1,441)	(2,190)	(3)	(427)	341[k]			(3,721)
	1,732	435	9,963	(1,699)	1,484	2,601	433	5,099	613	20,661
Profit (loss) before taxation[g]	3,145	757	10,004	2,242	1,986	4,910	(433)	2,870	1,714	27,195
Allocable taxes	1,333	530	3,504	610	1,084	1,771	(23)	813	410	10,032
Results of operations	1,812	227	6,500	1,632	902	3,139	(410)	2,057	1,304	17,163
Exploration and Production segment replacement cost profit before interest and tax										
Exploration and production activities subsidiaries (as above)	3,145	757	10,004	2,242	1,986	4,910	(433)	2,870	1,714	27,195
Midstream activities subsidiaries[h]	23	42	(347)	3	49	(26)	4	(23)	(13)	(288)
Equity-accounted entities[i]		4	27	171	614	63	2,613	487		3,979
Total replacement cost profit before interest and tax	3,168	803	9,684	2,416	2,649	4,947	2,184	3,334	1,701	30,886

a

These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries. They do not include any costs relating to the Gulf of Mexico oil spill. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia and BP is also investing in the LNG business in Angola.

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

c Includes costs capitalized as a result of asset exchanges.

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

e Presented net of transportation costs, purchases and sales taxes.

f Includes property taxes, other government take and the fair value loss on embedded derivatives of $309 million. The UK region includes a $822 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme.

g Excludes the unwinding of the discount on provisions and payables amounting to $313 million which is included in finance costs in the group income statement.

h Midstream activities exclude inventory holding gains and losses.

i The profits of equity-accounted entities are included after interest and tax.

j Excludes balances associated with assets held for sale.

k This amount represents the write-down of our investment in Sakhalin. A portion of these costs was previously reported within capitalized costs of equity-accounted entities with the remainder previously reported as a loan, which was not included in the disclosures of oil and natural gas exploration and production activities.

Oil and natural gas exploration and production activities continued

$ million

2010	Europe		North America		South America	Africa		Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Equity-accounted entities (BP share)[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties				142	5,778		14,486	3,192		23,598
Unproved properties				1,284	163		652			2,099
				1,426	5,941		15,138	3,192		25,697
Accumulated depreciation					2,250		6,300	2,674		11,224
Net capitalized costs				1,426	3,691		8,838	518		14,473
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved										
Unproved					9		66			75
					9		66			75
Exploration and appraisal costs[d]					2		94			96
Development				49	549		1,416	355		2,369
Total costs				49	560		1,576	355		2,540
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties					2,268		5,610	2,557		10,435
Sales between businesses							3,432	19		3,451
					2,268		9,042	2,576		13,886
Exploration expenditure					22		40			62
Production costs					316		1,602	184		2,102
Production taxes					911		3,567	2,029		6,507
Other costs (income)				67	75		3	(2)		143
Depreciation, depletion and amortization					269		954	363		1,586
Impairments and losses on sale of businesses and fixed assets							43			43
				67	1,593		6,209	2,574		10,443
Profit (loss) before taxation				(67)	675		2,833	2		3,443
Allocable taxes					260		475	33		768
Results of operations				(67)	415		2,358	(31)		2,675
Exploration and production activities equity-accounted entities after tax (as above)				(67)	415		2,358	(31)		2,675
Midstream and other activities after tax[f]		4	27	238	199	63	255	518		1,304
Total replacement cost profit after interest and tax		4	27	171	614	63	2,613	487		3,979

a These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. They do not include amounts relating to assets held for sale. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation as well as downstream activities of TNK-BP are excluded. The amounts reported for equity-accounted entities exclude the corresponding amounts for their equity-accounted entities.

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

c Includes costs capitalized as a result of asset exchanges.

d Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.
e Presented net of transportation costs and sales taxes.
f Includes interest, minority interest and the net results of equity-accounted entities of equity-accounted entities.

Supplementary information on oil and natural gas (unaudited)

Oil and natural gas exploration and production activities continued

$ million

	Europe		North America		South America	Africa	Asia		Australasia	2009 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	35,096	6,644	64,366	3,967	8,346	24,476		10,900	2,894	156,689
Unproved properties	752		5,464	147	198	2,377		733	1,039	10,710
	35,848	6,644	69,830	4,114	8,544	26,853		11,633	3,933	167,399
Accumulated depreciation	26,794	3,306	31,728	2,309	4,837	12,492		4,798	1,038	87,302
Net capitalized costs	9,054	3,338	38,102	1,805	3,707	14,361		6,835	2,895	80,097
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved	179		(17)					306		468
Unproved	(1)		370	1		18			10	398
	178		353	1		18		306	10	866
Exploration and appraisal costs[d]	183		1,377	79	78	712	8	315	53	2,805
Development	751	1,054	4,208	386	453	2,707		560	277	10,396
Total costs	1,112	1,054	5,938	466	531	3,437	8	1,181	340	14,067
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	2,239	68	972	99	1,525	1,846		636	785	8,170
Sales between businesses	2,482	809	15,100	484	1,409	5,313		6,257	726	32,580
	4,721	877	16,072	583	2,934	7,159		6,893	1,511	40,750
Exploration expenditure	59		663	80	16	219	8	49	22	1,116
Production costs	1,243	164	2,821	284	395	908	15	361	70	6,261
Production taxes	(3)		649	1	220			2,854	72	3,793
Other costs (income)[f]	(1,259)	51	2,353	145	184	144	76	967	178	2,839
Depreciation, depletion and amortization	1,148	185	3,857	170	697	2,041		757	96	8,951
Impairments and (gains) losses on sale of businesses and fixed assets	(122)	(7)	(208)		(11)	(1)		(702)[j]		(1,051)
	1,066	393	10,135	680	1,501	3,311	99	4,286	438	21,909
Profit (loss) before taxation[g]	3,655	484	5,937	(97)	1,433	3,848	(99)	2,607	1,073	18,841
Allocable taxes	1,568	76	1,902	(58)	916	1,517	(25)	682	2	6,580
Results of operations	2,087	408	4,035	(39)	517	2,331	(74)	1,925	1,071	12,261
Exploration and Production segment replacement cost profit before interest and tax										
Exploration and production activities subsidiaries (as above)	3,655	484	5,937	(97)	1,433	3,848	(99)	2,607	1,073	18,841
Midstream activities subsidiaries[h,j]	925	17	719	833	17	(27)	(37)	518	(315)	2,650
Equity-accounted entities[i]		5	29	134	630	56	1,924	531		3,309
Total replacement cost profit before interest and tax	4,580	506	6,685	870	2,080	3,877	1,788	3,656	758	24,800

a

These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia and BP is also investing in the LNG business in Angola.

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

c Includes costs capitalized as a result of asset exchanges.

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

e Presented net of transportation costs, purchases and sales taxes. Sales between businesses and third party sales have been amended in the US without net effect to total sales.

f Includes property taxes, other government take and the fair value gain on embedded derivatives of $663 million. The UK region includes a $783 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme.

g Excludes the unwinding of the discount on provisions and payables amounting to $308 million which is included in finance costs in the group income statement.

h Midstream activities exclude inventory holding gains and losses.

i The profits of equity-accounted entities are included after interest and tax.

j Includes the gain on disposal of upstream assets associated with our sale of our 46% stake in LukArco (see Note 5).

Oil and natural gas exploration and production activities continued

$ million

2009	Europe: UK	Europe: Rest of Europe	North America: US	North America: Rest of North America	South America	Africa	Asia: Russia	Asia: Rest of Asia	Australasia	Total
Equity-accounted entities (BP share)[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties					5,789		13,266	2,259		21,314
Unproved properties				1,378	197		737			2,312
				1,378	5,986		14,003	2,259		23,626
Accumulated depreciation					2,084		5,550	1,739		9,373
Net capitalized costs				1,378	3,902		8,453	520		14,253
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved										
Unproved					31		10			41
					31		10			41
Exploration and appraisal costs[d]					21		77	3		101
Development				30	538		1,182	246		1,996
Total costs				30	590		1,269	249		2,138
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties					1,977		4,919	1,874		8,770
Sales between businesses							2,838			2,838
					1,977		7,757	1,874		11,608
Exploration expenditure					23		37			60
Production costs					354		1,428	159		1,941
Production taxes					702		2,597	1,523		4,822
Other costs (income)					(69)		12	(2)		(59)
Depreciation, depletion and amortization					281		1,073	274		1,628
Impairments and losses on sale of businesses and fixed assets							72			72
					1,291		5,219	1,954		8,464
Profit (loss) before taxation					686		2,538	(80)		3,144
Allocable taxes					270		501			771
Results of operations					416		2,037	(80)		2,373
Exploration and production activities equity-accounted entities after tax (as above)					416		2,037	(80)		2,373
Midstream and other activities after tax[f]		5	29	134	214	56	(113)	611		936
Total replacement cost profit after interest and tax		5	29	134	630	56	1,924	531		3,309

a These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation as well as downstream activities of TNK-BP are excluded. The amounts reported for equity-accounted entities exclude the corresponding amounts for their equity-accounted entities.

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

c Includes costs capitalized as a result of asset exchanges.

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

e Presented net of transportation costs, purchases and sales taxes.
f Includes interest, minority interest and the net results of equity-accounted entities of equity-accounted entities.

Supplementary information on oil and natural gas (unaudited)

Movements in estimated net proved reserves

million barrels

Crude oil[a]	Europe		North America		South America	Africa	Asia		Australasia	2011 Total
	UK	Rest of Europe	US[e]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2011										
Developed	364	77	1,729		44	371		269	48	2,902
Undeveloped	431	221	1,190		58	374		325	58	2,657
	795	298	2,919		102	745		594	106	5,559
Changes attributable to										
Revisions of previous estimates	(1)	5	27		6	(68)		(131)	3	(159)
Improved recovery	14	8	97		1	10		70	6	206
Purchases of reserves-in-place			10		7			4		21
Discoveries and extensions			1		1	19				21
Production[b]	(41)	(12)	(162)		(13)	(68)		(50)	(9)	(355)
Sales of reserves-in-place	(34)		(34)		(29)	(12)		(31)		(140)
	(62)	1	(61)		(27)	(119)		(138)		(406)
At 31 December 2011[c]										
Developed	288	69	1,685		27	311		177	59	2,616
Undeveloped	445	230	1,173		48	315		279	47	2,537
	733	299	2,858		75	626		456	106	5,153
Equity-accounted entities (BP share)[f]										
At 1 January 2011										
Developed					408		2,388	370		3,166
Undeveloped					407	12	1,362	24		1,805
					815	12	3,750	394		4,971
Changes attributable to										
Revisions of previous estimates					(12)	2	677	(5)		662
Improved recovery					70		73			143
Purchases of reserves-in-place					98			1		99
Discoveries and extensions							25			25
Production					(30)		(316)	(76)		(422)
Sales of reserves-in-place					(244)					(244)
					(118)	2	459	(80)		263
At 31 December 2011[d g]										
Developed					349		2,596	256		3,201
Undeveloped					348	14	1,613	58		2,033
					697	14	4,209	314		5,234
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2011										
Developed	364	77	1,729		452	371	2,388	639	48	6,068
Undeveloped	431	221	1,190		465	386	1,362	349	58	4,462
	795	298	2,919		917	757	3,750	988	106	10,530
At 31 December 2011										
Developed	288	69	1,685		376	311	2,596	433	59	5,817

Undeveloped	**445**	**230**	**1,173**	**396**	**329**	**1,613**	**337**	**47**	**4,570**
	733	**299**	**2,858**	**772**	**640**	**4,209**	**770**	**106**	**10,387**

a Crude oil includes NGLs and condensate. Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
b Excludes NGLs from processing plants in which an interest is held of 28 thousand barrels per day.
c Includes 616 million barrels of NGLs. Also includes 20 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
d Includes 19 million barrels of NGLs. Also includes 310 million barrels of crude oil in respect of the 7.37% minority interest in TNK-BP.
e Proved reserves in the Prudhoe Bay field in Alaska include an estimated 82 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
f Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
g Total proved liquid reserves held as part of our equity interest in TNK-BP is 4,305 million barrels, comprising 95 million barrels in Venezuela, one million barrels in Vietnam and 4,209 million barrels in Russia. In 2011, BP aligned its reporting with TNK-BP by moving to a life of field reporting basis. Reasonable certainty of licence renewals is demonstrated by evidence of Russian subsoil law, track record of renewals within the industry and track record of success in obtaining renewals by TNK-BP. This has resulted in an increase in proved liquid reserves of 221 million barrels.

Movements in estimated net proved reserves continued

billion cubic feet

Natural gas[a]	Europe		North America		South America	Africa	Asia		Australasia	2011 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2011										
Developed	1,416	40	9,495	58	3,575	1,329		1,290	3,563	20,766
Undeveloped	829	430	4,248		6,575	2,351		268	2,342	17,043
	2,245	470	13,743	58	10,150	3,680		1,558	5,905	37,809
Changes attributable to										
Revisions of previous estimates	169	30		(9)	202	(206)		69	299	554
Improved recovery	56	1	597		84	15		28	22	803
Purchases of reserves-in-place	8		93	7				310		418
Discoveries and extensions			219		47					266
Production[b]	(146)	(8)	(737)	(5)	(811)	(232)		(244)	(291)	(2,474)
Sales of reserves-in-place	(12)		(363)	(23)	(274)			(323)		(995)
	75	23	(191)	(30)	(752)	(423)		(160)	30	(1,428)
At 31 December 2011[c]										
Developed	1,411	43	9,721	28	2,869	1,224		1,034	3,570	19,900
Undeveloped	909	450	3,831		6,529	2,033		364	2,365	16,481
	2,320	493	13,552	28	9,398	3,257		1,398	5,935	36,381
Equity-accounted entities (BP share)[e]										
At 1 January 2011										
Developed					1,075		1,900	71		3,046
Undeveloped					1,192	175	459	19		1,845
					2,267	175	2,359	90		4,891
Changes attributable to										
Revisions of previous estimates					(75)	20	683	(3)		625
Improved recovery					190			12		202
Purchases of reserves-in-place					31			76		107
Discoveries and extensions										
Production[b]					(167)		(264)	(20)		(451)
Sales of reserves-in-place					(96)					(96)
					(117)	20	419	65		387
At 31 December 2011[d f]										
Developed					1,144		2,119	104		3,367
Undeveloped					1,006	195	659	51		1,911
					2,150	195	2,778	155		5,278
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2011										
Developed	1,416	40	9,495	58	4,650	1,329	1,900	1,361	3,563	23,812
Undeveloped	829	430	4,248		7,767	2,526	459	287	2,342	18,888
	2,245	470	13,743	58	12,417	3,855	2,359	1,648	5,905	42,700
At 31 December 2011										
Developed	1,411	43	9,721	28	4,013	1,224	2,119	1,138	3,570	23,267
Undeveloped	909	450	3,831		7,535	2,228	659	415	2,365	18,392
	2,320	493	13,552	28	11,548	3,452	2,778	1,553	5,935	41,659

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

b Includes 196 billion cubic feet of natural gas consumed in operations, 155 billion cubic feet in subsidiaries, 41 billion cubic feet in equity-accounted entities and excludes 14 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.

c Includes 2,759 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

d Includes 174 billion cubic feet of natural gas in respect of the 6.27% minority interest in TNK-BP.

e Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

f Total proved gas reserves held as part of our equity interest in TNK-BP is 2,881 billion cubic feet, comprising 30 billion cubic feet in Venezuela, 73 billion cubic feet in Vietnam and 2,778 billion cubic feet in Russia. In 2011, BP aligned its reporting with TNK-BP by moving to a life of field reporting basis. Reasonable certainty of licence renewals is demonstrated by evidence of Russian subsoil law, track record of renewals within the industry and track record of success in obtaining renewals by TNK-BP. This has resulted in an increase in proved gas reserves of 185 billion cubic feet.

Movements in estimated net proved reserves continued

million barrels

Bitumen[a]		2011
	Rest of North America	Total
Equity-accounted entities (BP share)		
At 1 January 2011		
Developed		
Undeveloped	**179**	**179**
	179	**179**
Changes attributable to		
Revisions of previous estimates	**(1)**	**(1)**
Improved recovery		
Purchases of reserves-in-place		
Discoveries and extensions		
Production		
Sales of reserves-in-place		
	(1)	**(1)**
At 31 December 2011		
Developed		
Undeveloped	**178**	**178**
	178	**178**

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.

Supplementary information on oil and natural gas (unaudited)

Movements in estimated net proved reserves continued

million barrels of oil equivalent

Total hydrocarbons[a]	Europe		North America		South America	Africa	Asia		Australasia	2011 Total
	UK	Rest of Europe	US[e]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2011										
Developed	608	84	3,366	10	660	600		491	662	6,481
Undeveloped	574	295	1,923		1,192	779		371	462	5,596
	1,182	379	5,289	10	1,852	1,379		862	1,124	12,077
Changes attributable to										
Revisions of previous estimates	28	10	27	(2)	41	(103)		(119)	55	(63)
Improved recovery	24	8	200		15	12		75	10	344
Purchases of reserves-in-place	1		26	2	7			58		94
Discoveries and extensions			39		9	19				67
Production[b f]	(66)	(13)	(289)	(1)	(153)	(108)		(92)	(59)	(781)
Sales of reserves-in-place	(36)		(97)	(4)	(76)	(12)		(87)		(312)
	(49)	5	(94)	(5)	(157)	(192)		(165)	6	(651)
At 31 December 2011[c]										
Developed	531	76	3,362	5	522	522		355	675	6,048
Undeveloped	602	308	1,833		1,173	665		342	455	5,378
	1,133	384	5,195	5	1,695	1,187		697	1,130	11,426
Equity-accounted entities (BP share)[g]										
At 1 January 2011										
Developed					593		2,716	382		3,691
Undeveloped				179	613	43	1,441	27		2,303
				179	1,206	43	4,157	409		5,994
Changes attributable to										
Revisions of previous estimates				(1)	(25)	5	795	(5)		769
Improved recovery					103		73	2		178
Purchases of reserves-in-place					103			14		117
Discoveries and extensions							25			25
Production[b f]					(59)		(362)	(80)		(501)
Sales of reserves-in-place					(260)					(260)
				(1)	(138)	5	531	(69)		328
At 31 December 2011[d h]										
Developed					546		2,961	274		3,781
Undeveloped				178	522	48	1,727	66		2,541
				178	1,068	48	4,688	340		6,322
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2011										
Developed	608	84	3,366	10	1,253	600	2,716	873	662	10,172
Undeveloped	574	295	1,923	179	1,805	822	1,441	398	462	7,899
	1,182	379	5,289	189	3,058	1,422	4,157	1,271	1,124	18,071
At 31 December 2011										
Developed	531	76	3,362	5	1,068	522	2,961	629	675	9,829
Undeveloped	602	308	1,833	178	1,695	713	1,727	408	455	7,919
	1,133	384	5,195	183	2,763	1,235	4,688	1,037	1,130	17,748

a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
b Excludes NGLs from processing plants in which an interest is held of 28 thousand barrels of oil equivalent per day.
c Includes 616 million barrels of NGLs. Also includes 496 million barrels of oil equivalent in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
d Includes 19 million barrels of NGLs. Also includes 340 million barrels of oil equivalent in respect of the minority interest in TNK-BP.
e Proved reserves in the Prudhoe Bay field in Alaska include an estimated 82 million barrels of oil equivalent upon which a net profits royalty will be payable.
f Includes 34 million barrels of oil equivalent of natural gas consumed in operations, 27 million barrels of oil equivalent in subsidiaries, seven million barrels of oil equivalent in equity-accounted entities and excludes two million barrels of oil equivalent of produced non-hydrocarbon components which meet regulatory requirements for sales.
g Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
h Total proved reserves held as part of our equity interest in TNK-BP is 4,802 million barrels of oil equivalent, comprising 100 million barrels of oil equivalent in Venezuela, 14 million barrels of oil equivalent in Vietnam and 4,688 million barrels of oil equivalent in Russia. In 2011, BP aligned its reporting with TNK-BP by moving to a life of field reporting basis. Reasonable certainty of licence renewals is demonstrated by evidence of Russian subsoil law, track record of renewals within the industry and track record of success in obtaining renewals by TNK-BP. This has resulted in an increase in proved reserves of 253 million barrels of oil equivalent.

Supplementary information on oil and natural gas (unaudited)

Movements in estimated net proved reserves continued

million barrels

Crude oil[a]	Europe		North America		South America	Africa	Asia		Australasia	2010 Total
	UK	Rest of Europe	US[e]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2010										
Developed	403	83	1,862	11	49	422		182	58	3,070
Undeveloped	291	184	1,211	1	56	454		334	57	2,588
	694	267	3,073	12	105	876		516	115	5,658
Changes attributable to										
Revisions of previous estimates	20	3	(45)	1	(1)	(62)		(62)		(146)
Improved recovery	100	9	133		17	14		145	3	421
Purchases of reserves-in-place		33	6					38		77
Discoveries and extensions	31	1	80			19				131
Production[b j]	(50)	(15)	(211)	(2)	(19)	(87)		(43)	(12)	(439)
Sales of reserves-in-place			(117)	(11)		(15)				(143)
	101	31	(154)	(12)	(3)	(131)		78	(9)	(99)
At 31 December 2010[c g]										
Developed	364	77	1,729		44	371		269	48	2,902
Undeveloped	431	221	1,190		58	374		325	58	2,657
	795	298	2,919		102	745		594	106	5,559
Equity-accounted entities (BP share)[f]										
At 1 January 2010										
Developed					407		2,351	363		3,121
Undeveloped					405	9	1,198	120		1,732
					812	9	3,549	483		4,853
Changes attributable to										
Revisions of previous estimates					4	3	248	(20)		235
Improved recovery					33		269			302
Purchases of reserves-in-place										
Discoveries and extensions					1					1
Production					(35)[i k]		(313)	(69)		(417)
Sales of reserves-in-place							(3)			(3)
					3	3	201	(89)		118
At 31 December 2010[d]										
Developed					408		2,388	370		3,166
Undeveloped					407	12	1,362	24		1,805
					815[h]	12	3,750	394		4,971
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2010										
Developed	403	83	1,862	11	456	422	2,351	545	58	6,191
Undeveloped	291	184	1,211	1	461	463	1,198	454	57	4,320
	694	267	3,073	12	917	885	3,549	999	115	10,511
At 31 December 2010										
Developed	364	77	1,729		452	371	2,388	639	48	6,068

Undeveloped	431	221	1,190	465	386	1,362	349	58	4,462
	795	298	2,919	917	757	3,750	988	106	10,530

a Crude oil includes NGLs and condensate. Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
b Excludes NGLs from processing plants in which an interest is held of 29 thousand barrels per day.
c Includes 643 million barrels of NGLs. Also includes 22 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
d Includes 18 million barrels of NGLs. Also includes 254 million barrels of crude oil in respect of the 7.03% minority interest in TNK-BP.
e Proved reserves in the Prudhoe Bay field in Alaska include an estimated 78 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
f Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
g Includes 70 million barrels relating to assets held for sale at 31 December 2010. Amounts by region are: 6 million barrels in US; 30 million barrels in South America; and 34 million barrels in Rest of Asia.
h Includes 213 million barrels relating to assets held for sale at 31 December 2010.
i Includes 2 million barrels of crude oil sold relating to production since classification of equity-accounted entities as held for sale.
j Includes 15 million barrels of crude oil sold relating to production from assets held for sale at 31 December 2010. Amounts by region are: 2 million barrels in US; 6 million barrels in South America; and 7 million barrels in Rest of Asia.
k Includes 9 million barrels of crude oil sold relating to production from assets held for sale at 31 December 2010.

Movements in estimated net proved reserves continued

billion cubic feet

Natural gas[a]	Europe		North America		South America	Africa	Asia		Australasia	2010 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2010										
Developed	1,602	49	9,583	716	3,177	1,107		1,579	3,219	21,032
Undeveloped	670	397	5,633	453	7,393	1,454		249	3,107	19,356
	2,272	446	15,216	1,169	10,570	2,561		1,828	6,326	40,388
Changes attributable to										
Revisions of previous estimates	(8)	(5)	(1,854)	(11)	2	3		(142)	(191)	(2,206)
Improved recovery	152	6	830		512	18		83	58	1,659
Purchases of reserves-in-place		31	97	1				17		146
Discoveries and extensions	26		739	9	19	1,378				2,171
Production[b i]	(191)	(8)	(861)	(77)	(953)	(229)		(228)	(288)	(2,835)
Sales of reserves-in-place	(6)		(424)	(1,033)		(51)				(1,514)
	(27)	24	(1,473)	(1,111)	(420)	1,119		(270)	(421)	(2,579)
At 31 December 2010[c f]										
Developed	1,416	40	9,495	58	3,575	1,329		1,290	3,563	20,766
Undeveloped	829	430	4,248		6,575	2,351		268	2,342	17,043
	2,245	470	13,743	58	10,150	3,680		1,558	5,905	37,809
Equity-accounted entities (BP share)[e]										
At 1 January 2010										
Developed					1,252		1,703	80		3,035
Undeveloped					1,010	165	519	13		1,707
					2,262	165	2,222	93		4,742
Changes attributable to										
Revisions of previous estimates					(141)	10	382	2		253
Improved recovery					291			12		303
Purchases of reserves-in-place										
Discoveries and extensions					23					23
Production[b]					(168)[h j]		(244)	(17)		(429)
Sales of reserves-in-place							(1)			(1)
					5	10	137	(3)		149
At 31 December 2010[d]										
Developed					1,075		1,900	71		3,046
Undeveloped					1,192	175	459	19		1,845
					2,267[g]	175	2,359	90		4,891
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2010										
Developed	1,602	49	9,583	716	4,429	1,107	1,703	1,659	3,219	24,067
Undeveloped	670	397	5,633	453	8,403	1,619	519	262	3,107	21,063
	2,272	446	15,216	1,169	12,832	2,726	2,222	1,921	6,326	45,130
At 31 December 2010										
Developed	1,416	40	9,495	58	4,650	1,329	1,900	1,361	3,563	23,812
Undeveloped	829	430	4,248		7,767	2,526	459	287	2,342	18,888
	2,245	470	13,743	58	12,417	3,855	2,359	1,648	5,905	42,700

a

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

b Includes 204 billion cubic feet of natural gas consumed in operations, 166 billion cubic feet in subsidiaries, 38 billion cubic feet in equity-accounted entities and excludes 14 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.

c Includes 2,921 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

d Includes 137 billion cubic feet of natural gas in respect of the 5.89% minority interest in TNK-BP.

e Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

f Includes 740 billion cubic feet relating to assets held for sale at 31 December 2010. Amounts by region are: 158 billion cubic feet in US; 205 billion cubic feet in South America; and 377 billion cubic feet in Rest of Asia.

g Includes 50 billion cubic feet relating to assets held for sale at 31 December 2010.

h Includes 1 billion cubic feet of gas sales relating to production since classification of equity-accounted entities as held for sale.

i Includes 133 billion cubic feet of gas (excluding gas consumed in operations) relating to production from assets held for sale at 31 December 2010. Amounts by region are: 23 billion cubic feet in US; 27 billion cubic feet in South America; and 83 billion cubic feet in Rest of Asia.

j Includes 3 billion cubic feet of gas (excluding gas consumed in operations) relating to production from assets held for sale at 31 December 2010.

Supplementary information on oil and natural gas (unaudited)

Movements in estimated net proved reserves continued

		million barrels
Bitumen[a]		2010
	Rest of North America	Total
Equity-accounted entities (BP share)		
At 1 January 2010		
Developed		
Undeveloped		
Changes attributable to		
Revisions of previous estimates		
Improved recovery		
Purchases of reserves-in-place		
Discoveries and extensions	179	179
Production		
Sales of reserves-in-place		
	179	179
At 31 December 2010		
Developed		
Undeveloped	179	179
	179	179

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.

Movements in estimated net proved reserves continued

million barrels of oil equivalent

Total hydrocarbons[a]	Europe		North America		South America	Africa	Asia		Australasia	2010 Total
	UK	Rest of Europe	US[e]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2010										
Developed	680	91	3,514	135	596	613		455	612	6,696
Undeveloped	406	253	2,183	79	1,331	704		376	593	5,925
	1,086	344	5,697	214	1,927	1,317		831	1,205	12,621
Changes attributable to										
Revisions of previous estimates	18	2	(364)	(2)	(1)	(61)		(87)	(33)	(528)
Improved recovery	126	10	276		105	17		160	13	707
Purchases of reserves-in-place		38	22					41		101
Discoveries and extensions	36	1	207	2	4	257				507
Production[b f l]	(83)	(16)	(359)	(15)	(183)	(127)		(83)	(61)	(927)
Sales of reserves-in-place	(1)		(190)	(189)		(24)				(404)
	96	35	(408)	(204)	(75)	62		31	(81)	(544)
At 31 December 2010[c i]										
Developed	608	84	3,366	10	660	600		491	662	6,481
Undeveloped	574	295	1,923		1,192	779		371	462	5,596
	1,182	379	5,289	10	1,852	1,379		862	1,124	12,077
Equity-accounted entities (BP share)[g]										
At 1 January 2010										
Developed					623		2,645	377		3,645
Undeveloped					580	37	1,287	122		2,026
					1,203	37	3,932	499		5,671
Changes attributable to										
Revisions of previous estimates					(20)	6	314	(19)		281
Improved recovery					83		269	2		354
Purchases of reserves-in-place										
Discoveries and extensions				179	4					183
Production[b f]					(64)[k m]		(354)	(73)		(491)
Sales of reserves-in-place							(4)			(4)
				179	3	6	225	(90)		323
At 31 December 2010[d]										
Developed					593		2,716	382		3,691
Undeveloped				179	613	43	1,441	27		2,303
				179	1,206[j]	43	4,157	409		5,994
Total subsidiaries and equity-accounted entities (BP share)[h]										
At 1 January 2010										
Developed	680	91	3,514	135	1,219	613	2,645	832	612	10,341
Undeveloped	406	253	2,183	79	1,911	741	1,287	498	593	7,951
	1,086	344	5,697	214	3,130	1,354	3,932	1,330	1,205	18,292
At 31 December 2010										
Developed	608	84	3,366	10	1,253	600	2,716	873	662	10,172
Undeveloped	574	295	1,923	179	1,805	822	1,441	398	462	7,899
	1,182	379	5,289	189	3,058	1,422	4,157	1,271	1,124	18,071

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

b Excludes NGLs from processing plants in which an interest is held of 29 thousand barrels of oil equivalent per day.

c Includes 643 million barrels of NGLs. Also includes 526 million barrels of oil equivalent in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

d Includes 18 million barrels of NGLs. Also includes 278 million barrels of oil equivalent in respect of the minority interest in TNK-BP.

e Proved reserves in the Prudhoe Bay field in Alaska include an estimated 78 million barrels of oil equivalent upon which a net profits royalty will be payable.

f Includes 35 million barrels of oil equivalent of natural gas consumed in operations, 28 million barrels of oil equivalent in subsidiaries, 7 million barrels of oil equivalent in equity-accounted entities and excludes 2 million barrels of oil equivalent of produced non-hydrocarbon components which meet regulatory requirements for sales.

g Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

h Includes 1,311 million barrels of oil equivalent (197 million barrels of oil equivalent for subsidiaries and 1,114 million barrels of oil equivalent for equity-accounted entities) associated with properties currently held for sale where the disposal has not yet been completed.

i Includes 197 million barrels of oil equivalent relating to assets held for sale at 31 December 2010. Amounts by region are: 34 million barrels of oil equivalent in US; 64 million barrels of oil equivalent in South America; and 99 million barrels of oil equivalent in Rest of Asia.

j Includes 222 million barrels of oil equivalent relating to assets held for sale at 31 December 2010.

k Includes 2 million barrels of oil equivalent sold relating to production since classification of equity-accounted entities as held for sale.

l Includes 38 million barrels of oil equivalent (excluding gas consumed in operations) relating to production from assets held for sale at 31 December 2010. Amounts by region are: 6 million barrels of oil equivalent in US; 11 million barrels of oil equivalent in South America; and 21 million barrels of oil equivalent in Rest of Asia.

m Includes 9 million barrels of oil equivalent (excluding gas consumed in operations) relating to production from assets held for sale at 31 December 2010.

Supplementary information on oil and natural gas (unaudited)

Movements in estimated net proved reserves continued

million barrels

Crude oil[a]	Europe		North America		South America	Africa	Asia		Australasia	2009 Total
	UK	Rest of Europe	US[e]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2009										
Developed	410	81	1,717	11	47	464		195	56	2,981
Undeveloped	119	194	1,273	1	55	496		488	58	2,684
	529	275	2,990	12	102	960		683	114	5,665
Changes attributable to										
Revisions of previous estimates	7	(1)	165	2	18	(121)		(128)	3	(55)
Improved recovery	42	7	82		7	32		31	2	203
Purchases of reserves-in-place	1							1		2
Discoveries and extensions	184		73			114			7	378
Production[b]	(61)	(14)	(237)	(2)	(22)	(109)		(45)	(11)	(501)
Sales of reserves-in-place	(8)							(26)		(34)
	165	(8)	83		3	(84)		(167)	1	(7)
At 31 December 2009[c]										
Developed	403	83	1,862	11	49	422		182	58	3,070
Undeveloped	291	184	1,211	1	56	454		334	57	2,588
	694	267	3,073	12	105	876		516	115	5,658
Equity-accounted entities (BP share)[f]										
At 1 January 2009										
Developed					399		2,227	499		3,125
Undeveloped					409	11	944	199		1,563
					808	11	3,171	698		4,688
Changes attributable to										
Revisions of previous estimates					2	(2)	590	(28)		562
Improved recovery					50		8			58
Purchases of reserves-in-place										
Discoveries and extensions					3		87			90
Production					(37)		(307)	(71)		(415)
Sales of reserves-in-place					(14)			(116)		(130)
					4	(2)	378	(215)		165
At 31 December 2009[d]										
Developed					407		2,351	363		3,121
Undeveloped					405	9	1,198	120		1,732
					812	9	3,549	483		4,853
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2009										
Developed	410	81	1,717	11	446	464	2,227	694	56	6,106
Undeveloped	119	194	1,273	1	464	507	944	687	58	4,247
	529	275	2,990	12	910	971	3,171	1,381	114	10,353
At 31 December 2009										
Developed	403	83	1,862	11	456	422	2,351	545	58	6,191
Undeveloped	291	184	1,211	1	461	463	1,198	454	57	4,320
	694	267	3,073	12	917	885	3,549	999	115	10,511

a Crude oil includes NGLs and condensate. Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

b Excludes NGLs from processing plants in which an interest is held of 26 thousand barrels per day.

c Includes 819 million barrels of NGLs. Also includes 23 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

d Includes 20 million barrels of NGLs. Also includes 243 million barrels of crude oil in respect of the 6.86% minority interest in TNK-BP.

e Proved reserves in the Prudhoe Bay field in Alaska include an estimated 68 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

f Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Supplementary information on oil and natural gas (unaudited)

Movements in estimated net proved reserves continued

billion cubic feet

Natural gas[a]	Europe UK	Europe Rest of Europe	North America US	North America Rest of North America	South America	Africa	Asia Russia	Asia Rest of Asia	Australasia	2009 Total
Subsidiaries										
At 1 January 2009										
Developed	1,822	61	9,059	659	3,316	1,050		1,102	1,887	18,956
Undeveloped	582	402	5,473	468	7,434	1,382		1,308	4,000	21,049
	2,404	463	14,532	1,127	10,750	2,432		2,410	5,887	40,005
Changes attributable to										
Revisions of previous estimates	(114)	(8)	549	43	322	270		(231)	22	853
Improved recovery	34		550	5	322	49		82	75	1,117
Purchases of reserves-in-place	159							31		190
Discoveries and extensions	150		496	94	105	59			531	1,435
Production[b]	(243)	(9)	(907)	(100)	(929)	(249)		(241)	(189)	(2,867)
Sales of reserves-in-place	(118)		(4)					(223)		(345)
	(132)	(17)	684	42	(180)	129		(582)	439	383
At 31 December 2009[c]										
Developed	1,602	49	9,583	716	3,177	1,107		1,579	3,219	21,032
Undeveloped	670	397	5,633	453	7,393	1,454		249	3,107	19,356
	2,272	446	15,216	1,169	10,570	2,561		1,828	6,326	40,388
Equity-accounted entities (BP share)[e]										
At 1 January 2009										
Developed					1,498		1,560	176		3,234
Undeveloped					1,023	182	653	111		1,969
					2,521	182	2,213	287		5,203
Changes attributable to										
Revisions of previous estimates					(26)	(17)	204	(19)		142
Improved recovery					314		1	4		319
Purchases of reserves-in-place										
Discoveries and extensions					6		23			29
Production[b]					(165)		(219)	(25)		(409)
Sales of reserves-in-place					(388)			(154)		(542)
					(259)	(17)	9	(194)		(461)
At 31 December 2009[d]										
Developed					1,252		1,703	80		3,035
Undeveloped					1,010	165	519	13		1,707
					2,262	165	2,222	93		4,742
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2009										
Developed	1,822	61	9,059	659	4,814	1,050	1,560	1,278	1,887	22,190
Undeveloped	582	402	5,473	468	8,457	1,564	653	1,419	4,000	23,018
	2,404	463	14,532	1,127	13,271	2,614	2,213	2,697	5,887	45,208
At 31 December 2009										
Developed	1,602	49	9,583	716	4,429	1,107	1,703	1,659	3,219	24,067
Undeveloped	670	397	5,633	453	8,403	1,619	519	262	3,107	21,063
	2,272	446	15,216	1,169	12,832	2,726	2,222	1,921	6,326	45,130

a

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

b Includes 195 billion cubic feet of natural gas consumed in operations, 164 billion cubic feet in subsidiaries, 31 billion cubic feet in equity-accounted entities and excludes 16 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.

c Includes 3,068 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

d Includes 131 billion cubic feet of natural gas in respect of the 5.79% minority interest in TNK-BP.

e Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Supplementary information on oil and natural gas (unaudited)

Movements in estimated net proved reserves continued

million barrels of oil equivalent

Total hydrocrabons[a]	Europe		North America		South America	Africa	Asia		Australasia	2009 Total
	UK	Rest of Europe	US[e]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2009										
Developed	724	91	3,279	126	617	645		385	382	6,249
Undeveloped	219	264	2,217	81	1,337	734		714	747	6,313
	943	355	5,496	207	1,954	1,379		1,099	1,129	12,562
Changes attributable to										
Revisions of previous estimates	(13)	(2)	260	9	74	(74)		(168)	7	93
Improved recovery	48	7	177	1	63	40		45	15	396
Purchases of reserves-in-place	28							6		34
Discoveries and extensions	210		158	17	18	124			98	625
Production[b f]	(102)	(16)	(393)	(20)	(182)	(152)		(86)	(44)	(995)
Sales of reserves-in-place	(28)		(1)					(65)		(94)
	143	(11)	201	7	(27)	(62)		(268)	76	59
At 31 December 2009[c]										
Developed	680	91	3,514	135	596	613		455	612	6,696
Undeveloped	406	253	2,183	79	1,331	704		376	593	5,925
	1,086	344	5,697	214	1,927	1,317		831	1,205	12,621
Equity-accounted entities (BP share)[g]										
At 1 January 2009										
Developed					658		2,495	529		3,682
Undeveloped					586	42	1,057	218		1,903
					1,244	42	3,552	747		5,585
Changes attributable to										
Revisions of previous estimates					(2)	(5)	625	(32)		586
Improved recovery					104		8	1		113
Purchases of reserves-in-place										
Discoveries and extensions					4		92			96
Production[b f]					(66)		(345)	(75)		(486)
Sales of reserves-in-place					(81)			(142)		(223)
					(41)	(5)	380	(248)		86
At 31 December 2009[d]										
Developed					623		2,645	377		3,645
Undeveloped					580	37	1,287	122		2,026
					1,203	37	3,932	499		5,671
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2009										
Developed	724	91	3,279	126	1,275	645	2,495	914	382	9,931
Undeveloped	219	264	2,217	81	1,923	776	1,057	932	747	8,216
	943	355	5,496	207	3,198	1,421	3,552	1,846	1,129	18,147
At 31 December 2009										
Developed	680	91	3,514	135	1,219	613	2,645	832	612	10,341
Undeveloped	406	253	2,183	79	1,911	741	1,287	498	593	7,951
	1,086	344	5,697	214	3,130	1,354	3,932	1,330	1,205	18,292

a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
b Excludes NGLs from processing plants in which an interest is held of 26 thousand barrels of oil equivalent per day.
c Includes 819 million barrels of NGLs. Also includes 552 million barrels of oil equivalent in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
d Includes 20 million barrels of NGLs. Also includes 266 million barrels of oil equivalent in respect of the minority interest in TNK-BP.
e Proved reserves in the Prudhoe Bay field in Alaska include an estimated 68 million barrels of oil equivalent upon which a net profits royalty will be payable.
f Includes 34 million barrels of oil equivalent of natural gas consumed in operations, 29 million barrels of oil equivalent in subsidiaries, 5 million barrels of oil equivalent in equity-accounted entities and excludes 3 million barrels of oil equivalent of produced non-hydrocarbon components which meet regulatory requirements for sales.
g Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

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

The following tables set out the standardized measure of discounted future net cash flows, and changes therein, relating to crude oil and natural gas production from the group s estimated proved reserves. This information is prepared in compliance with FASB Oil and Gas Disclosures requirements.

Future net cash flows have been prepared on the basis of certain assumptions which may or may not be realized. These include the timing of future production, the estimation of crude oil and natural gas reserves and the application of average crude oil and natural gas prices and exchange rates from the previous 12 months. Furthermore, both proved reserves estimates and production forecasts are subject to revision as further technical information becomes available and economic conditions change. BP cautions against relying on the information presented because of the highly arbitrary nature of the assumptions on which it is based and its lack of comparability with the historical cost information presented in the financial statements.

		$ million
		2011
	Europe	North