Annual Report and Form 20-F 2010

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What's inside?

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

FORM 20-F

(Mark One)

REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) or (g)
OF THE SECURITIES EXCHANGE ACT OF 1934
OR
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended 31 December 2010
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 Byron E Grote
BP p.l.c.
1 St James's Square, London SW1Y 4PD
United Kingdom
Tel +44 (0) 20 7496 4495
Fax +44 (0) 20 7496 4630
(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 2011	**New York Stock Exchange**
Substitute Floating Rate Guaranteed Note due 2011	**New York Stock Exchange**
1.55% Guaranteed Notes due 2011	**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**
3.875% Guaranteed Notes due 2015	**New York Stock Exchange**
3.125% Guaranteed Notes due 2015	**New York Stock Exchange**
4.75% Guaranteed Notes due 2019	**New York Stock Exchange**
4.5% Guaranteed Notes due 2020	**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	18,796,461,292
Cumulative First Preference Shares of £1 each	7,232,838
Cumulative Second Preference Shares of £1 each	5,473,414

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes ☑ No ☐

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

Yes ☐ No ☑

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

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).*

Yes ☑ No ☐

*This requirement does not apply to the registrant until its fiscal year ending December 31, 2011.

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 ☑ 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:

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

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

Item 17 ☐ Item 18 ☐

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ☐ No ☑

Cross reference to Form 20-F

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.

Annulus
The space between two concentric objects, such as between the wellbore and casing of an oil well or between casing and tubing, where fluid can flow. It allows fluids, such as drilling mud, to circulate in the well.

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
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.

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.

OPEC
Organization of Petroleum Exporting Countries.

Ordinary shares
Ordinary fully paid shares in BP p.l.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 2010. 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 5-109 and 123-140, 142 and PC1. The Directors' Remuneration Report is on pages 111-121. The consolidated financial statements of the group are on pages 141-248 and the corresponding reports of the auditor are on pages 143-145. The parent company financial statements of BP p.l.c. and corresponding auditor's report are on pages PC1-PC16 and page PC2 respectively.

The statement of directors' responsibilities in respect of the consolidated financial statements, the independent auditor's report on the annual report and accounts to the members of BP p.l.c. and the parent company financial statements of BP p.l.c. and corresponding auditor's report do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

BP Annual Report and Form 20-F 2010 and *BP Summary Review 2010* may be downloaded from *www.bp.com/annualreport*. No material on the BP website, other than the items identified as *BP Annual Report and Form 20-F 2010* or *BP Summary Review 2010*, 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

BP Annual Report and Form 20-F 2010 contains certain forward-looking statements within the meaning of the US Private Securities Litigation Reform Act of 1995 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.

In order to utilize the 'Safe Harbor' provisions of the United States Private Securities Litigation Reform Act of 1995, BP is providing the following cautionary statement. This document contains certain forward-looking statements 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', 'plans', 'we see' or similar expressions. In particular, among other statements, (i) certain statements in the Business review (pages 6-82), including under the heading 'Outlook', with regard to strategy, management aims and objectives, future capital expenditure, the completion of planned and announced divestments and disposals, acquisitions and other transactions, future hydrocarbon production volume and the group's ability to satisfy its long-term sales commitments from future supplies available to the group, date(s) or period(s) in which production is scheduled or expected to come onstream or a project or action is scheduled or expected to begin or be completed, capacity of planned plants or facilities and impact of health, safety and environmental regulations; (ii) the statements in the Business review (pages 6-63 and 68-81) with regard to anticipated energy demand and consumption, global economic recovery, oil and gas prices, global reserves, refining capacity, expected future energy mix and the potential for cleaner and more efficient sources of energy, management aims and objectives, strategy, production, petrochemical and refining margins, anticipated investment in Alternative Energy, anticipated future project developments, growth of the international businesses, Refining and Marketing investments, reserves increases through technological developments, with regard to planned investment or other projects, timing and ability to complete announced transactions and future regulatory actions; (iii) the statements in the Business review (pages 23-26, 63-67 and 73) with regard to the plans of the group, the cost of and provision for future remediation programmes and environmental operating and capital expenditures, taxation, liquidity and costs for providing pension and other post-retirement benefits; and including under 'Liquidity and capital resources – Trend Information', with regard to global economic recovery, oil and gas prices, petrochemical and refining margins, production, demand for petrochemicals, production and production growth, depreciation, underlying average quarterly charge from Other businesses and corporate, costs, foreign exchange and energy costs, capital expenditure, timing and proceeds of divestments, balance of cash inflows and outflows, dividend and optional scrip dividend, cash flows, shareholder distributions, gearing, working capital, guarantees, expected payments under contractual and commercial commitments and purchase obligations; and (iv) certain statements in Chairman's letter (pages 6-7) and Business review (pages 10-11) in relation to an anticipated increase in the level of the dividend; 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; future levels of industry product supply, demand and pricing; operational problems; general economic conditions; political stability and economic growth in relevant areas of the world; changes in laws and governmental regulations; actions by regulators; exchange rate fluctuations; development and use of new technology; the success or otherwise of partnering; the actions of competitors; 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 27-32). 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 in the form of ADSs. (*See page 134 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.

Business review

Chairman's letter

Dear fellow shareholder

2010 was a profoundly painful and testing year. In April, a tragic accident on the Deepwater Horizon rig claimed the lives of 11 men and injured others. Above all else, I want to remember those men, and say that our thoughts remain with their families and friends. BP's priority is to ensure that the people who work for us, and with us, return home safely. The accident should never have happened. We are shocked and saddened that it did.

The spill that resulted caused widespread pollution. Our response has been unprecedented in scale, and we are determined to live up to our commitments in the Gulf. We will also do everything necessary to ensure BP is a company that can be trusted by shareholders and communities around the world.

In the days after the accident in the Gulf of Mexico the company faced a complex and fast-changing crisis. With oil escaping into the ocean, uncertainty grew around our ability to seal the well and restore the areas affected. This was an intense period, with the situation worsening almost daily. Our meeting with President Obama on 16 June 2010 provided reassurance to the US government that BP would do the right thing in the Gulf, and this marked a turning point. Through diligence and invention, our teams stopped the flow of oil in July and completed relief-well operations in September.

During these difficult days your board focused on three critical objectives.

First, we ensured the response team had the resources it required to stop the leak, contain and clean up the damage, and provide financial support to those affected. This was an unprecedented response to an industrial accident, with some 48,000 people involved at the height of the effort. We have set up a $20-billion fund to show our willingness and capacity to pay all legitimate claims for compensation. For the long term, we have committed $500 million to a 10-year independent research programme that will examine the environmental impact of the oil spilled and dispersants used. BP will continue to help restore the environment and economy of the Gulf, however long that takes.

Second, we resolved to understand what happened on and below the Deepwater Horizon, to apply the lessons learned and to make our findings available publicly. BP's comprehensive internal investigation concluded that a sequence of failures involving a number of different parties led to the explosion and fire.

We are implementing the report's recommendations. We have established a powerful safety and operational risk function, and we have enhanced risk management through the restructuring of our upstream business. We are also conducting a wide-ranging review of when and how we outsource operations.

Third, we moved to secure the long-term future of BP and our capacity to meet our financial responsibilities in the Gulf of Mexico. Decisive action was required here because events in the US led to a crisis of confidence in BP within the financial markets. In response, we made the difficult decision to cancel three dividend payments. We do not underestimate the effect of this on small and large shareholders alike. However, there is no doubt in my mind that this action steadied and strengthened our position at a critical point.

I am pleased that we have been able to resume dividend payments promptly. The dividend for the fourth quarter of 2010, to be paid in March 2011, is 7 cents per share (US$0.42 per ADS). The scrip dividend programme approved last year is in operation once again, and this presents an opportunity to take the dividend in shares or ADSs rather than cash. We intend to raise the level of the dividend as the company's circumstances and performance improve.

During the year we further reinforced our financial position. Having taken a total pre-tax charge of $40.9 billion in relation to the accident and spill, we announced our intention to sell up to $30 billion of assets. We have already secured almost $22 billion. We intend to reduce the net debt ratio to within the range of 10-20%, compared with our previously targeted range of 20-30%.

We have made significant changes to the board and I want to acknowledge Tony Hayward and Andy Inglis, who have left the company. Tony stood down as group chief executive on 1 October 2010. The board was saddened to lose someone whose long-term contribution to BP was so widely admired. Andy Inglis stood down on 31 October 2010. Andy was a strong leader of Exploration and Production and a significant contributor to the board.

BP is fortunate to have an exceptional successor to the role of group chief executive. Bob Dudley has spent his working life in the oil industry and has proved himself a robust, successful leader in the toughest circumstances. I am delighted to be working alongside a man of such substance and experience.

Douglas Flint will be standing down at the annual general meeting in April 2011, having taken up a new role as chairman of HSBC Holdings plc. Douglas has chaired our audit committee for the past year. DeAnne Julius will be standing down at the same time, having joined the board in 2001. DeAnne has chaired the remuneration committee since 2005 and is succeeded in that role by Antony Burgmans. Both DeAnne and Douglas have been immensely valuable board members. We thank them and wish them both well.

Boards must evolve if they are to engage effectively with new issues and opportunities. We have acted to strengthen the board of BP to ensure we have the right mix of skills, knowledge and experience as we work to achieve sustainable success in a fast-changing world. In early 2010 we appointed Paul Anderson and Ian Davis as non-executive directors. We have since made three further non-executive appointments. Admiral Frank L 'Skip' Bowman is former head of the US Nuclear Navy and was a member of the Baker Panel that reviewed safety at BP's US refineries. We will benefit from his exceptional experience on safety matters and his knowledge of BP. Brendan Nelson brings vast financial and auditing experience from KPMG, where latterly he was vice chairman. He is eminently well qualified to take over the chair of the audit committee following the annual general meeting. Phuthuma Nhleko will bring deep experience of emerging markets, gained while he was group president and chief executive officer of multinational telephony company MTN Group.

Clearly, after a very troubled and demanding 12 months, BP is a changed company. As a board we have much to do, and we are working with the executive team to ensure successful implementation of a refocused strategy built on the pillars of safety, trust and value creation. Foremost is the need to ensure the right checks and balances are in place across the company. The full board will continue to maintain close oversight of matters related to safety. And we will have even greater engagement on the strategic implications of risk.

Looking ahead, we believe that a growing population and rising levels of prosperity will create strong demand for energy. BP's ability to produce oil and gas from harsh environments means we have a vital contribution to make here. We will also continue to respond to climate change, and to the prospect of fossil fuels becoming a smaller part of the energy mix. For these reasons, BP must continue to be a leader in high-quality hydrocarbons today, while developing the intelligent options we will all rely on tomorrow. Lower-carbon resources remain central to this long-term strategy.

BP is able to help meet the world's growing need for energy, but we can only do this if we have the trust of society. To achieve this, we must ensure that safety and responsibility are at the heart of everything we do. We must show that we can be trusted to understand and manage our risks. And we must demonstrate that we respect the environment and the needs of local communities and society as a whole.

The many strengths of BP are united in our remarkable people, who showed in 2010 that they can rise to the sternest challenge. I thank them for their efforts.

While we face substantial challenges, shareholders must be in no doubt – BP has the determination and strength needed to restore its reputation and deliver long-term shareholder value. Through its refocused strategy, the company is working to become more agile and more competitive, with strong emphasis on realizing value rather than building volume and scale. We will not be afraid to develop new and innovative approaches that redefine the model of an international oil company, as our recently announced partnerships with Rosneft and Reliance demonstrate.

I want to end by thanking shareholders for their support. You have been steadfast through one of the most testing periods in BP's long history. We have learned many lessons about ourselves over the past 12 months, and these will never be forgotten. I believe we will emerge a stronger, wiser company with a very important role to play, for many years to come.

Carl-Henric Svanberg
Chairman
2 March 2011

More on board performance
bp.com/governance

Board of directors

As at 31 December 2010

From left to right

Sir William Castell
Senior Independent Director

Brendan Nelson
Non-Executive Director

Iain Conn
Chief Executive,
Refining and Marketing

Ian Davis
Non-Executive Director

Dr DeAnne Julius
Non-Executive Director

Antony Burgmans
Non-Executive Director

Carl-Henric Svanberg
Chairman

Dr Byron Grote
Chief Financial Officer

Bob Dudley
Group Chief Executive

Douglas Flint
Non-Executive Director

George David
Non-Executive Director

Cynthia Carroll
Non-Executive Director

Paul Anderson
Non-Executive Director

Frank Bowman
Non-Executive Director

Group chief executive's letter

Dear fellow shareholder

The tragic events of 2010 will forever be written in the memory of this company and the people who work here. The explosion and fire on the Deepwater Horizon rig shocked everyone within BP, and we feel great sadness that 11 people died. We are deeply sorry for the grief felt by their families and friends. We know nothing can restore the loss of those men.

The accident on 20 April 2010 turned into an unprecedented oil spill with deep consequences for jobs, businesses, communities, the environment and our industry. From this grew a corporate crisis that threatened the very existence of the company. And it all started in a part of the world that's very close to my heart. I grew up in Mississippi, and spent summers with my family swimming and fishing in the Gulf. I know those beaches and waters well. When I heard about the accident I could immediately picture how it might affect the people who live and work along that coast.

Yet, just days before the accident, I had been reflecting on the progress made by BP. The company had put safe and reliable operations at the centre of everything, and we had turned a corner on financial performance. Then came the unthinkable. A subsea blowout in deep water was seen as a very, very low-probability event, by BP and the entire industry – but it happened.

Following the accident, a search-and-rescue operation was carried out by the rig's owner, Transocean, together with BP and the US Coast Guard. This continued for four days and covered 5,000 square miles. On 22 April 2010 the Deepwater Horizon sank, and a major oil spill response was activated. At its peak this involved the mobilization of some 48,000 people, the deployment of around 2,500 miles of boom and the co-ordination of more than 6,500 vessels. Field operations brought together experts from key agencies, organizations and BP. Thousands of our people flew in from around the world and stayed and worked for weeks and months. Nearly 500 retirees from BP America called up to say they wanted to help. This was an extraordinary response.

As the response developed, the problems grew in complexity and scale. Tackling the leak on the seabed demanded groundbreaking technical advances and dauntless spirit. We also found ourselves in the midst of intense political and media scrutiny. We received incredible support and faced tremendous criticism, but our priorities remained clear – provide support to the families and friends of those 11 men who died, stop the leak, attack the spill, protect the shore, support all the people and places affected. We also committed to carry out an immediate and detailed internal investigation.

As a responsible party, under the Oil Pollution Act, we knew we would face wide-ranging claims and potential fines, but we resolved to go beyond what the law required of us. We made swift payments to support local economies, and gave a total of $138 million in direct state grants during 2010, which included behavioural health programmes. We set up the $20-billion Deepwater Horizon Oil Spill Trust to meet individual, business, government, local and state claims, and natural resource damages. We provided $500 million for the Gulf of Mexico Research Initiative, which is funding independent research to investigate impacts on affected ecosystems. And we contributed to a $100-million fund to support rig workers hit by the drilling moratorium.

To meet our financial commitments, we announced the sale of up to $30 billion in assets and, by the end of 2010, had agreed to $22 billion of disposals. We have also cut back on discretionary capital spending and secured additional credit lines. The sound underlying performance across our business continues to give us a solid foundation, and speaks volumes for the inner strengths of BP and our people.

As part of our response, we took the decision to cancel further dividends in 2010. While we know that many shareholders rely on their regular payments, we also had to protect the company and secure its long-term future. The board of BP took this decision with a heavy heart, but I believe it was the right thing to do in truly exceptional circumstances.

Our investigation report was published on 8 September 2010, and found that no single factor caused the accident. The report stated that decisions made by multiple companies and work teams contributed to the accident, and these arose from a complex and interlinked series of mechanical, human judgement, engineering design, operational implementation and team interface failures.

We have accepted and are implementing the report's recommendations. We are also sharing what we have learned with governments and others in our industry, and we are co-operating with a series of other investigations, inquiries and hearings.

2010 stands as an inflexion point for BP and our industry, and it is right that we should help lead the development of better ways to operate in deep water. Good risk identification and management is integral to becoming safer, and we are working with governments, service contractors and industry peers to take risk management and equipment design to the next level. Within BP, we have introduced more layers of protection and resilience, with our new safety and operational risk function empowered to intervene in any operation. To enhance our specialist expertise and risk management, we have re-organized our upstream business into three divisions – Exploration, Developments and Production. To encourage excellence in risk management throughout the organization, we are reviewing how we incentivize and reward people. And to think hard about what was previously unthinkable, we are looking further afield for insight and wisdom. I have spent time with experts from the nuclear and chemicals industries, and I am convinced that we in the energy industry have much to learn from them and others. We must take what we learn and embed it deep in the fabric of our organization.

Part of BP's task right now is to show we can be trusted to handle the industry's most demanding jobs, including exploration and production in deep water. Around 7% of the world's oil supplies come from this source, and we expect this will rise to nearly 10% by 2020. We are one of only a handful of companies with the financial and technological strengths needed to operate in these geographies. Before April 2010, BP had drilled safely in the deep waters of the Gulf of Mexico for 20 years. The governments of Egypt, China, Indonesia, Azerbaijan and the UK have shown confidence in our ability to operate safely at depths, having signed new deepwater drilling agreements with us in the second half of 2010.

It is important to remember why companies such as BP have to take on the risks they do. Around 40 years ago, international oil companies had access to the majority of the world's oil reserves. Today these companies can access a much smaller share. This still provides substantial opportunities for value creation, but reaching many of those reserves requires us to overcome severe physical, technical, intellectual and geopolitical challenges. Global energy demand continues to rise, so the world needs BP and others to meet these challenges in an environmentally sustainable way. In doing this, we can never eliminate every hazard, but we can become an industry leader in understanding and limiting risk. That's our goal.

Clearly, one of the consequences of the events of 2010 was a substantial loss of value and returns for our shareholders. I am pleased that we have been able to resume dividend payments, and our intention is to grow the dividend level in line with the company's improving circumstances. We are now taking action to create and realize greater value. We are increasing our investment in exploration, which is one of our distinctive strengths.

We are gaining access to a wide range of new upstream resource opportunities, and already have 32 project start-ups planned between now and 2016. We are taking an even more active approach to buying, developing and selling upstream assets, with a focus on maximizing returns rather than building volume. And we are divesting roughly half of our US refining capacity, so we can focus downstream investments on refining positions and marketing businesses where we have competitive advantage. This builds on the success BP's Refining and Marketing business has achieved in driving itself back to significantly improved performance and returns over the past few years.

In short, BP is moving swiftly to address its weaknesses and build on its strengths. While doing this we will not hesitate to go beyond the conventional business model of an international oil company. Since 2003 we have had a strong alliance onshore in Russia with TNK-BP. In January 2011 we announced our Arctic alliance with Rosneft, which further shows our strategy in action. Pending completion[a], this is expected to be the first major equity-linked partnership between a national and international oil company, with an agreement with Rosneft to receive 5% of BP's ordinary voting shares in exchange for approximately 9.5% of Rosneft's shares. Under the agreement, Rosneft and BP will seek to form a joint venture to explore and, if successful, develop three licence blocks in the South Kara Sea – an area roughly equivalent in size and prospectivity to the UK North Sea. BP and Rosneft have also agreed to establish an Arctic technology centre in Russia, which will work with research institutes, design bureaus and universities to develop technologies and engineering practices for the safe extraction of hydrocarbon resources from the Arctic shelf.

[a] On 1 February 2011 the English High Court granted an interim injunction restraining BP from taking any further steps in relation to the Rosneft transactions pending the outcome of arbitration proceedings. See Note 6 Events after the reporting period.

In February 2011 we announced a second historic agreement. This will, subject to completion, see BP and Reliance work together across the gas value chain in the fast-growing Indian market. This major strategic alliance will combine BP's deepwater capabilities with Reliance's project management and operations expertise.

BP is also partnering with another organization, Husky Energy, to develop a further important resource of energy – Canada's oil sands. These represent the second largest reserves in the world after the oilfields of Saudi Arabia. We will work with this resource in a way that fits with our long-term responsibilities and objectives, using steam assisted gravity drainage to extract the oil, and an efficient, integrated system to transport it. Our approach will have a relatively small footprint and should not be confused with opencast mining – we will not engage in mining. On a well-to-wheel basis, greenhouse gas emissions from Canadian oil produced this way are expected to be slightly higher than those from conventional crudes imported to North America.

Along with providing the hydrocarbons required over coming years, we are helping to build the sustainable options needed to meet growing demand for lower-carbon energy. Our natural gas operations will help to provide a lower-carbon bridge from oil and coal to renewables. We are building a material business to produce biofuels in Brazil, the US and the UK. We are becoming a leading player in wind energy. We have a long-established solar business. And we have made substantial investments in carbon-capture-and-storage technology. Lower-carbon resources are the fastest-growing sector in the energy market, and BP intends to develop its portfolio in step with this growth.

As to the immediate future, I expect 2011 to be a year of consolidation for BP, as we focus on completing our previously announced divestment programme, meeting our commitments in the US and bringing renewed rigour to the way we manage risk. There will also be an increasing emphasis on value over volume, as we sharpen our strategy and reshape the company for growth.

Looking back over recent days and months, our thoughts return to the men who lost their lives, to those who were injured and to the communities hit hard by the spill. I have heard people ask "Does BP 'get it'?" Residents of the Gulf, our employees and investors, governments, industry partners and people around the world all want to know whether we understand that a return to business-as-usual is not an option. We may not have communicated it enough at times, but yes, we get it. Our fundamental purpose is to create value for shareholders, but we also see ourselves as part of society, not apart from it. Put simply, our role is to find and turn energy resources into financial returns, but by doing that in the right way we can help create a prosperous and sustainable future for everyone. This is what people rightfully expect of BP. This is what will inspire and drive us over the next 12 months and far into the future.

Bob Dudley
Group Chief Executive
2 March 2011

More on our performance
bp.com/annualreport

Business review

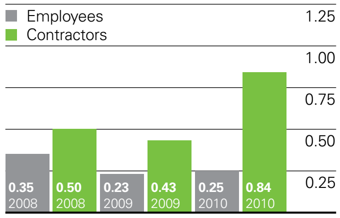
Progress in 2010

Safety

Personal safety – reported recordable injury frequency

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.

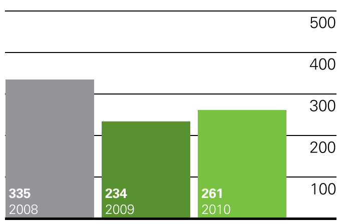
In 2010 our workforce RIF, which includes employees and contractors combined, was 0.61, compared with 0.34 in 2009 and 0.43 in 2008. The nature of the Gulf Coast response effort resulted in personal safety incident rates significantly higher than in other BP operations.



Process safety – oil spills

We report all 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.

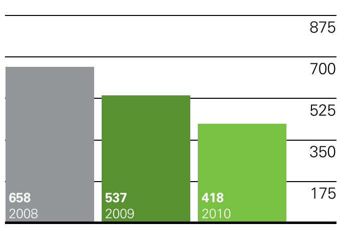
In 2010 there were 261 oil spills of one barrel or more, including the Gulf of Mexico oil spill. We are taking measures to strengthen mandatory safety-related standards and processes, including operational risk and integrity management.



Process safety – loss of primary containment

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.

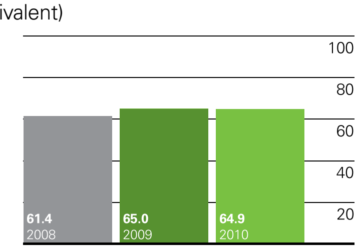
BP is progressively moving towards this as one of the key indicators for process safety, as we believe it provides a more comprehensive and better performance indicator of the safety and integrity of our facilities than oil spills alone.



Environment – greenhouse gas emissions[a] (million tonnes of carbon dioxide equivalent)

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. We have not included any emissions from the Gulf of Mexico oil spill and the response effort due to our reluctance to report data that has such a high degree of uncertainty.

We aim to manage our GHG emissions through a focus on operational energy efficiency and reductions in flaring and venting.



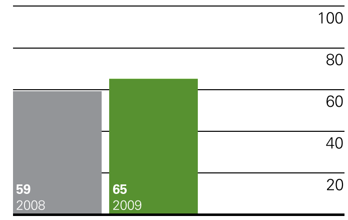
[a] See *BP Sustainability Review 2010* for more information on our GHG emissions performance.

People

Employee satisfaction (%)

The overall Employee Satisfaction Index comprises 10 key questions that provide insight into levels of employee satisfaction across a range of topics, such as pay and trust in management. We use a sample-based approach to achieve a representative view of BP.

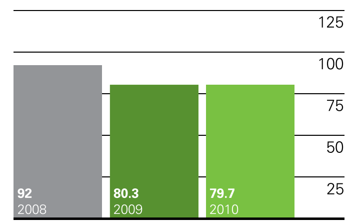
Our 2010 employee survey was delayed to allow for organizational changes to be reflected in the survey construction, with the survey expected to be carried out in summer 2011.



Number of employees[a] (thousands)

Employees include all individuals who have a contract of employment with a BP group entity.

In 2007 we began a process of making BP a simpler, more efficient organization. Since then our total number of employees has reduced by approximately 18,000, including around 9,200 in our non-retail businesses.

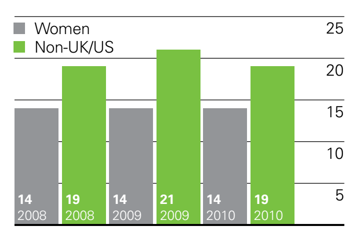


[a] As at 31 December.

Diversity and inclusion (%)

Each year we record the percentage of women and individuals from countries other than the UK and US among BP's top leaders. The number of top leaders in 2010 was 482, compared with 492 in 2009 and 583 in 2008.

BP has maintained the percentage of female leaders in 2010 and remains focused on building a more sustainable pipeline of diverse talent for the future.

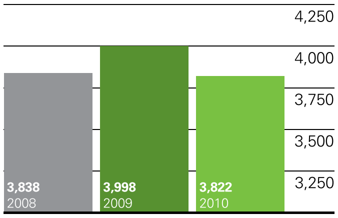


Performance

Production (thousand barrels of oil equivalent per day)

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.

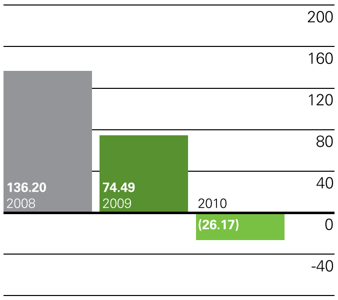
Reported production in 2010 was 4% lower than in 2009, due to the effect of entitlement changes in our production-sharing agreements, the effect of acquisitions and disposals, and the impact of events in the Gulf of Mexico.



Replacement cost profit (loss) per ordinary share (cents)

Replacement cost profit (loss) reflects the replacement cost of supplies. It is arrived at by excluding from profit inventory holding gains and losses and their associated tax effect. Replacement cost profit for the group is the profitability measure used by management. It is a non-GAAP measure. See page 23 for the equivalent measure on an IFRS basis.

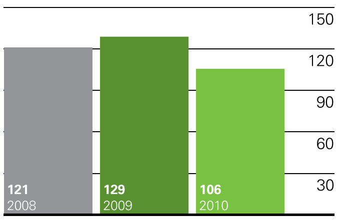
In 2010 we recorded a replacement cost loss primarily driven by a \$40.9-billion pre-tax charge in relation to the Gulf of Mexico incident.



Reserves replacement ratio[a] (%)

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.

Our reserves replacement ratio in 2010 exceeded 100% once again. We continue to drive renewal through new access, exploration, targeted acquisitions and a strategic focus on increasing resources from fields we currently operate.

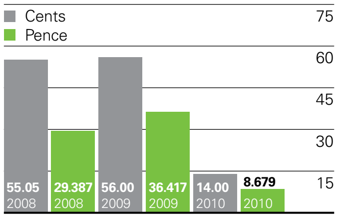


[a] Combined basis of subsidiaries and equity-accounted entities, excluding acquisitions and disposals.

Dividends paid per ordinary share

This measure shows the total dividend per share paid to ordinary shareholders in the year.

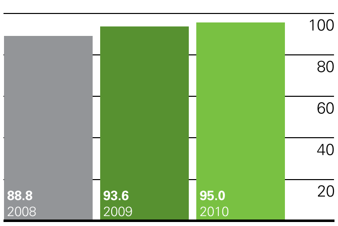
In June 2010 the BP board reviewed its dividend policy in light of the Gulf of Mexico incident, and the agreement to establish a \$20-billion trust fund, and decided to cancel ordinary share dividends in respect of the first three quarters of 2010.



Refining availability (%)

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

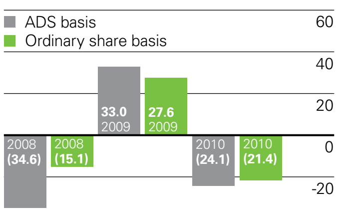
Refining availability continued its increasing trend in 2010, with the biggest contributor being the restoration of our Texas City refinery.



Total shareholder return (%)

Total shareholder return represents the change in value of a 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.

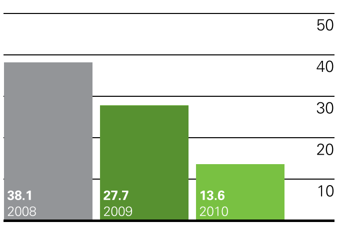
Total shareholder returns in 2010 were significantly impacted by the cancellation of dividend payments and the fall in share price brought about by the events in the Gulf of Mexico.



Operating cash flow ($ billion)

Operating cash flow is net cash flow provided by operating activities, from the group cash flow statement. Operating activities are the principal revenue-generating activities of the group and other activities that are not investing or financing activities.

The reduction in operating cash flow primarily reflected the impacts of the Gulf of Mexico incident.



Group overview

Our organization

BP is one of the world's leading international oil and gas companies.[a] We operate or market our products in more than 80 countries, providing our customers with fuel for transportation, energy for heat and light, retail services and petrochemicals products for everyday items.

As a global group, our interests and activities are held or operated through subsidiaries, jointly controlled entities or associates established in – and subject to the laws and regulations of – many different jurisdictions. These interests and activities covered two business segments in 2010: Exploration and Production and Refining and Marketing. BP's activities in low-carbon energy are managed through our Alternative Energy business, which is reported within Other businesses and corporate.

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). During the fourth quarter of 2010, as part of our wider response to the Gulf of Mexico incident, we decided to reorganize our Exploration and Production segment to create three global functional divisions: Exploration, Developments, and Production, integrated through a Strategy and Integration organization. This is designed to fundamentally change the way the segment operates, with a particular focus on managing risk, delivering common standards and processes and building personnel and technological capability for the future. The Exploration division is accountable for renewing our resource base through access, exploration and appraisal activities. The Developments division is accountable for the safe and compliant execution of wells (drilling and completions) and major projects. 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.

Refining and Marketing's activities include the supply and trading, refining, manufacturing, marketing and transportation of crude oil, petroleum and petrochemicals products and related services. The segment comprises a number of strategic performance units (SPUs), which are organized along either geographic or activity-related lines. Each SPU is of a scale that allows for a close focus on performance delivery, starting with safety, and includes the appropriate management of operating and financial parameters.

Our group functions and regions support the work of our segments and businesses. The key objectives of the functions are to establish and monitor fit-for-purpose functional standards across the group; to act as centres of deep functional expertise; to access significant leverage with third-party suppliers; and to establish and maintain capabilities among the functional staff employed within our operating businesses. In addition, the head of each region provides the required cross-segment integration and co-ordination of group activities in a particular geographic area and represents BP to external parties.

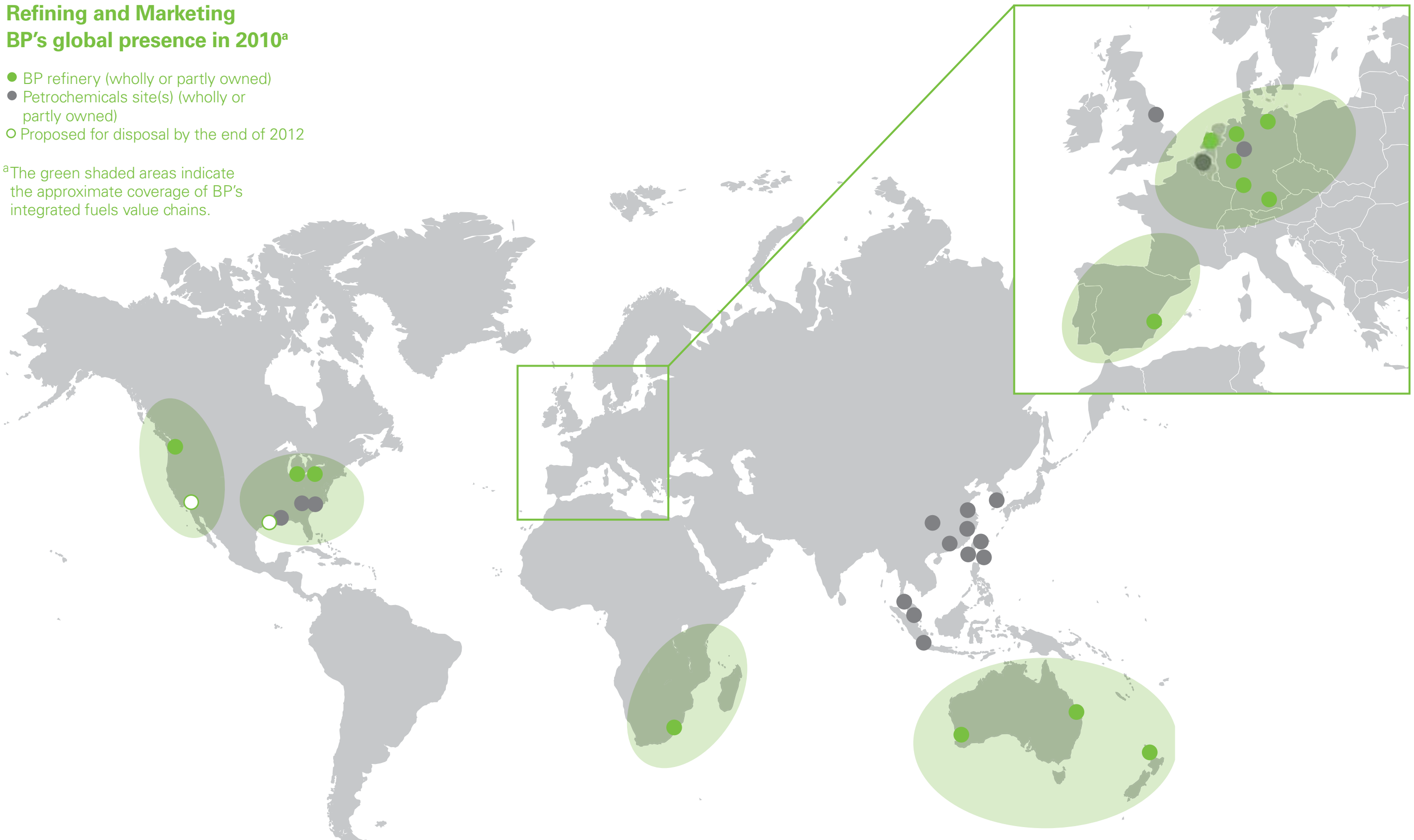
In June 2010, following the Gulf of Mexico incident, we established the Gulf Coast Restoration Organization (GCRO) and subsequently equipped it with dedicated resources and capabilities to manage all aspects of our response to the accident. This organization reports directly to the group chief executive and is overseen by a specific new board committee.

Among the changes we have made following the Gulf of Mexico incident, we have redefined and strengthened the scope and accountabilities of the group function for safety and operations, creating an enhanced, independent Safety and Operational Risk (S&OR) function, to oversee and audit the company's operations around the world. The function has its own expert staff embedded in BP's operating units, including exploration projects

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

Exploration and Production
BP's major areas of operation in 2010

Refining and Marketing
BP's global presence in 2010[a]



and refineries, with defined intervention rights with respect to BP's technical and operational activities. The function reports directly to the group chief executive and aims to provide assurance that BP's operations are carried out to common standards, and audits conformance to those standards.

The significant subsidiaries of the group at 31 December 2010 and the group percentage of ordinary share capital (to the nearest whole number) are set out in Financial statements – Note 46 on pages 220-221. See Financial statements – Notes 25 and 26 on pages 183 and 184 respectively for information on significant jointly controlled entities and associates of the group.

On 14 January 2011, BP and Rosneft Oil Company (Rosneft) announced that they had agreed a strategic global alliance. BP and Rosneft have agreed to seek to form a joint venture to explore and, if successful, develop three licence blocks on the Russian Arctic continental shelf. BP and Rosneft have entered into a related share swap agreement whereby, upon completion, BP will receive approximately 9.5% of Rosneft's shares in exchange for BP issuing new ordinary shares to Rosneft with an aggregate value of approximately $7.8 billion (as at close of trading in London on 14 January 2011), resulting in Rosneft holding 5% of BP's ordinary voting shares. See Legal proceedings on page 133 for information on an interim injunction, granted by the English High Court on 1 February 2011 restraining BP from taking any further steps in relation to the Rosneft transactions pending the outcome of arbitration proceedings.

On 21 February 2011, Reliance Industries Limited and BP announced that they intend to form an upstream joint venture in which BP will take a 30% stake in 23 oil and gas production-sharing contracts that Reliance operates in India, including the producing KG D6 block, and form a 50:50 joint venture for the sourcing and marketing of gas in India. BP will pay Reliance Industries Limited an aggregate consideration of $7.2 billion, and completion adjustments, for the interests to be acquired in the 23 production-sharing contracts. Future performance payments of up to $1.8 billion could be paid based on exploration success that results in development of commercial discoveries. Reliance will continue to be the operator under the production-sharing contracts. Completion of the transactions is subject to Indian regulatory approvals and other customary conditions.

Where we operate

BP's 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. Currently, around 68% of the group's fixed assets are invested in Organization for Economic Co-operation and Development (OECD) countries, with around 42% of our fixed assets located in the US and around 20% in Europe.

Our Exploration and Production segment included upstream and midstream activities in 29 countries in 2010 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. Our Exploration and Production segment 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.

In Refining and Marketing, we market our products in more than 70 countries, with a particularly strong presence in Europe and North America, and also manufacture and market our products across Australasia, in China and other parts of Asia, Africa and Central and South America. In the US, we own or have a share in five refineries and market fuel primarily under the ARCO and BP brands. See Refining and Marketing (Our strategy) on page 55 for further information on forthcoming portfolio changes in the US. In Europe, we own or have a share in seven refineries and we market extensively across the region, primarily under the Aral and BP fuel brands. Our long-established supply and trading activity is responsible for delivering value across the crude and oil products supply chain. Our petrochemicals business maintains a manufacturing position globally, with an emphasis on growth in Asia. Our lubricants business blends and markets lubricants globally, primarily under the Castrol brand, and is a growing business through market growth and the development of new products. We continue to seek opportunities to broaden our activities in growth markets such as China and India.

Our market

Energy markets in 2010 continued to recover from the impact of the global economic recession. Looking ahead, the long-term outlook is one of growing demand for energy[a], particularly in Asia, and of challenges for the industry in meeting this demand. Rising incomes and expanding urban populations are expected to drive demand, while the evolution towards a lower-carbon economy will require technology, innovation and investment.

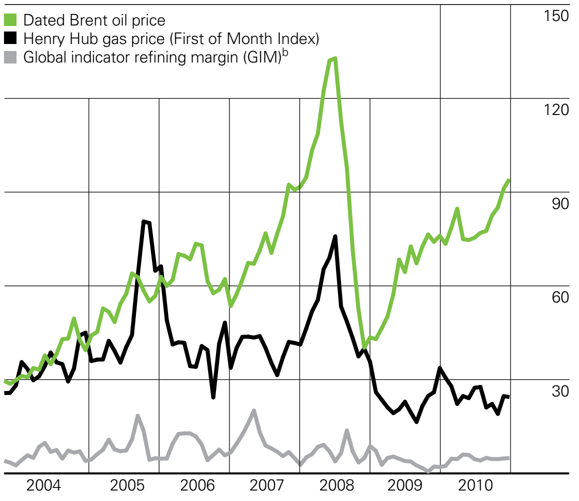
World oil consumption rebounded in 2010, with continued robust growth in China and other non-OECD countries and the first increase among OECD countries since 2005. Average crude oil prices in 2010 were higher than in the previous year. Average natural gas prices also increased in 2010. Refining margins stabilized as oil product demand recovered.

Economic context

The world economy continued to recover in 2010. We expect slower global growth in 2011, led by emerging economies, with developed countries lagging behind because of the need to deal with their internal imbalances. Energy demand, and in particular oil demand, follows this overall economic pattern, recovering strongly in 2010 but facing more challenging conditions as we move into 2011, especially in OECD markets.

Concerns about the volatility of commodity and financial markets, combined with renewed focus on climate change and the early experiences with efforts to reduce CO_2 emissions in the EU and elsewhere, have led to an increased focus on the appropriate role for markets, government oversight and other policy measures relating to the supply and consumption of energy. We expect regulation and taxation of the energy industry and energy users to increase in many areas over the short to medium term.

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



Source: Platts/BP.

Crude oil prices

Dated Brent for the year averaged $79.50 per barrel, about 29% above 2009's average of $61.67 per barrel. Prices traded in a relatively narrow band of $70-80 per barrel for most of the year before rising in the fourth quarter. Prices exceeded $90 per barrel in December, the highest level since October 2008.

Global oil consumption rebounded sharply, reflecting a recovery in the global economy and several one-time factors, rising by roughly 2.8 million b/d for the year (3.3%)[c], the largest annual increase since 2004. Growth was broadly-based, with the largest (volumetric) increases seen in China and the US. The relative stability in crude oil prices for much of the year reflected the stability of OPEC crude oil supply, as OPEC members sustained the production cuts implemented in late 2008 throughout 2010, with crude production averaging roughly 2 million b/d below the 2008 level. Commercial oil inventories in the OECD remained high for much of the year before falling as the global supply-balance began to tighten – and prices began to rise – later in the year.

The rebound in oil prices in 2010 followed a decline in 2009 – the first since 2001. Global oil consumption in 2009 reflected the economic slowdown, falling by roughly 1.2 million b/d for the year (1.7%)[d], the largest annual decline since 1982. The biggest reductions were early in the year, with OECD countries accounting for the entire global decline. Crude oil prices rose sharply in the second quarter in response to sustained OPEC production cuts and emerging signs of stabilization in the world economy, despite very high commercial oil inventories in the OECD. OPEC members cut crude oil production by roughly 2.5 million b/d[e] in 2009.

We expect oil price movements in 2011 to continue to be driven by the pace of global economic growth and its resulting implications for oil consumption, and by OPEC production decisions.

[a] *BP Energy Outlook 2030.*
[b] See footnote e on page 56.
[c] *Oil Market Report 10 February 2011* © OECD/IEA 2011, page 4, first paragraph.
[d] *BP Statistical Review of World Energy June 2010.*
[e] *Oil Market Report 10 February 2011* © OECD/IEA 2011, Table 1, page 59.

Natural gas prices

Natural gas prices strengthened in 2010, but were volatile. The average US Henry Hub First of Month Index rose to \$4.39/mmBtu, a 10% increase on the depressed prices in 2009.

Gas consumption recovered across the world along with the economy. In the US, a cold start in 2010, followed by a hot summer and low temperatures towards the end of the year also contributed to demand strength. Yet domestic production growth – of shale gas in particular – continued apace and limited price rises. Henry Hub gas prices stayed below coal parity in US power generation from the summer, leading to the displacement of coal by gas. 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 38% to an average of 42.45 pence per therm for 2010. Yet plentiful global LNG supply kept spot gas prices below oil-indexed contract levels for most of the year, causing competition with contract pipeline supplies and marginal European gas production. UK spot gas prices only attained contract price levels in December as cold weather caused rapid inventory draw-downs.

The rise in prices followed sharp declines in 2009. The recession and strong production had caused the average Henry Hub First of Month Index to fall in 2009 by 56% to \$3.99/mmBtu – the lowest level since 2002. In the UK, National Balancing Point prices averaged 30.85 pence per therm – 47% below the record prices of 58.12 pence per therm in 2008.

In 2011, we expect gas markets to continue to be driven by the economy, weather, domestic production trends and significant growth of global LNG supply.

Refining margins

Refining margins were slightly higher in 2010 as demand for oil products recovered strongly in line with the economic bounce-back from recession. Globally, oil demand grew at the fastest rate since 2004. New refining capacity continued to commission, but the strong demand recovery meant that unused refining capacity fell for the first time since 2005. The BP global indicator refining margin (GIM)[a] averaged \$4.44 per barrel, up 44 cents per barrel compared with 2009.

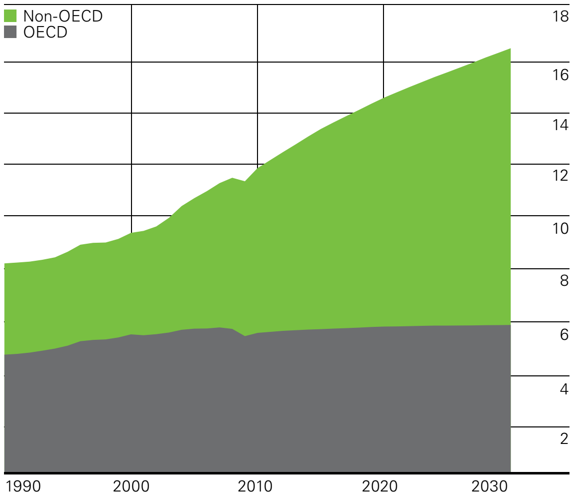
Margins in the Far East improved the most but continued to struggle – averaging \$1.63 per barrel in Singapore as new refining capacity continued to be added in the region. Margins also rose in both the North West Europe and the Mediterranean but European margins overall remained well below 2008 levels. Margins in the US were relatively unchanged, up slightly on the West and Gulf coasts but down in the Midwest.

Refining margins fell sharply in 2009 as demand for oil products collapsed in the wake of the global economic recession and as new refining capacity came onstream. The premium for light products above fuel oils reduced as demand for transport fuels fell along with the reduction in economic activity, compressing margins even for fully upgraded refineries.

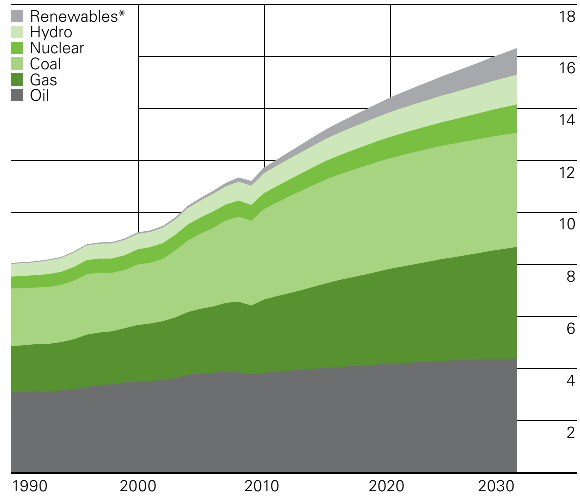
Looking ahead, refiners are likely to continue to operate with excess capacity globally, although near-term supply-demand fundamentals appear broadly in balance. From 2011, we will be reporting a new refining indicator margin, replacing the GIM, which we call the refining marker margin (RMM). This adopts a basis that we believe is more closely related to the approach used by many of our competitors. (*See Refining and Marketing on page 55 for further information on RMM.*)

[a] See footnote e on page 56.

Non-OECD economies drive consumption growth
(billion tonnes of oil equivalent)



Source: *BP Energy Outlook 2030*



*Includes biofuels.

Long-term outlook

Over the long term, global demand for primary energy is expected to continue to grow, but less rapidly than the global economy. Growing energy demand is underpinned by continuing population growth and by generally rising living standards in the developing world, including the expansion of urban populations. These drivers of energy demand growth are to some extent offset by efforts to improve efficiency in both the conversion and use of energy.

Global energy demand is projected to increase by around 40% between 2010 and 2030[a]. Fossil fuels are expected still to be satisfying as much as 80% of the world's energy needs in 2030. At current rates of consumption, the world has enough proved reserves of fossil fuels to meet these requirements[b] if investment is permitted to turn those reserves into production capacity. For example, in oil alone, there are reserves in place to satisfy approximately 45 years' demand at current rates of consumption[b]. However, to meet the potential growth in demand, continued investment in new technology will be required to boost recovery from declining fields and commercialize currently inaccessible resources. To play their part in achieving this, energy companies such as BP will need secure and reliable access to as-yet undeveloped resources. It is estimated that more than 80% of the world's oil reserves are held by Russia, Mexico and members of OPEC[b] – areas where international oil companies are frequently limited or prohibited from applying their technology and expertise to produce additional supply. New partnerships will be required to transform potential resources into proved reserves and eventually into production.

A more diverse mix of energy will also be required to meet this increased demand. Such a mix is likely to include both unconventional fossil fuel resources – such as oil sands, coalbed methane and natural gas produced from shale formations – and renewable energy sources such as biofuels, wind and solar power. Beyond simply meeting growth in overall demand, a diverse mix would also help to provide enhanced national and global energy security while supporting the transition to a lower-carbon economy. Improving the efficiency of energy use will also play a key role in maintaining energy market balance in the future.

Along with increasing supply, we believe the energy industry will be required to make hydrocarbons cleaner and more efficient to use – particularly in the critical area of power generation, for which the key hydrocarbons are currently coal and gas. The world has reserves of coal for around 120 years at current consumption rates[b], but coal produces more carbon than any other fossil fuel. Carbon capture and storage (CCS) may help to provide a path to cleaner coal, and BP is investing in this area, but CCS technologies still face significant technical and economic issues and are unlikely to be in operation at scale for at least a decade.

In contrast, we believe that in many countries natural gas has the potential to provide the most significant reductions in carbon emissions from power generation in the shortest time and at the lowest cost. These reductions can be achieved using technology available today. Combined-cycle turbines, fuelled by natural gas, produce around half the CO_2 emissions of coal-fired power, and are cheaper and quicker to build. It is estimated that there are reserves of natural gas in place equivalent to 63 years' consumption at current rates[b] and they are rising as new skills and technology unlock new unconventional gas resources. For these reasons, gas is looking to be an increasingly attractive resource in meeting the growing demand for energy, playing a greater role as a key part of the energy future.

At the same time, alternative energies also have the potential to make a substantial contribution to the transition to a lower-carbon economy, but this will require investment, innovation and time. Currently, biofuels, wind, solar, and other modern forms of renewable energy account for less than 2% of total global consumption[a]. Assuming continuing policy support and favourable technology trends, these forms of energy are likely to meet around 6% of total energy demand in 2030[a].

If industry and the market are to meet the world's growing demand for energy in a sustainable way, governments will be required to set a stable and enduring framework. As part of this, governments will need to provide secure access for exploration and development of fossil fuel resources, define mutual benefits for resource owners and development partners, and establish and maintain an appropriate legal and regulatory environment, including a mechanism for recognizing the cost of carbon.

[a] *BP Energy Outlook 2030.*
[b] *BP Statistical Review of World Energy June 2010.* 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 strategy

Delivering stability, restoring trust and value.

2010 has been a very challenging year for BP and there remains much to be done to address the repercussions of the tragic Gulf of Mexico oil spill. BP is committed to the restoration of the Gulf of Mexico coastline and its communities. BP will manage its liabilities arising from this deeply regretted accident and is committed to learn and share the lessons from the incident. Above all, we will work with regulators and industry globally to reduce the risk of this happening again.

BP's immediate priority beyond the Gulf is to regain the trust of our stakeholders by demonstrating that we understand and can manage the inherent risks across our whole portfolio. From there, we seek to rebuild value for our shareholders by re-establishing our competitive position within the sector.

BP believes that we can emerge from the shadow of the Gulf of Mexico incident a safer, more risk-aware business. Our strategy, which will continue to evolve over 2011, will remain focused on creating value for shareholders through safe, responsible exploration, development and production of fossil fuel resources because the world needs them; the manufacture, processing and delivery of better and more advanced products; and participation in the transition to a lower carbon future.

Our intention is to re-establish all necessary permissions to operate in the deepwater Gulf of Mexico and sustain business momentum outside of the Gulf; to restore value and growth through a rigorous focus on our portfolio of high-quality assets; to develop our people to ensure we have the right competencies and behaviours where they are needed; to learn and implement the lessons from the Gulf of Mexico and rigorously focus on the processes that will deliver safe and reliable operations and continuous improvement; and do so within a clear, conservative financial framework.

A safer, more risk-aware business

Our employees, investors, regulators and government partners expect us to put safety and operational integrity above all other concerns. We intend to build on our existing strengths to systematically manage operating risk by improving our understanding of risk exposure and taking the appropriate action to mitigate risk. Wherever we operate, we must embed the disciplined application of standards within BP's operating management system (OMS), as a single framework for all BP operations. (*See Safety on page 68 for further information on our OMS.*) We will demand independent checks and balances at multiple levels to provide better decision making and transparent governance of standards, capability, compliance and risk management. To effect this we have created a more powerful safety and operational risk function, independent of the business line and deployed into each operating entity across the BP portfolio. For further information on our safety priorities and performance, see Corporate responsibility – Safety on pages 68-71.

Fulfilling our commitments and earning back trust following the Gulf of Mexico incident

BP has committed to pay all legitimate claims by individuals, businesses and governments and has established a $20-billion trust fund, following consultation with the US government, to provide funds for that purpose. In addition, BP is working with federal and state agencies to assess the nature and extent of the impact on natural resources resulting from the Gulf of Mexico incident. Based on the assessment, federal and state trustees will prepare plans to restore, rehabilitate, replace or acquire the equivalent of injured resources under their trusteeship. The Oil Pollution Act 1990 (OPA 90) provides for restoration to a baseline condition, which is the condition the resources would have been in if the incident had not occurred. The assessment will also be used to identify any compensation that may be required for the loss of the resources, prior to restoration.

Reinstating a dividend in line with the circumstances of the company, as part of a conservative financial framework

BP will continue to invest with the aim of growing the company and shareholder value, sustainably and through the business cycle. We intend to underpin this with a conservative capital structure, which allows the flexibility to execute strategy while remaining resilient to the inherent volatility of the business. We will endeavour to actively manage day-to-day liquidity in order to meet the cash needs of the business, while maintaining the net debt ratio within a lower range of 10% to 20%. On 1 February 2011, we announced that quarterly dividend payments would resume. The quarterly dividend to be paid in March 2011 is 7 cents per share. The board believes this is an affordable and sustainable level which will allow the company to meet its commitments while continuing to invest in the business for growth and value.

Delivering the right high-quality portfolio

As part of the response to the Gulf of Mexico incident, we announced and are progressing disposals that are expected to deliver around $30 billion in proceeds over 2010 and 2011. During 2010, BP has successfully realized premium values for upstream and downstream assets as part of the programme. See Acquisitions and disposals on page 24. The disposal programme has been an opportunity to further upgrade and focus our portfolio and we intend to retain a capacity to reinvest, to acquire assets that enhance strategy and our portfolio on both a planned and an opportunistic basis through 2011.

The right people, skills, capability and incentivization

It is vital that we develop and deploy people with the skills, capability and determination required to meet our objectives. There remains, in our industry, a continuing shortage of professionals such as petroleum engineers and scientists, driven by changing demographics. Nonetheless, we have thus far been successful in building this capacity and we are committed to building and deploying capability with a strong safety and risk management culture, including revised reward mechanisms to foster professional pride in engineering, health, safety, security, the environment and operations.

The creation of a more powerful S&OR function represents a significant change that will strengthen our processes and capabilities in safety and risk management. In Exploration and Production, we have reorganized the segment into three functional divisions – Exploration, Developments and Production – each of which reports directly to the group chief executive. The intent is clear, to focus expertise and capability on a more concentrated asset base to reduce operational risk and deliver long-run sustainable improvement. In each division – and across the rest of the group – we will continue to develop group leadership and senior management teams, and focus recruitment on individuals with strong operational and technical expertise.

Focus on exploration and high-quality earnings

Through our strategy we aim to deliver value growth for shareholders by investing in our Exploration and Production business and safer operations everywhere, while at the same time enhancing efficiency and growing high-quality earnings and returns throughout all our operations.

In Exploration and Production, our 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 enduring positions in the world's key hydrocarbon basins with a focus on deepwater, gas (including unconventional gas) and giant fields. Our strategy is enabled by continuously reducing operating risk, strong relationships built on mutual advantage, deep knowledge of the basins in which we operate, and technology, together with building capability along the value chain in Exploration, Developments and Production.

We are increasing investment in Exploration, a key source of value creation at the front end of the value chain, and we are evolving the nature of our relationships, particularly with national oil companies. We will also continue to actively manage our portfolio, with a focus on value growth.

In Refining and Marketing, our strategy is to hold a portfolio of quality, efficient and integrated manufacturing and marketing positions underpinned by safe operations, leading technologies and strong brands. We will continue to access market growth opportunities in the emerging markets and intend to grow our international businesses. Over time we expect to shift capital employed from mature to high-growth regions.

In Alternative Energy, our strategy is to build material low-carbon energy businesses that are aligned with BP's core capabilities. In biofuels we are building advantaged positions in low-cost sustainable feedstocks such as Brazilian sugar cane, the lignocellulosic conversion of energy grasses in the US and the development of advantaged fuel molecules such as biobutanol. In the low-carbon power business we are building out our US wind portfolio and continue to grow our solar business. We continue to develop our capability in carbon capture and storage.

Leveraging technology as we look further ahead

As discussed under Our market on pages 16-18 of this report, we expect that the world will require a more diverse energy mix as the basis for a secure supply of energy over time. We intend to play a central role in meeting the world's continued need for hydrocarbons, with our Exploration and Production and Refining and Marketing activities remaining at the core of our strategy. We are also creating long-term options for the future in new energy technology and low-carbon energy businesses. We believe that this focused portfolio has the potential to be a material source of value creation for BP (*see pages 61-62*). We are also enhancing our capabilities in natural gas, which may prove to be a vital source of relatively clean energy during the transition to a lower-carbon economy and beyond. We intend to lead, support and shape this transition while working to achieve sector-leading levels of return for shareholders.

Our performance

Performance in 2010 was overshadowed by the well blowout and subsequent oil spill in the Gulf of Mexico. Beyond this tragic event, the ongoing underlying performance of the group was strong.

Safety

In April 2010, following a well blowout in the Gulf of Mexico, an explosion and fire occurred on the semi-submersible rig Deepwater Horizon, resulting in the tragic loss of 11 lives and a major oil spill. There were three other contractor fatalities during 2010. We deeply regret the loss of these lives and the impact from the oil spill. (*See Gulf of Mexico oil spill on page 34 for more information on the Deepwater Horizon accident.*)

Our priority remains to have safe, reliable and compliant operations worldwide. We have set up a more powerful safety and operational risk function. As an immediate step, we have reinforced the link between safety performance and reward in the fourth quarter of 2010. Other programmes are now under way, including a review of contractor management and a fresh look at how we manage risk systematically across BP.

We also continued to embed our OMS within the group, with all of our operating sites transitioning to the system by the end of February 2011.

Recordable injury frequency (RIF, a measure of the number of reported injuries per 200,000 hours worked) was 0.61 in 2010, compared with 0.34 in 2009 and 0.43 in 2008. The increase in 2010 was significantly impacted by the number of incidents arising in the response effort for the Gulf of Mexico oil spill, which resulted in significantly higher personal safety incident rates than for other BP operations.

The number of oil spills greater than one barrel was 261 in 2010 compared with 234 in 2009 and 335 in 2008. The volume spilled was dominated by the Gulf of Mexico incident. See Oil spill and loss of containment in Safety on page 68.

Our greenhouse gas (GHG) emissions[a] were 64.9Mte in 2010, compared with 65.0Mte in 2009. We have not included any emissions from the Gulf of Mexico incident and the response effort due to our reluctance to report data that has such a high degree of uncertainty.

People

During 2010, we continued to focus on increasing the level of specialist skills and expertise across the workforce. The exceptional response to the oil spill was a reassuring example of the capabilities and commitment of our staff.

The total number of non-retail staff was broadly stable in 2010, adjusting for staff reductions associated with asset disposals. Total non-retail recruitment was around 8,000. This was offset by around 7,700 staff leaving the company plus a further 2,300 staff leaving associated with asset disposals. The total number of employees (including retail staff) was 79,700 at the end of 2010.

Operating and financial performance

Our results in 2010 were greatly impacted by the charge recorded for the Gulf of Mexico oil spill incident. Steps were taken to strengthen the balance sheet, including a programme of asset disposals, with very good progress made. Cash and cash equivalents at the end of 2010 was $18.6 billion and the net debt ratio was 21%.

Notable achievements in 2010 include:

Exploration and Production

- Replacing more than 100% of our proved reserves, excluding acquisitions and disposals, on a combined basis of subsidiaries and equity-accounted entities[b].
- Taking final investment decisions on 15 projects, with an expected total BP net capital investment of $20 billion.
- Increasing production for the Rumaila field in Southern Iraq by more than 10% above the rate initially agreed between the Rumaila Operating Organization partners and the Iraqi Ministry of Oil in December 2009. This significant milestone means that BP and its partners became eligible for service fees from the first quarter of 2011.
- Accessing new resources across the globe – in Azerbaijan, China, the Gulf of Mexico, Indonesia, onshore North America and the UK.
- Making the Hodoa discovery in Egypt, the first Oligocene deepwater discovery in the West Nile Delta.
- TNK-BP increasing its production by 2.5% in 2010 compared with 2009.
- Securing agreements to dispose of almost $22 billion of non-core assets in line with our plans following the Gulf of Mexico oil spill.

Refining and Marketing

- Improving overall financial performance delivery, primarily driven by strong operational performance across all of our businesses, the continuation of our programme to deliver further efficiencies and a more favourable refining environment.
- Achieving a Solomon refining availability[c] of 95.0%, which is an increase of 1.4 percentage points compared with 2009.
- Achieving record volumes in petrochemicals and strong lubricants performance.
- Making significant progress in the Whiting refinery modernization project.
- Starting commercial production at our new joint venture acetyls plant in Nanjing, China.
- Castrol's sponsorship of the 2010 FIFA World Cup™ in South Africa.
- Successfully exiting from our convenience retail business in France.
- Completing the divestment of several packages of non-strategic terminals and pipelines in the US East of Rockies and West Coast.
- Selling our 15% interest in Ethylene Malaysia Sdn Bhd (EMSB) and 60% interest in Polyethylene Malaysia Sdn Bhd (PEMSB) to Petronas.

[a] See footnote a in Environment on page 72.
[b] See Exploration and Production – proved reserves replacement on page 42 for more detailed information on reserves replacement for subsidiaries and equity-accounted entities.
[c] 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.

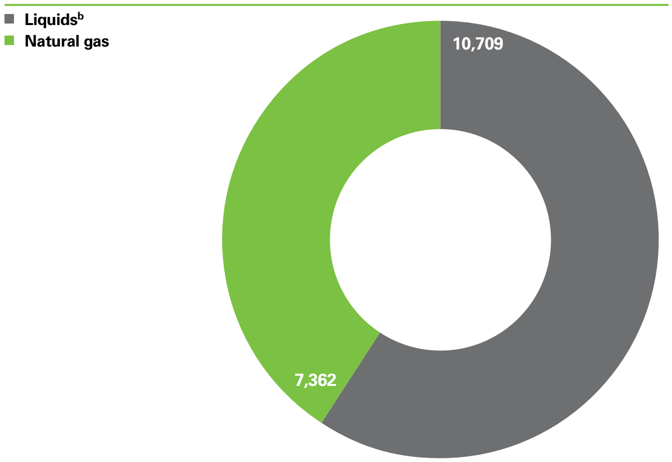
Oil and natural gas production and net proved reserves[a]

	2010	2009	2008	2007	2006
Crude oil production for subsidiaries (thousand barrels per day)	**1,229**	1,400	1,263	1,304	1,351
Crude oil production for equity-accounted entities (thousand barrels per day)	**1,145**	1,135	1,138	1,110	1,124
Natural gas production for subsidiaries (million cubic feet per day)	**7,332**	7,450	7,277	7,222	7,412
Natural gas production for equity-accounted entities (million cubic feet per day)	**1,069**	1,035	1,057	921	1,005
Estimated net proved crude oil reserves for subsidiaries (million barrels)[b]	**5,559**	5,658	5,665	5,492	5,893
Estimated net proved crude oil reserves for equity-accounted entities (million barrels)[c]	**4,971**	4,853	4,688	4,581	3,888
Estimated net proved bitumen reserves for equity-accounted entities (million barrels)	**179**	–	–	–	–
Estimated net proved natural gas reserves for subsidiaries (billion cubic feet)[d]	**37,809**	40,388	40,005	41,130	42,168
Estimated net proved natural gas reserves for equity-accounted entities (billion cubic feet)[e]	**4,891**	4,742	5,203	3,770	3,763

[a] Crude oil includes natural gas liquids (NGLs) and condensate. Production and 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.
[b] Includes 22 million barrels (23 million barrels at 31 December 2009 and 21 million barrels at 31 December 2008) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[c] Includes 254 million barrels (243 million barrels at 31 December 2009 and 216 million barrels at 31 December 2008) in respect of the 7.03% minority interest in TNK-BP (6.86% at 31 December 2009 and 6.80% at 31 December 2008).
[d] Includes 2,921 billion cubic feet of natural gas (3,068 billion cubic feet at 31 December 2009 and 3,108 billion cubic feet at 31 December 2008) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[e] Includes 137 billion cubic feet (131 billion cubic feet at 31 December 2009 and 2008) in respect of the 5.89% minority interest in TNK-BP (5.79% at 31 December 2009 and 5.92% at 31 December 2008).

Total net proved reserves 2010[a]

(million barrels of oil equivalent)



[a] Combined basis of subsidiaries and equity-accounted entities, on a basis consistent with general industry practice.
[b] Crude oil, condensate, natural gas liquids and bitumen.

During 2010, 1,503 million barrels of oil and natural gas, on an oil equivalent[a] basis (mmboe), were added, excluding purchases and sales, to BP's proved reserves (686mmboe for subsidiaries and 818mmboe for equity-accounted entities). At 31 December 2010, BP's proved reserves were 18,071mmboe (12,077mmboe for subsidiaries and 5,994mmboe for equity-accounted entities). Our proved reserves in subsidiaries are located primarily in the US (44%), South America (15%), the UK (10%), Australasia (9%) and Africa (11%). Our proved reserves in equity-accounted entities are located primarily in Russia (69%), South America (20%), and Rest of Asia (7%).

For a discussion of production, see Exploration and Production on page 43.

[a] Natural gas is converted to oil equivalent at 5.8 billion cubic feet (bcf) = 1 million barrels.

Selected financial information[a]

					$ million except per share amounts
	2010	2009	2008	2007	2006*
Income statement data					
Sales and other operating revenues from continuing operations[b]	**297,107**	239,272	361,143	284,365	265,906
Replacement cost profit (loss) before interest and tax[c]					
By business					
Exploration and Production	**30,886**	24,800	38,308	27,602	31,026
Refining and Marketing	**5,555**	743	4,176	2,621	5,661
Other businesses and corporate	**(1,516)**	(2,322)	(1,223)	(1,209)	(841)
Gulf of Mexico oil spill response[d]	**(40,858)**	–	–	–	–
Consolidation adjustment – unrealized profit in inventory	**447**	(717)	466	(220)	65
Replacement cost profit (loss) before interest and taxation from continuing operations[b]	**(5,486)**	22,504	41,727	28,794	35,911
Inventory holding gains (losses)	**1,784**	3,922	(6,488)	3,558	(253)
Profit (loss) before interest and taxation from continuing operations[b]	**(3,702)**	26,426	35,239	32,352	35,658
Finance costs and net finance expense or income relating to pensions and other post-retirement benefits	**(1,123)**	(1,302)	(956)	(741)	(516)
Taxation	**1,501**	(8,365)	(12,617)	(10,442)	(12,516)
Profit (loss) from continuing operations[b]	**(3,324)**	16,759	21,666	21,169	22,626
Profit (loss) for the year	**(3,324)**	16,759	21,666	21,169	22,601
Profit (loss) for the year attributable to BP shareholders	**(3,719)**	16,578	21,157	20,845	22,315
Per ordinary share – cents					
Profit (loss) for the year attributable to BP shareholders					
Basic	**(19.81)**	88.49	112.59	108.76	111.41
Diluted	**(19.81)**	87.54	111.56	107.84	110.56
Profit (loss) from continuing operations attributable to BP shareholders[b]					
Basic	**(19.81)**	88.49	112.59	108.76	111.54
Diluted	**(19.81)**	87.54	111.56	107.84	110.68
Replacement cost profit (loss) for the year[c]	**(4,519)**	14,136	26,102	18,694	22,823
Replacement cost profit (loss) for the year attributable to BP shareholders[c]	**(4,914)**	13,955	25,593	18,370	22,537
Per ordinary share – cents					
Replacement cost profit (loss) for the year attributable to BP shareholders[c]	**(26.17)**	74.49	136.20	95.85	112.52
Dividends paid per share – cents	**14.00**	56.00	55.05	42.30	38.40
– pence	**8.679**	36.417	29.387	20.995	21.104
Capital expenditure and acquisitions[e]	**23,016**	20,309	30,700	20,641	17,231
Ordinary share data[f]					
Average number outstanding of 25 cent ordinary shares (shares million undiluted)	**18,786**	18,732	18,790	19,163	20,028
Average number outstanding of 25 cent ordinary shares (shares million diluted)	**18,998**	18,936	18,963	19,327	20,195
Balance sheet data					
Total assets	**272,262**	235,968	228,238	236,076	217,601
Net assets	**95,891**	102,113	92,109	94,652	85,465
Share capital	**5,183**	5,179	5,176	5,237	5,385
BP shareholders' equity	**94,987**	101,613	91,303	93,690	84,624
Finance debt due after more than one year	**30,710**	25,518	17,464	15,651	11,086
Net debt to net debt plus equity[g]	**21%**	20%	21%	22%	20%

[a] This information, insofar as it relates to 2010, has been extracted or derived from the audited consolidated financial statements of the BP group presented on pages 141-227. 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] Excludes Innovene, which was treated as a discontinued operation in accordance with IFRS 5 'Non-current Assets Held for Sale and Discontinued Operations' in 2006.

[c] 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 81.

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

[e] Excluding acquisitions and asset exchanges, capital expenditure for 2010 was $19,610 million (2009 $20,001 million, 2008 $28,186 million, 2007 $19,194 million and 2006 $16,910 million). All 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. Capital expenditure in 2006 included $1 billion in respect of our investment in Rosneft.

[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 36 on page 198.

* As reported in Annual Report on Form 20-F. There was a $500 million ($315 million post tax) timing difference between the profit reported under IFRS in the Annual Report and Accounts and the profit reported under IFRS in *BP Annual Report on Form 20-F 2006*. For further information see *BP Annual Report and Accounts 2006*.

Profit or loss for the year

Loss attributable to BP shareholders for the year ended 31 December 2010 was $3,719 million and included inventory holding gains[a], 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. More information on non-operating items and fair value accounting effects can be found on pages 25-26. See Gulf of Mexico oil spill on page 34 and in Financial statements – Note 2 on page 158 for further information on the impact of the Gulf of Mexico oil spill on BP's financial results. See Exploration and Production on page 40, Refining and Marketing on page 55 and Other businesses and corporate on page 61 for further information on segment results.

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.

Profit attributable to BP shareholders for the year ended 31 December 2008 included inventory holding losses, net of tax, of $4,436 million and a net charge for non-operating items, after tax, of $796 million. In addition, fair value accounting effects had a favourable impact, net of tax, of $146 million relative to management's measure of performance.

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.

The primary additional factors reflected in profit for 2009, compared with 2008, were lower realizations and refining margins and higher depreciation, partly offset by higher production, stronger operational performance and lower costs.

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 2010 were $1,170 million compared with $1,110 million in 2009 and $1,547 million in 2008. The decrease in 2009, when compared with 2008, is largely attributable to the reduction in interest rates.

Net finance income relating to pensions and other post-retirement benefits in 2010 was $47 million compared with net finance expense of $192 million in 2009 and net finance income of $591 million in 2008. In 2010, compared with 2009, the improvement reflected the additional expected returns on assets following the increases in the pension asset base at the end of 2009 compared with the end of 2008. In 2009, the expected return on assets decreased significantly as the pension asset base reduced, consistent with falls in equity markets during 2008.

[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 7 on page 167 and further information on inventory holding gains and losses is provided on page 81.

Taxation

The credit for corporate taxes in 2010 was $1,501 million, compared with a charge of $8,365 million in 2009 and a charge of $12,617 million in 2008. The effective tax rate was 31% in 2010, 33% in 2009 and 37% in 2008. The group earns income in many countries and, on average, pays taxes at rates higher than the UK statutory rate of 28%. The decrease in the effective tax rate in 2010 compared with 2009 primarily reflects the absence of a one-off disbenefit that featured in 2009 in respect of goodwill impairment, and other factors.The decrease in the effective tax rate in 2009 compared with 2008 primarily reflects a higher proportion of income from associates and jointly controlled entities where tax is included in the pre-tax operating result, foreign exchange effects and changes to the geographical mix of the group's income.

Acquisitions and disposals

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 Azeri-Chirag-Gunashli (ACG) developments in the Caspian Sea, Azerbaijan for $2.9 billion, as part of a $7-billion transaction with Devon Energy. For further information on this transaction, including required government approvals, see Exploration and Production on page 43. As part of the response to the Gulf of Mexico oil spill, the group plans to deliver up to $30 billion of disposal proceeds by the end of 2011. 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 is for the sale of our interest in Pan American Energy to Bridas Corporation, $1 billion for the sale of our upstream 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, the latter completing in January 2011. See Financial statements – Note 4 on page 163.

In Refining and Marketing we made disposals totalling $1.8 billion, 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 are receivable in 2011. See Financial statements – Note 5 on page 164.

In 2008, we completed an asset exchange with Husky Energy Inc., and asset purchases from Chesapeake Energy Corporation as described on page 23.

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
	2010	2009	2008
Exploration and Production			
Impairment and gain (loss) on sale of businesses and fixed assets	**3,812**	1,574	(1,015)
Environmental and other provisions	**(54)**	3	(12)
Restructuring, integration and rationalization costs	**(137)**	(10)	(57)
Fair value gain (loss) on embedded derivatives	**(309)**	664	(163)
Other	**(113)**	34	257
	3,199	2,265	(990)
Refining and Marketing			
Impairment and gain (loss) on sale of businesses and fixed assets[a]	**877**	(1,604)	801
Environmental and other provisions	**(98)**	(219)	(64)
Restructuring, integration and rationalization costs	**(97)**	(907)	(447)
Fair value gain (loss) on embedded derivatives	**–**	(57)	57
Other	**(52)**	184	–
	630	(2,603)	347
Other businesses and corporate			
Impairment and gain (loss) on sale of businesses and fixed assets	**5**	(130)	(166)
Environmental and other provisions	**(103)**	(75)	(117)
Restructuring, integration and rationalization costs	**(81)**	(183)	(254)
Fair value gain (loss) on embedded derivatives	**–**	–	(5)
Other	**(21)**	(101)	(91)
	(200)	(489)	(633)
Gulf of Mexico oil spill response	**(40,858)**	–	–
Total before interest and taxation	**(37,229)**	(827)	(1,276)
Finance costs[b]	**(77)**	–	–
Total before taxation	**(37,306)**	(827)	(1,276)
Taxation credit (charge)[c]	**11,857**	(240)	480
Total after taxation	**(25,449)**	(1,067)	(796)

[a] 2009 includes $1,579 million in relation to the impairment of goodwill allocated to the US West Coast fuels value chain.
[b] Finance costs relate to the Gulf of Mexico oil spill. See Financial statements – Note 2 on page 158 for further details.
[c] Tax is calculated by applying discrete quarterly effective tax rates (excluding the impact of the Gulf of Mexico oil spill) on group profit or loss, to the non-operating items as they arise each quarter. However, the US statutory tax rate has been used for expenditures relating to the Gulf of Mexico oil spill 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 82.

			$ million
	2010	2009	2008
Exploration and Production			
Unrecognized gains (losses) brought forward from previous period	**(530)**	389	107
Unrecognized (gains) losses carried forward	**527**	530	(389)
Favourable (unfavourable) impact relative to management's measure of performance	**(3)**	919	(282)
Refining and Marketing			
Unrecognized gains (losses) brought forward from previous period	**179**	(82)	429
Unrecognized (gains) losses carried forward	**(137)**	(179)	82
Favourable (unfavourable) impact relative to management's measure of performance	**42**	(261)	511
	39	658	229
Taxation credit (charge)[a]	**(26)**	(213)	(83)
	13	445	146
By region			
Exploration and Production			
US	**141**	687	(231)
Non-US	**(144)**	232	(51)
	(3)	919	(282)
Refining and Marketing			
US	**19**	16	231
Non-US	**23**	(277)	280
	42	(261)	511

[a]Tax is calculated by applying discrete quarterly effective tax rates (excluding the impact of the Gulf of Mexico oil spill) on group profit or loss, to the fair value accounting effects as they arise each quarter.

Reconciliation of non-GAAP information

			$ million
	2010	2009	2008
Exploration and Production			
Replacement cost profit before interest and tax adjusted for fair value accounting effects	**30,889**	23,881	38,590
Impact of fair value accounting effects	**(3)**	919	(282)
Replacement cost profit before interest and tax	**30,886**	24,800	38,308
Refining and Marketing			
Replacement cost profit before interest and tax adjusted for fair value accounting effects	**5,513**	1,004	3,665
Impact of fair value accounting effects	**42**	(261)	511
Replacement cost profit before interest and tax	**5,555**	743	4,176

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 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 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 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 charges totalling $40.9 billion in 2010 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 determination of BP's negligence), the outcome of litigation, 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. 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 have regained some confidence after the banking crisis of 2008 but are still subject to volatility and 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 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 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, and could cause us to incur additional costs. In particular, our investments in the US, Russia, Iraq, Egypt, Libya and other countries could be adversely affected by heightened political and economic environment risks. See pages 14-15 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 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 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 have recognized a total charge of $40.9 billion during 2010 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 page 158 and Legal proceedings on pages 130-131. 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.

For more information on financial instruments and financial risk factors see Financial statements – Note 27 on page 185.

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.
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 incident.

Compliance and control risks

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

The Gulf of Mexico oil spill is likely to result in 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. For example, in the US, legislation is currently being considered that may impact BP's existing contracts with the US Government or limit its ability to enter into new contracts with the US Government. The US Government imposed a moratorium on certain offshore drilling activities, which was subsequently lifted in October 2010; however, the implications of the moratorium for how quickly the industry will return to drilling remains uncertain. 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.

For more information on environmental regulation, see pages 78-81.

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. 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 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 130-133. For further information on the risks involved in BP's trading activities, see Operational risks – Treasury and trading activities on page 31.

Liabilities and provisions – BP's potential liabilities resulting from pending and future claims, lawsuits 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 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 any natural resource damages associated with the spill and certain costs incurred 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 page 130.

BP is subject to a number of investigations related to the Incident by numerous federal and State agencies. See Legal proceedings on page 130. 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 their assessment of BP's culpability 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 costs arising out of the spill are recoverable from its partners and other parties responsible under OPA 90, such recovery is not certain and BP has recognized all of the costs incurred in its financial statements (see Financial statements – Note 2 on page 158, Note 37 on page 199 and Note 44 on page 218, under 'Contingent assets relating to the Gulf of Mexico oil spill').

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 our partners and 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 recent 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 are adjudicated by the Gulf Coast Claims Facility (GCCF) headed by Kenneth Feinberg, who was jointly appointed by BP and the US Administration. On 18 February 2011, the GCCF announced its final rules governing payment options, eligibility and substantiation criteria, and final payment methodology. The impact of these rules, or other events related to the adjudication of claims, on future payments by the GCCF is uncertain. Payments could ultimately be significantly higher or lower than the amount we have estimated for individual and business claims under OPA 90 included in the provision BP recognized for litigation and claims. (See Financial statements – Note 37 on page 199 under Litigation and claims.)

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 incident. 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 due to the nature of some of its business relationships' on page 32.

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 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 and damage to our reputation or licence to operate.

To help address health, safety, security, environmental and operations risks, and to provide a consistent framework within which the group can analyze the performance of its activities and identify and remediate shortfalls, BP implemented a group-wide operating management system (OMS). The embedding of OMS continues and following the Gulf of Mexico oil spill an enhanced S&OR function is being 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 compliance 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 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 incident 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 the environment and people and given the high volumes 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 31.

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 and breaches of regulations.
The reliability and security of our digital infrastructure are critical to maintaining the availability of our business applications. A breach of our digital security could cause serious damage to business operations and, in some circumstances, could result in injury to people, damage to assets, harm to the environment and breaches of regulations.

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 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.

Our systems of control

The board is responsible for the direction and oversight of BP. The board has set an overall goal for BP, which is to maximize long-term shareholder value through the allocation of its resources to activities in the oil, natural gas, petrochemicals and energy businesses. The board delegates authority for achieving this goal to the group chief executive (GCE).

The board maintains five permanent committees that are composed entirely of non-executives. The board and its committees monitor, among other things, the identification and management of the group's risks – both financial and non-financial. During the year, the board's committees engage with executive management, the general auditor and other monitoring and assurance providers (such as the group head of safety and operational risks, the group compliance and ethics officer and the external auditor) on a regular basis as part of their oversight of the group's risks. Significant incidents that occur and management's response to them are considered by the appropriate committee and reported to the board. In July the board established a new committee of non-executives, the Gulf of Mexico committee, to monitor the response of the company to the Gulf of Mexico incident through oversight of the new GCRO. The committee engages with GCRO management on a regular basis to monitor the response to the incident and management of the risks arising. (*See Board performance report on pages 90-105*.)

The company maintains a comprehensive system of internal control. This comprises the holistic set of management systems, organizational structures, processes, standards and behaviours that are employed to conduct our business and deliver returns for shareholders. 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. It addresses risks and how we should respond to them as well as the overall control environment. Each component of the system has been designed to respond to a particular type or collection of risks. Material risks are described in the Risk factors section (*see pages 27-32*).

Key elements of our system of internal control are: the control environment; the management of risk and operational performance (including in relation to financial reporting); and the management of people and individual performance. Controls include the BP code of conduct, our operating management system (OMS), our leadership framework and our principles for delegation of authority, which are designed to make sure employees understand what is expected of them.

As part of the control system, the GCE's senior team – known as the executive team – is supported by sub-committees that are responsible for and monitor specific group risks. These include the group operations risk committee (GORC), the group financial risk committee (GFRC), the resource commitments meeting (RCM), the group people committee (GPC), and the group's disclosure committee (GDC), which reviews the disclosure controls and procedures over reporting.

Operations and investments are conducted and reported in accordance with, and associated risks are thereby managed through, relevant standards and processes. These range from OMS which is the structured set of processes designed to deliver safe, responsible and reliable operating activity, to group standards, which set out processes for major areas such as fraud and misconduct reporting, through to detailed administrative instructions. The GCE conducts regular performance reviews with the segments and key functions to monitor performance and the management of risk and to intervene if necessary. People management is based on performance objectives, through which individuals are accountable for specific activities within agreed boundaries.

Following the Gulf of Mexico oil spill, the company established the GCRO in June to manage the company's response activities, including managing clean-up and restoration costs, claims management and litigation. Lessons learned from the incident and the recommendations of BP's internal investigation are being embedded into all areas of the system of internal control and in particular in OMS.

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 the first half of 2010, new sanctions against Iran and against companies that make investments that enhance Iran's ability to develop petroleum resources or provide or facilitate the production or import of refined petroleum products into Iran were adopted in the US under the Comprehensive Iran Sanctions Accountability and Divestment Act of 2010. The European Union and the UN also adopted new restrictive measures. The EU sanctions restrict the provision of certain technologies to Iranian entities and also prohibit providing assistance to help develop certain exploration and production, refining, and LNG facilities or operations in Iran.

BP has interests in, and is the operator of, two fields and a pipeline located outside Iran in which Naftiran Intertrade Co. Ltd, NICO SPV Limited (NICO) and Iranian Oil Company (UK) Limited have interests. One of these fields, the North Sea Rhum field, has suspended production pending clarification of the impact of the EU restrictive measures. The Shah Deniz field continues in operation under the EU measures. BP has purchased or shipped quantities of crude oil, refinery and petrochemicals feedstocks, blending components and LPG of Iranian origin or from Iranian counterparties primarily for sale to third parties in Europe and a small portion is used by BP in its own facilities in South Africa and Europe. BP incurs some port costs for cargos loaded in Iran and sometimes charters Iranian-owned vessels outside of Iran. Small quantities of lubricants are sold to non-Iranian third parties for use in Iran. Until recently BP held an equity interest in an Iranian joint venture that has a blending facility and markets lubricants for sale to domestic consumers. In January 2010, BP restructured its interest in the joint venture and currently maintains its involvement through certain contractual arrangements. BP does not seek to obtain from the government of Iran licences or agreements for oil and gas projects in Iran, is not conducting any technical studies in Iran, and does not own or operate any refineries or petrochemicals plants in Iran.

BP sells lubricants in Cuba through a 50:50 joint venture and trades in small quantities of lubricants. In Syria, BP sells lubricants through a distributor and BP obtains crude oil and refinery feedstocks for sale to third parties in Europe and for use in certain of its non-US refineries. In addition, BP sells crude oil and refined products into and from Syria and incurs port costs for vessels utilizing Syrian ports. BP sold small quantities of LPG to an agent on behalf of a Sudanese party for making aerosols in Sudan, but no longer makes such sales. A non-BP operated Malaysian joint venture has sold small quantities of petrochemicals into Burma; these sales have now terminated. A non-controlled and non-operated Brazilian biofuels joint venture in which BP has an interest sold a cargo of sugar cane by-products to Iran and to Syria.

BP supplies to airlines and shipping companies from Sanctioned Countries fuels and lubricants at airports and ports located outside these countries. BP sells to third parties who may re-sell to entities from Sanctioned Countries. A non-controlled, non-operated joint venture in Hamburg, Germany provided fuel delivery services (but did not sell fuel) to Iranian airlines. BP terminated all fuel sales to Iranian airlines as of July 2010 and to Sudanese airlines in December 2010. Sales to Iranian shipping companies have also been terminated. BP has registered, and paid required fees for, patents and trademarks in Sanctioned Countries.

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.

Gulf of Mexico oil spill

Incident summary

On 20 April 2010, following a well blowout in the Gulf of Mexico, an explosion and fire occurred on the semi-submersible rig Deepwater Horizon and on 22 April the vessel sank. Tragically, 11 people lost their lives and 17 others were injured. Hydrocarbons continued to flow from the reservoir and up through the casing and the blowout preventer (BOP) for 87 days, causing a very significant oil spill.

The Deepwater Horizon rig was operated by Transocean Holdings LLC and was drilling the Macondo exploration well. The well forms part of the Mississippi Canyon Block 252 (MC252) lease, in respect of which BP Exploration & Production Inc. was the named party and operator with a 65% working interest. The well was in a water depth of 5,000 feet and 43 nautical miles from shore.

BP tackled the leak at its source in multiple, parallel ways, which over time included: attempting to fit caps on the well, using containment systems to pipe oil to vessels on the surface, sealing the well through a static-kill procedure and drilling relief wells. BP recognized early in the incident that drilling relief wells constituted the ultimate means to seal and isolate the well permanently and stop the flow of oil and gas. Two relief wells were drilled, the first of which was started on 2 May; the second was started on 16 May as a contingency.

On 15 July, BP successfully shut in the Macondo well and then commenced a static-kill procedure. On 9 August, BP confirmed that the casing had been successfully sealed with cement. On 16 September, the first relief well intercepted the annulus of the Macondo well. After completing cementing operations on 19 September, BP, the federal government scientific team and the National Incident Commander concluded that the well-kill operations had successfully sealed the annulus.

BP then began the abandonment of the Macondo well, which included removing portions of the casing and setting cement plugs. This work was completed on 8 November. In parallel, operations to plug and abandon (P&A) the relief well that intercepted the Macondo well also took place and were completed on 30 September. P&A of the second relief well is in progress and is expected to complete in early March 2011. All response activities at the Macondo site (with the exception of the final seabed survey and seismic sweep, which are scheduled to take place at the end of first quarter in 2011), were completed on 8 January with the recovery of the buoy and anchor system for the free-standing riser.

The group income statement for the year ended 31 December 2010 includes a pre-tax charge of $40.9 billion in relation to the Gulf of Mexico oil spill. See Financial consequences on page 38 and Financial statements – Note 2 on page 158 for more details.

Key statistics

	2010
Total pre-tax cost recognized in income statement ($ million)	**40,935**
Total cash flow expended (pre-tax) ($ million)	**17,658**
Total payments from $20-billion trust fund ($ million)	**3,023**
Total number of claimants to GCCF[a]	**468,869**
Number of people deployed (at peak) (approximately)	**48,000**
Number of active response vessels deployed during the response (approximately)	**6,500**
Barrels of oil collected or flared (approximately)	**827,000**
Barrels of oily liquid skimmed from surface of sea (approximately)	**828,000**
Barrels of oil removed through surface burns (UAC estimate)	**265,450**

[a] Gulf Coast Claims Facility (GCCF).

Gulf Coast Restoration Organization (GCRO)

Following the accident, BP established a separate organizational unit – the Gulf Coast Restoration Organization (GCRO) – to provide the necessary leadership and dedicated resources to facilitate BP's fulfilment of its clean-up responsibilities and to support the long-term effort to restore the Gulf coast. The GCRO addresses all aspects of the response, including: executing our ongoing clean-up operations and all associated remediation activities; coordinating with government officials; keeping the public informed; and implementing the $20-billion Deepwater Horizon Oil Spill Trust established to meet certain of our financial obligations. At the end of 2010, the GCRO had a permanent staff of 100 employees and about 5,900 contractors including the Gulf Coast incident management team. The majority of the clean-up, maintenance and monitoring is being carried out by contract staff. Since inception, many other BP staff and contractors have been, and will continue to be, temporarily seconded to assist the permanent team and to provide additional resources or specialist skills where required.

Our response

BP immediately took responsibility for responding to the incident, taking steps to remedy the harm that the spill caused to the Gulf of Mexico, the Gulf coast environment, and the livelihoods of the people in the region. The US government formed a Unified Area Command (UAC) to link the organizations responding to the incident and provide a forum for those organizations to make co-ordinated decisions. If consensus could not be reached on a particular matter, the Federal On-Scene Coordinator (FOSC) made the final decision on response-related actions. BP's comprehensive response focused on three strategic fronts: stopping the flow of hydrocarbons at the source; working to capture, contain and remove oil offshore and near the shore; and cleaning and restoring impacted shorelines and beaches along the Gulf coast.

Initially BP mobilized a fleet of 30 vessels and over a million feet of protective boom. Thereafter the scale of activity grew rapidly, and at its peak included more than 6,500 vessels, more than 13 million feet of boom and almost 48,000 personnel.

BP also formed an investigation team charged with gathering the facts surrounding the accident, analysing available information to identify possible causes and making recommendations that would help prevent similar accidents in the future. The team concluded that no single action or inaction caused this accident. Rather, a complex and interlinked series of mechanical failures, human judgments, engineering design, operational implementation and team interfaces came together to allow the accident. Multiple companies, work teams and circumstances were involved over time. See Internal investigation and report on page 37 for further information on the investigation and its findings.

Subsea

Subsea intervention activities were initiated by BP immediately following the explosion. Initial attempts to stop the flow of oil focused on attempting to actuate the failed BOP with remotely operated vehicles (ROVs). At the same time, planning also began for two relief wells. Attempts to stop the flow of oil by activating the various components of the BOP continued until 5 May, while plans and tools for potential containment options were being developed in parallel.

From 5 May BP attempted to contain the flow of oil using a number of different strategies. Firstly, one of the three leak points was plugged with the installation of a drill pipe overshot and pack-off device, reducing the complexity of the seabed situation. Following a failed attempt to contain the flow of oil using a containment dome, a riser insert tube tool was successfully deployed in the end of the riser on 16 May. This allowed roughly 3,000 barrels of oil per day (b/d) to be captured and returned to the surface for processing on the drillship Discoverer Enterprise. An attempt was also made to 'top kill' the well by pumping heavy drilling mud into the well at high rates but this effort was unsuccessful. By shearing and removing a damaged section of riser from the lower marine riser package (LMRP) on top of the BOP stack, it was possible to attach a new containment system (sometimes referred to as a top hat). This system allowed for up to 15,000b/d of oil to be produced through this non-sealing LMRP cap via a riser to the Discoverer Enterprise for processing. Containment capacity was eventually enhanced to over 40,000b/d of oil. In total, approximately 827,000 barrels of crude oil were recovered using the various containment systems. On 10 July, the top-hat containment cap was removed from the LMRP to allow the installation of a three-ram capping stack, which was completed on 12 July.

The flow of oil into the Gulf of Mexico was finally stopped on 15 July. After verifying integrity of the capping stack, a static-kill procedure was executed. Following a series of tests and the pumping of heavy drilling mud, static conditions were achieved in the Macondo well on 3 August and cement was pumped in two days later. On 2 September, after a successful test of the cement plug, the capping stack was removed from the top of the BOP.

On 3 September, the BOP was removed from the Macondo wellhead to be replaced by the BOP stack from the Development Driller II. The Deepwater Horizon BOP was subsequently recovered to surface, preserved and shipped to the NASA Michoud Facility in Louisiana for examination by the US government and other parties.

Progress on the two relief wells continued in parallel with the containment operations outlined above. The first relief well was delayed on several occasions due to adverse weather and while critical testing and operations were conducted on the Macondo well. On 16 September, the first relief well successfully intersected the Macondo wellbore. On 19 September, after cementing operations on the relief well were complete, the Macondo well was officially declared killed.

The P&A of the first relief well was completed by the Development Driller III rig on 30 September. P&A of the Macondo well was concluded on 8 November by the Development Driller II, and the P&A of the second relief well is in progress and is expected to complete in early March 2011.

Work to recover and secure the subsea infrastructure used for the various containment systems commenced following completion of the Macondo well P&A programme and was completed on 8 January 2011.

During the latter stages of the response, work commenced to restore and decontaminate the many vessels involved in the incident. This is largely complete, with the remaining 25 vessels expected to be completed by the end of April 2011.

The only outstanding work associated with the Macondo site is the seabed and seismic surveys of the area. In consideration of, and subject to, the weather conditions, it is anticipated that the seabed and seismic surveys will take place at the end of first quarter of 2011.

Shoreline and surface

The priorities for the shoreline and surface response were removing oil from the surface of the Gulf, preventing oil from reaching the shoreline and cleaning up any oil that did reach the shores. The response strategy included aerial surveillance to understand where concentrations of oil were located, mechanical skimming, controlled surface burning, application of dispersants, and multiple in-water and onshore booming techniques. Onshore, multiple techniques for cleaning and removing oil from marshes, wetlands, and beaches were deployed. BP worked with local organizations to refine existing area contingency plans to enable the most effective response to the spill.

Extensive surface skimming activities took place, ranging from large-scale offshore skimmers to inland and shallow water equipment. The UAC also leveraged its Vessels of Opportunity (VoO) programme to assist with this and to support the fish and wildlife, Shoreline Clean-up Assessment Team (SCAT), and Rapid Assessment Team.

Controlled in situ burning of oil on the surface of the water was conducted where concentrations of oil with suitable characteristics could be identified. Approximately 400 controlled burns were performed, which in total removed an estimated 265,450 barrels of oil according to the UAC.

Chemical dispersants were deployed under the close supervision of the UAC. Dispersants are mixtures of solvents, surfactants and other additives that break up the surface tension of an oil slick or sheen and make oil more soluble in water. On the surface, dispersants help break oil down into microscopic droplets that can be dispersed through the seawater and more easily degraded by oil-eating bacteria. Subsea application of dispersants was used to break the oil into small particles that disperse throughout the water column, forming a more dilute oil-and-water solution that degrades more easily.

BP worked closely with state and local officials, seeking to prevent shoreline oiling. The effort involved significant deployment of boom. BP worked closely with experts from the US Coast Guard, the US Fish & Wildlife Service, the National Oceanic and Atmospheric Administration (NOAA), the National Park Service, as well as state agencies to identify the most sensitive wildlife habitats and prioritize appropriate spill countermeasures. These measures included booming wildlife refuges and using methods to deter wildlife from entering oiled areas. BP also established animal treatment facilities, with significant capacity to treat birds, mammals and turtles.

Once oiling of the shoreline had occurred, SCATs assessed the damage and developed clean-up methods for each type and area of impact, including treatment plans designed to optimize oil removal with minimal intrusion and impact to the marsh. Thousands of personnel organized into operating teams were mobilized for the clean-up efforts.

Beach-cleaning operations were undertaken in collaboration with residents from the highest impacted communities, with almost 11,000 community responders being trained in beach clean-up efforts.

Throughout this response, BP met with local officials and organized town halls and information sessions in the coastal communities. As the response continued, BP opened community outreach and claims centres in each of the coastal counties and established telephone call lines for all activities.

BP has committed to pay all legitimate claims to individuals, businesses and governments and to establish a $20-billion trust fund, following consultation with the US government. As part of the US Natural Resource Damage Assessment (NRDA) process, BP is working with federal and state trustees to identify wildlife and habitats that may have been injured; to restore the environment back to an objective baseline condition; to restore access to and use of the natural resources; and to compensate for losses caused by the incident. Finally, BP has provided long-term funding for response projects, research and community support programmes as part of our long-term commitment to the Gulf.

The Food and Drug Administration (FDA), the NOAA, and state agencies also conducted fisheries testing and monitoring throughout the response. These testing and monitoring programmes included smell and edible tissue tests for oil detection. Approximately 89,000 square miles of federal fisheries were closed at the peak of the response; as of 1 February 2011, 99.6% of federal fisheries were open to fishing. To date, BP has committed $127 million for ongoing monitoring, marketing, and tourism support in the Gulf States.

Restoration, research and other donations

In conjunction with the Gulf of Mexico Alliance (a partnership of the states of Alabama, Florida, Louisiana, Mississippi and Texas with the goal of significantly increasing regional collaboration to enhance the ecological and economic health of the Gulf of Mexico), we have established the Gulf of Mexico Research Initiative (GRI) providing $500 million to study and monitor the spill's potential long-term impacts on the environment and local public health. Specifically, the 10-year programme will examine the spread and fate of the oil and other contaminants, the degree of biodegradation, effects of the spill on local ecosystems, and detection, clean-up and mitigation technology. While the details of the programme were being developed, BP awarded a series of fast-track grants to five research groups, totalling $40 million. BP and the Gulf of Mexico Alliance appointed an equal number of research scientists to the governing board of the GRI and, in December, the GRI held its first meeting.

BP has now contributed a total of $260 million under its agreement to fund the $360-million cost of six berms in the Louisiana barrier islands project.

BP has established a $100-million charitable fund to support unemployed rig workers experiencing economic hardship as a result of the moratorium on deepwater drilling imposed by the US federal government. The Rig Worker Assistance Fund will be administered through the Gulf Coast Restoration and Protection Foundation, a supporting organization of The Baton Rouge Area Foundation.

In line with BP's previous commitment to donate its share of the revenue (net of royalties and transportation costs) from the sale of recovered oil to the National Fish and Wildlife Foundation (NFWF), total donations to date have amounted to $22 million.

Claims process and trust fund

BP initially established a claims process in accordance with the requirements of the Oil Pollution Act 1990 (OPA 90), allowing claimants to make a claim against BP as one of the designated responsible parties. BP has endeavoured to promptly pay all legitimate claims including those from individuals, businesses and government entities. BP paid $399 million in claim payments to individuals and businesses before 23 August 2010, when the administration of these claims was transferred to the Gulf Coast Claims Facility (GCCF) headed by Kenneth Feinberg. Mr Feinberg was jointly appointed by BP and the President of the United States to manage the GCCF. According to GCCF statistics, as of 31 December 2010, 468,869 claimants had submitted claims and $2,776 million in payments had been made. BP continues to evaluate and pay claims from government entities. State and local government entities, as at 31 December 2010, had received $550 million through the trust fund (see below) and BP directly to cover claims and response and removal advances and payments.

In support of the settlement of claims BP established the Deepwater Horizon Oil Spill Trust (Trust), and committed $20 billion to the Trust over a period of three-and-a-half years. While funds are building , BP has secured its commitments to the Trust by granting, conveying, and/or assigning to the Trust first priority perfected security interests in production payments pertaining to certain Gulf of Mexico oil and natural gas production. During 2010, BP made payments to the Trust totalling $5 billion and is committed to making additional payments of $1.25 billion, in one or more instalments, during and prior to the end of each calendar quarter commencing with the first calendar quarter of 2011 and continuing until the last calendar quarter of 2013. The trust fund is available to satisfy legitimate individual and business claims administered by the 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 and penalties will be paid separately and not from the Trust. Payments from the Trust are made as costs are finally determined or claims are adjudicated, whether by the GCCF, or by a court, or as agreed by BP. The GCCF evaluates all individual and business OPA 90 claims, excluding all government claims. The establishment of this Trust does not represent a cap or floor on BP's liabilities, and BP does not admit to a liability of any amount in the Trust. The Trust agreement provides for the term of the Trust to continue until 30 April 2016, subject to the right of the Individual Trustees to extend or expedite this expiry date under certain circumstances. Any amounts left in the Trust once all legitimate claims have been resolved and paid will revert to BP. See Financial statements – Note 2 on page 158, Note 37 on page 199 and Note 44 on page 218 for further information on the Trust and on contingent liabilities arising from the incident. See Proceedings and investigations relating to the Gulf of Mexico oil spill on pages 130-131 for information on legal proceedings.

Internal investigation and report

BP's investigation found that no single factor caused the Macondo well tragedy; rather, it concluded that decisions made by 'multiple companies and work teams' contributed to the accident which arose from 'a complex and interlinked series of mechanical failures, human judgments, engineering design, operational implementation and team interfaces.'

The report – based on a four-month investigation led by BP's head of Safety and Operations and conducted independently by a team of over 50 technical and other specialists drawn from inside BP and externally – found that:

- The annulus cement barrier – and in particular the cement slurry that was used – at the bottom of the Macondo well failed to contain hydrocarbons within the reservoir, as it was designed to do. The annulus cement probably experienced nitrogen breakout and migration, allowing gas and liquids to enter the wellbore annulus. The investigation team concluded that there were weaknesses in cement design and testing, quality assurance and risk assessment.
- The shoe track barriers at the bottom of the Macondo well failed to contain hydrocarbons as they were designed to do, allowing hydrocarbons to flow up the production casing. The shoe track barriers consisted of two barriers in the shoe track: the cement in the shoe track and the float collar. BP's investigation team identified a number of potential failure modes that could explain how both the shoe track cement and the float collar allowed hydrocarbon ingress into the production casing, but has not determined which of these failure modes occurred.
- The results of the negative pressure test were incorrectly accepted by BP and Transocean, although well integrity had not been established.
- Over a 40-minute period, the Transocean rig crew failed to recognize and act on the influx of hydrocarbons into the well until the hydrocarbons had passed through the BOP and into the riser and were rapidly flowing to the surface.
- Well control response actions failed to regain control of the well. The first well control actions were to close the BOP and diverter, routing the fluids exiting the riser to a mud gas separator rather than to the overboard diverter line. If fluids had been diverted overboard, rather than to the mud gas separator, there may have been more time to respond, and the consequences of the accident may have been reduced.
- Diversion of the hydrocarbons to the mud gas separator resulted in gas venting onto the rig. The design of the mud gas separator system allowed diversion of the riser contents to the mud gas separator vessel although the well was in a high-flow condition. This overwhelmed the mud gas separator system, resulting in gas venting onto the rig. This increased the potential for the gas to reach an ignition source.
- The flow of gas into the engine rooms through the ventilation system created a potential for ignition that the rig's fire and gas system did not prevent.
- Even after the explosion and fire had disabled its crew-operated controls, the rig's BOP on the seabed should have activated automatically to seal the well. But it failed to operate, probably because critical components were not working. Through a review of rig audit findings and maintenance records, the investigation team found indications of potential weaknesses in the testing regime and maintenance management system for the BOP.

The investigation team developed a series of recommendations based on the above findings. These recommendations cover contractor oversight and assurance, risk assessment, well monitoring and well-control practices, integrity testing practices and BOP system maintenance. The report makes the following recommendations, among others:

Procedures and engineering technical practices

- Update and clarify current practices to ensure that a clear and comprehensive set of cementing guidelines and associated Engineering Technical Practices (ETPs) are available as controlled standards.
- Review and update requirements for subsea BOP configuration.
- Update the relevant technical practices to incorporate certain improved design requirements for subsea wellheads.
- Review and update ETPs regarding negative-pressure testing.
- Clarify and strengthen standards for well-control and well-integrity incident reporting and investigation.
- Propose to the American Petroleum Institute the development of a recommended practice for design and testing of foam cement slurries in high-pressure, high-temperature applications.
- Review and assess the consistency, rigour and effectiveness of the current risk management and management of change processes practised by Drilling and Completions (D&C).

Capability and competency

- Reassess and strengthen the current technical authority's role in the areas of cementing and zonal isolation.
- Enhance D&C competency programmes to deepen the capabilities of personnel in key operational and leadership positions and augment existing knowledge and proficiency in managing deepwater drilling and wells.
- Develop an advanced deepwater well-control training programme that supplements current industry and regulatory training and embeds lessons learned from the Gulf of Mexico incident.
- Establish BP's in-house expertise in the areas of subsea BOPs and BOP control systems through the creation of a central expert team, including a defined segment engineering technical authority role to provide independent assurance of the integrity of drilling contractors' BOPs and BOP control systems.
- Request that the International Association of Drilling Contractors review and consider the need to develop a programme for formal subsea engineering certification of personnel who are responsible for the maintenance and modification of deepwater BOPs and control systems.

Audit and verification

- Strengthen BP's rig audit process to improve the closure and verification of audit findings and actions across BP-owned and BP-contracted drilling rigs.

Process safety performance management

- Establish D&C leading and lagging indicators for well integrity, well control and rig safety critical equipment.
- Require drilling contractors to implement an auditable integrity monitoring system to continuously assess and improve the integrity performance of well-control equipment against a set of established leading and lagging indicators.

Cementing services assurance

- Conduct an immediate review of the quality of the services provided by all cementing service providers. Confirm that adequate oversight and controls are in place within the service provider's organization and BP.

Well-control practices

- Assess and confirm that essential well-control and well-monitoring practices, such as well monitoring and shut-in procedures, are clearly defined and rigorously applied on all BP-owned and BP-contracted offshore rigs.

Rig process safety
- Require hazard and operability reviews of the surface gas and drilling fluid systems for all BP-owned and BP-contracted drilling rigs.
- Include in the hazard and operability reviews a study of all surface system hydrocarbon vents, reviewing suitability of location and design.

Blowout preventer design and assurance
- Establish minimum levels of redundancy and reliability for BP's BOP systems. Require drilling contractors to implement an auditable risk management process to ensure that their BOP systems are operated above these minimum levels.
- Strengthen BP's minimum requirements for drilling contractors' BOP testing, including emergency systems.
- Strengthen BP's minimum requirements for drilling contractors' BOP maintenance management systems.
- Define BP's minimum requirements for drilling contractors' management of changes for subsea BOPs.
- Develop a clear plan for remotely operated vehicle intervention as part of the emergency BOP operations in each of BP's operating regions, including all emergency options for shearing pipe and sealing the wellbore.
- Require drilling contractors to implement a qualification process to verify that shearing performance capability of blind shear rams is compatible with the inherent variations in wall thickness, material strength and toughness of the rig drill pipe inventory.
- Include testing and verification of these BOP recommendations in the rig audit process.

National Commission report

BP has co-operated fully with the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (National Commission), which released the full report of its investigation on 11 January 2011. The National Commission acknowledged the complexities and risks inherent to deepwater energy exploration and production; it also concluded that neither industry nor government was fully prepared to assess or manage those risks. The National Commission identified certain missteps and oversights by individuals at BP, Transocean and Halliburton that led to the blowout and concluded that its root cause involved systemic management failures in the industry. These management issues, the National Commission found, extended beyond BP to contractors that serve the entire industry. This included BP's failure to adequately address risks created by late changes to well design and procedures, inadequate testing of the Macondo cement slurry by BP and Halliburton, inadequate communication between BP, Halliburton and Transocean, inadequate communication between Transocean and its crew, and inadequate decision-making processes at the Macondo well. The National Commission also found regulatory failures to be a contributing factor to the Macondo tragedy, in particular the lack of administrative resources and technical expertise at the Minerals Management Service.

The National Commission's report made a number of recommendations in nine distinct areas for addressing the causes and consequences of the spill, including principally the following: improving the safety of offshore operations by enhancing the government's role and by establishing an industry-run, private-sector oversight entity; safeguarding the environment by increasing support for environmental science and regulatory review related to Outer Continental Shelf oil and gas activities; strengthening spill response planning and capacity; advancing well-containment capabilities by increasing government expertise and requiring enhanced containment plans by operators; dedicating funding by the US Congress to Gulf restoration; ensuring financial responsibility by raising the $75-million liability cap for offshore facility accidents; promoting Congressional awareness of the risks of offshore drilling; and developing expertise and research programmes devoted to exploration and spill containment in the Arctic.

Given the emerging consensus that the Gulf of Mexico accident was the result of multiple causes involving multiple parties, we support the National Commission's efforts to strengthen industry-wide safety practices. 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. Even prior to the conclusion of the National Commission's investigation, BP instituted changes designed to further strengthen safety and risk management. These changes include the creation of an enhanced Safety and Operational Risk function, reporting directly to group chief executive Bob Dudley, that maintains an independent view of the implementation of internal and external requirements and of safety and operational risks.

On 17 February 2011, the Commission's Chief Counsel published a separate report on his investigation about the causes of the incident. The Chief Counsel's investigation concluded that the blowout resulted from a series of engineering and management mistakes by the companies involved in the incident, including BP, Halliburton and Transocean.

Consequences of the accident for BP and its shareholders

Financial consequences

The group income statement for 2010 includes a pre-tax charge of $40.9 billion in relation to the Gulf of Mexico oil spill. This comprises costs incurred up to 31 December 2010, estimated obligations for future costs that can be estimated reliably at this time, and rights and obligations relating to the trust fund, described below.

Costs incurred during the year mainly related to oil spill response activities, which included the drilling of relief wells and other subsea interventions, surface response activities including numerous vessels, and shoreline response involving deployment of boom and beach cleaning activities.

Under US law BP is required to compensate individuals, businesses, government entities and others who have been impacted by the oil spill. Individual and business claims are administered by the GCCF, which is separate from BP. BP has established a trust fund of $20 billion to be funded over the period to the fourth quarter of 2013, which is available to satisfy legitimate individual and business claims administered by the 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 arising as a consequence of the Gulf of Mexico oil spill. In 2010, BP contributed $5 billion to the fund, and further quarterly contributions of $1.25 billion are to be made during the period 2011 to 2013. The income statement charge for 2010 includes $20 billion in relation to the trust fund, adjusted to take 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.

BP has provided for all liabilities that can be estimated reliably at this time, including fines and penalties under the Clean Water Act (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 natural resource damages claims under the OPA 90, litigation and fines and penalties except for those in relation to the CWA. These items are therefore contingent liabilities.

BP holds a 65% interest in the Macondo well, with the remaining 35% held by two joint venture partners. While BP believes and will assert that it has a contractual right to recover the partners' shares of the costs incurred, no recovery amounts have been recognized in the financial statements.

For a full understanding of the impacts and uncertainties relating to the Gulf of Mexico oil spill refer to Financial statements – Note 2 on page 158, Note 37 on page 199 and Note 44 on page 218. See also Risk factors on page 27 and Proceedings and investigations relating to the Gulf of Mexico oil spill on pages 130-131.

Share price and dividend consequences

As a result of the incident, BP's board reviewed its dividend policy and decided that no ordinary share dividends would be paid in respect of the first, second and third quarters of 2010. Furthermore, the BP share price suffered a significant fall on the London Stock Exchange, from 655 pence per share on the day of the incident to reach a trading low point of 296 pence per share on 25 June 2010. Although there has since been some recovery in the share price, at 493 pence per share on 18 February 2011, it remained considerably below its level immediately before the incident. (*See Share prices and listings on page 134 for further information on the performance of BP's share price.*)

Other consequences

BP's reputation has been damaged by the incident. For further information, see Risk factors on pages 27-32.

BP's long-term commitment to the Gulf of Mexico region

The Gulf of Mexico incident has had a profound impact on the people and economy of the Gulf coast as well as the offshore energy industry and BP.

From the beginning, BP has worked tirelessly to address the economic and environmental impact of the spill and has a dedicated team working closely with local and state officials to ensure that government claims are paid in a fair and expeditious manner.

BP has also provided funding to promote tourism and seafood safety – two cornerstones of the Gulf coast economy – and has worked closely with state and local leaders to restore the economic health of the region.

We recognize that environmental and economic restoration means more than just cleaning up the oil and paying for losses experienced across the Gulf coast. We intend to ensure that the long-term impacts of the oil spill are understood and remediated.

Exploration and Production

Organizational and governance changes in Exploration and Production

As part of our response to the Gulf of Mexico oil spill, at the beginning of the fourth quarter we decided to reorganize our Exploration and Production segment to create three separate divisions: Exploration, Developments, and Production, integrated through a Strategy and Integration organization. This is designed to change fundamentally the way we operate, with a particular focus on managing risk, delivering common standards and processes and building personnel and technological capability for the future.

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, building on the centralized developments organization established in 2010. 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 group Safety and Operational Risk (S&OR) function is being enhanced to further our objectives in safety, compliance and risk management and demonstrates our commitment to preventing future low-probability, high-impact incidents. It has its own expert staff embedded in the divisions and is responsible for ensuring that all operations are carried out to common standards and for auditing compliance with those standards.

The Strategy and Integration organization is accountable for optimization and integration across the divisions, including delivery of support from finance, procurement and supply chain, human resources and information technology.

Our Exploration and Production segment included upstream and midstream activities in 29 countries in 2010, including Angola, Azerbaijan, Canada, Egypt, Norway, Russia, Trinidad & Tobago (Trinidad), the UK, the US and other locations within Asia, Australasia, South America and Africa, as well as gas marketing and trading activities, primarily in Canada, Europe and the US. Upstream activities involve oil and natural gas exploration and field development and production. Our exploration programme is currently focused on Egypt, the deepwater Gulf of Mexico, Libya, the North Sea, Oman and onshore US. Major development areas include Angola, Azerbaijan, Canada, Egypt, the deepwater Gulf of Mexico, the UK North Sea and Russia. During 2010, production came from 20 countries. The principal areas of production are Angola, Azerbaijan, Egypt, Russia, Trinidad, 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 the US, the UK, Canada and Indonesia. 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 (SCP), which takes gas from Azerbaijan through Georgia to the Turkish border; and the Baku-Tbilisi-Ceyhan pipeline, running through Azerbaijan, Georgia and Turkey. Major LNG activities are located in Trinidad, Indonesia and Australia. 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 gas and power, and generate margins and fees associated with the provision of physical and financial products to third parties and additional 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 Argentina, Bolivia, Chile, Abu Dhabi, Venezuela and Russia, as well as some of our operations in Angola, Canada and Indonesia, are conducted through equity-accounted entities.

Our market

Energy markets recovered in 2010 from the impact of the global economic recession, with crude oil prices in particular bouncing back following a decline in 2009 – the first since 2001.

Dated Brent for the year averaged $79.50 per barrel, 29% above 2009's average of $61.67 per barrel. Prices fluctuated in a relatively narrow band of $70-$80 per barrel for most of the year before rising in the fourth quarter. Prices exceeded $90 per barrel in December, the highest level since October 2008.

In 2011, 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 strengthened in 2010, but were volatile. The average US Henry Hub First of Month Index rose to $4.39/mmBtu, a 10% increase from the depressed prices in 2009.

Gas consumption recovered across the world along with the economy. In the US, a cold start to 2010 followed by a hot summer and low temperatures towards the end of the year also contributed to demand strength. Yet domestic production growth – of shale gas in particular – continued apace and limited price rises. Henry Hub gas prices stayed below coal parity in US power generation from the summer, leading to the displacement of coal by gas. 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 38% to an average of 42.45 pence per therm for 2010. Yet plentiful global LNG supply kept spot gas prices below oil-indexed contract levels for most of the year, causing competition with contract pipeline supplies and marginal European gas production. UK spot gas prices only attained contract price levels from the end of November as cold weather caused rapid inventory draw-downs.

In 2011, we expect gas markets to continue to be driven by the economy, weather, domestic production trends and continued significant growth of global LNG supply.

Our strategy

In Exploration and Production, our 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 enduring positions in the world's key hydrocarbon basins with a focus on deepwater, gas (including unconventional gas) and giant fields. Our strategy is enabled by:

- Continuously reducing operating 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.

We are increasing investment in Exploration, a key source of value creation at the front end of the value chain, and we are evolving the nature of our relationships, particularly with National Oil Companies. We will also continue to actively manage our portfolio, with a focus on value growth.

Our performance

Key statistics

	2010	2009	2008
			$ million
Sales and other operating revenues[a]	**66,266**	57,626	86,170
Replacement cost profit before interest and tax[b]	**30,886**	24,800	38,308
Capital expenditure and acquisitions	**17,753**	14,896	22,227
			$ per barrel
Average BP crude oil realizations[c]	**77.54**	59.86	95.43
Average BP NGL realizations[c]	**42.78**	29.60	52.30
Average BP liquids realizations[c d]	**73.41**	56.26	90.20
Average West Texas Intermediate oil price[e]	**79.45**	61.92	100.06
Average Brent oil price[e]	**79.50**	61.67	97.26
			$ per thousand cubic feet
Average BP natural gas realizations[c]	**3.97**	3.25	6.00
Average BP US natural gas realizations[c]	**3.88**	3.07	6.77
			$ per million British thermal units
Average Henry Hub gas price[f]	**4.39**	3.99	9.04
			pence per therm
Average UK National Balancing Point gas price[e]	**42.45**	30.85	58.12
			thousand barrels of oil equivalent per day
Total production for subsidiaries[g h]	**2,492**	2,684	2,517
Total production for equity-accounted entities[g h]	**1,330**	1,314	1,321
Total of subsidiaries and equity-accounted entities[g h]	**3,822**	3,998	3,838
			million barrels of oil equivalent
Net proved reserves for subsidiaries	**12,077**	12,621	12,562
Net proved reserves for equity-accounted entities	**5,994**	5,671	5,585
Total of subsidiaries and equity-accounted entities	**18,071**	18,292	18,147

[a] Includes sales between businesses.
[b] Includes profit after interest and tax of equity-accounted entities.
[c] Realizations are based on sales of consolidated subsidiaries only, which excludes equity-accounted entities.
[d] Crude oil and natural gas liquids.
[e] All traded days average.
[f] Henry Hub First of Month Index.
[g] Net of royalties.
[h] 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.

2010 performance

Safety and operational risk

In Exploration and Production, safety, both process and personal, remains our highest priority. As described above, the organizational and governance changes in Exploration and Production and S&OR have been designed to ensure we achieve our objectives in this area. In addition, BP's operating management system (OMS) provides us with a systematic framework for safe, reliable and efficient operations. By the end of 2010 all of our exploration and production operations had completed their transition to OMS.

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

In 2010, excluding the impact of the Gulf of Mexico oil spill, further information on which can be found on page 34, Exploration and Production had 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 0.32. This is lower than 2009 when it was 0.39 and 2008 when it was 0.43. Our day away from work case frequency (DAFWCF) in 2010 was 0.063. This is higher than 2009 when it was 0.038 and 2008 when it was 0.057. This increase is largely due to day-away-from-work cases resulting from the Gulf of Mexico incident and an aviation incident in Canada.

In 2010, the number of reported Loss of Primary Containment (LOPC) incidents in Exploration and Production was 194, down from 321 in 2009. Excluding the impact of the Gulf of Mexico incident, the number of reported oil spills equal to or larger than 1 barrel during 2010 was 116, up from 112 in 2009. This is the first year since 1999 that the number of reported spills has increased.

Financial and operating performance

We continually seek access to resources and in 2010, in addition to new access resulting from acquisitions as detailed on page 43, this included Azerbaijan, where BP and the State Oil Company of the Republic of Azerbaijan (SOCAR) signed a new 30-year PSA on joint exploration and development of the Shafag-Asiman structure in the Caspian; China, where we farmed into Block 42/05 in the deepwater South China Sea; the Gulf of Mexico, where we were awarded 18 blocks through the Outer Continental Shelf Lease Sale 213, eleven of which have been executed and seven have yet to be executed; Indonesia, where we were awarded the North Arafura PSC onshore Papua; Jordan, where on 3 January 2010, we received approval from the Government of Jordan to join the state-owned National Petroleum Company (NPC) to exploit the onshore Risha concession in the north east of the country; onshore US, with further properties in the Eagle Ford shale gas play; and the UK, where we were awarded seven blocks in the 26th offshore licensing round.

Since the start of 2011, we have been awarded four blocks in the Ceduna Basin, offshore South Australia and, subject to partner and government approval, we have signed a new agreement with the China National Offshore Oil Corporation (CNOOC) to explore Block 43/11 in the South China Sea. We have also announced a strategic global alliance with Rosneft, which includes an agreement to explore and develop three licence blocks in Russia's South Kara Sea. See Legal proceedings on page 133 for information on an interim injunction, granted by the English High Court on 1 February 2011 and effective until 11 March 2011, restraining BP from taking any further steps in relation to the Rosneft transactions pending the outcome of arbitration proceedings.

On 21 February 2011, Reliance Industries Limited and BP announced their intention to form an upstream joint venture in which BP will take a 30% stake in 23 oil and gas production-sharing contracts that Reliance operates in India, and a 50:50 joint venture for the sourcing and marketing of gas in India. See page 43 for further information.

In November 2010, we announced the Hodoa gas discovery in the deepwater West Nile Delta area of Egypt.

Three major projects came onstream in 2010. Production commenced at the In Salah Gas compression project in Algeria, the Great White field in the Gulf of Mexico, and the Noel field in Canada. In 2010 we took final investment decisions on 15 projects.

Production was lower than last year, largely due to the impact of events in the Gulf of Mexico. After adjusting for the effect of entitlement changes in our PSAs and the effect of acquisitions and disposals, underlying production was 2% lower than 2009. In December 2010, we sustained production from the Rumaila field in Iraq at 10% above the initial production rate in 2009 to achieve the Improved Production Target, which is the first significant milestone in the rehabilitation of Rumaila. In 2010, full-year production growth in TNK-BP was 2.5%.

Sales and other operating revenues for 2010 were $66 billion, compared with $58 billion in 2009 and $86 billion in 2008. The increase in 2010 primarily reflected higher oil and gas realizations, partly offset by lower production. The decrease in 2009 primarily reflected lower oil and gas realizations.

The replacement cost profit before interest and tax for 2010 was $30,886 million, compared with $24,800 million for the previous year. 2010 included net non-operating gains of $3,199 million, primarily gains on disposals that completed during the year partly offset by impairment charges and fair value losses on embedded derivatives. (*See page 25 for further information on non-operating items.*) In addition, fair value accounting effects had an unfavourable impact of $3 million relative to management's measure of performance. (*See page 26 for further information on fair value accounting effects.*)

The primary additional factors contributing to the 25% increase in replacement cost profit before interest and tax were higher realizations, lower depreciation and higher earnings from equity-accounted entities, mainly TNK-BP, partly offset by lower production, a significantly lower contribution from gas marketing and trading and higher production taxes.

Total capital expenditure including acquisitions and asset exchanges in 2010 was $17.8 billion (2009 $14.9 billion and 2008 $22.2 billion). For further information on acquisitions and disposals see pages 43-44.

Development expenditure of subsidiaries incurred in 2010, excluding midstream activities, was $9.7 billion, compared with $10.4 billion in 2009 and $11.8 billion in 2008.

Prior years' comparative financial information

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 replacement cost profit before interest and tax for the year ended 31 December 2008 was $38,308 million and included a net charge for non-operating items of $990 million, with the most significant items being net impairment charges and net fair value losses on embedded derivatives, partly offset by the reversal of certain provisions. The impairment charge included a $517 million write-down of our investment in Rosneft based on its quoted market price at the end of the year. In addition, fair value accounting effects had an unfavourable impact of $282 million relative to management's measure of performance.

The primary additional factor contributing to the 35% decrease in the replacement cost profit before interest and tax for the year ended 31 December 2009 compared with the year ended 31 December 2008 was lower realizations. In addition, the result was impacted by lower income from equity-accounted entities and higher depreciation but the result benefited from higher production and lower costs, as a result of our continued focus on cost management.

Outlook

In 2011, we will seek to continuously drive operational risk reduction through the S&OR function. Through the restructuring into divisions, we intend to drive functional excellence across the lifecycle of exploration, developments and production and continue to focus on building our technological and human 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. We will continue to actively manage our portfolio with a focus on value growth.

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.

Our exploration and appraisal costs, excluding lease acquisitions, in 2010 were $2,706 million, compared with $2,805 million in 2009 and $2,290 million in 2008. 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 80% of 2010 exploration and appraisal costs were directed towards appraisal activity. In 2010, we participated in 479 gross (95.5 net) exploration and appraisal wells in 10 countries. The principal areas of exploration and appraisal activity were Egypt, the deepwater Gulf of Mexico, Libya, the North Sea, Oman and onshore US.

Total exploration expense in 2010 of $843 million (2009 $1,116 million and 2008 $882 million) included the write-off of expenses related to unsuccessful drilling activities in the deepwater Gulf of Mexico ($161 million), the North Sea ($42 million), Libya ($26 million), Angola ($24 million) and others ($4 million). It also included $157 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 18,071mmboe (12,077mmboe for subsidiaries and 5,994mmboe for equity-accounted entities) at 31 December 2010, a decrease of 1% (decrease of 4% for subsidiaries and increase of 6% for equity-accounted entities) compared with the 31 December 2009 reserves of 18,292mmboe (12,621mmboe for subsidiaries and 5,671mmboe for equity-accounted entities). Natural gas represented about 41% (54% for subsidiaries and 14% for equity-accounted entities) of these reserves. The change includes a net decrease from acquisitions and disposals of 307mmboe (303mmboe net decrease for subsidiaries and 4mmboe net decrease for equity-accounted entities). Acquisitions occurred in Azerbaijan, Canada, Norway and the US. Disposals occurred in Canada, Egypt and the US.

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 2010 the proved reserves replacement ratio excluding acquisitions and disposals was 106% (129% in 2009 and 121% in 2008) for subsidiaries and equity-accounted entities, 74% for subsidiaries alone and 166% for equity-accounted entities alone.

In 2010, net additions to the group's proved reserves (excluding production and sales and purchases of reserves-in-place) amounted to 1,503mmboe (686mmboe for subsidiaries and 818mmboe for equity-accounted entities), principally through 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 67% were associated with new projects and were proved undeveloped reserves additions. The remaining additions are in existing developments where they represent a mixture of proved developed and proved undeveloped reserves. Volumes added in 2010 principally relied on the application of conventional technologies. The principal reserves additions in our subsidiaries were in the US (Arkoma, Hawkville, Kuparuk, Mars, Prudhoe Bay, Thunder Horse, Tubular Bells), the UK (Kinnoull, Loyal, Machar, Schiehallion), Egypt (West Nile Delta), Trinidad (Immortelle) and Iraq (Rumaila). The principal reserves additions in our equity-accounted entities were in Argentina (Cerro Dragon), Bolivia (Margarita), Canada (Sunrise) and in Russia (Samotlor, Sorochinsko-Nikolskoye, Talinskoye, Uvat).

Fourteen per cent of our proved reserves are associated with production-sharing agreements (PSAs). The main countries in which we operated under PSAs in 2010 were Algeria, Angola, Azerbaijan, Egypt, Indonesia, Iraq and Vietnam.

Production

Our total hydrocarbon production during 2010 averaged 3,822 thousand barrels of oil equivalent per day (mboe/d). This comprised 2,493mboe/d for subsidiaries and 1,329mboe/d for equity-accounted entities, a decrease of 7% (decreases of 12% for liquids and 2% for gas) and an increase of 1% (increases of 1% for liquids and 3% for gas) respectively compared with 2009. In aggregate, after adjusting for entitlement impacts in our PSAs and the effect of acquisitions and disposals, production was 2% lower than 2009. For subsidiaries, 39% of our production was in the US, 18% in Trinidad and 9% in the UK.

We expect production in 2011 to be lower than in 2010 as a result of disposals, lower production from the Gulf of Mexico and the increased turnaround activity to improve the long-term reliability of the assets. As a result of these factors, reported production in 2011 is expected to be around 3,400mboe/d. The actual outcome will depend on the exact timing of disposals, the pace of getting back to work in the Gulf of Mexico, OPEC quotas and the impact of the oil price on our PSAs. In the Gulf of Mexico, there is industry-wide uncertainty around the pace at which new drilling activity will be restored following the lifting of the drilling moratorium in October 2010. No new permits for the drilling of deepwater wells (except for water injection and side track wells) had been issued to any company until the end of February 2011. BP has clear criteria for safely restarting drilling and completions activity, which include meeting all new regulatory requirements, addressing each of the recommendations of our internal investigation, compliance with our own standards and ensuring we have the right capability in place, along with appropriate contractor management.

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 2010, we continued to grow our portfolio of assets through acquisitions such as the transaction with Devon Energy, which significantly enhanced our position in a number of core strategic areas in Brazil, Azerbaijan and deepwater Gulf of Mexico, and the increase in our equity holding in the Valhall and Hod fields, potentially very significant fields in the North Sea with technological upsides.

We also undertook a number of disposals as part of our previously announced portfolio high-grading review. In total, these transactions generated $17 billion in proceeds during 2010 including prepayments of $6.2 billion for disposals yet to complete. See Financial statements – Note 4 on page 163. With regards to proved reserves, 102mmboe were acquired in 2010, all within our subsidiaries while 408mmboe were disposed of (approximately 404mmboe for subsidiaries and approximately 4mmboe for equity-accounted entities).

Acquisitions

- In March 2010, BP announced a broad-ranging transaction with Devon Energy to enhance its position in core strategic areas. BP agreed to pay Devon Energy $6.9 billion in cash for assets in Brazil, Azerbaijan and the US deepwater Gulf of Mexico.
  In addition, BP sold to Devon Energy a 50% stake in BP's Kirby oil sands interests in Alberta, Canada, for $500 million. The parties have agreed to form a 50:50 joint venture, operated by Devon, to pursue the development of the interest. Devon committed to fund an additional $150 million of capital costs on BP's behalf.
  In Brazil, subject to government and regulatory approvals, the transaction will give BP a diverse and broad deepwater exploration acreage position offshore Brazil with interests in eight licence blocks in the Campos and Camamu-Almada basins, as well as two onshore licences in the Parnaiba basin. The Campos basin blocks include three discoveries – Xerelete, pre-salt Wahoo and Itaipu – and the producing Polvo field.
  In the US deepwater Gulf of Mexico, BP gained a high-quality portfolio with interests in some 240 leases, with a particular focus on the emerging Paleogene play in the ultra-deepwater. The addition of Devon's 30% interest in the major Paleogene discovery, Kaskida, gave BP a 100% interest in the project. The assets also included interests in four producing oilfields: Magnolia, Merganser, Nansen, and Zia, and one non-producing asset.
  In Azerbaijan, acquisition of Devon's 3.29% (after pre-emption exercised by some of the partners) stake in the BP-operated Azeri-Chirag-Gunashli development increased BP's interest to 37.43%.
  The undeveloped Kirby oil sands leases are in the south-east of the Athabasca region of Alberta, close to the Devon-operated Jackfish development, which started production in 2007. BP and Devon have agreed an initial appraisal programme to assess the significant potential of the Kirby acreage and to establish a long-term development plan. In addition to forming the joint venture, BP and Devon have agreed to enter into a long-term heavy crude off-take agreement for production from the Kirby development as well as a portion of the production from some of Devon's other oil sands assets.
- Also in March 2010, BP announced that it had entered into a partnership in Canada with Value Creation Inc. (VCI) to develop the Terre de Grace (TDG) oil sands lease, one of VCI's large oil sands leases, in the Athabasca region. BP is now the operator and majority partner for the partnership, with VCI and BP together providing strategic direction and guidance. TDG is a large, contiguous 185,000 acres of high-quality oil sands land with substantial delineation of the East Graceland area and further potential in the less-delineated remainder of the leases. In 2010, capital expenditure in relation to the formation of this partnership was $900 million.
- On 1 September 2010, BP increased its equity holding in the significant Norwegian Valhall and Hod fields by acquiring 7.9% interest in the Valhall field and 12.5% in the Hod field from Total. The transaction increased the equity holding in Valhall to 35.95% and Hod to 37.5%. The final purchase consideration was $492 million. The acquisition is expected to strengthen BP's existing business in Norway and the North Sea.
- In September 2010, BP announced an agreement with Devon Energy in which BP acquired 40.82% of Devon's existing share in Block 42/05 in the South China Sea. The remaining 59.18% of Devon's share was purchased by Chevron, who will be the operator in the exploration phase under the amendment agreements to the production-sharing contract with CNOOC. All pre-development spending will be incurred by BP and Chevron. During the development phase, CNOOC has the right to back-in to a 51% share in the project thus leaving working interest shares as follows: BP 20%, CNOOC 51%, Chevron 29%.
- On 24 January 2011, BP exercised a preferential right to acquire Shell's working interest in the Marlin and Dorado producing fields for a total consideration of $257 million. This brings BP's working interest in both fields to 100%.
- On 21 February 2011, Reliance Industries Limited and BP announced that they intend to form an upstream joint venture in which BP will take a 30% stake in 23 oil and gas production-sharing contracts that Reliance operates in India, including the producing KG D6 block, and form a 50:50 joint venture for the sourcing and marketing of gas in India. BP will pay Reliance Industries Limited an aggregate consideration of $7.2 billion, and completion adjustments, for the interests to be acquired in the 23 production-sharing contracts. Future performance payments of up to $1.8 billion could be paid based on exploration success that results in development of commercial discoveries. Reliance will continue to be the operator under the production-sharing contracts. Completion of the transactions is subject to Indian regulatory approvals and other customary conditions.

Disposals

- In July 2010, BP announced that it had entered into several agreements to sell upstream assets in the US, Canada and Egypt to Apache Corporation (and an existing partner that exercised pre-emption rights). The deals, together worth a total of $7 billion, comprise BP's Permian Basin assets in Texas and south-east New Mexico, US; its Western Canadian upstream gas assets; and the Western Desert business concessions and East Badr El-din exploration concession in Egypt. These transactions were completed during 2010.
- On 3 August 2010, BP announced that it had agreed to sell its oil and gas exploration, production and transportation business in Colombia to a consortium of Ecopetrol, Colombia's national oil company (51%), and Talisman of Canada (49%). The two companies agreed to pay BP a total of $1.9 billion in cash, subject to customary post-completion price adjustments, for 100% of the shares in BP Exploration Company (Colombia) Limited (BPXC), the wholly-owned BP subsidiary company that held BP's oil and gas exploration, production and transportation interests in Colombia. Following the approval of the Colombian authorities, completion occurred on 24 January 2011.
- On 31 August 2010, BP completed the sale of its entire interest in the Overthrust assets (Painter Complex Gas Plant, Painter Reservoir Unit and Whitney Canyon field and inlet facility) to Merit Energy Company for $217 million.
- On 18 October 2010, BP announced it had reached agreement to sell its upstream businesses and associated interests in Venezuela and Vietnam to TNK-BP for a total of $1.8 billion subject to customary post-completion price adjustments. The agreement includes BP's interests in the Petroperijá, Boquerón and PetroMonagas joint ventures in Venezuela and, in Vietnam, BP's 35% operating interest in the Lan Tay and Lan Do gas fields (Block 6.1) and associated pipeline and power generation interests. Block 6.1 partners, PetroVietnam and ONGC Videsh Ltd, have waived pre-emption rights to purchase BP's Block 6.1 interest. BP will retain an economic interest in these assets through its 50% interest in TNK-BP.
- In October 2010, BP announced it had reached an agreement with its partner, Hess Corporation, for the sale of a 20% interest in the Tubular Bells field in the Gulf of Mexico. Hess agreed to acquire the 20% interest from BP for $40 million and became the operator. The increased ownership brought Hess's working interest in Tubular Bells to 40%. Chevron holds a 30% interest and BP retains 30%. Tubular Bells, which was discovered in 2003, is a deepwater field approximately 135 miles south-east of New Orleans, Louisiana.
- On 25 October 2010, BP announced that it had reached agreement to sell its recently acquired interests in four mature producing deepwater oil and gas fields in the US Gulf of Mexico to Marubeni Oil and Gas for $650 million. BP acquired the interests in the fields – Magnolia, Merganser, Nansen and Zia – from Devon Energy earlier in 2010 as part of the wider acquisition of assets in the Gulf of Mexico, Brazil and Azerbaijan, but determined that they did not fit well with the rest of the group's assets in the region and would be of more value to another company.
- On 28 November 2010, BP announced that it had entered into an agreement to sell its interests in Pan American Energy (PAE) to Bridas Corporation. PAE is an Argentina-based oil and gas company owned by BP (60%) and Bridas Corporation (40%). Bridas Corporation will pay BP a total of $7.06 billion in cash for BP's interest in PAE. The transaction is expected to be completed in 2011. The transaction excludes the shares of PAE E&P Bolivia Ltd. Completion of the transaction is subject to closing conditions including the receipt of all necessary governmental and regulatory approvals.
- On 14 December 2010, BP announced that it had reached agreement to sell its upstream assets in Pakistan to United Energy Group for $775 million. Subject to certain closing conditions, including the receipt of all necessary governmental and regulatory approvals, closing is anticipated to occur by the end of the first quarter of 2011.
- During 2010, BP also announced its intention to divest its interest in the Tuscaloosa fields in Louisiana, the Wattenberg plant in Colorado and its NGL business in Canada.
- On 22 February 2011, BP announced its intention to sell its interests in a number of operated oil and gas fields in the UK. The assets involved are 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. BP aims to complete the disposals around the end of 2011, subject to receipt of suitable offers and regulatory and third party approvals. 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 these intended transactions.

The following discussion reviews operations in our Exploration and Production business by continent and country, and lists associated significant events that occurred in 2010. Where relevant, 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.

- In July 2010, the UK Parliament's Energy and Climate Change Select Committee launched an investigation into the safety of deepwater drilling in the UK, in light of the accident in the Gulf of Mexico. In September, BP provided both written and oral evidence to the Committee, as did a number of other operators and organizations with a stake in the UK Continental Shelf (UKCS).
- In the UK, BP has been closely involved in communicating the lessons learned from the Gulf of Mexico oil spill to industry and the regulatory authorities, and has also been widely represented in the Oil Spill Prevention and Response Advisory Group (OSPRAG), a group formed in late May to co-ordinate and lead the UK's response to such incidents. BP has provided support, for example, through the transfer of two containment devices to Oil Spill Response Limited's Southampton depot and by leading the design and procurement of a capping stack for use in the deepwater of the UKCS. The capping stack project is due for completion in mid-2011.
- The European Commission published its policy and pre-legislative communication on offshore safety in October 2010. Preparation of a draft legislative package is now with the European Commission services, for expected publication in spring 2011.
- BP is scheduled to drill a deepwater exploration well in the west of Shetland during 2011 and, together with its drilling contractor, plans to implement all relevant lessons from the Gulf of Mexico accident during the planning and execution of that well. Much has already been done during 2010 in the North Sea business to further improve the safety of drilling operations.
- In October 2010, BP was awarded interests in seven offshore exploration blocks in the 26th round of UK Continental Shelf licensing. Five of these blocks are BP-operated and two are partner-operated. This represents the largest licence award for BP in the UK for more than 10 years.
- On 27 October 2010, the European Union followed the UN and US in enacting further restrictive measures against Iran (the EU Regulations). The EU Regulations target, among other things, legal persons, entities or bodies outside of Iran that have direct or indirect Iranian ownership.
- On 16 November 2010, production from the Rhum gas field in the central North Sea was suspended pending clarification from the UK government on certain aspects of the EU Regulations. This action was taken to comply with the notification requirements in the EU Regulations. Rhum is owned by BP (50%) and the Iranian Oil Company (50%) under a joint operating agreement dating back to the early 1970s.

Rest of Europe

Our activities in the Rest of Europe are in Norway.

- On 9 November 2010, the development of the Norwegian oil and gas field Skarv reached a significant milestone with the naming ceremony of the Skarv Floating Production, Storage and Offloading (FPSO) unit. The ceremony took place in Geoje in South Korea. The vessel will operate in the Norwegian Sea close to the Arctic Circle, 210km off the coast of Nordland. It is due to start production at the Skarv oil and gas field in the autumn of 2011.
- In 2010, the Valhall redevelopment project passed a major milestone with the completion of the heavy lift programme. The main deck and living quarters were successfully installed offshore in July 2010. The living quarters are scheduled to be ready for habitation in April 2011, with production start-up from the new facility scheduled for early 2012.

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 impact of the Gulf of Mexico oil spill and BP's response please see pages 34-39. Also see page 43 under Production.

- On 31 March 2010, first oil was achieved from the Great White field (BP 33.3%) located in the ultra-deep waters of the Gulf of Mexico. Production is processed by the Perdido Regional Host floating production facility (BP 27.5%), an integrated spar and drilling rig. The development is operated by Shell on behalf of BP and Chevron. Great White marks the first development of a Paleogene (Lower Tertiary) reservoir in the Gulf of Mexico and is expected to represent 80% of the estimated total production through the Perdido Host.
- In September 2010, the final investment decision was made for the Mars B (BP 28.5%) deepwater development, located approximately 130 miles south of New Orleans, Louisiana in the Gulf of Mexico. The development will include a second tension-leg platform, named Olympus, to enhance recovery from the Mars field. The Mars B development will draw production from eight Mississippi Canyon blocks – 762, 763, 764, 805, 806, 807, 850 and 851.
- In March 2010, BP participated in lease sale 213. Following this sale we were awarded 18 leases, 11 of which have now been executed, a further seven leases were awarded but have not yet been executed.

Lower 48 states

Our North America Gas business operates onshore in the Lower 48 states producing natural gas, natural gas liquids and coalbed methane across 14 states. In 2010, we drilled over 200 wells as operator across the US, including start-up operations in the Eagle Ford shale. Shale gas assets are becoming an increasingly important part of our North America Gas business.

We have not included any proved undeveloped reserves expected to commence development beyond five years in our disclosed volumes, although we are committed to development beyond five years in many fields.

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.

Two key aspects of BP's business strategy in Alaska are commercializing the large undeveloped natural gas resource within our 26.4% interest in Prudhoe Bay and unlocking the large undeveloped viscous and heavy oil resources within existing North Slope fields through the application of advanced technology.

- In 2010, we progressed the previously announced development activities for the Liberty oilfield, which is located on federal leases about six miles offshore in the Beaufort Sea, and east of the Prudhoe Bay oilfield. The planned development includes up to six ultra-extended reach wells, including four producers and two injectors, to be drilled from existing infrastructure in the BP-operated Endicott field to minimize the onshore and offshore environmental footprint. As part of a continuous evaluation of project design, materials, and systems, we suspended physical construction of the rig on-site in the fourth quarter. Following a review of engineering and design elements, and resolution of any issues, we plan to continue rig construction. As this review moves forward, we will develop a revised project schedule. BP drilled the Liberty discovery well in 1997, and is the operator and sole owner of the field.
- 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. At the end of 2006, based on the DNR's termination of the Unit, BP wrote off all historical costs associated with the PTU. In January 2009, ExxonMobil was granted permission by the DNR, under a conditional interim decision, to conduct drilling operations on two of the 31 leases comprising the PTU. On 11 January 2010, the Alaska Superior Court reversed the DNR's administrative decision to terminate the unit. The DNR petitioned the State of Alaska Supreme Court for limited review, and the petition was granted in the second quarter of 2010. As of the end of 2010, the case is still pending before the Alaska Supreme Court. ExxonMobil and the State of Alaska have also informed the other unit owners, including BP, that they are negotiating a settlement agreement. BP has asked to participate in the settlement discussions.

Canada

In Canada, BP is focused on one of the world's largest petroleum resource basins, Canada's oil sands, using in-situ technology. In-situ technology is different to mining in that it limits land disturbance and requires no tailing ponds. The in-situ technology that BP Canada plans to use is steam-assisted gravity drainage (SAGD) which 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 and natural gas liquids, markets natural gas, is the largest marketer in Canada of natural gas liquids and has significant exploration interests in the Canadian Beaufort Sea.

- In November 2010, phase 1 of the Sunrise oil sands project (BP 50%) was sanctioned. BP and its partner, Husky Energy Inc, have committed funding to build facilities, drill wells and create the operational systems and resources to bring Sunrise phase 1 into production. First production of bitumen is expected in 2014, building to 60,000 barrels per day gross capacity over the subsequent 24 months. Long-term drilling and facility development is planned to continue thereafter in order to maintain that rate for 40 years or more. Future additional phases of Sunrise are being contemplated.
- In July 2010, BP signed a joint operating agreement with ExxonMobil Canada Limited and Imperial Oil Resources Ventures Limited, a subsidiary of ExxonMobil, to exchange 50% of BP's working interest in the EL 449 field for 50% working interest in Imperial/Exxon's EL 446 field, both in the Canadian Beaufort Sea. Under this agreement, operatorship was assigned to Imperial with BP remaining actively involved in major exploration decisions.
- In 2010, interpretation of the 2009 3D-seismic survey of licences in the Canadian Beaufort Sea commenced and access to seismic data for the EL 446 licence was acquired.

South America

Trinidad & Tobago

BP holds exploration and production licences covering 904,000 acres offshore of the east coast. Facilities include 13 offshore platforms and one onshore processing facility. Production comprises oil, gas and NGLs.

- On 21 April 2010, BP Trinidad & Tobago's (bpTT) Serrette platform was installed in Trinidad waters in bpTT's east coast offshore acreage. The Serrette platform is located 51 kilometres north of bpTT's Mango development. It represents the first development in the northern area of bpTT's Columbus Basin acreage and has been equipped to enable future development opportunities in this area. Serrette, bpTT's thirteenth offshore production platform, is the fifth normally unmanned installation (NUI), designed and constructed in Trinidad & Tobago. The Serrette project was sanctioned in May 2009 and has a design capacity of 1 billion cubic feet per day and will deliver a peak production of 500 million standard cubic feet per day. The platform will tie into the Cassia B platform. Drilling is expected to commence in the first quarter of 2011 and production is planned for the second quarter of 2011.

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% equity in the first Angolan LNG project.

- In August 2010, Total, as operator of Block 17 (BP 16.67%), announced the development of the Cravo Lirio Orquidea Violeta (CLOV) project and the award of the principal contracts. This project is the fourth development in Angola's deepwater offshore Block 17, after Girassol, Dalia and Pazflor, and is located approximately 140 kilometres from Luanda and 40 kilometres north-west of Dalia in water depths ranging from 1,100 to 1,400 metres. The CLOV development will lead to four fields coming onstream. Drilling is expected to start in 2012 and first oil is expected in 2014. A total of 34 subsea wells are planned to be tied back to the CLOV FPSO unit, which will have a processing capacity of 160mb/d and a storage capacity of approximately 1.8 million barrels.
- Sanctioned in 2008, PSVM comprises the development of the Plutão, Saturno, Vênus and Marte fields, in a water depth of approximately 2,000 metres, some 400 kilometres north-west of Luanda. In 2010, BP commenced the offshore stage of this major project with the arrival of several vessels into Angola waters. Pile installation has been completed and installation of the production flowlines started. Parallel to this, in Singapore the PSVM FPSO was modified to include the new Turret Support Structure. Oil production from PSVM is scheduled to start in 2011. The remaining discoveries in Block 31 will be developed through hubs similar to the first development, PSVM.

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 2010, the In Salah compressions project successfully achieved first gas.
- During 2010, the next phase of the In Amenas development was approved with the award of the engineering primary contracts for compression. The In Salah Southern Fields project is expected to be approved in early 2011 with first gas for both projects expected by 2014.
- In September 2010, the Algerian government approved an extension to the second prospecting period for the Bourarhet Sud block.

Libya

In Libya, BP is in partnership with the Libyan Investment Corporation (LIC) 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 net assets in Libya at 31 December 2010 were $212 million.

- The first phase of the offshore 3D seismic acquisition was completed in October 2009, fulfilling BP's marine 3D seismic commitment. The programme covered a surface area of 17,000 square kilometres and was the largest offshore 3D proprietary survey ever undertaken by an international energy company. It involved the deployment of the largest and most powerful data-processing facility ever installed on a seismic vessel and included a technology trial of a multi-azimuth (MAZ) seismic technique, the first ever three-azimuth seismic survey in Libyan waters.
- The onshore 3D seismic acquisition in BP's Ghadames acreage commenced in November 2008 and is ongoing. This 14,000 square kilometre commitment represents one of the largest single 3D land seismic commitments in the industry.
  The programme involves the first at-scale deployment of the ISS™ seismic acquisition technology, a cutting-edge proprietary BP technique using independent simultaneous sources that is allowing BP to operate one of the most efficient land seismic programmes in the world today. The technology has enabled BP to acquire high-quality, densely-sampled 3D land data for the same cost as 3D marine or 2D land data while minimizing environmental impacts, a major achievement for the industry.
- Due to the outbreak of political unrest in Libya, the BP office in Tripoli was closed on 21 February 2011 and our Libyan operations suspended. All BP expatriate staff and their families have been evacuated from Libya. Currently, it is not possible to say what impact the ongoing unrest, potential political changes and international sanctions will have on the now-suspended seismic operations and start-up of the exploration drilling programme which had been scheduled to commence onshore and offshore in 2011.

Egypt

BP has a long-standing history in Egypt, successfully operating there for over 45 years. To date BP has produced almost 40% of Egypt's entire oil production and supplies more than 35% of the domestic gas demand with its partners. In 2010, BP Egypt production was 133mboe/d. Net assets at 31 December 2010 were $6,107 million. BP is working to meet Egypt's domestic market growth by actively exploring in the Nile Delta and investing to add production from existing discoveries.

- In July 2010, BP signed a new agreement with the Egyptian Ministry of Petroleum and the Egyptian General Petroleum Corporation to develop the significant hydrocarbon resources in the North Alexandria and West Mediterranean deepwater concessions. Production from the West Nile Delta development, at an estimated investment of $9 billion gross, is projected to reach up to 1 billion cubic feet per day, providing a major new source of gas for the domestic market in Egypt. The first phase will develop gas and associated condensate through subsea development of five offshore fields into a new purpose-built onshore gas plant on Egypt's Mediterranean coast. First gas is expected in late 2014. The new agreement amends the commercial terms and the governance structure for the two concessions located in the West Nile Delta, enabling BP and its partner, RWE Dea, to proceed with the development.
- On 24 November 2010, BP announced that it has made a significant gas discovery in the deepwater West Nile Delta area. The Hodoa discovery is located in the West Mediterranean deepwater Nile Delta concession, some 80 kilometres northwest of Alexandria. The WMDW-7 well was drilled to a depth of 6,350 metres and is the first Oligocene deepwater discovery in the West Nile Delta area. Further appraisal is under way. BP operates and holds 80% of the West Mediterranean deepwater concession with RWE Dea holding the remaining 20%. Hodoa was drilled by the Pride North America semi-submersible rig, in a water depth of 1,077 metres.

- Due to the recent significant political unrest in Cairo and other major cities in Egypt, the BP Egypt office in Cairo was closed from 28 January for a period of 10 days. Furthermore, BP expatriate staff and their families were evacuated from Egypt. The BP Egypt office was reopened on 7 February, and national staff returned to work. Most expatriate staff and families returned to Egypt during February. Production at BP Egypt's joint ventures (GUPCO and PHP) was not affected by the office closures. The office closure and staff evacuation will have some short-term impacts on project activity. On 11 February, President Mubarak resigned and handed over power to the Supreme Council of the Egyptian Armed Forces. Currently, it is not possible to say what impact, if any, future politicial changes will have on the BP Egypt business.

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.

- In June 2010, BP was awarded joint study rights with the Indonesia Directorate General of Oil and Gas on the West Sanga Sanga block immediately adjacent to the Sanga-Sanga PSA. This study involves gathering, processing and interpreting data to evaluate the viability of a coalbed methane (CBM) project in the area. The award of the joint study secures matching rights for BP and its partner over the 3,500-square kilometre area when the area will be tendered for production-sharing contracts (PSC), allowing them to change their bid to match that of the highest bidder at that time.

China

BP's upstream asset in the country is the Yacheng offshore gas field (BP 34.3%) in the South China Sea, one of the biggest offshore gas fields in China. Yacheng supplies the Castle Peak Power Company gas for up to 70% of Hong Kong's gas-fired electricity generation. Additional gas is also sold to the Hainan Holdings Fuel & Chemical Corporation Limited.

- On 12 January 2011, BP announced that it had signed a new agreement with the China National Offshore Oil Corporation (CNOOC) for deepwater exploration in Block 43/11 in the South China Sea, subject to partner and government approval.

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.

- On 9 March 2010, the steering committee for the development of the ACG field sanctioned investment in the Chirag Oil Project (COP). This is the next major capital investment in the ongoing development of the ACG field in the Azerbaijan sector of the Caspian Sea. The project is planned to increase oil production and recovery from the field through a new offshore facility which is designed to fill a critical gap in the field infrastructure between the existing Deepwater Gunashli and Chirag-1 platforms.
- On 7 June 2010, the government of Azerbaijan and the government of Turkey signed a Memorandum of Understanding (MOU) as part of a package of documents that will regulate the sale of Azerbaijani gas to Turkey and transit terms for transportation of the gas to the European markets through the territory of Turkey. This marks a major step forward towards conclusion of required agreements for Shah Deniz Stage 2 gas sales to Turkey and beyond, and is a milestone that underpins the significance of the Stage 2 development plans and paves the way for the project to move forward towards a final investment decision by the Shah Deniz partnership. At this stage, discussions to define the best option for further gas marketing and sales continue and these are led by the Azerbaijani government in conjunction with the Shah Deniz partnership.
- On 7 October 2010, BP and the State Oil Company of the Republic of Azerbaijan (SOCAR) signed a new PSA for the joint exploration and development of the Shafag-Asiman structure in the Azerbaijan sector of the Caspian Sea. Under the PSA, which is for 30 years, BP will be the operator with 50% working interest and SOCAR will hold the remaining 50% equity. The block lies some 125 kilometres (78 miles) to the south east of Baku. It covers an area of some 1,100 square kilometres and has never been explored before. It is located in a deepwater section of about 650-800 metres with reservoir depth of about 7,000 metres.
- On 24 December 2010, BP and its partners received a five-year PSA extension for Shah Deniz from SOCAR. The PSA extension allows the Shah Deniz partners to negotiate new long-term gas contracts and underpins the economics of the project.
- During 2010, the remedial work necessary following the subsurface gas release that occurred beneath the Central Azeri platform in September 2008 was completed. With the exception of two wells that were abandoned, all wells on the Central Azeri platform are online and in service.
- Naftiran Intertrade Co (NICO) Ltd is an Iranian company and has a less than 10% non-operating interest in Shah Deniz. NICO was selected as a Shah Deniz project participant by the State of Azerbaijan when the Shah Deniz PSA was awarded in June 1996. 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.

Russia

- On 14 January 2011, BP and Rosneft[a] announced a strategic global alliance. Rosneft and BP have agreed to explore and develop three licence blocks in Russia's South Kara Sea covering approximately 125,000 square kilometres. Additionally, BP has agreed to issue 988,694,683 ordinary BP shares to Rosneft (representing 5% of BP) in a swap where Rosneft has agreed to transfer 1,010,158,003 ordinary Rosneft shares to BP (representing 9.5% of Rosneft). Finally, BP and Rosneft have agreed to other joint pursuits including the establishment of an Arctic technology centre in Russia, joint technical studies in the Russian Arctic beyond the South Kara Sea area and the search for additional international collaboration opportunities. The share swap transaction is subject to certain listing approvals and the completion of certain administrative requirements. The share swap agreement is subject to the outcome of arbitration proceedings between BP and Alfa Petroleum Holdings Limited (APH) and OGIP Ventures Limited (OGIP) who have raised issues relating to the share swap agreement and the alliance. APH is a company owned by Alpha Group. APH and OGIP each own 25% of TNK-BP in which BP also has a 50% shareholding. See further information in Legal proceedings on page 133.

TNK-BP

TNK-BP, an associate owned by BP (50%) and Alfa Group and Access-Renova (AAR) (50%), is an integrated oil company operating in Russia and Ukraine. BP's investment in TNK-BP is reported in the Exploration and Production segment. The TNK-BP group's major assets are held in OAO TNK-BP Holding. Other assets include the BP-branded retail sites in the Moscow region and interests in OAO Rusia Petroleum and the OAO Slavneft group. The workforce comprises more than 43,000 people.

- 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 715 thousand barrels per day. TNK-BP supplies approximately 1,400 branded filling stations in Russia and Ukraine and has more than 25% market share of the Moscow retail market.

[a] BP already holds a 1.3% investment in Rosneft Oil Company with a carrying value of $948 million.

- On 17 February 2010, the TNK-BP board of directors endorsed investment projects totalling more than $1.8 billion to be spent in 2010 – 2012. Of this amount, $1.7 billion is allocated for two major upstream projects: full field development and creation of regional infrastructure in the eastern part of the Uvat group of fields and further development of the Verkhnechonskoye oilfield in East Siberia. Members of the board also endorsed TNK-BP's participation in a joint venture between National Petroleum Consortium LLP and Petroleos de Venezuela (PDVSA), the state oil company of Venezuela, to appraise and develop the JUNIN 6 block in Venezuela and to release funding of $180 million to support these activities in 2010 – 2012.
- On 28 May 2010, TNK-BP announced completion of a deal to acquire 100% of the Vik Oil group of companies in the Ukraine. Previously Vik Oil owned 118 fuel stations in 13 Ukrainian regions, as well as 8 oil depots, 49 petrol tankers and 122 land plots in various stages of development. TNK-BP paid $302 million for these interests.
- On 28 February 2011, TNK-BP announced that it had sold its interest in the Kovykta gas field to Gazprom.

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. During the year, Elvary Neftegaz, via its Russian affiliate, held geological and geophysical studies licences with the Russian Ministry of Natural Resources and Ecology (MNRE) to perform exploration seismic and drilling operations in a licence area off the east coast of Russia. To date, 2D and 3D seismic data has been acquired and four wells have been drilled in the licence area. In 2010, additional electromagnetic surveys were performed in advance of future drilling commitments. In the fourth quarter of 2010, the value of BP's investment in Sakhalin was written-down to reflect the current outlook on the future recoverability of the investment.

Middle East and Pakistan

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.

- On 3 January 2010, BP received approval from the government of Jordan to join the state-owned National Petroleum Company to exploit the onshore Risha concession in the north-east of the country. BP established an office in February and has started its exploration and appraisal work programme, including commencement of a 5,000-square kilometre seismic programme.
- On 11 October 2010, after 32 years as operator of the Sharjah concession area, BP agreed to transfer its operatorship of the concession to the government of Sharjah. BP will retain its equity ownership of 40% of the concession until expiry in November 2013.
- During 2010, major milestones achieved in the Oman Khazzan Makarem gas appraisal programme included the award of the contract for early engineering, design and concept studies for the potential long-term development of hydrocarbon resources in the block, and the commissioning of early well test facilities.

Iraq

Following a successful bid with PetroChina to run the Rumaila oil field in June 2009, the technical service contract (TSC) became effective on 17 December 2009. BP holds a 38% share and is the lead contractor. Rumaila is one of the world's largest oilfields and was discovered by BP in 1953. It currently produces approximately half of Iraq's oil exports and comprises five producing reservoirs. BP together with its partners is actively refurbishing the wells and facilities.

- On 1 July 2010, the Rumaila Operating Organization (ROO) was established and began to take over operatorship of the Rumaila oilfield from South Oil Company (SOC), one of the state-owned oil companies in Iraq. The ROO is made up of approximately 4,000 assignees from BP, PetroChina and SOC, and its creation is one of the first steps in the plan to grow Rumaila production to 2.85 million barrels per day over the next few years.
- In September 2010, BP and PetroChina, as the international partners in the ROO, signed an agreement with the British Council to fund dedicated English language tuition for approximately 500 employees of the ROO. The British Council teachers will be based in the Rumaila oilfield and provide training for the current English language teachers in SOC and the local North Rumaila Village school. According to the TSC, BP and PetroChina are required to spend $5 million per year on education and this agreement with the British Council is the first major programme funded as part of this commitment.
- In December 2010, as a result of increasing activity throughout 2010, production was sustained at 10% above the initial production rate to achieve the improved production target which is the first significant milestone in the rehabilitation of Rumaila. Achievement of IPT was formally agreed with the Government of Iraq on 25 December 2010 and consequently the Contractors (BP and PetroChina) in accordance with the TSC, become eligible for Service Fees during 2011.

Australasia

Australia

BP is one of seven partners in the North West Shelf (NWS) venture. Six partners (including BP) hold an equal 16.67% interest in the infrastructure and oil reserves and an equal 15.78% interest in the gas and condensate reserves, with a seventh partner owning the remaining 5.32% of gas and condensate reserves. 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.

- The North Rankin 2 project linking a second platform to the existing North Rankin A platform, sanctioned in 2008, remains on track for start-up in late 2012. On completion, the North Rankin A and North Rankin B platforms will operate as a single integrated facility and recover low-pressure gas from the North Rankin and Perseus gas fields.
- The Janz-Io field (BP 5.375%) development, which is part of the Greater Gorgon project, is on track. The Jansz-Io field will be developed as part of the Greater Gorgon project, which will comprise three LNG trains, each with a capacity of 5 million tonnes per annum (mtpa), on Barrow Island, with first gas expected in 2014. As part of this, a unitization and unit operating agreement has been executed with the joint venture partners and sales and purchase agreements for the wellhead sale of raw gas and repurchase of LNG ex-Barrow Island have been executed between BP and Shell.
- 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.

Eastern Indonesia

- On 26 November 2010, BP was awarded a 100% interest in the North Arafura oil and gas PSA in onshore Papua province. The PSA was signed in Jakarta by representatives of the government and BP. The North Arafura PSA is located on the coast of the Arafura Sea, 480 kilometres south east of the BP-operated Tangguh plant, covering an area of just over 5,000 square kilometres. BP expects to commence seismic operations on the block in the near future.

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 2010 by country.

BP's onshore US crude oil and product pipelines and related transportation assets are included under Refining and Marketing (*see page 55*).

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

Alaska

BP owns a 46.9% interest in the Trans-Alaska Pipeline System (TAPS), with the balance owned by four other companies. BP also owns a 50% interest in a joint venture company called 'Denali – The Alaska Gas Pipeline' (Denali). The remaining 50% of Denali is owned by a subsidiary of ConocoPhillips. The proposed Denali project consists of a gas treatment plant (GTP) on Alaska's North Slope, transmission lines from the Prudhoe Bay and Point Thomson fields to the GTP, an Alaska mainline that would run from the North Slope of Alaska to the Alaska-Yukon border, and a Canada mainline that would transport gas from the Alaska-Yukon border to Alberta. Also included are delivery points along the route to help meet local natural gas demand in Alaska and Canada. Denali's cost estimate for the GTP and pipelines is approximately $35 billion.

- Denali conducted concurrent 90-day open season bidding processes for both the US and Canadian portions of the Denali project during the third quarter of 2010, the bidding for each concluded on 4 October 2010. Conditional bids were received for significant capacity from potential shippers. At the end of 2010, Denali is evaluating the bids received, and confidential negotiations with potential shippers continue in an effort to reach binding agreements. If agreements can be concluded for sufficient capacity, Denali will seek certification from the Federal Energy Regulatory Commission (FERC) of the US and the National Energy Board (NEB) of Canada to move forward with project construction. Denali would manage the project, and would own and operate the pipeline when completed. BP may consider other equity participants, including pipeline companies, that can add value to the project and help manage the risks involved.
- On 12 January 2010, an agreement to settle challenges to TAPS carrier interstate tariff rate filings for the calendar year 2008 and the first half of 2009 was signed by the TAPS carriers and those challenging the tariffs at the US FERC. The agreement was approved by the US FERC on 1 April 2010. Under the terms of the settlement, in the second quarter of 2010 BP paid additional refunds to third-party shippers, amounting to $0.4 million, representing the $0.12/bbl difference between the $3.45/bbl tariff rate on which the interim refunds paid in 2009 for this period were based, and the $3.33/bbl tariff rate in the approved settlement agreement.

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 2010 of 598mboe/d. BP also operates and has a 29.5% 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 1,700mmcf/d to a natural gas terminal at Teesside in north-east England. CATS offers natural gas transportation and processing services. In addition, BP operates the Dimlington/Easington gas processing terminal (BP 100%) on Humberside and the Sullom Voe oil and gas terminal in Shetland.

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. BP is technical operator of, and holds a 25.5% interest in, the 693-kilometre South Caucasus Pipeline (SCP), which takes gas from Azerbaijan through Georgia to the Turkish border. 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).

On 21 July 2010, the BTC pipeline exceeded a daily average of 1 million barrels per day for the first time, recording a daily export figure of 1.057 million barrels. A Drag Reducing Agent (DRA) was utilized to achieve this milestone.

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 2010 included:

- In Trinidad, BP's net share of the capacity of Atlantic LNG Trains[a] 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 LNG 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 and the Far East.
- We have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company, which in 2010 supplied 5.85 million tonnes (302,231mmscf) of LNG.
- 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 year 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 17 million tonnes of LNG in 2010.
- Also in Indonesia, BP has its first operated LNG plant, Tangguh (BP 37.16%), in Papua Barat. The first phase of Tangguh, which is in its first full year of operations, comprises two offshore platforms, two pipelines and an LNG plant with two production trains with a total capacity of 7.6mtpa. The Tangguh project has six long-term contracts in place to supply LNG to customers in China, South Korea, Mexico and Japan.
- In Australia, we are 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 2.7mtpa of LNG.
- 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 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, support 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 year due to the accessibility of shale gas and increased pipeline builds in North America. This has resulted in limited basis differentials and faster production responses to price. However, new markets are continuing to develop with continental European markets opening up and LNG becoming more liquid. The supply and trading function supported the group through a period of uncertainty in the credit markets concerning BP's financial position during the Gulf of Mexico oil spill.

[a] See footnote a on page 48.

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 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 27 to the Financial statements on pages 185-190.

The range of contracts that the group enters into is described in Certain definitions – commodity trading contracts, on page 82.

Oil and gas disclosures

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

Average sales price per unit of production

$ per unit of production[a]

	Europe		North America		South America	Africa	Asia		Australasia	Total group average
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Average sales price[b]										
Subsidiaries										
2010										
Liquids[c]	**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[c]	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
2008										
Liquids[c]	89.82	93.77	89.22	64.42	91.61	89.44	–	97.20	86.33	90.20
Gas	8.41	6.96	6.77	7.87	4.90	4.46	–	3.63	9.22	6.00
Equity-accounted entities[d]										
2010										
Liquids[c]	**–**	**–**	**–**	**–**	**61.60**	**–**	**60.39**	**6.72**	**–**	**52.81**
Gas	**–**	**–**	**–**	**–**	**1.97**	**–**	**1.91**	**7.83**	**–**	**2.04**
2009										
Liquids[c]	–	–	–	–	51.01	–	47.27	5.59	–	41.93
Gas	–	–	–	–	1.90	–	1.51	5.25	–	1.68
2008										
Liquids[c]	–	–	–	–	56.39	–	73.7	4.80	–	61.39
Gas	–	–	–	–	1.97	–	1.68	10.53	–	1.94

[a]Units of production are barrels for liquids and thousands of cubic feet for gas.
[b]Realizations include transfers between businesses.
[c]Crude oil and natural gas liquids.
[d]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			Russia	Rest of Asia		
The average production cost per unit of production[a]										
Subsidiaries										
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
2008	12.19	8.74	9.02	15.35	2.34	6.72	–	5.24	1.74	7.24
Equity-accounted entities										
2010	**–**	**–**	**–**	**–**	**6.32**	**–**	**5.04**	**0.97**	**–**	**4.26**
2009	–	–	–	–	6.12	–	4.63	0.94	–	3.95
2008	–	–	–	–	5.84	–	5.97	0.87	–	4.73

[a]Units of production are barrels for liquids and thousands of cubic feet for gas. Amounts do not include ad valorem and severance taxes.

Licence expiry

The group holds no licences due to expire within the next three years that would have a significant impact on BP's reserves or production.

Resource progression

BP manages its hydrocarbon resources in three major categories: prospect inventory, contingent resources and proved reserves. When a discovery is made, volumes usually transfer from the prospect inventory to the contingent resources category. The contingent resources move through various sub-categories as their technical and commercial maturity increases through appraisal activity.

At the point of final investment decision, most proved reserves will be categorized as proved undeveloped (PUD). Volumes will subsequently be recategorized from PUD to proved developed (PD) as a consequence of development activity. When part of a well's proved reserves depends on a later phase of activity, only that portion of proved reserves associated with existing, available facilities and infrastructure moves to PD. The first PD bookings will typically occur at the point of first oil or gas production. Major development projects typically take one to 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.

Contingent resources in a field will only be recategorized as proved reserves when all the criteria for attribution of proved status have been met and the proved reserves are included in the business plan and scheduled for development, typically within five years. 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. There are volumes of proved undeveloped reserves scheduled to commence after five years in Trinidad and Canada that are part of ongoing development activities for which BP has a historical track record of completing comparable projects. In all cases, the volumes are being progressed as part of an adopted development plan, which calls for drilling of wells over an extended period of time given the magnitude of the development.

Total development expenditure in Exploration and Production, excluding midstream activities, was $12,044 million in 2010 ($9,675 million for subsidiaries and $2,369 million for equity-accounted entities). The major areas converted in 2010 were Azerbaijan, Indonesia, Russia, Trinidad and the US.

In 2010, we converted 1,481mmboe of proved undeveloped reserves to proved developed reserves through ongoing investment in our upstream development activities. The table below describes the changes to our proved undeveloped reserves position through the year.

	volumes in mmboe
Proved undeveloped reserves at 1 January 2010	7,952
Revisions of previous estimates	(247)
Improved recovery	1,062
Discoveries and extensions	689
Purchases	74
Sales	(150)
Total in year proved undeveloped reserves changes	9,380
Progressed to proved developed reserves	(1,481)
Proved undeveloped reserves at 31 December 2010	7,899

BP bases its proved reserves estimates on the requirement of reasonable certainty with rigourous 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. In addition, we are conducting a fundamental review of how the group incentivizes business performance, including reward strategy, with the aim of encouraging excellence in safety, compliance and operational risk management.

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 2010

Seventy-five per cent of our total proved reserves of subsidiaries at 31 December 2010 were held through unincorporated joint ventures (76% in 2009), and 31% of the proved reserves were held through such unincorporated joint ventures where we were not the operator (27% in 2009).

Estimated net proved reserves of liquids at 31 December 2010[a b c]

			million barrels
	Developed	Undeveloped	Total
UK	364	431	795
Rest of Europe	77	221	298
US	1,729	1,190	2,919[d]
Rest of North America	–	–	–
South America	44	58	102[e]
Africa	371	374	745
Rest of Asia	269	325	594
Australasia	48	58	106
Subsidiaries	2,902	2,657	5,559
Equity-accounted entities	3,166	1,984	5,150[f]
Total	6,068	4,641	10,709

Estimated net proved reserves of natural gas at 31 December 2010[a b]

			billion cubic feet
	Developed	Undeveloped	Total
UK	1,416	829	2,245
Rest of Europe	40	430	470
US	9,495	4,248	13,743
Rest of North America	58	–	58
South America	3,575	6,575	10,150[g]
Africa	1,329	2,351	3,680
Rest of Asia	1,290	268	1,558
Australasia	3,563	2,342	5,905
Subsidiaries	20,766	17,043	37,809
Equity-accounted entities	3,046	1,845	4,891[h]
Total	23,812	18,888	42,700

Net proved reserves on an oil equivalent basis

			million barrels of oil equivalent
	Developed	Undeveloped	Total
Subsidiaries	6,481	5,596	12,077
Equity-accounted entities	3,691	2,303	5,994
Total	10,172	7,899	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, 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 2010 marker prices used were Brent $79.02/bbl (2009 $59.91/bbl and 2008 $36.55/bbl) and Henry Hub $4.37/mmBtu (2009 $3.82/mmBtu and 2008 $5.63/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 78 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 22 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[f] Includes 254 million barrels of crude oil in respect of the 7.03% minority interest in TNK-BP.
[g] Includes 2,921 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[h] Includes 137 billion cubic feet of natural gas in respect of the 5.89% minority interest in TNK-BP.

www.bp.com/downloads/oilandgasproduction

BP's net production by major field for 2010, 2009 and 2008.

Liquids

				thousand barrels per day
Subsidiaries				BP net share of production[a]
	Field or area	**2010**	2009	2008
UK[b]	ETAP[c]	**28**	34	27
	Foinaven[d]	**24**	29	26
	Other	**85**	105	120
Total UK		**137**	168	173
Norway[b]	Various	**40**	40	43
Total Rest of Europe		**40**	40	43
Total Europe		**177**	208	216
Alaska	Prudhoe Bay[d]	**67**	69	72
	Kuparuk	**42**	45	48
	Milne Point[d]	**23**	24	27
	Other	**34**	43	50
Total Alaska		**166**	181	197
Lower 48 onshore[b]	Various	**90**	97	97
Gulf of Mexico deepwater[b]	Thunder Horse[d]	**120**	133	24
	Atlantis[d]	**49**	54	42
	Mad Dog[d]	**30**	35	31
	Mars	**23**	29	28
	Na Kika[d]	**25**	27	29
	Horn Mountain[d]	**14**	25	18
	King[d]	**21**	22	23
	Other	**56**	62	49
Total Gulf of Mexico deepwater		**338**	387	244
Total US		**594**	665	538
Canada[b]	Various[d]	**7**	8	9
Total Rest of North America		**7**	8	9
Total North America		**601**	673	547
Colombia	Various[d]	**18**	23	24
Trinidad & Tobago	Various[d]	**36**	38	38
Venezuela[b]	Various	**–**	–	4
Total South America		**54**	61	66
Angola	Greater Plutonio[d]	**73**	70	69
	Kizomba C Dev	**31**	43	30
	Dalia	**20**	32	34
	Girassol FPSO	**18**	22	22
	Other	**28**	44	46
Total Angola		**170**	211	201
Egypt[b]	Gupco	**47**	55	41
	Other	**12**	16	16
Total Egypt		**59**	71	57
Algeria	Various	**17**	22	19
Total Africa		**246**	304	277
Azerbaijan[b]	Azeri-Chirag-Gunashli[d]	**94**	94	97
	Other	**9**	7	8
Total Azerbaijan		**103**	101	105
Western Indonesia[b]	Various	**2**	5	7
Other	Various	**14**	17	16
Total Rest of Asia[b]		**119**	123	128
Total Asia		**119**	123	128
Australia	Various	**30**	31	29
Other	Various	**2**	–	–
Total Australasia		**32**	31	29
Total subsidiaries[e]		**1,229**	1,400	1,263
Equity-accounted entities (BP share)				
Russia – TNK-BP[b]	Various	**856**	840	826
Total Russia		**856**	840	826
Abu Dhabi[f]	Various	**190**	182	210
Other	Various	**1**	12	10
Total Rest of Asia[b]		**191**	194	220
Total Asia		**1,047**	1,034	1,046
Argentina	Various	**75**	75	70
Venezuela[b]	Various	**23**	25	19
Bolivia[b]	Various	**–**	1	3
Total South America		**98**	101	92
Total equity-accounted entities		**1,145**	1,135	1,138
Total subsidiaries and equity-accounted entities		**2,374**	2,535	2,401

[a] Production excludes royalties due to others whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] In 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 Tubular Bells and King fields 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. In 2008, BP concluded the migration of the Cerro Negro operations to an incorporated joint venture with PDVSA while retaining its equity position, and TNK-BP disposed of some non-core interests.
[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 29 net mboe/d of NGLs from processing plants in which BP has an interest (2009 26mboe/d and 2008 19mboe/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	2010	2009	2008
		million cubic feet per day BP net share of production[a]		
UK[b]	Bruce/Rhum[c]	**100**	110	165
	Brae East	**46**	62	71
	Other	**326**	446	523
Total UK	**472**	618	759	
Norway[b]	Various	**15**	16	23
Total Rest of Europe		**15**	16	23
Total Europe		**487**	634	782
Lower 48 onshore[b]	San Juan[c]	**629**	659	682
	Jonah[c]	**185**	227	221
	Arkoma Central	**164**	194	240
	Arkoma West	**128**	65	–
	Arkoma East	**112**	67	–
	Wamsutter[c]	**126**	146	136
	Other	**531**	597	607
Total Lower 48 onshore	Total	**1,875**	1,955	1,886
Gulf of Mexico deepwater[b]	Thunder Horse[c]	**80**	83	11
	Other	**183**	220	219
Total Gulf of Mexico deepwater		**263**	303	230
Alaska	Various	**46**	58	41
Total US	**2,184**	2,316	2,157	
Canada[b]	Various	**202**	263	245
Total Rest of North America		**202**	263	245
Total North America		**2,386**	2,579	2,402
Trinidad & Tobago	Mango[c]	**544**	664	471
	Cashima/NEQB[c]	**679**	571	375
	Kapok[c]	**541**	540	619
	Cannonball[c]	**156**	225	336
	Amherstia[c]	**252**	197	288
	Other[c]	**301**	233	357
Total Trinidad		**2,473**	2,430	2,446
Colombia	Various	**71**	62	84
Venezuela[b]	Various	**–**	–	2
Total South America		**2,544**	2,492	2,532
Egypt[b]	Temsah	**90**	118	109
	Ha'py[c]	**73**	94	94
	Taurt[c]	**75**	73	24
	Other	**192**	177	145
Total Egypt		**430**	462	372
Algeria	Total	**126**	159	112
Total Africa		**556**	621	484
Pakistan[b]	Various[c]	**150**	173	162
Azerbaijan[b]	Various[c]	**132**	126	143
Western Indonesia[b]	Sanga-Sanga	**69**	71	69
	Other	**1**	35	97
Total Western Indonesia		**70**	106	166
China	Yacheng	**95**	83	91
Vietnam	Various[c]	**77**	63	61
Sharjah	Various[c]	**50**	59	73
Total Rest of Asia		**574**	610	696
Total Asia		**574**	610	696
Australia	Perseus/Athena	**165**	142	229
	Goodwyn	**118**	139	74
	Angel	**133**	120	6
	Other	**46**	39	71
Total Australia		**462**	440	380
Eastern Indonesia	Tangguh[c]	**323**	74	1
Total Australasia		**785**	514	381
Total subsidiaries[d]		**7,332**	7,450	7,277
Equity-accounted entities (BP share)				
Russia – TNK-BP[b]	Various	**640**	601	564
Total Russia		**640**	601	564
Western Indonesia	Various	**30**	31	31
Kazakhstan[b]	Various	**–**	11	8
Total Rest of Asia		**30**	42	39
Total Asia		**670**	643	603
Argentina	Various	**379**	378	385
Bolivia[b]	Various	**11**	11	63
Venezuela[b]	Various	**9**	3	6
Total South America		**399**	392	454
Total equity-accounted entities[d]		**1,069**	1,035	1,057
Total subsidiaries and equity-accounted entities		**8,401**	8,485	8,334

[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 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 Tubular Bells and King fields 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 it's interests in LukArco to Lukoil and the Bolivian government nationalized, with compensation payable, Pan American Energy's shares of Chaco. In 2008, BP concluded the migration of the Cerro Negro operations to an incorporated joint venture with PDVSA while retaining its equity position, and TNK-BP disposed of some non-core interests.

[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 business is responsible for the supply and trading, refining, manufacturing, marketing and transportation of crude oil, petroleum, petrochemicals products and related services to wholesale and retail customers. Within Refining and Marketing, BP markets its products in more than 70 countries. We have significant operations in Europe and North America and also manufacture and market our products across Australasia, in China and other parts of Asia, Africa and Central and South America.

Our organization is managed through two main business groupings: fuels value chains (FVCs) and international businesses (IBs). The FVCs integrate the activities of refining, logistics, marketing, supply and trading, on a regional basis, recognizing the geographic nature of the markets in which we compete. This provides the opportunity to optimize our activities from crude oil purchases to end consumer sales through our physical assets (refineries, terminals, pipelines and retail stations). The IBs operate on a global basis and include the manufacturing, supply and marketing of lubricants, petrochemicals, aviation fuels and liquefied petroleum gas (LPG).

Our market

The 2010 operating environment improved overall along with the global economy but was nevertheless still challenging in certain markets. Global oil demand grew by 2.8 million b/d, with growth in the OECD for the first time since 2005. However, aggregate OECD oil demand in 2010 remained 3.8 million b/d below the 2005 peak.

Annual BP global indicator refining margins in 2010 were slightly higher than 2009 levels although the quarterly variation was within a smaller range. Within the year, margins followed the pattern of a typical year, with a peak in the second quarter. However, fourth-quarter margins defied historic trends to exceed third-quarter levels because of early winter weather in the Northern Hemisphere. As a result, the BP global indicator refining margin (GIM), as defined in footnote (e) on page 56, averaged $4.44 per barrel in 2010. From 2011, we will be reporting a new refining indicator margin, replacing the GIM, which we call the refining marker margin (RMM). This adopts a basis that we believe is more closely related to the approach used by many of our competitors. RMMs are simplified regional margin indicators based on product yields and a representative 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. As a result it is numerically larger than the GIM and uses a much smaller product range.

In Europe, where diesel accounts for a large proportion of regional consumption, refining margins increased as demand for commercial transport improved with stronger economic activity. In the US, where refining is more highly upgraded and the transport market is more gasoline oriented, refining margins were slightly ahead of 2009. Refining margins improved the most in Asia Pacific compared to 2009, but still only averaged $1.63/bbl because of continued additions to refining capacity in the region.

Relatively wider fuel oil to crude differentials and light-heavy crude spreads benefited our highly upgraded refineries and had a positive impact on our financial performance in 2010 compared with 2009.

Although oil demand grew, 2010 was also characterized by very low market volatility in the oil markets. A balanced market in crude, together with record inventory levels, led the oil price to remain stable throughout 2010. After reaching record average levels in 2009, the volatility of dated Brent prices declined in 2010 to the lowest average level in percentage terms, since 1995. This contrast in the level of market volatility between early 2009 and 2010, led to a significantly weaker supply and trading contribution to the financial performance of Refining and Marketing.

In our IBs, demand for our petrochemicals products has improved from the low levels in late 2008 and early 2009 caused by the global recession. This has resulted in an improved environment overall, despite increases in industry capacity. In the aviation industry passenger numbers appear to have recovered from the depths of the financial crisis in 2008 and 2009. We have seen a recovery in demand for lubricants from the lows of the past two years in the automotive sector and most strongly in the industrial sector of the market following a marked decline in 2009. Within the context of overall demand, we continue to see a gradual shift towards higher-quality and higher-margin premium and synthetic lubricants. Base oil prices have risen throughout the year.

Our strategy

Refining and Marketing is the product and service-led arm of BP, focused on fuels, lubricants, petrochemicals products and related services. We aim to be excellent in the markets we choose to be in – those that allow BP to serve the major energy markets of the world. We are in pursuit of competitive returns and sustainable growth, underpinned by safe manufacturing operations and technology, as we serve customers and promote BP and our brands through quality products.

We believe that key to success in Refining and Marketing is holding a portfolio of quality, integrated and efficient positions. The FVC strategy globally focuses on feedstock-advantaged, upgraded, well-located refineries integrated into advantaged logistics and marketing. In pursuit of this, in the US, we intend to divest our Texas City refinery and southern part of our West Coast FVC, including the Carson refinery, roughly halving our US refining capacity by the end of 2012, subject to all necessary legal and regulatory approvals. BP will ensure the fulfilment of the current regulatory obligations associated with the Texas City refinery is reflected in any transaction.

In our remaining US FVCs, as well as in our non-US FVCs, we believe we have a portfolio of well-located refineries, integrated with strong marketing positions offering the potential for improvement and growth, either through market growth, margin growth or new access.

Within the IBs, our strategy is to continue to grow these businesses, which are materially exposed to growth markets.

Over time we expect to shift the balance of participation and capital employed from established to growth regions.

Our objective has been to improve our performance by focusing on achieving safe, reliable and compliant operations, restoring missing revenues and delivering sustainable competitive returns and cash flows. We intend to improve our financial performance[a] by at least $2 billion between 2009 and 2012, primarily underpinned by identified efficiency opportunities. We expect growth to result from the pursuit of further cost efficiencies, improved portfolio quality and capturing integration benefits as well as margin share growth. In addition, post 2012 we plan to grow our margin through the completion of the upgrade to our Whiting refinery, which is already under way.

We believe that these outcomes will enable us to be a leading player in each of the markets in which we choose to participate.

[a] This performance improvement will be measured by comparing Refining and Marketing's replacement cost profit 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 environment, foreign exchange impacts and price-lag effects for crude and product purchases.

Our performance

Key statistics

	2010	2009	2008
			$ million
Sales and other operating revenues[a]	**266,751**	213,050	320,039
Replacement cost profit before interest and tax[b]	**5,555**	743	4,176
Capital expenditure and acquisitions	**4,029**	4,114	6,634
			thousand barrels per day
Total refinery throughputs	**2,426**	2,287	2,155
Refining availability[c]	**95.0%**	93.6%	88.8%
			thousand tonnes
Total petrochemicals production[d]	**15,594**	12,660	12,835
			$ per barrel
Global indicator refining margin (GIM)[e]			
US West Coast	**6.16**	5.88	7.42
US Gulf Coast	**4.96**	4.63	6.78
US Midwest	**5.19**	5.43	5.17
Northwest Europe	**3.80**	3.26	6.72
Mediterranean	**3.29**	2.11	6.00
Singapore	**1.63**	0.21	6.30
BP Average GIM	**4.44**	4.00	6.50

[a] Includes sales between businesses.
[b] Includes profit after interest and tax of equity-accounted entities.
[c] 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.
[d] A minor amendment has been made to comparative periods.
[e] The global indicator refining margin (GIM) is the average of regional industry indicator margins weighted for BP's crude refining capacity in each region. Each regional indicator margin is based on a single representative crude with product yields characteristic of the typical level of upgrading complexity. The indicator margin may not be representative of the margins achieved by BP in any period because of BP's particular refining configurations and crude and product slate.

2010 performance

Safety and operational risk

Safety, both process and personal, remains our top priority. During 2010, personal safety in Refining and Marketing as measured by incident frequencies was slightly worse than 2009, and process safety as measured by our severity-weighted process safety incident index improved by 25%.

One of the primary controls to mitigate or minimize safety and operational risk is the effective, sustained implementation and embedding of our operating management system (OMS). OMS also covers robust contractor management processes. All of Refining and Marketing's major operations had transitioned to OMS by the end of 2010, with only one regional logistics operation completing the process by the end of February 2011.

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

During 2010 Refining and Marketing had two workforce fatalities. In our Rotterdam refinery, a contractor was fatally injured during civil construction works and in the Rhine fuels value chain in Germany, a contractor truck driver was fatally injured in a multiple vehicle accident.

The recordable injury frequency (RIF), which measures the number of recordable injuries to the BP workforce per 200,000 hours worked, was 0.35. This is slightly higher than 2009 when it was 0.32, but significantly lower than in 2008 when it was 0.48. Seventy-seven severe vehicle accidents occurred in Refining and Marketing's operations during 2010 (71 in 2009).

In terms of operational integrity, the number of losses of primary containment (LOPC), which measures unplanned or uncontrolled releases of material from primary containment, was 12% higher in 2010 than in 2009, however this was still over 20% lower than in 2008. The process safety incident index (PSII), which is a weighted index to reflect both the number and severity of events per 200,000 hours worked, fell from 0.48 in 2009 to 0.36 in 2010. The average severity of the process safety-related LOPC events has reduced relative to 2009.

The number of oil spills greater than one barrel increased in 2010 (132) compared with 2009 (113), although this was still significantly lower both in number and volume than for 2008.

In our US refineries, we continued to implement the recommendations of the BP US Refineries Independent Safety Review Panel and regulatory bodies and have made significant progress in 2010. See Corporate responsibility, Safety section on page 68 for further information on progress.

To enhance further the focus on safety during 2010, Refining and Marketing established a segment operational risk committee that meets on a quarterly basis, chaired by the segment chief executive. This committee reviews critical risks, conducts an in-depth review of process safety and also aims to ensure appropriate risk management and mitigating actions are in place and prioritized.

Financial and Operating performance

Our 2010 performance continued to benefit from the fundamental improvements we have been making across the business, including improved availability within our refining system, the efficiency of our operations and growing margin share in our marketing businesses.

Replacement cost profit before interest and tax for the year ended 31 December 2010 was $5,555 million, compared with $743 million for the previous year. 2010 included a net gain for non-operating items of $630 million, mainly relating to gains on disposal partly offset by restructuring charges. (*See page 25 for further information on non-operating items.*) In addition, fair value accounting effects had a favourable impact of $42 million relative to management's measure of performance. (*See page 26 for further information on fair value accounting effects.*)

The primary additional factors contributing to the increase in replacement cost profit before interest and tax were improved operational performance in the fuels value chains, continued strong operational performance in the international businesses and further cost efficiencies, as well as a more favourable refining environment. Against this very good operational delivery, the results were impacted by a significantly lower contribution from supply and trading compared with 2009.

Sales and other operating revenues for 2010, analysed in the table below, were $267 billion compared with $213 billion in 2009. This increase was primarily due to increasing prices. The decrease in 2009 compared with 2008 primarily reflected a decrease in prices.

	2010	2009	2008
			$ million
Sale of crude oil through spot and term contracts	**44,290**	35,625	54,901
Marketing, spot and term sales of refined products	**209,221**	166,088	248,561
Other sales and operating revenues	**13,240**	11,337	16,577
	266,751	213,050	320,039

The following tables set out oil sales volumes by type for the past three years and give further details of refined product marketing sales by product type:

Refined products	2010	2009	2008
			thousand barrels per day
US	**1,433**	1,426	1,460
Europe	**1,402**	1,504	1,566
Rest of World	**610**	630	685
Total marketing sales[a]	**3,445**	3,560	3,711
Trading/supply sales[b]	**2,482**	2,327	1,987
Total refined product sales	**5,927**	5,887	5,698
Crude oil[c]	**1,658**	1,824	1,689
Total oil sales	**7,585**	7,711	7,387

[a] Marketing sales are 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] 113 thousand barrels per day of the crude volumes relates to revenues reported by Exploration and Production.

			thousand barrels per day
Marketing sales by refined product	**2010**	2009	2008
Aviation fuel	**546**	495	501
Gasolines	**1,326**	1,444	1,500
Middle distillates	**1,012**	1,012	1,055
Fuel oil	**391**	418	460
Other products	**170**	191	195
Total marketing sales	**3,445**	3,560	3,711

Marketing volumes were 3,445mb/d, slightly lower than 2009, principally reflecting the disposal of our retail businesses in Greece and France.

Our 2010 operational performance was strong, with Solomon refining availability at 95.0% for the year and refining throughputs up by 139mb/d for the year. Our refining utilization was well above industry averages. In the international businesses, the petrochemicals business was able to capture the benefit of the demand recovery, and achieve record volumes.

Prior years' comparative financial information

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 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 the expected future cash flows. The decrease in profit was also driven by the very significantly weaker environment, where refining margins fell by almost 40%. This was partly offset by significantly stronger operational performance in the FVCs, with 93.6% Solomon refining availability, lower costs and improved performance in the international businesses. In addition, fair value accounting effects had an unfavourable impact of $261 million relative to management's measure of performance.

The replacement cost profit before interest and tax for the year ended 31 December 2008 was $4,176 million and included a net credit for non-operating items of $347 million. The most significant non-operating items were net gains on disposal (primarily in respect of the gain recognized on the contribution of the Toledo refinery to a joint venture with Husky Energy Inc.) partly offset by restructuring charges. In addition, fair value accounting effects had a favourable impact of $511 million relative to management's measure of performance.

Compared with 2008, our 2009 performance was driven by the high level of non-operating items described above and a significantly weaker environment than in 2008, where refining margins fell by almost 40%. This was partly offset by significantly stronger operational performance in the fuels value chains, with 93.6% refining availability, as well as lower costs and improved performance in the international businesses.

Outlook

In 2011, the overall economic environment is expected to continue to recover, albeit at a relatively slow pace globally. The refining marker margin (RMM) in 2011 is expected to remain in a range more reflective of pre-2004 levels and our forward plans are currently based on a RMM range of $8-12 per barrel.

Our priorities in 2011 remain consistent with those in 2010 and we intend to build on the momentum we have established around improving financial performance and operations. We will continue to focus on delivering safe, reliable and compliant operations, improving the performance of our integrated FVCs, in particular in the US, and driving further cost efficiencies across all our businesses. We intend to increase slightly our investment levels in 2011 versus 2010, focused 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 expect the number and cost of refinery turnarounds in 2011 and 2012 to be higher than in 2010.

As explained in Our strategy on page 55, our US refining capacity is expected to halve when we complete the disposal of our Texas City refinery and the southern part of our West Coast FVC.

The following table summarizes the BP group's interests in refineries and average daily crude distillation capacities at 31 December 2010.

					thousand barrels per day
				Crude distillation capacities[a]	
	Refinery	Fuels value chain	Group interest[b] %	Total	BP share
Europe					
Germany	Bayernoil	Rhine	22.5%	215	48
	Gelsenkirchen[c]	Rhine	50.0%	265	132
	Karlsruhe	Rhine	12.0%	324	39
	Lingen[c]	Rhine	100.0%	93	93
	Schwedt	Rhine	18.8%	237	45
Netherlands	Rotterdam[c]	Rhine	100.0%	377	377
Spain	Castellón[c]	Iberia	100.0%	110	110
Total Europe				1,621	844
US					
California	Carson[c]	US West Coast	100.0%	266	266
Washington	Cherry Point[c]	US West Coast	100.0%	234	234
Indiana	Whiting[c]	US Mid-West	100.0%	405	405
Ohio	Toledo[c]	US Mid-West	50.0%	160	80
Texas	Texas City[c]	–	100.0%	475	475
Total US				1,540	1,460
Rest of World					
Australia	Bulwer[c]	ANZ	100.0%	102	102
	Kwinana[c]	ANZ	100.0%	143	143
New Zealand	Whangerei	ANZ	23.7%	118	28
South Africa	Durban	Southern Africa	50.0%	180	90
Total Rest of World				543	363
Total				3,704	2,667

[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 operated by BP.

Fuels value chains

We have six regionally organized integrated FVCs (*see map on page 15*), each of which optimizes the activities of our assets across the supply chain – from crude delivery to the refineries; manufacture of high-quality fuels; pipeline and terminal infrastructure and marketing and sales to our customers.

In addition to the FVCs, the Texas City refinery is operated as a standalone, predominantly merchant, refining business that also supports our marketing operations on the east and Gulf coasts of the US.

As explained in Our strategy on page 55, we intend to divest the Texas City refinery complex and exit the southern part of our US West Coast FVC business, including the Carson refinery, by the end of 2012.

We also have a number of regionally focused fuels marketing businesses that are not integrated into a refinery, covering the UK, Turkey, China and our remaining business-to-business fuels marketing activities in France.

We currently own or have a share in 16 refineries, which produce refined fuel products that we then supply to retail and commercial customers.

Our refining focus is to maintain and improve our competitive position through sustainable, safe, reliable, compliant and efficient operations of the refining system and disciplined investment for integrity management, to achieve competitively advantaged configuration and growth.

For BP, the strategic advantage of a refinery relates to its location, integration, scale and configuration to produce fuels from lower-cost feedstocks in line with the demand of the region. Strategic investments in our refineries are focused on securing the safety and reliability of our assets while improving our competitive position. In addition, we continue to invest to develop the capability to produce the cleaner fuels that meet the requirements of our customers and their communities.

The following table outlines by region the volume of crude oil and feedstock processed by BP for its own account and for third parties. Corresponding BP refinery capacity utilization data is summarized below.

			thousand barrels per day
Refinery throughputs[a]	**2010**	2009	2008
US	**1,350**	1,238	1,121
Europe	**775**	755	739
Rest of World	**301**	294	295
Total	**2,426**	2,287	2,155
Refinery capacity utilization			
Crude distillation capacity at 31 December[b]	**2,667**	2,666	2,678
Refinery utilization[c]	**91%**	86%	81%
US	**93%**	85%	77%
Europe	**91%**	89%	87%
Rest of World	**84%**	83%	80%

[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. The measure was redefined in 2009 to be more consistent with industry standards.

Refinery throughputs increased by 139mb/d in 2010 relative to 2009, driven principally by higher availability, particularly at Texas City and Whiting.

In addition to refined petroleum products we also blend and market biofuels. 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 that we blend and supply.

Our fuels strategy focuses on optimizing the integrated value of each FVC that is responsible for the delivery of ground fuels to the market. We do this by co-ordinating our marketing, refining and trading activities to maximize synergies across the whole value chain. Our priorities are to operate an advantaged infrastructure and logistics network (which includes pipelines, storage terminals and road or rail tankers), drive excellence in operating and transactional processes, and deliver compelling customer offers in the various markets in which we operate. The fuels business markets a comprehensive range of refined oil products primarily focused on the ground fuels sector.

The ground fuels business supplies fuel and related convenience services to retail consumers through company-owned and franchised retail sites, as well as other channels, including wholesalers and jobbers. It also supplies 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, as well as southern and eastern 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).

At 31 December 2010, BP's worldwide network consisted of some 22,100 sites, primarily branded BP, ARCO and Aral. During 2010 we sold around 400 sites in France to Delek Europe B.V. These will continue to be operated under the BP brand through a brand licensing agreement.

Our retail convenience operations offer consumers a range of food, drink and other consumables and services on the fuel forecourt in a convenient and innovative manner. The convenience offer includes brands such as ampm, Wild Bean Café and Petit Bistro.

In the US, our ampm brand is operated as a convenience retail franchise model. Overall in the US, by the end of 2010 there were 11,300 branded retail sites, of which 1,100 were branded ampm, compared with 11,500 and 1,200 respectively at the beginning of 2010.

In Europe, we had approximately 8,400 branded retail sites at the end of 2010. We are also one of the largest forecourt convenience retailers, with about 1,600 convenience retail sites in nine countries. We are growing our food-on-the-go and fresh grocery services through BP-owned brands and partnerships with leading retailers such as Marks & Spencer.
In addition, at the end of 2010, we had approximately 2,400 branded retail sites outside Europe and the US in countries such as Australia, New Zealand and South Africa.

The table below outlines the number of BP-branded retail sites by region.

			Number of retail sites operated under a BP brand
Retail sites[a b]	**2010**	2009	2008
US	**11,300**	11,500	11,700
Europe	**8,400**	8,600	8,600
Rest of World	**2,400**	2,300	2,300
Total	**22,100**	22,400	22,600

[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.

The group has a long-established integrated supply and trading function 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 business has trading offices in Europe, the US and Asia to enable the function to maintain a presence in the regionally connected global markets.

The oil supply and trading function has operated through a period of challenging trading conditions in 2010 due to lower price volatility, tighter product and sweet vs sour crude oil spreads, and reduced contango (i.e. spot vs future price) opportunities. The weaker trading environment is a result of OPEC crude supply availability, refining and storage spare capacity. The supply and trading function supported the group through a period of uncertainty in the credit markets concerning BP's financial position following the Gulf of Mexico oil spill.

The function 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 for its refineries where this will provide incremental margin.

Along with the supply activity described above, the function seeks to create incremental trading opportunities. It enters into the full range of exchange-traded commodity derivatives, over-the-counter (OTC) contracts and spot and term contracts that are described in Certain definitions – commodity trading contracts, on page 82. In order to facilitate the generation of trading margin from arbitrage, blending and storage opportunities, it also both 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, which is described in Financial statements – Note 27 on pages 185-190.

In 2010, the FVCs accounted for roughly three-quarters of the operating capital employed[a] in Refining and Marketing and generated just under half of the replacement cost profit.

Significant events in the FVCs in 2010 were as follows:

- The Whiting refinery modernization project made significant progress in 2010 as above ground construction began, including the reactors for the new gasoil hydrotreater, the new towers on the revamped crude distillation unit and the coker's six new drums. Two third-party world-scale hydrogen units were commissioned in 2010 and began providing hydrogen to the refinery. Progress on important pipeline interconnections completed in 2010 will allow Whiting early access to greater crude imports and product export opportunities.
- In the US, BP's reputation suffered as a result of the oil spill in the Gulf of Mexico, which had an adverse impact on our branded fuels marketing, but this had recovered by year end. We offered additional marketing support to our customers in an attempt to mitigate these declines.
- In the Gulf of Mexico region, sales were down year on year by up to 30% in some sites in the second quarter, but regained ground over the second half of 2010.
- In October, BP opened a cutting-edge fuels technology development centre in South Africa, which will focus on quality assurance, technical service and marketing support for the local market.
- The integrated supply and trading function within the FVCs announced that it was reorganizing its internal structure in order to simplify the organization and reduce costs.
- In October, BP sold its French retail business to Delek Europe B.V.
- During 2010, BP also completed the divestment of several packages of non-strategic terminals and pipelines in the US East of Rockies and West Coast. This programme of divestment of non-strategic pipelines and terminals will continue during 2011.
- Following a strategic review of our businesses in southern Africa, we intend to focus our activities within the continent on South Africa and Mozambique. As a result, BP agreed to sell its fuels marketing businesses in Namibia, Zambia and Botswana to Puma Energy and in addition, BP intends to sell its 50% interest in BP Malawi and BP Tanzania to Puma Energy. The sale of BP Tanzania to Puma Energy is subject to the pre-emption rights of its co-shareholders. Only the sale of the Botswana business had been completed as at 31 December 2010, the other sales are expected to be completed in 2011.
- During 2010 BP completed the sale of a number of European terminals as part of ongoing asset optimization activities.

[a] Operating capital employed is total assets (excluding goodwill) less total liabilities, excluding finance debt and current and deferred taxation.

International businesses

Our IBs provide quality products and services to customers in more than 70 countries worldwide with a significant focus on Europe, North America and Asia. Our products include aviation fuels, lubricants, LPG and petrochemicals that are sold for use in the manufacture of a range of products, such as fabrics, fibres and various plastics. We believe each of these IBs is competitively advantaged in the markets in which we have chosen to participate. Such advantage is derived from several factors, including location, proximity of manufacturing assets to markets, physical asset quality, operational efficiency, technology advantage and the strength of our brands. Each business has a clear strategy focused on investing in its key assets and market positions in order to deliver value to its customers and outperform its competitors.

In 2010, the IBs accounted for just under a quarter of the segment's operating capital employed[a] and just over half of the replacement cost profit.

Marketing sales in the international businesses include sales of global fuels and lubricants. The following table sets out the detail by business.

			thousand barrels per day
International businesses sales volumes	**2010**	2009	2008
Air BP	**450**	434	478
LPG	**58**	67	64
Lubricants	**50**	49	54
	558	550	596

Lubricants

We manufacture and market lubricants and related products and services to the automotive, industrial, marine and energy markets across the world. We sell products direct to our customers in around 45 countries and use approved local distributors for the remaining locations. Customer focus, distinctive brands, superior technology and relationships remain the cornerstones of our long-term strategy.

BP markets primarily through its major brands of Castrol and BP, and also the Aral brand in some specific markets. Castrol is a recognized brand worldwide and we believe it provides us with a significant competitive advantage.

In the automotive lubricants sector, 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. In 2010, roughly 30% of replacement cost profit before interest and tax was generated from emerging markets, which we believe continue to have the potential for significant long-term growth.

BP's marine lubricants business is one of the largest global suppliers of lubricants to the marine industry, with global presence in over 800 ports. BP's industrial lubricants business is a leading supplier to those sectors of the market involved in the manufacture of automobiles, trucks, machinery components and steel. BP is also a leading supplier of lubricants for the offshore oil and aviation industries.

Petrochemicals

We manufacture and market four main product lines: purified terephthalic acid (PTA), paraxylene (PX), acetic acid, and olefins and derivatives (O&D). Our strategy is to leverage our industry-leading technology in selected markets, to grow the business and to deliver industry-leading returns. New investments are targeted principally in the higher-growth Asian markets.

PTA is a raw material used in the manufacture of polyesters used in fibres, textiles and film, and polyethylene terephthalate (PET) bottles. Acetic acid is a versatile intermediate chemical used in a variety of products such as paints, adhesives and solvents, as well as its use in the production of PTA. We have a strong global market share in the PTA and acetic acid markets, with a major manufacturing presence in Asia, particularly China. PX is a feedstock for PTA production. We also produce a number of other speciality petrochemicals products.

In O&D, we crack naphtha to produce ethylene and other products and derivatives. Our SECCO joint venture between BP, Sinopec and its subsidiary, Shanghai Petrochemical Company, is the largest olefins cracker in China and is BP's single largest investment in China. BP also co-owns one other naphtha cracker site outside of Asia, which is integrated with our Gelsenkirchen refinery in Germany.

We have a total of 18 manufacturing sites operating in the UK, the US, Belgium, Germany, China, Indonesia, South Korea, Malaysia and Taiwan, including our joint ventures.

The following table summarizes BP's petrochemicals production capacity, at 31 December 2010.

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	1,342
	Decatur	PTA	100.0	1,043
		Paraxylene (PX)	100.0	1,101
		Naphthalene dicarboxylate	100.0	29
	Texas City	Acetic acid	100.0	583[c]
		PX	100.0	1,271
		Metaxylene	100.0	123
				5,492
Europe				
UK	Hull	Acetic acid	100.0	532
		Acetic anhydride	100.0	153
		Ethylidene diacetate	100.0	4
Belgium	Geel	PTA	100.0	1,343
		PX	100.0	631
Germany	Gelsenkirchen	Olefins and derivatives	50.0 to 61.0	1,764[b d]
	Mülheim	Solvents	50.0	130[b]
				4,557
Rest of World				
China	Caojing	Olefins and derivatives	50.0	3,103[b]
	Chongqing	Acetic acid	51.0	215[b]
		Esters	51.0	52[b]
	Nanjing	Acetic acid	50.0	274[b]
	Zhuhai	PTA	85.0	1,549[e]
Indonesia	Merak	PTA	50.0	253[b]
Korea	Ulsan	Acetic acid	51.0	261[b]
		Vinyl acetate monomer	34.0	56[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	471[b]
	Mai Liao	Acetic acid	50.0	179[b]
				8,261
Total BP share of capacity at 31 December 2010				18,310

[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] Sterling Chemicals plant, 100% of the output of which is marketed by BP.
[d] Group interest varies by product.
[e] BP Zhuhai Chemical Company Ltd is a subsidiary of BP, the capacity of which is shown above at 100%.

Global fuels

The supply of aviation fuels and LPG is managed globally in the global fuels SPU.

Air BP is one of the world's largest and best known aviation fuels suppliers, serving many of the major commercial airlines, as well as the general aviation and military sectors.

We have annual marketing sales in excess of 400mb/d. 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.

The LPG business sells bulk, bottled, automotive and wholesale LPG products in 10 countries, with annual sales in excess of 50 thousand barrels per day. During the past few years, we have introduced new consumer offers in established markets, developed opportunities in growth markets and pursued new demand such as the German Autogas market.

Significant events in 2010 were:

- Castrol was a sponsor of the 2010 FIFA World Cup™ in South Africa and used this to deliver a significant programme of brand visibility and customer engagement. Castrol leveraged the sponsorship to support our businesses in all regions. We have seen increased brand awareness for our Castrol master brand and product brands.
- In July 2010, Castrol opened a new lubricants technology development centre in China. Employing scientists and engineers from China and abroad, this team will work collaboratively with vehicle manufacturers, distributors and other partners, focusing on cutting-edge lubricant

technology development and support, as well as providing world-class training for customers and distributors.

- During 2010, the LPG business further simplified its portfolio. In China, the LPG business decided to focus its in-country operations on core marketing activities and sold its interest in the China Zhuhai cavern complex. This completes the exit from all major China LPG import facilities. In Europe, BP sold its LPG businesses in Spain and Denmark.
- The BP YPC Acetyls Company (Nanjing) Limited (BYACO) joint venture between BP and Yangzi Petrochemical Co. Ltd (a subsidiary of Sinopec) successfully commenced commercial production at its 548,000 tonnes per annum (ktepa) acetic acid plant in the fourth quarter of 2010.
- The petrochemicals business started a debottleneck project to add a further 200ktepa PTA capacity at the BP Zhuhai Chemical Company Limited site in Guangdong province (China), which is scheduled for completion in the first quarter of 2012. This additional capacity employs BP's latest proprietary technology and will bring the site's total PTA capacity to 1,750ktepa, continuing our growth in China.
- During 2010, BP sold its 15% interest in Ethylene Malaysia Sdn Bhd (EMSB) and its 60% interest in Polyethylene Malaysia Sdn Bhd (PEMSB) to Petronas.

Other businesses and corporate

Other businesses and corporate comprises the Alternative Energy business, Shipping, the group's aluminium business, Treasury (which includes interest income on the group's cash and cash equivalents), and corporate activities worldwide.

The replacement cost loss before interest and tax for the year ended 31 December 2010 was $1,516 million, compared with $2,322 million for the previous year. 2010 included a net charge for non-operating items of $200 million. (*See page 25 for further information on non-operating items.*) The primary additional factors affecting 2010's result compared with that of 2009 were improved business performance, more favourable foreign exchange effects and cost efficiencies.

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 replacement cost loss before interest and tax for the year ended 31 December 2008 included a net charge for non-operating items of $633 million.

The primary additional factors reflected in 2009's result compared with that of 2008 were a weaker margin environment for Shipping and our BP Solar business and adverse foreign exchange effects.

Key statistics

			$ million
	2010	2009	2008
Sales and other operating revenues[a]	**3,328**	2,843	4,634
Replacement cost profit (loss) before interest and tax[b]	**(1,516)**	(2,322)	(1,223)
Capital expenditure and acquisitions	**1,234**	1,299	1,839

[a] Includes sales between businesses.
[b] Includes profit after interest and tax of equity-accounted entities.

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 solar, along with demonstration projects and technology development in carbon capture and storage (CCS).

Our market

It is well accepted that a more diverse mix of energy will be required to meet 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, wind power has grown rapidly in many countries and is now growing globally at an annual rate of 30%[a], while installed solar photovoltaic capacity is predicted to increase from 15GW in 2008 to 410GW in 2035[b] and between 2010 and 2030, biofuels are expected to contribute 30% of the global growth in supply of liquid fuels[c].

Our performance

Alternative Energy continues to make progress against its commitment to invest $8 billion by 2015. Our investment since 2005 is more than $5 billion[d]. Our wind business has added 125MW of gross capacity during 2010, with the commercial start-up of the Goshen North wind farm. In our solar business, we achieved sales of 325MW and signed several strategic supply deals (*see Solar on page 62*). Our biofuels business acquired the lignocellulosic assets from Verenium Corporation Inc. for $98 million. In April, we completed the sale of our 35% interest in K-Power, a gas-fired power asset in Gwangyang, South Korea, to SK Holdings Co. Ltd for $316 million.

[a] Global Wind Energy Council – *Annex Stats 2009.*
[b] *World Energy Outlook 2010* ©OECD/IEA 2010, page 306.
[c] *BP Energy Outlook 2030.*
[d] The majority of costs have been capitalized, some were expensed under IFRS.

	2010	2009	2008
Wind – net rated capacity at year-end (megawatts)[a]	**774**	711	432
Solar – module sales (megawatts)[b]	**325**	203	162

[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 1,362MW in 2010, 1,237MW in 2009 and 785MW in 2008. This includes 32MW of capacity in the Netherlands which is managed by our Refining and Marketing segment.

[b] Solar sales are the total sales of solar modules to third-party customers, expressed in MW. Previously we reported the theoretical cell production capacity of our in-house solar manufacturing facilities. Reporting sales volumes operating data brings us in line with the broader solar industry.

Biofuels

BP believes that it has a key 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. BP has production facilities operating, or in the planning and construction phases, in the US, Brazil and the UK.

In 2010, we acquired Verenium's lignocellulosic biofuels business for $98 million, providing BP with integrated end-to-end capability. This included a pilot plant and a demonstration facility in Jennings, Louisiana, as well as research and development facilities in San Diego, California; lignocellulosic biofuels technology and related intellectual property (IP); and lignocellulosic enzyme technology and related IP.

The blending and distribution of biofuels continues to be carried out by our Refining and Marketing segment, in line with regulation. BP is one of the largest blenders and marketers of biofuels in the world.

Wind

In wind power, BP has focused its business in the US, where we have developed one of the leading wind portfolios.

During 2010, full commercial operations commenced at the 125MW Goshen North wind farm (BP 50%) in Bonneville County, Idaho. We also commenced construction at the Cedar Creek 2 wind farm in Colorado and the project is expected to be in commercial operation in 2011 with a capacity of around 250MW.

BP increased its net wind generation capacity to 774MW during 2010, an increase of 9% over the prior year.

Solar

In 2010, we achieved sales of 325MW, an increase of 60% over 2009. BP Solar's organization, with over 900 employees worldwide, is structured to serve the residential, commercial, and utility markets with sales and marketing offices in major markets around the world. Our joint venture manufacturing facilities are located in Xi'an, China and Bangalore, India. In March, BP Solar announced the closure of manufacturing at its Frederick facility, in Maryland, US, as it moves its manufacturing to lower-cost locations. BP Solar will maintain its US presence in sales and marketing, research and technology, project development, and key business support activities. In support of our manufacturing restructuring, we have signed a number of strategic cell supply agreements with suppliers, including JA Solar Holdings Co. Ltd and Hareon Solar Technology, providing BP Solar with access to around 200MW of mono-crystalline and multi-crystalline solar cells in 2011.

Carbon capture and storage

BP has played a leading role in the carbon capture and storage (CCS) industry for more than 10 years, and today focuses on demonstration projects and a continuing programme of research and technology development.

In Algeria, we are moving into Phase 2 of our joint industry project that monitors the CO_2 injection and storage operation at the In Salah gas field. With our partners Sonatrach and Statoil, we have been injecting up to 1 million tonnes of CO_2 a year since 2004, demonstrating secure geological storage through a comprehensive monitoring programme that is subject to independent academic review by a scientific advisory board.

Since 2007, we have been developing the Hydrogen Energy California 250MW power project with CCS with our partner Rio Tinto. The project is currently in its feasibility engineering design phase.

Separately, the 400MW Hydrogen Power Abu Dhabi project with CCS awaits 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

The size of our managed international fleet has not changed since 2009. At the end of 2010, we had 54 international vessels (37 medium-size crude and product carriers, four 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 have 14 specialist vessels (two double-hulled lubricants oil barges and 12 offshore support vessels).

Time-charter vessels

BP has 84 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.

2010 has seen continuing pirate activity in the Gulf of Aden, extending well into the Indian Ocean (from the east coast of Somalia to approximately 250 miles west of the Maldives) and to the north into the Arabian Sea. Despite an increasing level of piracy activity, the number of vessels actually attacked and/or hijacked has remained roughly the same as 2009, 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 supports the protective measures recommended in the international shipping industry guide *Best Management Practice 3 – Piracy off the Coast of Somalia and Arabian Sea Area*.[a]

Aluminium

Our aluminium business is a non-integrated producer and marketer of rolled aluminium products, headquartered in Louisville, Kentucky, US. Production facilities are located in Logan County, Kentucky, and are jointly owned with Novelis. The primary activity of our aluminium business is the supply of aluminium coil to the beverage can business, which it manufactures primarily from recycled aluminium.

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. For information on the role performed by Treasury in managing the group's liquidity in the aftermath of the Gulf of Mexico oil spill, see Liquidity and capital resources on pages 63-64 and Financial statements – Note 2 on page 158. Trading activities are underpinned by the compliance, control, and risk management infrastructure common to all BP trading activities.

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 has been reviewed following the Gulf of Mexico oil spill and it has been concluded that the group will continue with its current approach of not generally purchasing insurance cover.

[a] Jointly published by industry bodies, including the Oil Companies International Marine Forum (OCIMF) and supported by military operations in the region.

Liquidity and capital resources

Following the Gulf of Mexico oil spill, the group 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.

In June, Moody's Investors Service and Standard & Poor's (S&P) downgraded the group's long-term credit ratings from Aa1 (stable outlook) and AA (stable outlook) respectively, to A2 (negative watch) and A (negative watch) respectively. Fitch downgraded BP to BBB. All three rating agencies have subsequently removed the group from ratings watch, Moody's and Fitch have currently placed the group's rating on A2 (stable outlook) and A (stable outlook) respectively, and S&P has placed our rating on A (negative outlook).

Following the incident the group was required to make substantial cash payments in connection with the oil spill. Investors in BP's US Industrial Revenue/Municipal bonds and in bonds associated with long-term gas supply contracts largely exercised their option to tender the bonds for repayment. As a result, at 31 December 2010, BP was holding all $1.5 billion of the outstanding bonds associated with long-term gas supply contracts and had repaid $2.5 billion of US Industrial Revenue/Municipal bonds with BP either holding or retiring the bonds. The group also experienced increased requirements to post letters of credit to collateralize a number of environmental liabilities in the US and the UK totalling $624 million and post further cash collateral under trading agreements totalling $728 million.

In response, BP instigated a programme early in the second quarter of 2010 to increase available liquidity. We secured additional bank lines totalling $12 billion and announced the temporary suspension of quarterly dividend payments beginning with the payment that had been scheduled to occur in June 2010. BP also announced a disposal programme aimed at raising $30 billion to be completed by the end of 2011. Significant deposits were negotiated as part of these transactions. Deposits totalling $5 billion were held at the end of the third quarter and $6.2 billion was held at the end of the year, significantly increasing available liquidity. Including deposits, $17 billion was raised through the disposal programme in 2010. A further $0.7 billion of funds were raised through borrowings which were secured on working capital and other assets. BP also raised $4.6 billion during the third quarter from syndicated bank loans backed by future crude oil sales over a five-year period from BP's interests in specific offshore Angola and Azerbaijan fields.

These initiatives and the strength of our underlying cash flows (including forecasting under different stress scenarios) ensured the group had sufficient working capital to meet its requirements at all times.

Early in the fourth quarter of 2010, BP accessed the US and European capital markets with bond issuances totalling $6.25 billion, with maturities of between four and 10 years.

Financial framework

As part of our response to the Gulf of Mexico oil spill, we revised our financial framework during 2010. The aim of the revised framework is to provide the group with financial flexibility in the medium term, as we complete our $30-billion disposal programme and fulfil our commitment to fund the Deepwater Horizon Oil Spill Trust. See Financial statements – Note 2 on page 158.

We intend to invest to grow the company and shareholder value sustainably through the business cycle and we intend to maintain a capital structure that allows the group to execute its strategy and is resilient to inherent volatility.

We also intend to maintain a significant liquidity buffer and to reduce our net debt ratio to within a range of 10-20%, compared with our previously targeted range of 20-30%. For further information on net debt, which is a non-GAAP measure, see Financial statements – Note 36 on page 198.

We will seek to maintain shareholder distributions in line with operating performance through the business cycle. On 1 February 2011, we announced the resumption of quarterly dividend payments, at a level we believe is prudent and recognizes our current circumstances. We still face uncertainties as to the amount and timing of future cash flows and we have an obligation to contribute $5 billion per annum to the Deepwater Horizon Oil Spill Trust for each of the next three years. Our intention is to increase the dividend over time, in line with the circumstances of the company.

Dividends and other distributions to shareholders

In June 2010, the BP board reviewed its dividend policy in light of the Gulf of Mexico oil spill and the agreement to establish the $20-billion trust fund, deciding that no ordinary share dividends would be paid in respect of the first three quarters of 2010. On 1 February 2011, BP announced the resumption of quarterly dividend payments, with a fourth-quarter dividend of 7 cents per share.

We believe this level is supported by the success of our disposal programme thus far, and by the improving business environment, but is balanced by the recognition of our continuing obligation to fund the Trust until the end of 2013 and the need to retain financial flexibility. We intend to increase the dividend level over time in line with the circumstances of the company. The total dividend paid to BP shareholders in 2010 was $2.6 billion, compared with $10.5 billion for 2009. The dividend paid per share was 14 cents, a decrease of 75% compared with 2009. In sterling terms, the dividend decreased 76%. We determine the dividend in US dollars, the economic currency of BP.

During 2010 and 2009, the company did not repurchase any of its own shares.

Financing the group's activities

A summary of financing activities during 2010 following the Gulf of Mexico oil spill is included on page 63. 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, or by using currency swaps when funds have been raised in currencies other than US dollars.

The group's finance debt at 31 December 2010 amounted to $45.3 billion (2009 $34.6 billion). Of the total finance debt, $14.6 billion is classified as short term at the end of 2010 (2009 $9.1 billion). Included within short-term debt is $6.2 billion relating to the previously mentioned deposits received for announced disposal transactions still pending legal completion post the balance sheet date (2009 nil). The short-term balance also includes $6.9 billion for amounts repayable within the next 12 months relating to long-term borrowings (2009 $3.9 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 2010, outstanding commercial paper amounted to $1.0 billion (2009 $0.4 billion). Due to the uncertainty of commercial paper markets in times of crisis, we choose not to include our commercial paper balances when conducting stress tests of our liquidity. We do, nonetheless, make use of these markets when they are commercially attractive.

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 2010, the amount drawn down against the DIP was $12.3 billion (2009 $11.4 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 recent capital market bond issuances contained any additional financial covenants compared to the group's capital markets issuances prior to the Gulf of Mexico oil spill.

The maturity profile and fixed/floating rate characteristics of the group's debt are described in Financial statements – Note 35 on page 197.

Net debt was $25.9 billion at the end of 2010, a slight reduction from the 2009 year-end net debt position of $26.2 billion. Included in net debt are cash and cash equivalents of $18.6 billion at 31 December 2010 (2009 $8.3 billion). The ratio of net debt to net debt plus equity was 21% at the end of 2010, compared with 20% at the end of 2009.

BP manages its cash position to ensure the group has liquidity as and when required. 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. Further information on the management of liquidity risk and credit risk is provided in Financial statements – Note 27 on pages 188-190, and on the cash position in Financial statements – Note 31 on page 191.

BP expects to maintain a strong cash position. This, together with our lower net debt ratio target, aims to ensure the group has the flexibility to meet future financial obligations and reflects a prudent approach to managing the balance sheet and the liquidity requirements of the company.

The group also has access to significant sources of liquidity in the form of committed bank facilities. At 31 December 2010, the group had available undrawn committed borrowing facilities of $12.5 billion (2009 $5.0 billion), made up of:

- $5.3 billion of standby facilities, of which $0.4 billion is available to draw and repay by mid-September 2011, $4.6 billion until mid-October 2011, and $0.3 billion until mid-January 2013.
- $7.2 billion of 364-day facilities, of which $4.0 billion can be drawn until late May 2011, $2.0 billion drawn until the end of June 2011, $0.7 billion drawn until early July 2011 and $0.5 billion drawn until late August 2011. Any amounts drawn are repayable up to 364 days from the date of drawing.

With the level of undrawn committed bank facilities increasing since the Gulf of Mexico oil spill incident and with the levels of cash increasing, our overall liquidity levels strengthened over the course of 2010.

BP believes that, taking into account the substantial amounts of undrawn borrowing facilities and 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. There remains significant uncertainty regarding the amount and timing of future expenditures and the implications for future activities. See Risk factors on pages 27-32, and Financial statements – Note 2 on page 158, Note 37 on page 199 and Note 44 on page 218 for further information.

Off-balance sheet arrangements

At 31 December 2010, the group's share of third-party finance debt of equity-accounted entities was $6,987 million (2009 $6,483 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 2010 are $404 million (2009 $319 million) in respect of liabilities of jointly controlled entities and associates and $664 million (2009 $667 million) in respect of liabilities of other third parties. Of these amounts, $355 million (2009 $286 million) of the jointly controlled entities and associates guarantees relate to borrowings and for other third-party guarantees, $649 million (2009 $633 million) relates to guarantees of borrowings.

Contractual commitments

The following table summarizes the group's principal contractual obligations at 31 December 2010, 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 35 on page 197 and more information on operating leases is given in Financial statements – Note 15 on page 175.

							$ million
							Payments due by period
Expected payments by period under contractual obligations and commercial commitments	Total	2011	2012	2013	2014	2015	2016 and thereafter
Balance sheet obligations							
Borrowings[a]	41,550	9,200	6,439	7,486	6,054	5,443	6,928
Finance lease future minimum lease payments	1,126	153	377	56	51	51	438
Deepwater Horizon Oil Spill Trust funding liability	15,008	5,008	5,000	5,000	–	–	–
Decommissioning liabilities[b]	14,876	461	453	370	362	413	12,817
Environmental liabilities[b]	3,903	1,763	545	275	189	158	973
Pensions and other post-retirement benefits[c]	25,670	1,916	1,905	1,403	976	983	18,487
Total balance sheet obligations	102,133	18,501	14,719	14,590	7,632	7,048	39,643
Off-balance sheet obligations							
Operating leases[d]	13,973	3,521	2,475	1,878	1,413	1,032	3,654
Unconditional purchase obligations[e]	166,942	97,355	16,330	9,291	6,778	5,634	31,554
Total off-balance sheet obligations	180,915	100,876	18,805	11,169	8,191	6,666	35,208
Total	283,048	119,377	33,524	25,759	15,823	13,714	74,851

[a] Expected payments include interest payments on borrowings totalling $3,221 million ($888 million in 2011, $679 million in 2012, $520 million in 2013, $362 million in 2014, $225 million in 2015 and $547 million thereafter), and exclude disposal deposits of $6,197 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 2011 include purchase commitments existing at 31 December 2010 entered into principally to meet the group's short-term manufacturing and marketing requirements. The price risk associated with these crude oil, natural gas and power contracts is discussed in Financial statements – Note 27 on page 186.

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

							$ million
							Payments due by period
Unconditional purchase obligations	Total	2011	2012	2013	2014	2015	2016 and thereafter
Crude oil and oil products	101,671	70,572	7,058	3,582	2,207	1,934	16,318
Natural gas	36,147	19,780	5,117	2,827	2,078	1,450	4,895
Chemicals and other refinery feedstocks	8,912	2,055	1,278	923	888	858	2,910
Power	2,784	1,915	688	162	16	2	1
Utilities	925	156	154	111	98	89	317
Transportation	8,525	1,184	875	796	726	637	4,307
Use of facilities and services	7,978	1,693	1,160	890	765	664	2,806
Total	166,942	97,355	16,330	9,291	6,778	5,634	31,554

The group expects its total capital expenditure, excluding acquisitions and asset exchanges, to be around $20 billion in 2011. The following table summarizes the group's capital expenditure commitments for property, plant and equipment at 31 December 2010 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	2011	2012	2013	2014	2015	2016 and thereafter
Committed on major projects	31,376	15,193	7,205	4,304	2,170	986	1,518
Amounts for which contracts have been placed	11,279	7,239	1,966	1,093	504	316	161

In addition, at 31 December 2010, the group had committed to capital expenditure relating to investments in equity-accounted entities amounting to $1,033 million. Contracts were in place for $517 million of this total.

Cash flow

The following table summarizes the group's cash flows.

			$ million
	2010	2009	2008
Net cash provided by operating activities	**13,616**	27,716	38,095
Net cash used in investing activities	**(3,960)**	(18,133)	(22,767)
Net cash provided by (used in) financing activities	**840**	(9,551)	(10,509)
Currency translation differences relating to cash and cash equivalents	**(279)**	110	(184)
Increase in cash and cash equivalents	**10,217**	142	4,635
Cash and cash equivalents at beginning of year	**8,339**	8,197	3,562
Cash and cash equivalents at end of year	**18,556**	8,339	8,197

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 provided by operating activities for the year ended 31 December 2009 was $27,716 million compared with $38,095 million for 2008 reflecting a decrease in profit before taxation of $9,159 million, an increase in working capital requirements of $8,944 million and a decrease in dividends from jointly controlled entities and associates of $725 million. These were partly offset by a decrease in income taxes paid of $6,500 million, higher depreciation, depletion, amortization and impairment charges of $1,329 million and an increase in charges for provisions of $948 million.

Net cash used in investing activities was $3,960 million in 2010, compared with $18,133 million and $22,767 million in 2009 and 2008 respectively. The decrease in 2010 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. The decrease in cash used in investing activities in 2009 compared to 2008 reflected a decrease in capital expenditure and acquisitions of $2,356 million and an increase in disposal proceeds of $1,752 million.

Net cash provided by financing activities was $840 million in 2010 compared with $9,551 million net cash used in 2009 and $10,509 million net cash used in 2008. The net increase in cash provided in 2010 reflects 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 decrease in 2009 reflected a $2,774 million decrease in the net repurchase of shares and an increase in net proceeds from long-term financing of $1,406 million; these were partly offset by an increase in net repayments of short-term debt of $3,090 million.

The group has had significant levels of capital investment for many years. Cash flow in respect of capital investment, excluding acquisitions, was $18.9 billion in 2010, $21.4 billion in 2009 and $23.7 billion in 2008. 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 $25.9 billion at the end of 2010, $26.2 billion at the end of 2009 and was $25.0 billion at the end of 2008.

During the period 2008 to 2010, our total sources of cash amounted to $101 billion, whilst our total uses of cash amounted to $93 billion. The net cash provided of $8 billion, along with an increase in finance debt of $7 billion, resulted in an increase in our balance of cash and cash equivalents of $15 billion over the three-year period. During this period, the price of Brent crude oil has averaged $79.48 per barrel. The following table summarizes the three-year sources and uses of cash.

	$ billion
Sources of cash	
Net cash provided by operating activities	79
Disposals	22
	101
Uses of cash	
Capital expenditure	64
Acquisitions	3
Net repurchase of shares	2
Dividends paid to BP shareholders	23
Dividends paid to minority interests	1
	93
Net source of cash	8
Increase in finance debt	7
Increase in cash and cash equivalents	15

Disposal proceeds received during the three-year period were significantly higher than cash used for acquisitions, as a result in particular of our disposal programme started in 2010. Net investment (capital expenditure and acquisitions less disposal proceeds) during this period averaged $15 billion per year. Dividends paid to BP shareholders totalled $23 billion during the three-year period, with no ordinary share dividends being paid in respect of the first three quarters of 2010. Net repurchase of shares was $2 billion, which included $3 billion in 2008 in respect of our share buyback programme less net proceeds from shares issued in connection with employee share schemes over the three years. Finally, cash was used to strengthen the financial condition of certain of our pension plans. In the past three years, $3 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 16-18.

We expect production in 2011 to be lower than in 2010 as a result of divestments, lower production from the Gulf of Mexico and increased turnaround activity to improve the long-term reliability of the assets. As a result of these factors, reported production in 2011 is expected to be around 3,400mboe/d. The actual outcome will depend on the exact timing of divestments, the pace of resumption of operations in the Gulf of Mexico, OPEC quotas and the impact of the oil price on our PSAs.

In Refining and Marketing, refiners are likely to continue to operate with excess capacity globally, although near-term supply-demand fundamentals appear broadly in balance. We expect the number and cost of our refinery turnarounds in 2011 and 2012 to be higher than in 2010.

In Other businesses and corporate, the underlying average quarterly charge for 2011 is expected to be around $400 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 be around $20 billion in 2011, an increase compared with 2010.

Having received a total of $17 billion for disposal proceeds and disposal deposits in 2010, we are targeting around a further $13 billion in 2011.

The discussion above contains forward-looking statements, particularly those regarding global economic recovery and outlook for oil and gas markets, oil and gas prices, refining margins, production, demand for petrochemicals products, effective tax rate, operating and capital expenditure, timing and proceeds of divestments, contractual commitments, balance of cash inflows and outflows, net debt ratio, and dividend and optional scrip dividend. 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 are urged to read the cautionary statement on page 4 and Risk factors on pages 27-32, 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.

Corporate responsibility

The Deepwater Horizon explosion and subsequent spill had major human and environmental consequences, demonstrating the importance of safe and responsible operations. We deeply regret the loss of lives and injuries suffered, and the impact to the environment and livelihoods of local people.

We are committed to understanding and applying the lessons from the accident. Already, we are making some fundamental changes in the way we operate.

These measures include:

- The creation of an enhanced safety and operational risk function that is independent of the business line and is represented in every BP operation.
- The reorganization of our upstream business to create three functional divisions, each reporting directly to the group chief executive. (*See Exploration and Production on pages 40-41 for further details.*)
- A review of employee reward frameworks to increase the focus on performance in safety, compliance, and operational risk management. (*See Employees on page 74 for further details.*)
- An examination of how we can strengthen the oversight of contractors.

Strengthening these core areas will require some profound changes in how we operate and will take several years to fully embed.

In 2010, the company reported 14 workforce fatalities, including the 11 workers on the Deepwater Horizon in the US and three other work-related fatalities in the Netherlands, Germany and Canada. All 14 individuals were contractors. We deeply regret the loss of these lives and recognize the tremendous loss felt by their families, friends and co-workers.

Safety

Gulf of Mexico oil spill investigations and recommendations

In the immediate aftermath of the Deepwater Horizon explosion, 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 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. See Gulf of Mexico oil spill on pages 34-39.

As a result, the investigation team made 26 recommendations specific to drilling, which we accepted and are implementing 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 and verification, and personnel competence.

Several external investigations into the Deepwater Horizon accident and response are under way in the US, including those by the Marine Board, the National Academy of Engineering, the Chemical Safety Board, the US Congress, the Department of Justice and the Securities and Exchange Commission (SEC). In addition, the Presidential Commission issued its report on 11 January 2011. See page 38 in Gulf of Mexico oil spill for a summary of the findings. As the findings of these investigations are made public, we will make them available on *www.bp.com/gulfofmexico*.

Subsequent actions to date to strengthen BP's safety management

Following the accident, BP immediately undertook a variety of activities to further strengthen its oil spill prevention, containment and response capability. These include:

- BOPs used on BP-operated projects, along with other well-control equipment, were checked to confirm that they had been properly maintained and are capable of shutting in the well in an emergency.
- Remotely operated vehicles were confirmed to be capable of activating BOPs in emergency situations.
- New decision matrix, designed to aid key decisions on well design and operations, was developed and distributed to our operations globally.
- Two containment hats were delivered to the UK to aid North Sea containment capability.
- We updated our oil spill response plan, and submitted it to the US Department of the Interior.

Meanwhile, our upstream teams are working to implement the 26 recommendations made by BP's internal investigation team. These will be tracked in the quarterly HSE and operations integrity report supplied to the executive team.

Safety and operational risk

Safety and operational risk management requirements, encapsulated by our operating management system (OMS), are set by a central, dedicated function, with periodic reviews by the board and executive committees. The operational delivery of these requirements is the responsibility of the businesses.

As a result of the Gulf of Mexico incident, BP has redefined and strengthened the scope and accountabilities of the group function for safety and operations, creating a new independent function, Safety and Operational Risk (S&OR). We are deploying S&OR professionals, many of whom were previously reporting to local business leaders, in all of BP's operations throughout 2011.

The core responsibilities of S&OR are to:

- Provide checks and balances independent of the business line.
- Strengthen mandatory safety-related standards and processes, including operational risk management.
- Provide an independent view on operational risk.
- Assess and enhance the competency and capability of our workforce in matters related to safety.

The head of S&OR is a member of BP's most senior executive team along with the heads of Refining and Marketing, and Exploration and Production. S&OR oversees and audits the company's operations around the world, assuring that all operations are carried out in line with the group's OMS. While the business line continues to be accountable for operational delivery, S&OR holds the authority to intervene in safety and operational risk aspects of BP's technical and operational activities.

Governance processes

The board's safety, ethics and environment assurance committee (SEEAC) receives updates from the executive team's group operations risk committee (GORC), which is chaired by the group chief executive. These updates include quarterly reports monitoring major incidents, near-misses and performance in both process and personal safety across the group. The group chief executive and the head of S&OR attend SEEAC meetings and report on the group's safety performance; this is measured through developing leading and lagging safety indicators. SEEAC also receives information directly from S&OR, other parts of the business and external sources, including the independent expert appointed to monitor the implementation of recommendations made by the BP US Refineries Independent Safety Review Panel following the 2005 incident at our Texas City refinery.

See Board performance report on pages 90-105 for further information on the activities of the board's committees, including the Gulf of Mexico committee established to oversee the work of the Gulf Coast Restoration Organization (GCRO).

Operating management system

In 2008, we launched OMS, our group-wide framework to drive a rigourous and systematic approach to safety, risk management, and operational integrity across the company. OMS integrates all requirements regarding health, safety, security, environment and operational reliability, as well as related issues such as maintenance, contractor relations and organizational learning, into a common system.

The principles and standards of OMS are supported by detailed company practices, as well as other technical guidance materials. OMS mandates that certain standards, group-defined practices and group engineering technical practices be implemented company-wide; these include, among others, the assessment, prioritization and management of risk; incident investigation; integrity management; and environmental and social requirements for major new projects.

The OMS includes these essential requirements, specifically addressing crisis and continuity management and emergency response:

- Identify crisis and continuity management scenarios utilising the entity risk register, the output of the entity's major accident risk assessment and other information.
- Implement and maintain crisis and continuity management plans to manage the scenarios identified. These will include procedures from initiation to response and recovery. At site level these plans shall include arrangements for evacuation and, where needed, for initial shelter-in-place.
- Validate the plans through exercising them at defined intervals. Review the plans at least annually to reflect changes in hazards, risks, organization or contact details, and implement identified improvements.
- Provide access to trained personnel, resources, medical emergency and other facilities needed to implement and execute the crisis and continuity management plans.
- Implement, maintain and exercise a documented process for accounting for personnel during and after an emergency evacuation.

OMS defines the process for BP business units to implement the system and continuously improve their operational performance in all areas, including safety. The embedding of a comprehensive management system such as OMS across a global company is a multi-year process.

The transition to OMS requires each operation to develop a local OMS (LOMS) that describes how the operation addresses site-specific local operating risks to meet group standards and practices and comply with applicable HSSE legal requirements, while focusing on their specific activities. As an essential step in developing its LOMS, the business unit conducts an assessment of the gaps between the standards and practices contained in OMS and the business unit's local processes and procedures, and then develops a gap-closure plan. Every year, after the initial gap assessment, each business unit conducts another assessment to identify the additional steps to be taken to improve performance.

To formally transition to OMS, an operation issues a handbook for the workforce to follow, completes a management-of-change document that details the changes involved, and obtains formal sign-off by the segment operating authority and business unit leader. All of BP's major operations had transitioned to OMS by the end of 2010, with the remaining one regional logistics operation completing the process by the end of February 2011.

BP will continue to evolve OMS, incorporating implementation experience as well as learnings from incident investigations, audits and risk assessments, and by strengthening mandatory practices.

Gulf of Mexico incident and the OMS

The Gulf of Mexico operations completed their transition to OMS in December 2009 and now continue to work towards full conformance to the OMS. Recommendations from BP's internal investigation into the Deepwater Horizon incident will be implemented within our group-wide OMS framework where appropriate; this includes updates around contractor management and oil spill preparedness and response. Once the external investigations have produced their findings, we will carry out a review on the OMS framework; this is expected to be completed in the third quarter of 2011. See Subsequent actions to date on page 68 for information about our immediate activities to further strengthen our oil spill prevention, containment and response capability.

Process safety management

Process safety involves applying good design principles, along with robust engineering, operating and maintenance practices, to managing operations safely. For BP, this means ensuring the plant is designed, maintained and operated properly to avoid failures such as spills or explosions that can result in injuries and impacts to the environment.

In September 2010, BP published *Deepwater Horizon Containment and Response: Harnessing Capabilities and Lessons Learned*, a report shared with the US Bureau of Ocean Energy Management, Regulation and Enforcement. These learnings are intended to benefit our own operations and potentially those of our peers, in case of a future incident.

The report identifies four broad lessons from the Deepwater Horizon incident:

- Collaboration: a broad range of stakeholders came together in the wake of the Deepwater Horizon incident to provide effective solutions and build new capabilities. It would have been extremely difficult for any one company alone to address challenges on the scale of the Deepwater Horizon incident. The response benefited from close collaboration with and the capabilities of the US Coast Guard, Bureau of Ocean Energy Management, Regulation and Enforcement and dozens of other partners and stakeholders from government, industry, academia and the affected communities, as well as around the globe.
- Systemization: the response to the incident required the development of extensive systems, procedures and organizational capabilities to adapt to changing and unique conditions. As the Deepwater Horizon spill continued despite efforts at the wellhead, the response effort progressed, expanded, and took on not just new tasks and directions but new personnel and resources. As a result, from source to shore, existing systems were evolved and expanded and new ones developed to advance work flow, improve co-ordination, focus efforts and manage risks. The adoption of these systems will ensure the ability to respond to future spills more rapidly at scale with a clear direction as to personnel, resource and organizational needs.
- Information: timely and reliable information was essential across both the containment and response operations to achieve better decision-making, ensure safe operations and inform stakeholders and the public.
- Innovation: the urgency in containing the spill and dealing with its effects drove innovations in tools, equipment, processes and know-how, ranging from incremental enhancements to step changes in technologies and techniques, that have advanced the state of the art and laid the foundation for future refinements as part of an enhanced regime for any type of source-to-shore response.

BP joined the Marine Well Containment Company (MWCC), a non-profit initiative with ExxonMobil, Shell, ConocoPhillips and Chevron designed to quickly deploy effective equipment in case of another underwater blowout in the US Gulf of Mexico. The well containment equipment used in the Deepwater Horizon response will preserve existing capability for use by the oil and gas industry in the US Gulf of Mexico while the MWCC member companies build a system that exceeds current response capabilities. BP has also offered to make available to the MWCC BP technical personnel with experience from the Deepwater Horizon response.

Oil spills and loss of containment

We strive to prevent future oil spills by weaving process safety into every stage of the design, operation and management of our operations. We monitor the integrity of all our operations, vessels and pipelines used to produce, process and transport oil and other hydrocarbons – with the aim of preventing any loss of hydrocarbons from their primary containment. Accordingly, we record all losses of containment, losses of hydrocarbons from our assets (which we monitor as an enduring indicator of process safety), and losses or spills that reach land or water.

The loss of primary containment metric below includes any unplanned or uncontrolled release of material, excluding non-hazardous releases such as water, from a tank, vessel, pipe, rail car or equipment used for containment or transfer.

Although there are several third-party estimates of the flow rate or total volume of oil spilled from the Deepwater Horizon incident, we believe that the total volume of oil spilled cannot be finalized until further information is collected and the analysis, such as the condition of the blowout preventer, is completed. Once such determination has been made, we will report on the spill volume as appropriate. See Financial statements – Note 37 on page 199 for information about the volume used to determine the estimated liabilities.

Loss of primary containment and oil spills (excluding Gulf of Mexico oil spill in respect of volume)

Loss of primary containment – number of all incidents[a]	**418**	537	658
Loss of primary containment – number of oil spills[b]	**261**	234	335
Number of oil spills to land and water	**142**	122	170
Volume of oil spilled (thousand litres)	**1,719**	1,191	3,440
Volume of oil unrecovered (thousand litres)	**758**	222	911

[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).

Reports of the US refineries' Independent Expert

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.

During 2010, Mr Wilson kept the committee updated on his work activities and BP's progress in implementing the recommendations, including the outcome of his visits to each of BP's five US refining sites. In March 2010 he published his third annual report (the Third Report) that assessed BP's progress against the 10 Panel recommendations and associated commentary. In that report, which was published in full on BP's website, he found that, in the three years since the Panel issued its report in January 2007, BP had made significant improvements in response to all 10 Panel recommendations. He found measureable improvement across nearly all the common indicators used by BP to track process safety performance; although results varied from refinery to refinery for individual indicators, he found that the composite of these indicators, both at individual refineries and across all BP's US refineries, reflected improvement over time.

Mr Wilson also found, however, that, while significant gaps had been closed and most of the new systems, processes, standards, and practices required for continued process safety improvements had been developed, much work remained to be done to fully implement them. The Third Report stated that BP must demonstrate improved capability for systematic management of these systems, processes, standards, and practices so it can accelerate the overall pace of implementing the 10 Panel recommendations. It also identified the following areas at BP's US refineries in which more focused attention was required:

- addressing overtime issues, and in particular high individual overtime rates;
- the development and implementation of management systems for safety instrumented systems (SIS), required by BP's internal standards, to address areas such as documentation, training for personnel competency, and auditing (collectively, "SIS life cycle" issues);
- taking advantage of certain additional opportunities to further strengthen the process safety culture at BP's US refineries and increasing the pace to achieve this desired culture change; and
- addressing issues of non-conformance with standards and practices and ensuring that installed equipment continues to meet applicable standards and practices.

On 23 February 2011, Mr Wilson presented his fourth annual report (the Fourth Report) to the committee. He found that, throughout 2010, BP's executive management continued to emphasize the importance of safe, reliable, and compliant operations. Even though the year was particularly challenging for BP following the Gulf of Mexico incident, he noted that, during and after the incident response, process safety and personal safety performance continued to be a major focus for executive management. The Fourth Report stated that, during the year, group-level activities continued to focus on the development and enhancement of competency and capability programs, effective audits, and ongoing maintenance and support for the OMS. The five US refineries continued to demonstrate good progress in a number of key areas, and they successfully accelerated the pace of implementation in several other key areas. However, some areas require special emphasis going forward, and the US refineries are addressing these needs through interventions or renewed commitments to accelerated implementation plans.

The Fourth Report assessed the company's progress against the areas identified in the Third Report as requiring more focused attention and found that:

- in relation to reduction of overtime rates, the US refineries had reduced their average overtime rates to levels that are perceived to be at or near industry norms for both operations and maintenance personnel in 2010, and significant reductions in overtime rates for individuals had also been achieved, with only a few people exceeding BP's individual overtime target at the end of 2010;
- in relation to SIS management systems, the US refineries had made accelerated progress in 2010 in addressing SIS life-cycle requirements; the Fourth Report noted that rigourous implementation of these new SIS life-cycle policies and procedures for all existing and newly installed SISs will be a challenging task;
- in relation to process safety culture, the US refineries had developed a common safety culture vision in 2010 and progress was being made in communicating the new vision; the Fourth Report also noted that progress is being made toward improved communication, co-operation and sharing between the refineries and commented on some improvements with respect to individuals adopting a more proactive and self-critical approach towards identifying and addressing risks. The Fourth Report noted that input from Mr Wilson was still sometimes required to catalyze the identification of and timely response to process safety issues; and
- in relation to implementing internal and external standards and practices, BP had clearly identified those standards and practices that apply to the US refineries and is implementing them through risk-prioritized plans. The Fourth Report noted that, although progress is being made in the implementation of standards and practices, special emphasis will be required to address certain remaining issues in a timely manner, including: the time required to implement some new standards; the need to identify requirements in standards that apply retroactively to existing equipment; and the need for a process to ensure that existing equipment remains in conformance with applicable standards.

The Fourth Report also identified three additional areas that warrant special emphasis in order to implement selected Panel recommendations effectively:

- additional sustained efforts, building on sincere messages from executive management to date, may be required to ensure that executive management effectively stimulates and supports a process safety culture within BP's US refineries that promotes industry-leading process safety performance;
- with the exception of action items resulting from audits and incident investigations, overdue process safety action items were not being reported to executive management and to the board, as recommended by the Panel; in addition, Mr Wilson recommended that BP consider

- ways to systematically gather information sufficient to ensure completion of identified process safety action items within reasonable time periods; and
- in the second half of 2010, the quality of some aspects of incident investigations and reports did not maintain the levels achieved in 2009. In response, a Continuous Improvement Team was chartered that developed a number of process improvements to be implemented in early 2011.

The Fourth Report is expected to be published in full in March 2011 and will be made available on our website.

Capability development

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

This training provision 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 defined by our OMS. To date, approximately 11,800 managers, supervisors and technicians have attended at least one workshop within the Operations Essentials programme; additionally, more than 35,000 eLearning modules have been completed.

We communicate our expectations for qualified, competent and experienced contractor personnel through our procurement process. These become obligations within the formal contract. We further manage capability development of our strategic suppliers through a formalized performance review process at operational and strategic levels that is informed with performance data around agreed key metrics. The result of these performance review meetings is agreed joint plans to deliver the performance outcomes required.

The challenges of the Gulf of Mexico incident accelerated learning and capability development for both BP and those who worked with us on the response and for the oil industry. It is hoped that by sharing these lessons, the wider industry will be able to respond more effectively and efficiently to any similar incidents.

BP and third-party responders learned valuable lessons in collaboration, systemization, information-sharing, command and protocol. Some of the most valuable capability advancements were technical, with particularly valuable experiences in the areas of subsea containment systems, remotely operated vehicles, reservoir visualization, hydrate inhibition, rapid retrofitting, and application of dispersants. The shoreline response effort has built an expanded resource of trained responders, and the vessels of opportunity programme has built a base of trained, vetted and locally knowledgeable responders.

Safety performance

BP reports publicly on its personal safety performance according to standard industry metrics. In 2010, our overall reported recordable injury frequency (RIF) was 0.61, compared with 0.34 in 2009 and 0.43 in 2008. The nature of the Gulf Coast response effort has resulted in personal safety incident rates significantly higher than other BP operations. Injuries occurred primarily during boom deployment and the beach clean-up activities, and relate to a working population rapidly recruited to work in new roles, in unfamiliar environments.

Our reported day away from work case frequency (DAFWCF) in 2010 was 0.193, compared with 0.069 in 2009 and 0.080 in 2008. This increase is due in large part to the response effort, but also reflects a substantial increase in the rest of BP. There were nine day away from work cases resulting from the Deepwater Horizon accident and nine as a result of the air crash in Canada.

We apply a formal process designed to ensure that adequate controls to mitigate our internal risks are in place, while constantly looking for ways to strengthen these systems. BP reviews risks at all levels of the organization and, following the Gulf of Mexico incident, our group chief executive challenged our operations to ensure that all risk reviews correctly identify and mitigate lower-probability but higher-impact events.

BP takes major incidents and high-potential incidents very seriously; the more significant incidents are scrutinized by GORC, who has the option to require operations leaders to provide assurance that corrective measures are being taken.

BP has learned important lessons from major incidents at our Texas City refinery in 2005 and the Prudhoe Bay field in Alaska in 2006. We implemented our six-point plan, designed to address the immediate risks and priorities, and then began the roll-out of our OMS underpinned by our capability programmes, and strengthened our global audit team.

In the Gulf of Mexico, our internal investigation and resultant report form only a starting point for what is expected to be an extended process to fully analyse the Gulf of Mexico accident and implement the appropriate measures designed to prevent recurrence.

Contractor management

BP's OMS formalizes standards and recommended practices for selecting and working with contractors. This includes assessing the contractor's safety performance as part of the selection process, and defining safety requirements in contracts.

As a result of the Gulf of Mexico accident, which involved multiple contracting partners, we are reviewing how best to provide consistent and effective contractor oversight. This process began in late 2010 and will be focusing on the way we work with contractors for all onshore and offshore rig activities, particularly in regard to safety and operational risk.

Environment

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 present challenges around their environmental sensitivity and managing our impact on the areas where we operate is at the core of our activities.

We strive to minimize our impacts, whether to land, air, water or wildlife, through a systematic approach, supported by rigorous risk assessment and management, preventive measures and training.

Environmental management

We work to understand the sensitivities of the environments in which we operate and our responsibilities from beginning to end of our projects. By adopting a full project cycle approach to environmental management, we strive to identify the potential environmental impacts of our new projects, in the planning stage and during operations. We continue this approach after operations have ended, through our remediation strategy.

Our environmental and social group defined practices (E&S GDP), launched in April 2010, detail the requirements to help us identify and manage the environmental and social risks of major new projects, projects in new access locations and those that could affect an international protected area. Our E&S GDP is aligned with environmental and social standards and practices generally accepted in the oil and gas industry.

These group defined practices include environmental and social requirements for nine key issues: international protected areas; water management; drilling wastes and discharges; greenhouse gas (GHG) emissions (including energy efficiency and flaring); ozone depleting substances; indigenous people; physical resettlement; security and human rights; and impact assessment.

All our major operating sites are certified under the international environmental management system standard ISO 14001, with the Texas City plant and Tangguh LNG facility successfully receiving certification in 2010.

No new projects entered an international protected area in 2010. Our international protected areas classification includes the International Union for the Conservation of Nature (IUCN) I-IV, Ramsar and World Heritage designations.

Oil spill response plans

We continue to develop and assimilate lessons from the response to the Gulf of Mexico oil spill, which we plan to incorporate into our OMS – specifically on oil spill preparedness and response.

All of BP's operations are required to comply with all applicable laws, including those requirements relating to dealing with the environmental impact of oil spills or leaks, in all regions where we operate. Within OMS, BP has a control document on crisis and continuity management that covers recommendations and approved good practice. OMS also requires environmental risks and hazards to be identified and managed, including those related to unplanned events e.g. oil spills. Country-specific regulators require such plans to be in place and approved as part of our licence to operate.

We complete environmental impact assessments (EIAs) for many of our projects, which include information on the potential environmental impact that might occur in the event of a spill, and use modelling and predictive assessments of where and how oil might impact identified environmentally sensitive sites, species or commercially vulnerable sites.

We then formulate crisis management and oil spill plans, building off the information in the EIA. Environmentally sensitive areas are mapped, preventative response plans agreed, and clean-up and remediation procedures established to determine clean-up end points. These plans address potential scenarios and response strategies, including how we would work with designated regulatory bodies in the event of a spill and what personnel and equipment would be needed.

The response techniques with the least environmental impact are usually agreed based on the sensitivity of the relevant environment. In many countries where BP operates, the regulator will determine and agree on the procedures to deal with the environmental impact.

Acute response plans are often focused on the physical containment and recovery of the spilled oil, though they will 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.

The potential actions during the acute stages of an offshore spill response include:

- Booms can be placed around the spill to gather the oil. A curtain is attached to its underside to prevent the oil from sliding out underneath it and spreading further.
- Sorbents can absorb the oil.
- In situ burning can be used to reduce the amount of oil on the water.
- Skimming equipment can be placed around the area to scoop it from the water's surface.
- Chemical dispersants can help the oil break up more quickly and mix more easily with the water column. Specific dispersants have been developed for different oils. The net environmental benefit of using chemical dispersants should always be considered and assessed before use.

For onshore operations, BP's refineries each have detailed spill response plans that include passive and active containment measures that are appropriate for their specific location and type of operation.

In conjunction with the US authorities, BP has gained significant experience in combating and mitigating a major oil release. The learnings from our spill response experience will be incorporated into the current remediation plans and procedures and also shared with governments, regulators and the industry world-wide.

In the unlikely event of multiple concurrent spills, 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 would be a challenge for the group, our response plans are not interdependent. Further, the plans do not contain physical or financial constraints – BP is committed to devoting such resources as are necessary to mitigate the consequences of any spill to people and the environment.

BP has also joined the Marine Well Containment Company (MWCC) and will make our underwater well containment equipment available to all oil and gas companies operating in the Gulf of Mexico. The well containment equipment used in the Gulf of Mexico oil spill response will preserve existing capability for use by the oil and gas industry in the US Gulf of Mexico, while the MWCC member companies build a system that exceeds current response capabilities. BP has also offered to make available to the MWCC BP technical personnel with experience from the Gulf of Mexico oil spill response. BP considers that the deepwater intervention experience and specialized equipment will be important to the industry as a whole as well as the MWCC. In addition to the MWCC, we work with all of the other seven major international spill response organizations in the world.

See Gulf of Mexico oil spill on pages 34-39 for further information on BP's response to the incident.

Gulf of Mexico – environmental impact and long-term commitments

The Gulf of Mexico oil spill affected water, shores, marshlands and wildlife. Immediately following the accident, BP and personnel from the US National Oceanic and Atmospheric Association, the US Environmental Protection Agency (EPA), and many other governmental agencies began patrolling the waters of the Gulf, sampling the waters looking for residual oil, or injured birds and marine life. BP has worked to support testing and sampling throughout the region.

BP is committed to understanding the long-term environmental impacts of the oil spill. In June 2010, we established the GCRO to manage all aspects of the immediate response to the incident and our long-term efforts to restore the regional environment.

In partnership with the Gulf of Mexico Alliance, we have set up the Gulf of Mexico Research Initiative (GRI), pledging to provide $500 million to study and monitor the spill's potential impacts on the environment and local public health.

See Gulf of Mexico oil spill on pages 34-39 for further information on BP's response to the incident.

Canadian oil sands

Canada's oil sands are believed to hold one of the world's largest untapped supplies of oil, second in size only to the resources in Saudi Arabia. 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 expected to start in 2014. The other two proposed projects, Pike and Terre de Grace, are still in the early stages of development.

We reviewed and approved the decision to invest in Canadian oil sands projects, taking into consideration 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 we plan to use, in-situ steam-assisted gravity drainage technology, involves the injection of steam underground. The steam liquefies the bitumen, allowing it to flow to the surface through production wells. Unlike mining, in-situ development creates a smaller physical footprint and does not involve tailing ponds.

Climate change

Climate change is a major global issue – one that justifies precautionary action and represents a significant challenge for society, the energy industry, and BP.

Our GHG emissions were 64.9Mte in 2010, compared with 65.0Mte in 2009[a]. We have not included any emissions from the Gulf of Mexico incident and the response effort due to our reluctance to report data that has such a high degree of uncertainty.

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

We aim to manage our GHG emissions through a focus on operational energy efficiency and reductions in flaring and venting. Also, we expect that additional regulation of GHG emissions in the future and international accords aimed at addressing climate change will have an increasing impact on our businesses, operating costs and strategic planning, but may also offer opportunities in the development of low-carbon technologies and businesses. See Regulation of the group's business – Greenhouse gas regulation on page 78.

To help address this expectation, we factor a carbon cost into our investment appraisals and the engineering design of new projects. We do this by requiring larger projects, and those for which emissions costs would be a material part of the project, to make realistic assumptions about the likely carbon price during the lifetime of the project. In industrialized countries, this assumption is currently $40 per tonne of CO_2. This is used as a basis for assessing the economic value of the investment and for optimizing the way the project is engineered and the consequences for emissions. This helps to ensure our investments are competitive under scenarios in which the price of carbon is higher than it is today.

Adaptation to climate change impacts

For several years BP has sponsored research, including climate modelling, into the impacts of climate change on both existing operations and new projects. Introduced in 2010, the E&S GDP now requires screening for potential climate change impacts in major new projects, projects in new access locations and those that could affect an internationally protected area.

For larger projects where climate impacts are identified as a risk, we put a mitigation programme in place. Our current engineering practices address climate impacts in the same way as any other physical and ecological impacts. These practices are periodically reviewed and updated.

For many climate-related impacts, the appropriate engineering solutions are already known, because somewhere in our operations we already have experience and design facilities to withstand weather extremes, such as hurricanes, monsoons and Arctic conditions.

Water

To improve our understanding and act upon the growing global issue of water scarcity, BP is taking a more strategic approach to water management. We are currently developing our plans in regards to water management, which include increasing our capability to manage emerging water risks and engaging with external organizations to develop sustainable water management practices.

Environmental expenditure

			$ million
	2010	2009	2008
Environmental expenditure relating to the Gulf of Mexico oil spill			
Spill response	**13,628**	–	–
Additions to environmental remediation provision	**929**	–	–
Other environmental expenditure			
Operating expenditure	**716**	701	755
Capital expenditure	**911**	955	1,104
Clean-ups	**55**	70	64
Additions to environmental remediation provision	**361**	588	270
Additions to decommissioning provision	**1,800**	169	327

BP incurred significant costs in 2010 in response to the Gulf of Mexico oil spill. The spill response cost of $13,628 million includes amounts provided during 2010 of $10,883 million, of which $9,840 million has been expended during 2010, and $1,043 million remains as a provision at 31 December 2010. The majority of this remaining amount is expected to be expended during 2011. In addition, a further $2,745 million of clean-up costs were incurred in the year that were not provided for.

Additions to environmental provisions in 2010 in respect of the Gulf of Mexico oil spill relate to BP's commitment to fund the $500-million Gulf of Mexico Research Initiative, a research programme to study the impact of the incident on the marine and shoreline environment of the Gulf coast, and the estimated costs of assessing injury to natural resources. BP faces claims under the Oil Pollution Act of 1990 for natural resource damages, but the amount of such claims cannot be estimated reliably until the size, location and duration of the impact is assessed.

For further information relating to the Gulf of Mexico oil spill see Financial statements – Note 2 on page 158, Note 37 on page 199 and Note 44 on page 218.

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 $716 million in 2010 was at a similar level to 2009, while in 2008, it was lower due to a reduction in new projects undertaken. In addition, there was a significant reduction in the sulphur oil premium paid due to a greater use of low-sulphur fuel.

Similar levels of operating and capital expenditures are expected in the foreseeable future. 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. The charge for environmental remediation provisions in 2010 included $307 million resulting from a reassessment of existing site obligations and $54 million in respect of provisions for new sites. The charge for environmental remediation provisions in 2009 included $582 million resulting from a reassessment of existing site obligations and $6 million in respect of provisions for new sites.

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.

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. 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 during the year.

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 37 on page 199.

Employees

Number of employees at 31 December	US	Non-US	Total
2010			
Exploration and Production	**7,900**	**13,200**	**21,100**
Refining and Marketing[a]	**12,400**	**39,900**	**52,300**
Other businesses and corporate	**1,700**	**4,500**	**6,200**
Gulf Coast Restoration Organization	**100**	**–**	**100**
	22,100	**57,600**	**79,700**
2009			
Exploration and Production	8,000	13,500	21,500
Refining and Marketing[a]	12,700	38,900	51,600
Other businesses and corporate	2,100	5,100	7,200
	22,800	57,500	80,300
2008			
Exploration and Production	7,700	13,700	21,400
Refining and Marketing[a]	19,000	42,500	61,500
Other businesses and corporate	2,600	6,500	9,100
	29,300	62,700	92,000

[a] Includes 15,200 (2009 13,900 and 2008 21,200) service station staff.

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 are reviewing the way we express BP's values and the content of our leadership framework with a goal of ensuring they support our aspirations for the future, align explicitly with our code of conduct and translate into responsible behaviours in the work we do every day. In 2011, we expect to carry out a programme to renew employee and contractor awareness of our values and the behaviours everyone in BP needs to exhibit as we work to reset our priorities as a company.

We had approximately 79,700 employees at 31 December 2010, compared with approximately 80,300 a year ago. Since 2007, when we began a process of making BP a simpler, more efficient organization, our total number of employees has reduced by approximately 18,000, including around 9,200 in our non-retail businesses.

BP announced significant changes to our organization in 2010 designed to strengthen safety and risk management across the group, including the creation of an enhanced S&OR function and the re-organization of the upstream segment into three divisions: Exploration, Developments and Production, integrated through a Strategy and Integration function.

The group people committee, chaired by the group chief executive continues to take overall responsibility for policy decisions relating to employees. In 2010, this included senior-level talent reviews and succession planning, new hire and promotion assessments, leadership training and reward strategy, including the structure and operation of incentive programmes.

In 2011, our focus will be on rebuilding trust with all our stakeholders, including our employees. Our people priorities continue to be to ensure the right employees are in the right roles, while building a sustainable talent pipeline; to build capability and embed our required leadership behaviours; and to manage and reward performance while ensuring a focus on diversity and inclusion (D&I) in everything we do.

Sustainable talent pipeline

In managing our people, we seek to attract, develop and retain highly talented individuals who can contribute to BP's delivery of its strategy and plans. We place significant emphasis on developing our leaders internally, although we recruit outside the group when we do not have specialist skills in-house or when exceptional people are available. In 2010, we appointed 47 people to group leadership positions, 33 of which were internal candidates.

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. In 2010, we extended these assessments to cover new hires into middle and junior management roles, carrying out over 900 external assessments for new hires and promotions during the year. In 2011, we will be launching a new technical assessment process to complement these existing processes with more focus on detailed technical capability.

Our ongoing three-year graduate development programme continued in 2010. It currently has about 1,400 participants from all over the world.

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 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 incident, BP has been seeking the same or comparable pay and benefits for employees transferring to other companies.

Building capability and developing leaders
The group chief executive and each member of the executive team held review meetings to ensure a rigorous and consistent talent and succession process is followed for all group leadership roles.

We continue to work to embed appropriate leadership behaviours throughout our organization. In 2010, we piloted a new group leader development programme with leaders in the US. All group leaders will be expected to participate in the programme from 2011 onwards.

Our group-wide suite of management development programmes, Managing Essentials, has now run in 42 countries, with more than 21,000 participants. This includes new modules introduced in 2010, such as a mandatory D&I training programme for leaders that has had over 3,000 participants so far.

Managing and rewarding performance
We are conducting a fundamental review of how the group incentivizes business performance, including reward strategy, with the aim of encouraging excellence in safety, compliance and operational risk management. This review is closely linked to the refresh of our values and behaviours and to our work in embedding leadership behaviours throughout the group. We expect to deliver a revised individual performance management framework in 2011.

In the final quarter of 2010, individual performance bonuses were based solely on the achievement of safety targets.

We encourage employee share ownership. For example, through the ShareMatch plan run in around 60 countries, we match BP shares purchased by our employees.

Diversity and inclusion
Diversity and inclusion (D&I) involves acknowledging, valuing and leveraging our similarities and differences for business success, and is central to our employee processes in BP. The group chief executive chairs the global D&I council, which is supported by a North American regional council and segment councils. Each of our businesses has a D&I plan against which progress is measured. We are also incorporating detailed D&I 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. For example, in Azerbaijan, national employees now make up around 88% of BP's team. 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 2010, 14% of our top 482 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.

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
At our annual leadership forum in late 2010, our group chief executive and other senior leaders reinforced BP's commitment to achieving excellence in safety, compliance and risk management. 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.

Our 2010 employee survey was delayed to allow for organizational changes to be reflected in the survey construction, with the survey expected to be carried out in the third quarter of 2011.

The code of conduct
We have a code of conduct designed to ensure that all employees comply with legal requirements and our own standards. The code defines what BP expects of its people in key areas such as safety, workplace behaviour, bribery and corruption and financial integrity. Our employee concerns programme, OpenTalk, enables employees to raise questions, receive guidance on the code of conduct and report suspected breaches of compliance or other concerns. The number of cases raised through OpenTalk in 2010 was 742, compared with 874 in 2009.

In the US, former US 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 2010, 552 dismissals were reported by BP's businesses for non-adherence to the code of conduct or unethical behaviour compared to 524 in 2009. This number excludes dismissals of staff employed at our retail service station sites for more minor incidents.

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.

Social and community issues
We strive to make our impact on society and communities a positive one by running our operations responsibly and by investing in communities in ways that benefit both local populations and BP.

Managing our impact
We believe each BP project has the potential to benefit local communities by creating jobs, tax revenues and opportunities for local suppliers. A positive impact also means making sure that human rights are respected, that we engage openly with people who could be affected by our projects and that local cultural heritage is preserved.

Our OMS lays out the steps and safeguards we believe are necessary to maintain socially responsible operations at our projects and operations.

For major new projects, projects in new locations and those that could affect an internationally protected area, detailed group practices apply. These include guidance on how the project should go about identifying groups that could be affected by the project, consulting with them to understand their needs and concerns and carrying out an impact assessment to evaluate the potential negative and positive community impacts. These are often carried out along with assessments of health, safety, environmental and other impacts.

Following the impact assessment, we review the project plans with a view to avoiding, mitigating or minimizing any negative impacts, such as noise, odour or other forms of community disturbance, and making the most of positive impacts.

Socio-economic investments
We invest in development programmes that we believe will 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, supporting education and other community needs and sharing technical expertise with local governments.

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 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.

We work with local authorities, community groups and others to deliver community programmes matched to local interests and needs. These range from education programmes to community infrastructure programmes that help people in developing economies access basic resources such as drinking water and healthcare.

We use our technical knowledge and global reach where relevant to support governments in their efforts to develop their economies sustainably. 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 and other pitfalls.

We support various voluntary, multi-stakeholder initiatives aimed at sharing best practice and improving industry-wide management of key social and economic challenges. We are a member of the Extractive Industries Transparency Initiative, which supports the creation of a standardized process for transparent reporting of company payments and government revenues from oil, gas and mining. We are also a participant in the Voluntary Principles on Security and Human Rights through which we have developed a robust internal process designed to ensure that the security of our operations around the world is maintained in a manner consistent with our group stance on human rights.

Our direct spending on community programmes in 2010 was $115.2 million, which included contributions of $22.9 million in the US, $36.7 million in the UK (including $6.5 million to UK charities, relating to $3.6 million for art, $1.3 million for community development, $0.8 million for education, $0.5 million for health and $0.3 million for other purposes), $3 million in other European countries and $52.6 million in the rest of the world. Funding for our response effort and long-term commitments to the Gulf Coast region is handled by the Gulf Coast Restoration Organization.

Research and technology

BP's research and technology (R&T) model is one of selective technology leadership. We have chosen 20 major technology programmes that support our competitive performance in resource access, advanced conversion, differentiated products and lower-carbon energy. BP enhanced its scientific capability in 2010 through the recruitment of a new chief scientist and chief bioscientist.

External assurance is achieved through the Technology Advisory Council, which advises the board and executive management on the state of R&T within BP. The council typically comprises eight to 10 eminent business and academic technology leaders.

In 2010, our expenditure on research and development (R&D) was $780 million, compared with $587 million in 2009 and $595 million in 2008. See Financial statements – Note 14 on page 175. The 2010 amount includes $211 million of R&D expenditure related to the Gulf of Mexico oil spill. Despite the redeployment of many technologists in response to the spill, underlying R&D expenditure for 2010 remained similar to the two preceeding years. The $780 million total excludes payments made in relation to the Gulf of Mexico Research Initiative, outlined below.

Collaboration plays an important role across the breadth of BP's R&D activities, but particularly in those areas that benefit from fundamental scientific research:

- In response to the Gulf of Mexico oil spill, BP has established the Gulf of Mexico Research Initiative, a 10-year $500-million open-research programme into the effects of the spill. The ultimate goal of the research efforts will be to improve society's ability to mitigate the impacts of hydrocarbon pollution and related stressors of the marine environment. In 2010, BP awarded $40 million of short-term contracts for immediate research into the effects of the spill.
- BP has significant, long-term research programmes with major universities and research institutions around the world, exploring areas from energy bioscience and conversion technology to carbon mitigation and nanotechnology in solar power. 2010 marked two significant milestones – the 10-year anniversaries of both the Carbon Mitigation Initiative (CMI) at Princeton University and the BP Institute for Multiphase Flow (BPI) at the University of Cambridge. The success of the CMI has resulted in agreement for BP to support an additional five years of research. BP has also agreed to increase the BPI endowment fund to support an extra senior researcher and part-time administrator.
- The BP Foundation funded the new McKenzie Chair in Earth Sciences at the University of Cambridge. The Chair will ensure the continued excellence of research and teaching of quantitative earth sciences in the department.
- At the Energy Biosciences Institute (EBI) in Berkeley, US, the investment in foundational research platforms has started to generate innovations with direct commercial relevance. The first of these are being adopted by the biofuels business into commercial practice. The EBI's capabilities developed for the study of microbially-enhanced oil and gas recovery were leveraged to study the microbial biodegradation of the oil spill in the Gulf of Mexico.
- 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 2010, the ETI had commissioned over $92 million of work covering more than 20 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.
- The Energy Sustainability Challenge is a multi-disciplinary research programme aimed at understanding pressures on freshwater availability and increasing competition for land and mineral resources, driven by the impact of increasing population and urbanization on energy demand. Research projects with leading universities are under way, investigating the effects of natural resource scarcities on patterns of energy supply and consumption, and which technologies are likely to be needed in an increasingly resource-constrained world.

Exploration and Production

In our Exploration and Production segment, technology investment is focused on ensuring safe, reliable operations, strengthening our portfolio, getting more from our resource base and winning new access.

- The Gulf of Mexico oil spill required rapid innovation of new technologies to cap the well and contain the spill. Innovation will continue as part of Gulf restoration efforts. BP worked with industry partners, multiple government agencies, and academia to develop solutions and, as a result, now has a set of additional assets covering:
  - An inventory of immediately deployable open and closed containment systems proven at depth with associated operating procedures.
  - Proven systems for processing and transporting contained oil.
  - Diagnostic and surveillance techniques for dispersed oil analysis and monitoring.
  - Plans and organizational models for the immediate deployment of dedicated source containment.
  - Enhanced technologies and procedures to drill relief wells in deep water.
  - Experience in using all of the above capabilities.
- BP continues to develop and apply innovative exploration technologies. Following the successful use of the ISS™ seismic acquisition technique in Libya in 2009, we have conducted field trials, combined with cableless node receivers to further increase seismic acquisition efficiency. Positive test results led to a decision to acquire 3,000 square kilometres of the 2010/11 Libya onshore acquisition programme using this method.
- Through the inherently reliable facilities (IRF) flagship technology programme, BP is developing a fundamental understanding of corrosion and erosion risks and corresponding mitigation barriers and techniques. The IRF programme has developed fibre optic pipeline monitoring technologies to reduce the risk of third-party interference and monitor for leaks. These were deployed on the Baku-Tbilisi-Ceyhan pipeline in 2010, and further applications are planned.
- 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 can add 2 billion boe to our reserves. As at the end of 2010, BP has treated 56 wells with Bright Water™ technology in Alaska, Argentina, Azerbaijan and Pakistan, which has delivered increased reserves at a development cost of less than $6 per barrel, and with an 80% success rate. Following field trials in Alaska, LoSal™ EOR in the Clair field (UK North Sea) is now in front end engineering design stage. The Clair Ridge LoSal EOR project will be the world's first offshore LoSal technology waterflood. Following extensive EOR studies for the Schiehallion field in the West of Shetland, BP and co-owners have approved the design of the new Quad 204 Schiehallion FPSO (the floating production, storage and offloading unit, which is expected to be sanctioned in the second quarter of 2011) to be fully polymer EOR ready.

Refining and Marketing

In our Refining and Marketing segment, technology is delivering performance improvements across all businesses. For example:

- Technology advances in our refining and logistics businesses give us better understanding and processing of different feedstocks, optimization of our assets, enhanced flexibility and reliability of our refineries, and stronger margins. In 2010, following extensive development work with BP and Imperial College London, Permasense launched a new integrity-monitoring system that enables frequent, repeatable wall-thickness monitoring. This provides previously unavailable insights into the condition and capability of oil and gas assets. The Permasense system has been proven in operation at BP refineries in Germany and the US, and is now being deployed at our refineries worldwide.

ISS, *LoSal*, *Invigorate* and *InnerCool* are trade marks of BP p.l.c.
Bright Water is a trade mark of Nalco Energy Services LP.

- In fuels and lubricants, our technology focus is on supplying products with greater fuel efficiency and reduced CO_2 emissions. In partnership with original equipment manufacturers, BP has developed a new passenger car engine oil offering 2.4% fuel saving; a transmission oil for military vehicles with a 1.5% fuel saving; and the turbine oil for the new Boeing 787 Dreamliner. We are working on prototype fuels to optimize the performance and efficiency of next-generation engines and to enable increased biofuel content to meet national mandates. In the US, BP's Invigorate™ gasoline has been endorsed by BMW for its superior performance in cleaning engine fuel injection systems.
- In 2010, we opened a new lubricants technology centre in Shanghai, China, and a new fuels technology centre in Johannesburg, South Africa. Both represent the first investments of their type in those countries for an international oil company and underpin BP's commitment to these important markets.
- Our proprietary processing technologies and operational experience continue to reduce the manufacturing costs and environmental impact of our petrochemicals plants, helping to maintain competitive advantage in purified terephthalic acid (PTA), paraxylene, and acetic acid. Learning from successful project implementations in Asia, continuous improvement of our CATIVA® technology for manufacture of acetic acid maintains BP's world-class capital and operating cost position.
- In the field of conversion technology, we continue to work with potential third-party licensees to commercialize BP's fixed-bed Fischer-Tropsch technology. This technology can be applied to the conversion of unconventional feedstocks, including biomass, to high-quality diesel and other liquid hydrocarbons. In addition, BP and KBR agreed a 25-year collaboration to promote, market, and execute licensing and engineering services for the slurry-bed residue and coal-upgrading Veba Combi Cracker (VCC) Technology. VCC Technology 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

BP's Alternative Energy portfolio covers a wide range of renewable and low-carbon energy technologies.

- In 2010, our biofuels business acquired Verenium's lignocellulosic biofuels business, which will accelerate the development of lignocellulosic ethanol technology to commercialization. BP has acquired: R&D facilities in San Diego, California; intellectual property related to proprietary lignocellulosic biofuels R&D and conversion technology; a pilot plant and demonstration facility in Jennings, Louisiana; and BP is now the sole owner of Vercipia Biofuels, which is commercializing production of lignocellulosic ethanol.
- In the wind business, the quest for more energy-efficient wind turbine generators continues. In the US, BP Wind Energy is testing state-of-the-art laser wind sensor units to deliver improved wind turbine performance and increase energy output.
- In our solar business, a new technology designed to make solar cells more efficient in extremely high temperatures, InnerCool™ solar technology, is being piloted at a university in Saudi Arabia, where we have demonstrated increases in energy generation of approximately 3%. We have also developed and introduced a new anti-reflective glass coating for solar modules, reducing the amount of energy lost through reflection and allowing more light to reach the cells, thus increasing energy generation by up to 4% compared to plain glass modules.
- In 2010, the first phase of BP's joint industry project with Sonatrach and Statoil at In Salah, Algeria – to demonstrate new technologies for monitoring stored CO_2 – drew to a close. The project is helping to set operational parameters for the secure geological storage of CO_2, with particular highlights including the Quantitative Risk Assessment developed, tested and benchmarked at In Salah, as well as the integration of technologies, such as satellite imaging and 3D and 4D seismic, to better understand the behaviour of CO_2 plumes in the subsurface.

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 therefore 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 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). 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 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 a portion of the area covered by the exploration licence. Both exploration and production licences are generally for a specified period of time (except for licences in the US, which typically remain in effect until production ceases). The term of BP's licences and the extent to which these licences may be renewed vary by area.

Frequently, BP conducts its exploration and production activities in joint ventures with other international oil companies, state companies or private companies. These joint ventures may be incorporated or unincorporated ventures. Whether incorporated or unincorporated, relevant agreements will set out each party's level of participation or ownership interest in the joint venture. Conventionally, all costs, benefits, rights, obligations, liabilities and risks incurred in carrying out joint venture operations under a lease or licence are shared among the joint venture parties according to these agreed ownership interests. Ownership of joint venture property and hydrocarbons to which the joint venture 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 themselves, each joint venture party will generally be liable to meet these in proportion to its ownership interest. In many upstream operations, a party (known as the operator) will be appointed (pursuant to a joint operator agreement (JOA)) to carry out day-to-day operations on behalf of the joint venture. The operator is typically one of the joint venture parties and will carry out its duties either through its own staff, or by contracting out to third-party contractors or service providers. BP acts as operator on behalf of joint ventures in a number of countries where we have exploration and production activities.

Frequently, work will be contracted out to third-party service providers who have the relevant expertise not available within the joint venture or operator's organization. The relevant contract will specify the work to be done and the remuneration to be paid and will set out how major risks will be allocated between the joint venture and the service provider. Typically, the joint venture 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 might also contain detailed 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. Contractors will also typically seek to cap their overall liability to the joint venture parties. The allocation of those risks and the provision of any cap on liability will be determined following 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, particularly in Abu Dhabi, Angola, Egypt, Norway, the UK, the US, Russia, South America 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 also are environmental laws that require us to remediate and restore areas damaged by the accidental or unauthorized release of hazardous materials 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 37 on page 199 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 of $100,000 or more. 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 73.

Greenhouse gas regulation

Increasing concerns about climate change have led to a number of international, national and regional measures to limit greenhouse gas (GHG) emissions; additional stricter measures can be expected in the future. Current measures and developments affecting our businesses include the following:

- The Kyoto Protocol currently commits 38 ratified parties to meet emissions targets in the commitment period 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 80 countries, including all the major economies and many developing countries, have made such commitments. 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.

- The European Union (EU) Climate Action and Renewable Energy Package which requires increased greenhouse gas reductions, improvements in energy efficiency and increased renewable energy use by 2020, as well as including the Revision of the EU Emissions Trading Scheme (EU ETS) directive. This regulates approximately one-fifth of our reported 2009 global CO_2 emissions and can be expected to require additional expenditure from 2013 when the next revision of the scheme (EU ETS Phase 3) comes into effect. The main changes in EU ETS will be a significant increase in the auctioning of allowances, the end of free allocations for electricity production, an expanded scope covering additional commercial sectors and gases, certain free allocations determined mainly by EU-wide sector benchmarks as compensation for carbon leakage (relocation to less regulated jurisdictions), and consideration of carbon capture and storage installations.
- The EU Renewables Energy Directive (RED) requires that the share of energy from renewable sources in all forms of transport in 2020 be at least 10 % of the final consumption of energy in transport in that member state.
- 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 from 2011.
- BP's facilities in the UK are subject to the UK Carbon Reduction Commitment Scheme (CRC EES), which has recently been modified to end the recycling of revenues back to participants. This can be expected to require additional expenditures for compliance.
- Australia has committed to reduce its GHG emissions by between 5-25% below 2000 levels by 2020, depending on the extent of international action. A proposed GHG emissions trading scheme (CPRS) has been scrapped by the incoming coalition government, but a forum (the Multi Party Climate Change Committee) has been established to investigate options for implementing a carbon price and to help build consensus on Australia's measures to address climate change.
- New Zealand has agreed to cut GHG emissions by 10-20% from 1990 levels by 2020, subject to certain conditions. 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.
- In the US, following the failure to pass comprehensive climate legislation, the US Environmental Protection Agency (EPA) is pursuing 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, EPA finalized regulations imposing light duty vehicle emissions standards for GHGs.
  - The EPA finalized the initial GHG mandatory reporting rule (MRR) in 2009 and amended or proposed amendments to it several times during 2010.
  - The EPA finalized permitting requirements for new or modified large GHG sources in 2010, with these regulations taking effect in January 2011.
  - The EPA's efforts to regulate GHG emissions through the CAA are subject to numerous legal challenges and active political debate so that the final content and scope of GHG regulation in the US remains 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 and is on target to complete emissions cap-and-trade, low carbon fuel, and other GHG regulations in 2011 for programme start up in January 2012.
- Canada has adopted an action plan to reduce emissions to 17% below 2005 levels by 2020 and the national government seeks a co-ordinated approach with the US on environmental and energy objectives.

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.

US and EU regulations

Approximately 62% of our fixed assets are located in the US and the EU. US and EU environment, health and safety regulations significantly affect BP's exploration and production, refining, 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 GHG emissions. Additionally, many states have separate 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 (CWA) regulates wastewater and other effluent discharges from BP's facilities, and BP is required to obtain discharge permits, install control equipment and implement operational controls and preventative measures.
- The Resource Conservation and Recovery Act (RCRA) regulates the generation, storage, transportation and disposal of wastes associated with our operations and can require corrective action at locations where such wastes have been 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 contaminated site or arranged for waste disposal 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) and other federal and state laws.
- 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.
- 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 approximately 150 BP facilities. These regulations require security vulnerability assessments, security mitigation plans and security upgrades, increasing our cost of operations.

The OPA 90 is implemented through regulation issued by the EPA, the US Coast Guard, the DOT, the Occupational Safety and Health Administration and various states; Alaska and the west coast states are currently the most demanding. There is an expectation that the OPA 90 and its regulations will become more stringent in 2011. 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 2011, we expect more unannounced exercises and potential penalties for any failure to demonstrate required preparedness even without any OPA 90 amendments.

The US refineries of BP Products North America Inc. (BP Products) are subject to a consent decree with the EPA to resolve 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. For further disclosures relating to the Texas City refinery, please see Legal proceedings on page 132.

Various environmental groups and the EPA have challenged certain aspects of the operating permit issued by the Indiana Department of Environmental Management (IDEM) for our upgrades to the Whiting refinery. In response to these challenges, the IDEM has reviewed the permits and responded formally to the EPA. The EPA, either directly or through the IDEM, can cause the permit to be modified, reissued or, in extreme circumstances, terminated or revoked. BP is in discussions with the EPA, the IDEM and certain environmental groups over these issues and alleged CAA violations at the Whiting refinery. Settlement negotiations continue in an effort to resolve these matters. BP is also in settlement discussions with the EPA relating to alleged 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 our operations and profitability. These include:

- The EU Climate Action and Renewable Energy Package and the Emissions Trading Scheme (ETS) Directive (*see Greenhouse gas regulation on page 78*).
- The EU European Integrated Pollution Prevention and Control (IPPC) Directive imposes a unified environmental permit requirement on our major European sites, including refineries and chemical facilities, and requires assessments and upgrades to our facilities. A proposed Industrial Emission Directive would replace the IPPC Directive. It would merge several existing industrial emission directives, impose tighter emission standards for large combustion plants and be more prescriptive as to the emission limits that have to be achieved by Best Available Techniques (BAT). When finally transposed into national legislation it will result in requirements for further emission reductions at our EU sites.
- The European Commission (EC) 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. The EC is also considering the use of a NO_x and SO_2 trading scheme as a tool to achieve emission reductions. 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 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.
- 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. Having complied with the 2008 pre-registration requirements, we have now completed full registration of all the substances that we were required to submit by the regulatory deadline of 1 December 2010. This first phase covered high tonnage/high hazard chemicals; chemicals with lower production/import tonnage materials will be subject to registration in the period 2013-2018. REACH affects our refining, petrochemicals, lubricants and other manufacturing or trading/import operations.

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 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. The compliance deadline for substances was 1 December 2010 and maintaining compliance will be integrated into the operating processes of our manufacturing and marketing businesses in Europe. We are also required to notify hazard classifications to the European Chemicals Agency for inclusion in a publicly available inventory of hazardous chemicals before 3 January 2011. The CLP will also apply to mixtures (e.g. lubricants) by 2015.

- 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 beginning in 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 CO_2 emissions and energy costs for additional refining.
- 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.

Maritime regulations

BP Shipping's operations are subject to extensive national and international regulations governing liability, operations, training, spill prevention and insurance. These include:

- In US waters, the OPA 90 imposes liability and spill prevention and planning requirements governing, amongst others, tankers, barges and offshore facilities. It also mandates a levy on imported and domestically produced oil to fund the oil spill response. Following the 2010 oil spill in the Gulf of Mexico, several members of the US Congress have introduced bills proposing to increase or eliminate the OPA 90 liability caps, some of them seek to impose a retroactive expansion of liability. At this time, none of the bills have been enacted into law and their fate is uncertain. 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 (1) 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 (2) contributing parties in the consenting states have received at least 40 million tonnes of contributing cargoes in the preceding year.

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.

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.

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 principally due 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 as well as certain contracts to supply physical volumes at future dates. Under IFRS, these inventories and contracts are recorded at historic cost and on an accruals basis respectively. 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 and contracts 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.

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 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 which the inventory and the supply and capacity contracts in question are valued based on fair value using relevant forward prices prevailing at the end of the period. 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 26.

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 49-50 and in Refining and Marketing on pages 58-59. 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.

OTC 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.

Directors and senior management

Directors and senior management

The following lists the company's directors and senior management as at 18 February 2011.

Name		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
D J Flint	Non-Executive Director	January 2005
Dr B E Grote	Executive Director (Chief Financial Officer)	August 2000
Dr D S Julius	Non-Executive Director	November 2001
B R Nelson	Non-Executive Director	November 2010
F P Nhleko	Non-Executive Director	February 2011
M Bly	Executive Vice President (Safety and Operational Risk)	October 2010
R Bondy	Group General Counsel	May 2008
S Bott	Executive Vice President (Human Resources)	March 2005
Dr M C Daly	Executive Vice President (Exploration)	October 2010
R Fryar	Executive Vice President (Production)	October 2010
A Hopwood	Executive Vice President (Exploration and Production, 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
S Westwell	Executive Vice President (Strategy and Integration)	January 2008

Mr C-H Svanberg was appointed chairman on 1 January 2010. Mr P M Anderson was appointed as a director on 1 February 2010 and Mr I E L Davis was appointed as a director on 2 April 2010. Mr E B Davis, Jr and Sir Ian Prosser retired as directors on 15 April 2010.

Mr A G Inglis resigned as a director on 31 October 2010. Dr A B Hayward resigned as group chief executive on 1 October 2010 and as a director on 30 November 2010. Mr R W Dudley became group chief executive on 1 October 2010. Mr B R Nelson and Mr F L Bowman were appointed as directors on 8 November 2010 and Mr F P Nhleko was appointed as a director on 1 February 2011.

At the company's 2010 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 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, Mr D J Flint, Dr B E Grote, Dr A B Hayward, Mr A G Inglis, Dr D S Julius, and Mr C-H Svanberg.

Mr D J Flint and Dr D S Julius will retire at the conclusion of the company's 2011 AGM. All of the other directors will offer themselves for election/re-election at the company's 2011 AGM.

Dr H Schuster has been appointed as executive vice president, human resources, in succession to Mrs S Bott with effect from 1 March 2011.

David Jackson (58) 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 remuneration committee

Carl-Henric Svanberg (58) 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 (55) 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 with responsibility for the broad oversight of the company'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 succeeded Dr Hayward as group chief executive of BP p.l.c.

P M Anderson

Member of the chairman's, safety, ethics and environment assurance and Gulf of Mexico committees

Paul Anderson (65) 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 rejoined 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 and safety, ethics and environment assurance committees

Frank Bowman (66) 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. He is president of Strategic Decisions, LLC and a director of Morgan Stanley Mutual Funds.

A Burgmans, KBE

Member of the chairman's, remuneration and safety, ethics and environment assurance committees

Antony Burgmans (64) 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 and safety, ethics and environment assurance committees

Cynthia Carroll (54) 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 Anglo Platinum Ltd.

Sir William Castell, LVO

Member of the chairman's, Gulf of Mexico and nomination committees and chairman of the safety, ethics and environment assurance committee

Sir William (63) 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.

I C Conn

Iain Conn (48) 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 Group plc and chairman of The Advisory Board of Imperial College Business School.

G David

Member of the chairman's, audit, Gulf of Mexico and remuneration committees

George David (68) joined BP's board in February 2008. He spent his career with United Technologies Corporation (UTC), as its chief executive between 1994 and 2008 and chairman from 1997 until his retirement in December 2009. He is a former director of Citigroup, Inc.

I E L Davis

Member of the chairman's, audit, nomination and remuneration committees and chairman of the Gulf of Mexico committee

Ian Davis (59) 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.

D J Flint, CBE

Member of the chairman's and nomination committees and chairman of the audit committee

Douglas Flint (55) joined BP's board in 2005. He trained as a chartered accountant and was made a partner at KPMG in 1988. In 1995, he was appointed group finance director of HSBC Holdings plc and in 2009 his role was broadened to chief financial officer, executive director, risk and regulation. He was appointed chairman of HSBC with effect from 3 December 2010. He was chairman of the Financial Reporting Council's review of the Turnbull Guidance on Internal Control. Between 2001 and 2004, he served on the Accounting Standards Board and the Standards Advisory Council of the International Accounting Standards Board. He will retire from the BP board at the conclusion of the 2011 AGM.

Dr B E Grote
Byron Grote (62) 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 and chief financial officer in 2002. He is a non-executive director of Unilever NV and Unilever PLC.

Dr D S Julius, CBE
Member of the chairman's and nomination committees and chairman of the remuneration committee
DeAnne Julius (61) joined BP's board in 2001. She began her career as a project economist with the World Bank in Washington. From 1986 until 1997, she held a succession of posts, including chief economist at British Airways and Royal Dutch Shell Group. From 1997 to 2001, she was a full-time member of the Monetary Policy Committee of the Bank of England. She is chairman of the Royal Institute of International Affairs and a non-executive director of Roche Holdings SA and Jones Lang LaSalle, Inc. She will retire from the BP board at the conclusion of the 2011 AGM.

B R Nelson
Member of the chairman's and audit committees
Brendan Nelson (61) 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 following which he was appointed vice chairman until his retirement in 2010. In 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.

F P Nhleko
Member of the chairman's and audit committees
Phuthuma Nhleko (50) 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 will step down as group chief executive of MTN Group at the end of March 2011 to become vice-chairman of the MTN Group and chairman of MTN International.

Senior management

M Bly
Mark Bly (51) 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 (49) 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.

S Bott
Sally Bott (61) joined BP in 2005 as an executive vice president responsible for global human resources. She joined Citibank in 1970 and was in the economics department and the finance function before joining human resources. She was appointed human resources vice president in 1979. In 1994, she joined Barclays De Zoete Wedd, an investment bank, as head of human resources and in 1997 became group human resources director of Barclays plc. From 2000 to early 2005, she was managing director of Marsh and McLennan and head of global human resources at Marsh Inc. In 2008, she was elected as a non-executive director of UBS AG. She will retire as BP's group human resources director at the end of April 2011.

Dr M C Daly
Mike Daly (57) 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 (47) 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 (53) joined BP in 1980 as a petroleum engineer. Following a series of operational roles and roles in corporate planning and exploration and production planning, in 1999, he was appointed business unit leader in Azerbaijan, returning to London in 2001 as the upstream chief of staff. In 2004, he became strategic performance unit leader for BP's North America Gas business 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 exploration and production, strategy and integration.

B Looney

Bernard Looney (40) 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 CEO's executive 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 (52) 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.

Dr H Schuster

Helmut Schuster (50) 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. In February 2011 it was announced that he was appointed group human resources director and a member of BP's executive team in succession to Sally Bott with effect from 1 March 2011.

S Westwell

Steve Westwell (52) joined BP in the manufacturing and supply division of BP Southern Africa in 1988. Following various retail positions in the UK and the US, he was appointed head of retail and a member of the board of BP Southern Africa Pty. In 2003, he became president and chief executive officer of BP Solar, and in 2004, group vice president of natural gas liquids, power, solar and renewables. In 2005, he was appointed group vice president of Alternative Energy. He joined the executive team in 2008 and is executive vice president, strategy and integration.

Directors' interests

Current directors	At 31 Dec 2010	At 1 Jan 2010	Change from 31 Dec 2010 to 24 Feb 2011
C-H Svanberg	925,000	–	–
R W Dudley	280,799[a]	276,846[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	339,637[b]	293,216[b]	77,916
G David	159,000[a]	39,000[a]	–
D J Flint	15,000	15,000	–
Dr B E Grote	1,372,643[c]	1,291,643[c]	–
Dr D S Julius	15,000	15,000	–

Directors leaving the board	At resignation/ retirement	At 1 Jan 2010
E B Davis, Jr	77,238[a d]	76,497[a]
Dr A B Hayward	677,488[e]	535,383
A G Inglis	309,823[f g]	259,163[f]
Sir Ian Prosser	16,301[h]	16,301

Directors joining the board	At 31 Dec 2010	On appointment	Change from 31 Dec 2010 to 24 Feb 2011
P M Anderson	6,000[a]	6,000[a i]	–
F L Bowman	2,520[a]	2,520[a j]	4,800
I E L Davis	10,000	10,000[k]	–
B R Nelson	–	–[l]	–
F P Nhleko	–	–[m]	–

[a] Held as ADSs.
[b] Includes 48,024 shares held as ADSs at 31 December 2010 and 47,320 shares held as ADSs at 1 January 2010.
[c] Held as ADSs, except for 94 shares held as ordinary shares.
[d] On retirement at 15 April 2010.
[e] On resignation at 30 November 2010.
[f] Includes 34,962 shares held as ADSs.
[g] On resignation at 31 October 2010.
[h] On retirement at 15 April 2010.
[i] On appointment at 1 February 2010.
[j] On appointment at 8 November 2010.
[k] On appointment at 2 April 2010.
[l] On appointment at 8 November 2010.
[m] On appointment at 1 February 2011.

The above figures 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.

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.

Corporate governance

Board performance report

Dear shareholder

The tragic loss of life on the Deepwater Horizon and subsequent events in the Gulf of Mexico dominated the work of the board over the year. The following report describes how your board addressed the immediate crisis while working to ensure a complex, global business continued to operate effectively.

I believe the board responded strongly during the crisis. Our first priority was to provide the guidance, resources and support required by our response teams in the Gulf of Mexico. We met as a full board on 25 occasions during the year. A dedicated Gulf of Mexico committee was formed to enable the board to respond quickly and appropriately as events unfolded. During the summer, the chairs of the committees and I met regularly to ensure work was co-ordinated and the right issues were being addressed in a timely way.

There remains much for the board to do. We are giving particular attention to the ways in which the company applies the many lessons learned, in particular in the process safety area, and meets its ongoing commitments in the US. We are also working with the executive team to ensure BP pursues a clear strategic direction that is well matched to future opportunities and challenges.

There has been significant change on the board. Five new non-executives have joined over the past 12 months and we have a new group chief executive. The board is a strong and united team with a breadth of experience that will serve the company well.

Events in the Gulf of Mexico represent a watershed for the company. In terms of the board, it is essential that we employ the most effective processes and governance mechanisms, and I am leading a review of the structures and tools that were in place during 2010. We will examine the results of our board and committee evaluations, which are described in this report. We will carefully consider the constructive feedback I have received from shareholders and others. Our goal is to be a board that not only responds to the issues of the past but that also anticipates the challenges of the future as BP's business changes and evolves to the demands of a global organization in the twenty-first century. I look forward to reporting to you on this in the future.

We are required to comply with the new UK Corporate Governance Code from next year. To ensure we meet standards of best practice we have already adopted the requirements of the new Code as the basis for assessing the BP board's performance, in addition to complying with the June 2008 Combined Code.

Finally, I want to emphasize the importance the board places on trust and transparency. It is right that we share our thoughts and actions with you, and we will use all appropriate channels of communication to provide timely and helpful information.

I would like to take this opportunity to thank all of my colleagues for their time commitment and support during the year.

Carl-Henric Svanberg
Chairman

BP's governance framework

The BP board works within a clear framework described in its governance principles. These describe the board's role, how it operates, how it relates to executive management and the main tasks of its committees. These are available on the corporate governance page of our website. In all its work the board has to consider specific issues – including health, safety, the environment and BP's reputation. Put simply, the board needs to set the right tone from the top.

Our main areas of focus are:

- Active consideration of long-term strategy.
- Monitoring executive management and the performance of the company.
- Obtaining assurance that material risks to BP are identified and that systems of risk management and internal control are in place to manage such risks.
- Board and executive management succession.

We keep the board governance principles under regular review and we consider their effectiveness as part of the annual board evaluation.

Board activities in 2010

Over the year, the board met 25 times as we responded both to events in the Gulf of Mexico and subsequently in the financial markets, meeting at least weekly as the crisis developed. The board had to organize its work to respond to the crisis while ensuring the other parts of the company continued to perform. During the summer we formed the Gulf of Mexico committee whose primary responsibility was the oversight of the Gulf Coast Restoration Organization and whose work is described further in this report.

With the exception of the two non-executive directors who joined the board in November, each non-executive director has visited the Gulf of Mexico at least once; the chairman and the chair of the safety, ethics and environment assurance committee (SEEAC) have made more frequent visits and the Gulf of Mexico committee held meetings in the US.

Gulf of Mexico

The board identified seven priorities in its response to the crisis:

1. Containment and clean-up of the spill

The board monitored the company's work in containing the spill and subsequently capping the well. The board received regular updates from BP management and was kept in daily contact as the company responded to the spill in cleaning the beaches and working with affected communities. Through the group chief executive, the board was kept appraised of the work of the Unified Command in the US. The board is still monitoring this work through the Gulf of Mexico committee (see below).

2. Claims

The company's commitment to meet legitimate claims was agreed to and is being monitored by the board, who received updates on the number and quantum of claims paid by the company and the time taken to process claims received. The board approved the proposal to appoint Kenneth Feinberg to discharge the trust fund and agreed to the fund's terms and structure. Oversight of BP's activities with respect to the Gulf Coast Claims Facility, the Deepwater Horizon Oil Spill Trust and response to fines and penalties is part of the remit of the Gulf of Mexico committee and, going forward, the committee will maintain its monitoring of this area and report this back to the board.

The board also discussed and approved the settlement with the White House on the establishment of the trust fund, believing this would reinforce the company's stated commitment to honour all legitimate claims arising from the incident.

3. Liquidity
The events in the Gulf of Mexico, particularly the early inability to cap the well, had a major impact on the company's standing in the financial community and its ability to raise cash on historic terms after its credit rating was downgraded. This was closely monitored by the board so that prompt remedial action could be taken.

With the uncertainty in the financial markets and the establishment of the $20-billion trust fund, the board considered it necessary to review its dividend policy. Despite the company's strong underlying financial performance and asset position, the board believed that additional confidence was needed that the company could manage the uncertainty over the timing and extent of the costs and liabilities relating to the spill going forward. The board decided that in these circumstances it needed to take a prudent and conservative approach to the company's financial position. Accordingly it decided to cancel the first-quarter dividend and to announce that there would be no interim dividends in respect of the second and third quarters of 2010. The board indicated it would consider the resumption of dividend payments in 2011 at the time of the fourth quarter 2010 results, when the board expected it would have a clearer picture of the longer-term impact of the incident. On 1 February 2011, it was announced that quarterly dividend payments would recommence.

To further increase the company's available cash resources, the board significantly reduced the company's organic capital spending in 2010 and increased planned divestments to a target of $30 billion.

The board ensured that the market was kept fully informed of the company's position.

4. Investigation
Mark Bly – head of the Safety and Operations function – was asked by the then group chief executive to undertake an investigation aimed at analysing the chain of events surrounding the incident on the Deepwater Horizon and to make recommendations to enable the prevention of a similar accident. The investigation team was tasked to work independently from other BP spill response activities and separately from any investigation conducted by other companies or investigation teams.

The Deepwater Horizon Accident Investigation Report (BP's Investigation Report) was published in September and outlined eight key findings relating to the causes of the accident; for further detail, see Gulf of Mexico oil spill on page 34. The report did not identify any single action or inaction that caused the accident and concluded that a complex and interlinked series of mechanical failures, human judgments, engineering design, operational implementation and team interfaces came together to allow the initiation and escalation of the accident. A series of 26 recommendations were developed to address each of the report's key findings and these have formed the basis of an action plan. The board tasked the group chief executive and senior management team to implement this action plan across BP and asked SEEAC to oversee this process.

The board is monitoring the hearings of other, non-BP investigations and will consider how the conclusions from these investigations fit within the framework of findings and actions arising from BP's own report.

5. Internal initiatives
Following the accident, a number of internal initiatives have been commenced by executive management, with frequent reporting back to the board including examining what can be learnt to further improve BP's risk processes and the company's oversight of contractors. A number of these initiatives are still ongoing and will conclude in the course of 2011.

As incoming chief executive, Bob Dudley announced that a new safety and risk division would be created (the Safety and Operational Risk Function) and that the Exploration and Production segment would be restructured from a single business into three functional divisions (Exploration, Developments and Production). Splitting the upstream business into separate functions is intended to foster the long-term development of specialist expertise and to reinforce accountability for risk management.

6. Reputation
During the crisis and afterwards, the board had extensive discussions about the reputational impact of the event, including how it might affect BP's licence to operate both in the US and elsewhere. This work continues to focus on BP's relationship with shareholders, governments, communities and indeed all those who come into contact with BP through its business operations.

The chairman, the chief executive, the chairman of SEEAC and senior management have been actively involved in discussions with shareholders and other groups in an endeavour to address concerns and to start to rebuild trust.

7. Strategy
The events in the Gulf of Mexico led the board to undertake a review of strategy. Led by the group chief executive and his team, the board attempted to address the key challenge of how to regain shareholder value and address core issues, including:

- Simplification (how to focus the company's operations across a wide geography).
- How the company could manage risk more tightly.
- How BP could focus on its core capabilities.
- The opportunity to reset the company's portfolio.

The board held three away-day discussions on strategy during the year; these were robust and explored a wide range of strategic options. The outcome of these deliberations on strategy was presented to the investor community on 1 February 2011. For detail of our strategy presentation, see Our strategy on page 19.

Management and organizational changes

In late July the board and Tony Hayward agreed that he would step down as group chief executive on 1 October, to be succeeded by Bob Dudley, and would leave the company and the board at the end of November. This decision was made following a series of extensive discussions by the board as to what strategic focus BP as a company should have in the longer term and what leadership was best equipped to embark on this next phase.

Through the nomination committee, the board engaged external advisers who identified an external candidate and existing executive director, Bob Dudley, for the position of group chief executive. After interviews and detailed consideration it was concluded that Bob Dudley had the strong industry, operational and geopolitical experience required for the role and, as a result, was appointed as group chief executive. Bob Dudley has handed over his duties as head of the Gulf Coast Restoration Organization to Lamar McKay, president and chairman of BP America.

In September the board agreed with Andy Inglis, executive director and head of the upstream business, that in order to facilitate the new organizational structure, he would relinquish his role and step down from the board at the end of October – leaving the company at the end of 2010. The executive vice presidents heading the three new upstream divisions report directly to Bob Dudley and the board decided that on the basis of this reporting line it would not replace Andy Inglis's position as an upstream executive director on the board. From 1 November 2010, executive director membership of the board has been reduced to three.

Other board activities in 2010

At the start of each year the board plans and agrees a forward agenda for its work and that of its committees so that it can balance its workload and achieve its tasks (namely, strategy, risk and the oversight of the company's performance and operation of the system of delegation). Our forward-planning process allows for urgent issues to be accommodated – and following the Gulf of Mexico incident, the focus of the board's activities shifted in response to the challenges and activities taking place.

This process also gives the board the ability to deal with pressing and ongoing business. These included a review of opportunities in Russia, the global economic outlook, the 2011 annual plan, group risks, Alternative Energy and BP's HR function. The board considered the group's statutory reports and the broader aspects of corporate reporting, received regular updates on the group's financial outlook and discussed the company's financial results.

The independent expert appointed to provide an objective assessment of the BP US Refineries Independent Safety Review Panel (Duane Wilson) made his annual presentation to the board. Further details on his activities are outlined in the report of the SEEAC below.

The board and risk management

One of the tasks of the BP board is to ensure that the company is run effectively and that the material risks to the group are identified, understood and that the systems of risk management and internal control are in place to manage these risks.

Integral components in discharging this task are:

- Regular reviews of the material risks to the group and their recognition in the company's annual plan.
- Ensuring through the board's system of delegation that its approach to risk is adopted by the group chief executive (GCE) and that decisions are taken in accordance with this system.
- Maintaining through the board and its committees clear oversight of the system of internal control and risk management established and maintained by the group chief executive.

The board's monitoring of risk

Each year the board reviews the key group risks and how they are managed as part of the annual group plan. The board decides which risks will be monitored by the board and which will be allocated to the committees with appropriate reporting to the board. A high-level work programme for the board and its committees is set on the basis of a forward agenda that reflects the board's core tasks and the key group risks.

Geopolitical and reputational risks are considered by the board. Reports are received from the committees to whom specific risk oversight has been allocated. The audit committee monitors the management of financial risk while the SEEAC monitors the management of non-financial risk. In addition, the Gulf of Mexico committee was formed in 2010 specifically to oversee the activities of the Gulf Coast Restoration Organization.

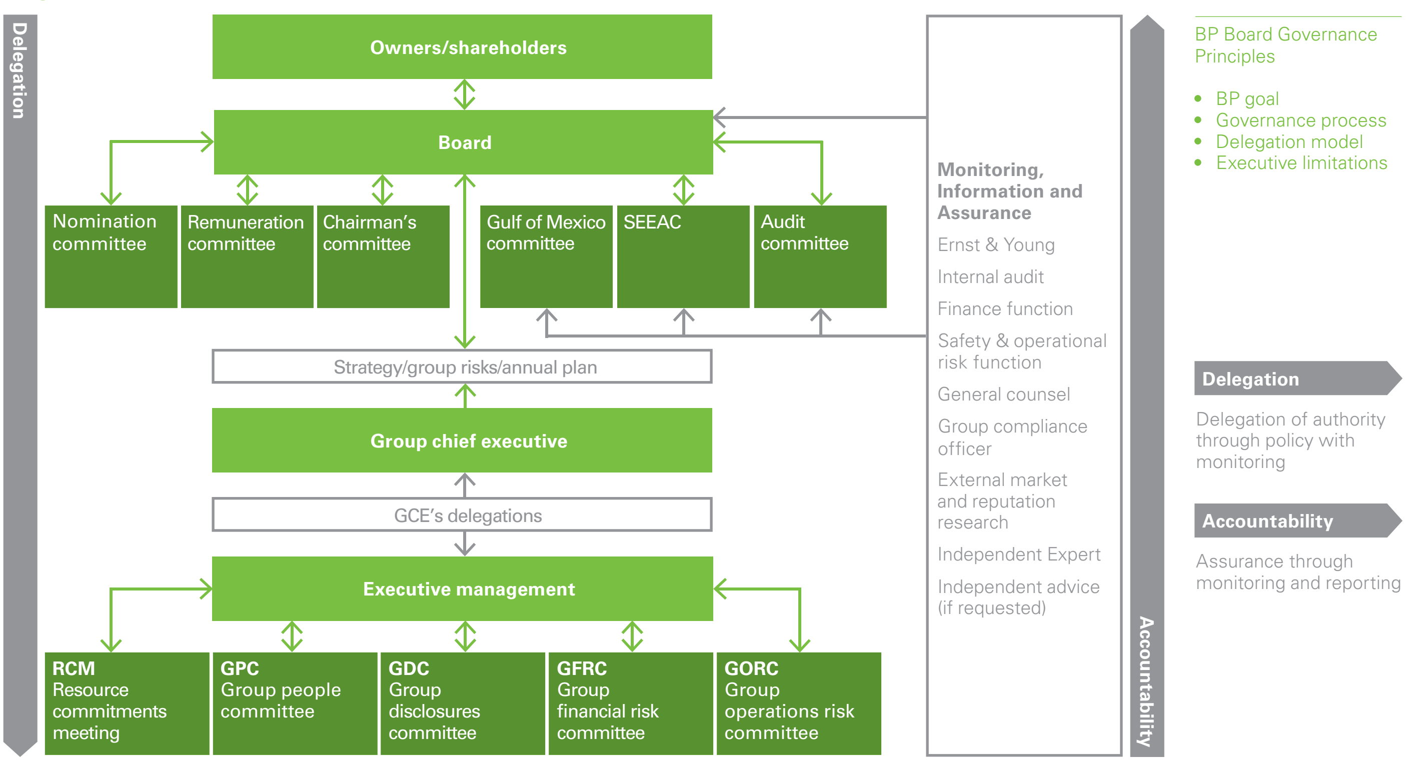
Under BP's governance framework, authority for the executive management of BP is delegated to the group chief executive (subject to defined limits and monitoring). Executive management has responsibility for the delivery of projects (for example, the development of upstream projects is managed by a specialist group known as the Global Projects Organization).

The board's committees review the reporting by business and function, which includes the safety and environmental performance of projects. The committees receive regular reports from the group compliance and ethics, the internal audit and the safety and operational risk functions. The audit reports highlight the key findings and management actions arising from that work.

As part of the board's risk oversight activities, the audit committee and SEEAC hold an annual joint meeting to assist the board in assessing the effectiveness of the company's internal control and risk management systems.

BP's general auditor (head of the internal audit function) reports on audit work on risk management activities across the group and attends meetings of both the audit committee and SEEAC. The general auditor and the group compliance and ethics officer have direct access to the chairs of both committees. Meetings are held both with and without the presence of management.

BP governance framework



BP's system of internal control

The board is responsible for maintaining a sound system of internal control and delegates the establishment and maintenance of this system to the group chief executive. Management systems, organizational structures, processes, standards and behaviours are all components of BP's system of internal control.

Management of risk and operational performance is one of the three elements of BP's system of internal control. Businesses identify, prioritize, manage, monitor and improve the management of risks on a day-to-day basis to equip them to deal with hazards and uncertainties. The key risks, and how they are managed, are reported up through the line in a consistent manner to enable business planning, appropriate intervention and ultimately board oversight.

This enables the identification of the most important risk management activities. Audit processes are designed to consider whether selected risk management activities are designed and operating effectively.

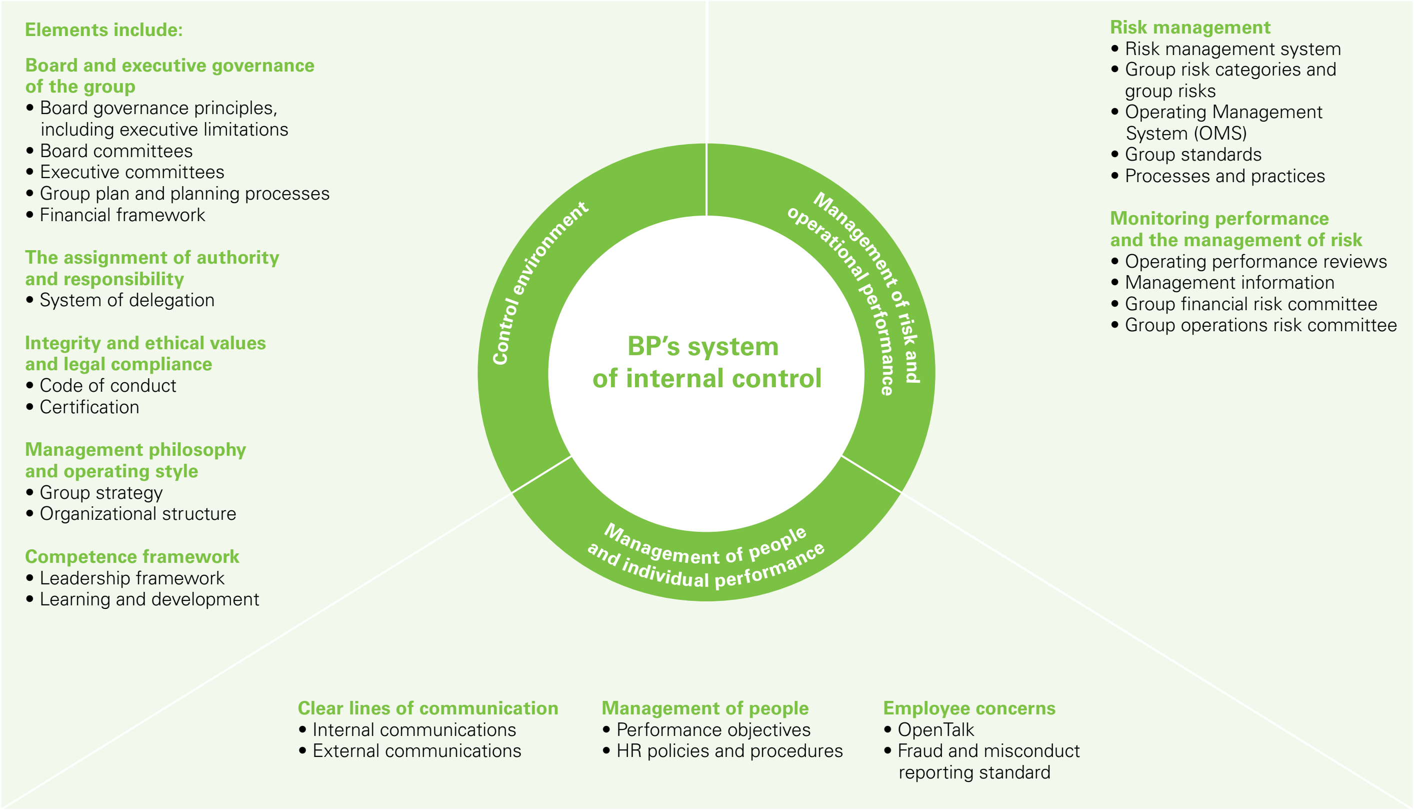
Investments and operations

BP's operations and investments are conducted and reported in accordance with, and associated risks are thereby managed through, relevant standards and processes. These range from OMS (which is the structured set of processes designed to deliver safe, responsible and reliable operating activity), to group standards (which set out processes for major areas such as fraud and misconduct reporting), through to detailed administrative instructions.

BP has an established investment approvals and assurance process which provides a set of policies and procedures for all its investment decisions, including BP's decisions to invest in partner-operated or joint venture activities. These include a consistent set of economic assumptions used to evaluate projects (including oil and carbon pricing), together with an assessment of financial and non-financial risk, economic return and other factors that may be relevant. Potential investments must also be screened against BP's group-defined practice on environmental and social matters.

Material commitments (including those involving long-term commitments or which potentially involve reputational issues) are reviewed and endorsed by an executive-level committee – the Resource Commitments Meeting (RCM). The board is kept updated of the RCM activities through the circulation of RCM minutes in advance of each board meeting. The board annually considers a review of capital projects and their performance against investment criteria.

BP's system of internal control



Executive team and committees

The group chief executive and his senior team are supported by executive-level sub-committees, that are responsible for and monitor specific group risks: the group operations risk committee (GORC), the group financial risk committee (GFRC), the group people committee (GPC), the resources commitments meeting (RCM) and the group disclosure committee (GDC). These committees provide input and data to the risk management process by the executive, as do the group compliance and ethics function, the safety and operational risk audit function and the group's financial control team.

The GCE conducts regular performance reviews with the businesses and key functions to monitor performance and the management of risk and to intervene if necessary. People management is based on annual and long-term objectives, through which employees are directed towards delivering specific elements of the group plan within agreed boundaries.

BP has an annual certification process in which team leaders are asked to discuss with their teams and then submit a certificate regarding their and their team's understanding of and adherence to BP's code of conduct and the reporting of any breaches.

Board and committee attendance

	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
Carl-Henric Svanberg	25	25									8[c]	8	8[c]	8
Sir William Castell	25	24			9[c]	9			9	6	8	8	8	8
Paul Anderson	23	21			8	8			9	9			7	7
Frank 'Skip' Bowman	2	2			1	1							1	1
Antony Burgmans	25	19			9	8	6	6					8	7
Cynthia Carroll	25	19			9	7							8	6
George David	25	21	15	15			6	6	9	9			8	7
Erroll Davis, Jr	4	3	5	5	3	2							1	1
Ian Davis	22	21	10	9			4	3	9[c]	9	4	1	7	7
Douglas Flint	25	25	15[c]	14							6	6	8	7
DeAnne Julius	25	23					6[c]	6			8	8	8	8
Brendan Nelson	2	2	1	1										
Sir Ian Prosser	4	3	5	5			2	1			3	3	1	1
Executive directors:														
Bob Dudley	25	25												
Iain Conn	25	24												
Byron Grote	25	25												
Tony Hayward	24	23												
Andy Inglis	23	23												

[a] Total number of meetings the director was eligible to attend.
[b] Total number of meetings the director did attend.
[c] Committee chairman.

Board meetings and attendance

As part of its forward agenda, the board normally plans to hold one of its meetings at the company's offices in Washington and at least one meeting at or near one of the company's operational locations (enabling the opportunity for board site visits). In 2010, the board held one meeting in Washington but due to the increased number of meetings and associated constraints on time, held the remainder of its meetings in London or via teleconference. A total of 25 board meetings were held during the year.

Membership of the BP plc board

Throughout 2010 Carl-Henric Svanberg has led the board as chairman. Sir William Castell was appointed senior independent director in April 2010 following the retirement of Sir Ian Prosser at the AGM.

Neither the chairman nor the senior independent director is 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.

During the year, there were a number of changes to the board:

- Sir Ian Prosser and Erroll Davis, Jr retired from the board at the AGM in April 2010.
- Two non-executive directors were appointed prior to the 2010 AGM: Paul Anderson in February 2010 and Ian Davis in April 2010.
- Dr Tony Hayward stepped down as group chief executive on 1 October 2010 and left the board on 30 November 2010.
- Andy Inglis stepped down as chief executive, Exploration and Production and as an executive director of the board at the end of October 2010.
- Two further non-executive directors were appointed on 8 November 2010, Frank 'Skip' Bowman and Brendan Nelson.

In addition, Phuthuma Nhleko joined the board as a non-executive director on 1 February 2011.

At the AGM in April 2011, Dr DeAnne Julius (chair of the remuneration committee) and Douglas Flint (chair of the audit committee) will retire from the board. Their committee chair roles will be assumed by Antony Burgmans (remuneration) and Brendan Nelson (audit).

The board is composed of the chairman, 11 non-executive directors and three executive directors. The board governance principles state that the number of directors should not normally exceed 16. The board has decided that it will maintain the current level of executive director membership on the board, with reporting of exploration and production activities that were previously represented by Andy Inglis now being undertaken by Bob Dudley.

The chairman's committee reviews the systems for senior executive development and determines the succession plan for the group chief executive, executive directors and other senior members of executive management.

The nomination committee identifies, evaluates and recommends candidates for appointment or reappointment as non-executive directors and keeps under review the mix of knowledge, skills and experience of the board necessary to ensure an orderly succession. Given the size of the BP board and the need to deliver a steady refreshment of board appointments, the committee has developed a longer term 'pipeline' of potential non-executive talent on which it expects to draw as the need for new appointments arises.

Director appointment, tenure and elections

The chairman and non-executive directors of BP serve on the basis of letters of appointment. Non-executives ordinarily retire at the AGM following their 70th birthday. Executive directors have service contracts with the company, which are expressed to retire at a normal retirement age of 60 (subject to age discrimination).

Details of all payments to directors appear in the directors' remuneration report.

BP does not place a term limit on a director's service as the company proposes all its directors for annual re-election by shareholders (a practice we have followed since 2004). New board members are subject to election by shareholders at the first AGM following their appointment. The chairman and the nomination committee keep the tenure of directors under consideration as part of a continual review of board skills and balance.

Indemnity and insurance

In accordance with BP's Articles of Association, directors are granted an indemnity from the company in respect of liabilities incurred as a result of their office, to the extent permitted by law. In respect of those liabilities for which directors may not be indemnified, the company maintained a directors' and officers' liability insurance policy throughout 2010. During the year, a review of the terms and scope of the policy was undertaken. The policy has been renewed for 2011. Although their defence costs may be met, neither the company's indemnity nor insurance provides cover in the event that the director is proved to have acted fraudulently or dishonestly. UK company law permits the company to advance costs to directors for their defence in investigations or legal actions.

Time commitment and outside appointments for directors

Letters of appointment to the BP board do not set out fixed time commitments for board duties as the company believes that the time required by directors may change depending on business events (as was demonstrated during 2010). Membership of the board represents a significant time commitment and it is expected that directors will allocate sufficient time to the company to perform their duties effectively. The nomination committee keeps this under regular review.

BP permits executive directors to take up one external board appointment, subject to the agreement of the chairman and 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.

Non-executive directors may serve on a number of outside boards, provided they continue to demonstrate their commitment to discharge their duties to BP effectively. The nomination committee keeps under review the nature of 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 directors' other commitments are inconsistent with those required by BP.

Board independence

The governance principles require our non-executive directors to be independent in character and judgement and free from any business or other relationship that could materially interfere with the exercise of their judgement. The board has determined that those non-executive directors who served during 2010 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.

Board support and external advice

Support to the board and its committees is provided through the company secretary's office, which reports to the chairman. Within BP, the company secretary has no executive function and his appointment is determined by the nomination committee and his remuneration determined by the remuneration committee.

Under the BP board governance principles, any director is entitled to obtain independent, professional advice relating their own responsibilities and the affairs of BP. Directors are also expected to obtain independent advice where there is consideration of any matter in which a director may have an interest that could conflict with the interests of the company.

Induction and board learning

All directors receive a full induction programme when they join the board, including a session on BP's system of governance and the legal duties of directors of a listed company. Non-executive directors receive a wider programme that covers the business of the group and is tailored according to a director's own background and the board committees on which they will serve. During the year we undertook induction programmes for our new non-executive directors, which in some cases are continuing. The programme covers BP's business, an overview of its functions, the company's strategic approach and financial framework and the group's approach to risk management. Each non-executive director had a separate induction session on the board committee(s) of which they are a member and all had a private session with the company's external auditor. In 2010 we also continued the induction programme for the chairman – including visits to BP operations around the world.

The events of the year resulted in the board concentrating on issues in the upstream business and in the US, with planned visits to other locations such as a joint venture petrochemicals plant in Asia and to BP's fuel and lubricants technology site, being postponed. The SEEAC visited the Texas City refinery in February. There is a full programme of visits for 2011. Non-executive directors are expected to participate in at least one site visit per year.

The programme of board learning events was amended following events in April to include detailed briefings on aspects of deepwater drilling and technology options for killing the well. The board also received verbal and written updates on legal and regulatory issues.

Board evaluation

BP conducts an annual evaluation of the performance and effectiveness of the board and its committees. The evaluation of individual directors is undertaken by the chairman, with the chairman's own performance evaluated by the chairman's committee (led by the senior independent director).

By building on the results of the previous year's evaluation, the board tries to achieve a continuous cycle of evaluation, targeted actions arising from the review and performance improvement. Actions taken by the board during the year in response to the outcome of the 2009 review included the scheduling of more informal sessions outside board meetings to maximize the utility of the time available for the board and an active planning of committee and board succession to ensure appropriate cross membership between related committees.

With the evaluation of the board's performance being largely dominated by events in the Gulf of Mexico, it was felt that the 2010 evaluation needed to be undertaken in as robust and rigorous a manner as possible. The board decided to appoint an external facilitator (a different individual to the external facilitator who undertook the 2009 evaluation) to work with the company to undertake this year's review.

The evaluation of the board was undertaken through one-on-one interviews with each board member (with the exception of Frank Bowman and Brendan Nelson who joined the board late in the year). Evaluation of the board committees was managed through the use of online questionnaires.

The outcome of these evaluations is reported in the work of committees at the end of this report.

The results of this evaluation work were presented in meetings of the board and each of its committees in January 2011 during which there were discussions of the lessons learned as the board and its committees performed their responsibilities during the months of intense and unprecedented operational, reputational and legal challenges to BP following the 20 April 2010 incident.

The evaluation highlighted a number of strengths and identified the following areas for further development in the coming year:

- Conduct additional site visits and participate in detailed briefings on significant operating activities of the company, including upstream businesses.
- Review and, if necessary, revise the company's board governance principles.
- Clarify the board's role in the crisis planning process.
- Build on the strong working relationships within the board to continue and enhance good communication and cohesion.
- Co-ordinate and clarify external and stakeholder communications.
- Meet more often with senior managers below the level of executive directors as part of the board's management succession oversight function.
- Remain involved in strategic planning and related risk analyses.

Communication

Shareholder engagement

Given the events of last year, communication with our shareholders has been particularly important. In addition to contact with our large and institutional investors, we have welcomed the communication we have had with our private shareholders – with many letters and emails coming through to the chairman, to the group chief executive and to other parts of the company. While these represent a diverse range of viewpoints, both positive and negative about the company, they have also enabled the board to be informed about the wider shareholder perception of events and the company's reaction to them.

During the incident and beyond, we attempted to keep our shareholders and the wider market informed of events and progress through various channels – including press releases, webcasts, teleconferences and meetings. The group chief executive, executive directors and senior management engaged with shareholders across a broad range of issues.

In parallel, the chairman met with investors in the US and UK on a one-to-one and group basis, as did other senior, non-executive directors. The views and reactions discussed with the company in these webinars and meetings provided valuable feedback and input into the board's thinking over the period of the crisis and our deliberations on strategy.

The company maintains a programme of engagement with a range of shareholders on issues relating to the group. Presentations given by the group to the investment community are available to download from the 'Investors' section of our website.

We held our annual meeting with our largest investors and the chairman and chairs of our main board committees in March 2010. Topics discussed at this session included the work of the board and its committees over the year, key challenges and the company's position on the shareholder resolution on oil sands. We find this meeting a useful way for investors to hear about the work of our committees and for our non-executive directors to engage in dialogue with investors. It is intended that a similar meeting will be held in March 2011.

The board gains independent feedback on the views of our institutional investors on the company, its performance and its investor relations programme through an annual investor audit which is undertaken by external advisors.

AGM

We have strong participation at our AGM, with attendance usually exceeding a thousand people. With the size and geographic diversity of our shareholder base, we try to make the AGM accessible through the use of webcasting and advance voting – either online, by post or telephone. Votes on all matters (except procedural issues) are taken by a poll at our AGM – meaning that every vote cast, whether by proxy or made in person, is counted.

The chairs of the board committees and the chairman were present during the 2010 AGM. Board members met shareholders on an informal basis after the main business of the meeting.

Average voting levels at the 2010 AGM decreased slightly to 60%, compared to 61% in 2009. However, the number of webcast downloads for the 2010 AGM increased over 2009 levels. We make our webcast, speeches and presentations from the AGM available on the BP website after the event, together with the outcome of voting on the resolutions.

International advisory board

In 2009, BP formed an international advisory board (IAB) whose purpose is to advise the chairman, chief executive and board of BP p.l.c. on strategic and geopolitical issues relating to the long-term development of the group. The IAB advises on:

- How global and regional trends in the areas of economics, politics and business might affect the development of BP's business in the long term.
- How the international business community and individual governments perceive BP's plans and programmes of activities.

The IAB is chaired by our previous chairman, Peter Sutherland. Other members of the BP IAB are Kofi Annan, Josh Bolten, Dr Ernesto Zedillo, President Romano Prodi and Lord Patten of Barnes. Dr Javier Solana will join the IAB in 2011. Bob Dudley and Carl-Henric Svanberg attend the IAB meetings.

The IAB will normally meet in person twice a year, but members also provide advice and counsel to the chairman, the group chief executive and the board of BP p.l.c. when needed (including during events in the Gulf of Mexico). In 2010, the IAB met once (as one meeting was cancelled due to travel disruption following the volcanic ash cloud).

Committee Reports

Audit committee report

The audit committee's agenda in 2010, like that of the board, was significantly shaped by the tragic events in the Gulf of Mexico. These required the committee to focus additional attention and go in greater depth into matters concerning BP's response to the incident, in particular in this committee regarding the financial consequences. Considerable time and effort was spent reviewing and challenging BP's assessment of the likely cost of its immediate and longer-term financial responsibilities and the adequacy of disclosure both around these financial consequences and the related contingencies which were unable to be expressed financially at each reporting date. We also critically reviewed the control aspects surrounding the deployment of BP's financial and physical resources in responding to the incident and, at the height of the crisis, critically examined the group's liquidity and funding position.

While all of these matters were also covered by the board in full session, and many were independently covered from a different perspective by the newly formed Gulf of Mexico committee, the audit committee was extensively engaged in the detailed review of the financial reporting aspects of the incident and the company's response. It was also important that the committee maintained its regular oversight with respect to internal controls and financial integrity across the remainder of the company's activities and consequentially, as reported below, we held a number of extra meetings to ensure our originally planned agenda could be fulfilled in addition to the heightened workload arising from the Gulf of Mexico incident.

I regret that this will be both my first and last audit committee report, as I am stepping down from the board following my appointment as chairman of HSBC Holdings plc. This has been a very challenging year and I want to express my sincere thanks to the members of the audit committee and those who have contributed to satisfying our enquiries for having worked together so effectively. I am certain this will continue under Brendan Nelson's leadership.

Douglas Flint
Chair of the Audit Committee

Committee members

Douglas Flint – committee chair (from 15 April 2010)
George David
Ian Davis (appointed 2 April 2010)
Brendan Nelson (appointed 8 November 2010)
Phuthuma Nhleko (appointed 1 February 2011)

Members who left during the year:

Sir Ian Prosser – previously chair of the committee (retired 15 April 2010)
Erroll Davis, Jr (retired 15 April 2010)

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.

Douglas Flint is group chairman (formerly chief financial officer and executive director, risk and regulation) of HSBC Holdings plc and a former member of the Accounting Standards Board and the Standards Advisory Council of the International Accounting Standards Board. The board is satisfied that he is the audit committee member with recent and relevant financial experience as outlined in the UK Corporate Governance Code and the June 2008 Combined Code.

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 Flint may be regarded as an audit committee financial expert as defined in Item 16A of Form 20-F.

Douglas Flint became chair of the audit committee upon the retirement of Sir Ian Prosser from the board in April 2010. As noted above, following his appointment as chairman of HSBC Holdings plc, he will retire from the BP board at the AGM in April 2011. Brendan Nelson will become chair of the audit committee from this time. Upon Mr Flint's retirement, Mr Nelson will become the audit committee financial expert as defined in Item 16A of Form 20-F.

The board considered Mr Nelson's extensive skills and experience made him the ideal candidate to succeed Douglas Flint. Mr Nelson served as a member of the UK Board of KPMG from 2000 to 2006 following which he was appointed vice chairman until his retirement in 2010. In KPMG International he held a number of senior positions including global chairman, banking and global chairman, financial services. Subsequent to retiring from KPMG he was appointed a non-executive director of The Royal Bank of Scotland Group plc where he is chairman of the Group Audit Committee.

Committee role and structure

The role and responsibilities of the audit committee are set out in the Appendix of BP's board governance principles and available on our website. We keep these under review and test their effectiveness in our annual evaluation of the audit committee.

The committee met 15 times in 2010: this was a significant increase over the previous year with additional time being needed to cover the financial and control aspects of the incident in the Gulf of Mexico. As it does each year, the committee held a joint meeting with the safety, ethics and environment assurance committee (SEEAC) in January to review the general auditor's report on internal control and risk management systems for 2010.

Each meeting of the committee is attended by the group chief financial officer, the deputy 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.

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 2010, external specialist legal advice was provided to the committee by Sullivan & Cromwell LLP, Freshfields Bruckhaus Deringer LLP and Kirkland and Ellis LLP and financial advice was provided by KPMG and Morgan Stanley. 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 2010 evaluation indicated that members recognized the openness and transparent nature of the materials and presentations provided by management.

Training and visits

Responding to events in the Gulf of Mexico, there was increased focus on accounting policy applicable to the circumstances arising from the incident and the committee received briefings on the relevant accounting policy applications, particularly provisioning and related disclosure. Other technical updates the committee received included developments in financial reporting, in oil and gas reserves disclosure and in relation to taxation changes.

Induction programmes tailored around their roles on the audit committee were prepared for the two new members who joined during the year. These included sessions on tax, treasury, our trading operations, accounting, financial authorities and the structure of BP's finance function. Both had separate, private sessions with the external and internal auditors. During 2011, we will undertake an audit committee induction programme for Phuthuma Nhleko.

The audit committee held one of its regular meetings at BP's UK trading operations and combined this with a visit to the trading floors which provided the opportunity to meet and put questions to employees. Members of the committee also visited the Gulf of Mexico.

Committee activities

Gulf of Mexico

The committee considered critically the financial reporting arising from the incident in the Gulf of Mexico, including the impact on the company's liquidity, provisions and contingencies, risk factor disclosure, the associated accounting treatment arising from events and the approval of market announcements. It has also received reports from the general auditor and the group controller on the status of financial controls in the new Gulf Coast Restoration Organization.

Financial reporting

The group's quarterly financial reports, the 2009 Annual Report and Accounts, the Annual Review and the 20-F 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 (such as for the Gulf of Mexico spill response, litigation, environmental remediation and decommissioning), contingencies and impairment testing. Further details on impairment reviews are included in the Financial statements – Note 5 on page 164 and Note 11 on page 173. Each year, the committee also reviews the company's disclosures relating to oil and gas reserves.

Monitoring business risk

The committee operates a regular cycle of review of risk, control and assurance from BP's businesses and supporting functions. During the year, the committee undertook a controls review of the US Midwest fuels value chain and received an update on risk, governance and controls activities relating to TNK-BP. The latter included the reports on the system of internal control, TNK-BP's quarterly financial reporting procedures and certain tax matters. Functional reviews were held of information technology and services, procurement, integrated supply and trading and BP's business service centres.

Other areas of review by the committee included the central case planning assumptions for oil and gas prices and refining margins that are utilized in the group's investment appraisal process as well as impairment reviews, a review of the delivery of major projects and the risk management and investment strategy relating to pensions and retirement benefits.

During the year the chief financial officer reported on the work of the group financial risk committee – this is an executive-level committee that provides assurance to the executive on the management of BP's financial risk.

Internal control, audit and risk management

The forward agenda for the audit committee contains standing items on internal control – these include the quarterly internal audit findings report, an evaluation of internal controls, and an annual assessment of BP's enterprise level controls.

An important input into the board's review of the company's system of risk management and internal control 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 includes information on the results of audit work undertaken by the safety and operational risk audit team and reviews by the group's financial control team.

External auditors

In 2010, the committee held two scheduled meetings with the external auditors without management being present. These sessions, without the presence of executive management, offered an opportunity for direct feedback and dialogue between both the committee and the auditors. In addition, the chair of the audit committee meets privately with the external auditors before each audit committee.

Performance of the external auditors is evaluated by the audit committee each year, with particular emphasis on their independence, objectivity and viability. 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, for example this year in impairment testing and liquidity reviews.

We maintain auditor independence through limiting non-audit services to tax and audit-related work that fall within defined categories. 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 14.5% was for non-audit work (*see Financial statements – Note 17 on page 176*). After four years of reductions, the fees and services provided by Ernst & Young for audit and non-audit work increased slightly in 2010 due to additional work required consequent upon the Gulf of Mexico incident.

The audit committee considers both the fee structure and the audit engagement terms and monitors progress during the year. It has recommended to the board that the reappointment of Ernst & Young as the company's external auditors be proposed to shareholders at the 2011 AGM.

Internal audit

Progress of internal audit against the annual schedule of audits is monitored on a quarterly basis, and the committee looks at the key findings and tracking of any material actions that are overdue or have been rescheduled. A programme of work by internal audit is proposed each year for the committee's approval and in reviewing this, the committee looks at whether it believes key risks facing the company have been appropriately addressed. The programme in 2010 was supplemented considerably by additional work related to risks and controls consequent upon the Gulf of Mexico incident. The programme for 2011 also reflects an enhanced risk environment and 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. He also meets as necessary with the committee chair between meetings.

Each year the committee reviews internal audit's staff resources in both number and expertise to seek assurance that they are sufficient to fulfil its role. The committee was also satisfied that internal audit had appropriate access to information and that management was committed in the provision of that information. The committee also seeks the views of the external auditors on the effectiveness and quality of internal audit.

Other activities

Through quarterly updates by the group compliance and ethics officer and general auditor, the committee monitors fraud, misconduct and non-compliance with the BP code of conduct and remedial actions undertaken as a result. The annual certification report which is signed by the group chief executive is also reviewed by the committee.

Financial issues and concerns that have been flagged through the company's employee concerns programme OpenTalk, are reviewed by the committee – which tracks trends in both the case type and time taken to close out queries and reports.

Committee evaluation

The audit committee examines its performance and effectiveness on an annual basis. In 2010, the committee used an internally designed questionnaire administered by external consultants. It looked at key areas, including the clarity of its role and responsibilities, the balance of skills among its members and the effectiveness of reporting its work to the board. The review concluded inter alia that it had been effective and was satisfied with the extent of training it received but would seek to make time for more. Overall the committee considered it had the right composition in terms of expertise and resource to undertake its activities effectively.

Safety, ethics and environment assurance committee report

The tragic incident in the Gulf of Mexico, and the extensive activities that were undertaken in response, required and received the full attention of the whole board. It was agreed, early on, that SEEAC should focus its efforts with respect to the incident upon monitoring the pace and effectiveness of the company's group wide response to the recommendations of BP's Investigation Report (further information on the report is on page 91). The Gulf of Mexico committee, of which I am a member, was established as a separate committee to monitor the ongoing restoration activities in the Gulf of Mexico. This enabled the SEEAC to retain its focus on the key non-financial risks within its previously planned agenda for the year, as you will read in the report below.

Nonetheless, I and my SEEAC colleagues made a number of visits to the Gulf of Mexico to gain first-hand assurance of the activities to cap the Macondo well and remediate the impact of the oil spill. I believe the combined response of all those involved was outstanding but we all remained deeply saddened that the incident had occurred and that 11 lives had been lost. Our forward focus on the recommendations of BP's Investigation Report is intended to provide board-level assurance that such an incident could not recur.

I believe the committee is well resourced to fulfil its tasks and this has been further strengthened by the recent appointment of Frank 'Skip' Bowman to the board. Frank Bowman had served on the BP US Refineries Independent Safety Review Panel and brings to SEEAC his extensive safety experience from his time as head of the US Nuclear Navy.

Sir William Castell
Chair of the Safety Ethics and Environment Assurance Committee

Committee members

Sir William Castell – committee chair
Paul Anderson (appointed 2 February 2010)
Frank 'Skip' Bowman (appointed 8 November 2010)
Antony Burgmans
Cynthia Carroll

Members who left during the year:

Erroll Davis, Jr (retired 15 April 2010)

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 full list of the tasks and responsibilities of the SEEAC is available on our website

The committee met nine times in 2010. The increased number of meetings held in 2010 primarily reflected the committee's work in reviewing the company's actions in response to BP's Investigation Report. These meetings also provided input for the board's review of that report and established an ongoing monitoring process for SEEAC. One meeting early each year is held jointly with the audit committee to review BP's internal control and risk management systems and to discuss the forward programme of the internal audit function. In January 2011 this meeting was extended to enhance the focus on the integrated approach of audit work including that of the safety and operational risk audit function.

In addition to the committee membership, each SEEAC meeting is attended by the group chief executive, the executive vice president for safety and operational risk (Mark Bly), the general auditor (head of internal audit) and the lead partner from our external auditors. Four times during the year the committee held private sessions for the committee members only (without the presence of executive management) after the main business of the meeting, to discuss any issues arising or matters on the minds of the committee membership. The committee also held a private session with the group compliance and ethics officer. Between meetings, discussions involving the committee chair and secretary, the external auditor's lead partner, the general auditor and executive management occur as appropriate.

Committee processes

Information and advice

Information to the committee comes from both inside and outside the company. The business segments and regional organizations provide direct reports to the committee but there is also cross-business information on a group wide level from our functions, including the safety and operations risk function, internal audit, group compliance and ethics, group legal and HR. During the year, the main external input into the committee has been from Mr 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. During the year SEEAC members have received briefings from external retained counsel, primarily Kirkland and Ellis LLP.

Training and visits

The committee visited the Texas City refinery in March 2010 to see the progress made against the BP US Refineries Independent Safety Review Panel report. This followed up on their observations from their previous visit in September 2007 and the committee chairman's visit in April 2008. The committee was joined by four other directors and received an extensive update on process safety progress since the 2005 incident. Their observations were consistent with the reports received from the Independent Expert.

Planned visits to other sites during the year were cancelled to enable the committee to reorganize its schedule to focus upon issues arising from the Macondo incident. Each member of SEEAC visited operations in the Gulf of Mexico at least once during the year, with the SEEAC chair making a number of visits to the region and its command centres to observe first hand BP's response efforts and the progress of attempts to kill the well and mitigate the effects of the oil spill. A separate technical briefing was provided to the committee (and other board members) on exploration drilling by the relevant functional managers.

Induction programmes for the two new members of SEEAC were organized during the year and, in the case of Frank Bowman, is still ongoing in 2011.

Committee activities

Safety and operations

Discussion on personal and process safety and operational risk and performance forms a large part of the committee's agenda. The committee receives regular reports from the safety and operational risk function, including the quarterly reports prepared for executive management on the group's HSE performance and operational integrity. In 2010, excluding meeting time specifically addressing the Gulf of Mexico incident, the SEEAC utilized 42% of its agenda on safety and operational risk matters including process safety. This small reduction, compared with the 51% recorded in 2009, reflected the committee's commitment to gaining assurance in other areas of its remit including crisis and continuity management, regulatory compliance, environmental monitoring, security and product quality risk.

The committee also examined quarterly audit reports from BP's internal audit and safety and operations 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. Safety and environmental performance of projects was included within the reporting by segment and performance unit.

Activities from the executive-level group operations risk committee (GORC) are reported to the SEEAC by its chair at each meeting. The SEEAC received regular updates on the company's interaction with regulatory agencies, and the committee chairman received a briefing from legal counsel on the OSHA citations in respect of Texas City.

Gulf of Mexico

The committee examined BP's Investigation Report and its recommendations before providing input for the board's review of the report prior to its publication. The committee noted that the BP investigation team had conducted its investigation independently from the teams managing regular operations and the ongoing response to the incident. The committee also reviewed, and reported to the board, management's early actions in response to lessons learned. The action plan that has been developed from the 26 recommendations of BP's Investigation Report will be tracked in its implementation by the committee, against agreed timelines and milestones. In monitoring progress against BP's Investigation Report's recommendations, the safety and operations audit function will provide SEEAC with quarterly tracking reports and reporting updates will be made by upstream's executive vice president Developments and by the group chief executive. The committee is also monitoring other, non-BP investigations to determine how the conclusions from these relate to the action plan and activities arising from BP's Investigation Report.

The committee will also keep under review the implementation of the new safety and operational risk organizational structure and the resourcing it requires to support the decision and intervention rights it has in all aspects of the group's technical and operational activities, including key investment decisions.

Independent Expert

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 Review Panel (aimed at improving process safety performance at BP's five US refineries).

During the year, Mr Wilson kept the committee updated on his workplan and the outcome of his visits to each of BP's five US refining sites. In March, he published his third annual report that assessed BP's progress against the 10 panel recommendations. In his report, which was published in full on BP's website, he concluded that the company had made significant improvements in response to all 10 recommendations but that much work remained to be done. Mr Wilson's fourth report will be published in full and available on our website in March 2011 and a summary of the third and fourth reports is provided in Safety on page 70.

Regional and functional reports

The committee receives a report each year on the progress made in HSE at TNK-BP, noting however that formal oversight of the joint venture's HSE performance and policies is exercised by TNK-BP's own HSE committee. It was reported that TNK-BP continued to make significant progress in addressing the main safety, ethical and environmental challenges confronting it since its creation in 2003. Nonetheless, significant areas remain for improvement and the committee will continue to monitor progress regularly.

With joint venture operations in Iraq getting under way, the committee sought and received an update on the risks and management of security in Iraq.

Other topics

During the year, the committee examined the company's crisis response and continuity management plans. It also reviewed the risk identification and company's proposed mitigations relating to hydrocarbon product quality.

Developments in the measurement of greenhouse gas emissions were considered by the committee in the context of regulatory compliance and as part of the company's tracking and disclosure processes.

Committee evaluation

For its 2010 evaluation, the SEEAC used a questionnaire administered by external consultants to examine the committee's performance and effectiveness. The review looked at different areas, including the balance of skills and experience among its membership, quality and timeliness of information the committee receives, the level of challenge between committee members and management and how well the committee communicates its activities and findings to the board.

The committee concluded that it should endeavour to increase its site visits and training, noting that the particular circumstances of 2010 had reduced the opportunity for such activities except in relation to the Gulf of Mexico. It also believed that it could improve the prioritization of its agendas through more focused pre-read material. The committee considered its current membership provided a well-balanced resource and also noted the valuable contribution made by the Independent Expert.

Gulf of Mexico committee report

Following the accident in the Gulf of Mexico a separate business organization was set up to manage the group's long-term response to the incident – the Gulf Coast Restoration Organization (GCRO). The board subsequently created the Gulf of Mexico committee in recognition of the scale of the long-term response and to oversee the activities of the GCRO, thereby freeing up more of the board's time to devote sufficient attention to the oversight and strategic direction of the group as a whole.

The committee has met with leaders and management of the GCRO on a frequent basis in 2010, in order to oversee their running of the organization and to cover each of the committees tasks listed below, with a particular focus on legal and claims-related matters.

I believe the committee has taken a rigorous approach to its work – maintaining a detailed view of the complex issues involved in the aftermath of the incident and providing an effective oversight role on behalf of the board for a number of important areas. This has been reflected in the frequency of meetings the committee has held since the committee was formed in the summer. As we move into the next phase of the company's response in the Gulf of Mexico, I expect the timetable for the committee to stabilize and, during the course of 2011, the committee will continue to review the frequency and structure of its meetings.

Ian Davis
Chair of the Gulf of Mexico Committee

Committee members

Ian Davis – committee chair
Paul Anderson
Sir William Castell
George David

Membership of the Gulf of Mexico committee includes two of our US-based non-executive directors and chair of the SEEAC. Two members of the committee are also on the audit committee, which has helped inform discussions at the latter relating to the provision for incident-related costs.

Each meeting of the committee is attended by Lamar McKay, President of the GCRO, and by Jack Lynch, general counsel to the GCRO. Our chairman, group chief executive and group general counsel join the meeting whenever possible. Senior management from GCRO also attend meetings of the committee as appropriate. Support is provided to the committee by the company secretary's office.

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 in 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 ownership of the group's response to the incident. The workings and conclusions of the committee are transparent to and discussed regularly with the board, who receive briefings on the committee's activities through the circulation of minutes, and through verbal reports that the committee chair provides at board meetings.

The committee undertakes the following tasks:

- Monitoring the remediation work to mitigate the effects of the oil spill in the waters of the Gulf of Mexico and on the affected shorelines.
- Overseeing a co-ordinated response programme with affected communities and states, and overseeing the approach for relationships with communities, states and the US government on issues relating to the incident.
- Overseeing the legal and communication strategy for litigation involving the company or its subsidiaries arising from the incident or its aftermath, including government claims for fines and penalties.
- Overseeing the strategy connected with claims, recognizing the independent nature of the connected Gulf Coast Claims Facility.
- Overseeing BP's activities and responsibilities with respect to the Gulf Coast Claims Facility and the Deepwater Horizon Oil Spill Trust.
- Overseeing the process for distribution of the goodwill fund for rig workers who have been impacted by the drilling moratorium imposed by the US government.
- Overseeing expenditures and investments that fall outside the established claims administration process, or any redirection of resources outside the normal course of business.
- Reviewing and monitoring management strategy and actions to restore the group's reputation in the US and supporting management in any activities aimed at that goal.

The committee also considers and reviews the GCRO's management of operational and strategic risks connected with the response to the incident. This includes priorities, mitigation plans, resources and the effectiveness of activities.

The committee met on nine occasions in 2010 after its formation in July 2010.

Committee processes

Information and advice

The committee receives its information from the leadership of the GCRO. Legal briefings are regularly provided by the group and GCRO general counsels, who are joined on occasion by other internal and external legal counsel.

BP's internal audit function has conducted reviews of certain of GCRO's activities and processes, and these have been summarized for the committee's review. Primary monitoring of the management of financial risk is undertaken by the audit committee with monitoring of the management of safety (and other non-financial) risk by the SEEAC.

Training and visits

The high frequency of meetings since July 2010 has helped the committee to become effective in each of its tasks. Three of these meetings were held in the US and were of extended duration, providing the opportunity for the committee to meet members of the GCRO leadership team.

Committee activities

The committee's activities have included the following:

Legal

Legal updates from the general 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 Resources Damages Assessment process, and legal aspects of the claims processes. The committee has also monitored engagement with other responsible parties, contractors and the other working interest owners in the Macondo well.

Claims

The committee has monitored the status of claims from individuals and businesses, which since late August have been administered by the 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 reports on the progress of clean-up and remediation activities, and on the phased transition of activities from the Unified Area Command to BP's control. The committee has also been briefed on the results of independent studies of air, water and sediment samples in the Gulf of Mexico. Metrics will be provided to the committee through 2011 to enable remediation activities to be monitored relative to the plan.

Reputation

The committee has monitored the political landscape and the views of the American people, in part from independent polling data relating to many aspects of BP's response to the incident. This has helped inform many of the committee's discussions, and the committee will continue to receive polling data on a regular basis in 2011.

Other topics

The committee has received reports on the status of the $500-million Gulf of Mexico Research Initiative (GRI). Research grants will be administered by the GRI's independent research board, and the committee will receive periodic updates to monitor that the distribution of funds is in accordance with the principles of sound science.

The committee has reviewed the status of payments from the $100-million Rig Worker Assistance Fund (Fund). This fund is independently administered by the Baton Rouge Area Foundation, with BP having no right to direct payments from the Fund. The committee will receive periodic updates on the status of payments from the Fund.

Committee evaluation

The committee has recently examined its performance and effectiveness. The committee concluded that meetings need not be as frequent in 2011. Meetings will be approximately monthly, with several meetings scheduled to take place in the US.

Remuneration committee report

Committee members

Dr DeAnne Julius – committee chair
Antony Burgmans
George David
Ian Davis (appointed 2 April 2010)

Members who left during the year:

Sir Ian Prosser (retired 15 April 2010)

Committee role and structure

The committee determines on behalf of the board the terms of engagement and remuneration of the group chief executive, the chairman and executive directors and to report on those to shareholders. The committee is independently advised.

The chairman of the board attends meetings of the committee. DeAnne Julius will retire as chair of the remuneration committee at the 2011 AGM, from which time Antony Burgmans will assume the committee chairmanship.

Further details on the committee's role, authority and activities during the year are set out in the directors' remuneration report, on page 111 which is the subject of a vote by shareholders at the 2011 AGM.

Nomination and chairman's committee reports

I chair both the nomination and the chairman's committees. These committees have had fuller agendas in 2010 than in previous years as the events and challenges of the year unfolded. The work of the committees has been inevitably intertwined and for this reason I am writing here to introduce the reports which appear below.

During the year the non-executive directors have been engaged in ensuring the board remained focused on its tasks and organizing its time in an effective way. This has not only been through the formal work of the chairman's committee but also through very regular informal contact particularly during the height of the crisis.

Membership of the board has had to evolve over the year both to address the normal succession process and to address the issues with which the board has had to deal. The nomination committee has been actively involved in all of this.

Carl-Henric Svanberg
Chair of the Nomination and Chairman's Committees

Nomination committee report

Committee members

Carl-Henric Svanberg – committee chair
Sir William Castell
Ian Davis (joined upon becoming chair of the Gulf of Mexico committee in August 2010)
Douglas Flint (joined upon becoming chair of the audit committee in April 2010)
Dr DeAnne Julius

Members who left during the year
Sir Ian Prosser (retired 15 April 2010)

The committee met eight times during 2010.

Committee role and structure

The committee identifies, evaluates and recommends candidates for the appointment or re-appointment as directors and for the appointment as company secretary.

The committee keeps the mix of knowledge, skills and experience of the board under regular review (always in consultation with the chairman's committee) to ensure an orderly succession of directors. The outside directorships and broader commitments of the non-executive directors are also monitored by the nomination committee.

The committee consists of the chairman and the chairs of the main board committees.

Committee activities

The committee reviewed the independence and roles of each of the directors prior to recommending them for re-election at the 2010 AGM.

After the appointment of Paul Anderson and Ian Davis before the 2010 AGM the committee kept under review the list of potential candidates for non-executive directors to meet the developing requirements of the company and the board.

It had been anticipated that DeAnne Julius would stand down at the 2011 AGM, however, in the autumn of 2010, Douglas Flint announced that he would stand down also at the 2011 AGM upon his appointment as chairman of HSBC. The committee had been keeping the skills of the board under review, and as a result Brendan Nelson and Frank 'Skip' Bowman joined the board in November 2010 and Phuthuma Nhleko in February 2011. External advisers were involved in all three appointments.

In keeping under review the breadth of board skills, the committee took into account not only the vacancies that were appearing on the board but also considered what was necessary to ensure the breadth of experience around the board table. In particular, they considered the requirements of the group's operations within the developing world. In all of their deliberations they were mindful of the contribution made by the IAB.

During the summer the committee worked closely with the chairman's committee on the succession of Bob Dudley as group chief executive. External advisers were used throughout this process.

The committee continues to focus on the evolution of the board as it moves to a new stage in its development.

For its 2010 evaluation, the nomination committee used a questionnaire to examine the committee's performance and effectiveness. The committee concluded that, overall, it had worked well during a challenging year and that the board had undergone substantial change, which had been supported effectively through the committee. The evaluation concluded that the goal for the committee was to move forward with a better rhythm to ensure board refreshment in terms of skills and diversity.

Chairman's committee report

Committee members

Carl-Henric Svanberg – committee chair
Sir William Castell
Paul Anderson (appointed 2 February 2010)
Frank 'Skip' Bowman (appointed 8 November 2010)
Cynthia Carroll
George David
Ian Davis (appointed 2 April 2010)
Douglas Flint
Dr DeAnne Julius
Brendan Nelson (appointed 8 November 2010)
Phuthuma Nhleko (appointed 1 February 2011)

Members who left during the year:
Erroll Davis, Jr (retired 15 April 2010)
Sir Ian Prosser (retired 15 April 2010)

The committee met eight times in 2010.

Committee role and structure

The committee is comprised of the chairman and all the non-executive directors.

The main tasks of the committee are:

- Evaluating the performance and effectiveness of the group chief executive.
- Reviewing the structure and effectiveness of the business organization of BP.
- Reviewing the systems for senior executive development and determining the succession plan for the group chief executive, executive directors and other senior members of executive management.
- Determining any other matter that 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

Early in 2010 the committee determined that Sir William Castell should take on the role of senior independent director upon the retirement of Sir Ian Prosser from the board at the 2010 Annual General Meeting.

Following the accident in the Gulf of Mexico, the committee kept under review the ability of BP's business organization to respond to the challenges that arose while ensuring there was continued focus on the effectiveness of the rest of its global business. This involved ensuring that the board was focusing on the right issues and organizing itself in an appropriate manner. Throughout the crisis in the Gulf of Mexico the committee has actively considered the company's relations with shareholders and others with whom it came into contact, particularly state and federal governments.

The committee evaluated the performance of the group chief executive in early 2010 and formally reviewed succession planning within the group in September 2010. The committee was central to discussions in the summer over the future of Tony Hayward as group chief executive and his replacement by Bob Dudley.

The committee reviews with Bob Dudley his proposals for the enhanced safety and operation function and his reorganization of the Exploration and Production segment on the departure of Andy Inglis. There was no formal evaluation of the chairman in early 2010 as he was only recently in post. His performance was evaluated in early 2011 as part of the overall evaluation of the board.

The committee reviewed the skills of the board and formed collective views of those needed to meet the challenges of the company for the future. The chairman's committee worked closely with the nomination committee in matters around executive and non-executive succession.

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 and the June 2008 Combined 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) and the June 2008 Combined Code, including principle C.2 (internal control).

The board has an established process by which the effectiveness of the risk management and internal control systems are reviewed as required by provision C.2.1 of the UK Corporate Governance Code and the June 2008 Combined Code. This process enables the board and its committees to consider the systems of risk management and internal control being operated for managing significant risks, including strategic, safety and operational and compliance and control risks, throughout the year. The process does not extend to joint ventures or associates.

As part of this process, the board and the audit 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 the general auditor and 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 and the June 2008 Combined Code provided by the Financial Reporting Council. In December 2010, 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 January 2011 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 systems of risk management and internal control over risks arising in the categories of strategic, safety and operational and compliance and control and considered the control environment that responds to risk. 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 compliance and ethics 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.

As disclosed elsewhere in this *Annual Report and Form 20-F 2010*, material internal control aspects of the Gulf of Mexico spill are being dealt with through the establishment of the Gulf Coast Restoration Organization and the implementation of the recommendations of BP's Investigation Report and through the consideration of other reports and investigations, some of which are still in process.

The Gulf Coast Restoration Organization was set up to manage the company's response activities. This organization has created the framework designed to enable the company to manage the operations and transactions now arising from the incident; including clean-up and restoration costs, claims management and litigation.

In order to ensure that lessons learnt from the event are embedded into the controls in the Operating Management System of the company, the company is undertaking a significant exercise to implement the recommendations of the BP's Investigation Report, and consider other reports and investigations into the incident.

The board established an additional committee, the Gulf of Mexico committee, to engage with management on a regular basis to monitor the response to the Gulf of Mexico spill and the management of risks arising from the incident.

In the board's view, the information it received was sufficient to enable it to review the effectiveness of the company's risk management and internal control systems in accordance with the Internal Control Revised Guidance for Directors (Turnbull).

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.

UK Corporate Governance Code compliance

BP complied throughout 2010 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 exigencies of the business. 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, who makes a recommendation to the board as a whole for final approval, within the limits set by shareholders.

BP also complied with the June 2008 Combined Code, with the exception of A.4.4 (letters of appointment) and B.2.2 (remuneration of the chairman) for the same reasons as outlined above for the UK Corporate Governance Code.

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 on pages 97-104*). 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'. As reported in *BP Annual Report on Form 20-F*, the board determined that Douglas Flint 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 on page 97*). Upon Mr Flint's retirement in April 2011, Mr Nelson will become 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, deputy chief financial officer, group controller, general auditors 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.

In June 2005, BP published a code of conduct, which is applicable to all employees.

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 2010 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 2010 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 2010 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report appearing on page 143 of this *Annual Report and Form 20-F 2010*.

Changes in internal control over financial reporting

The material impact of the Gulf of Mexico oil spill on the financial results of the company presented challenges for the company's internal control over financial reporting. As discussed in the Business Review section, response operations following the incident were managed by the Unified Area Command (UAC) using, in some cases, processes and systems that the company did not determine or control. As parties outside of the company had final decision-making authority on response-related actions, the activities undertaken by the company and its sub-contractors, and the associated costs, were not wholly within the company's control. A high level of activity and expenditure was generated in a very short time with limited documentation around sourcing and commitments. In addition, the potential for breakdowns in process and controls is increased when company employees are focused on immediate response actions in an emergency situation and working in uncertain conditions.

As a result of the magnitude of this unprecedented event, and in order to separately disclose the financial impacts, new processes and related controls were established to identify and segregate costs, calculate accruals and estimate provisions for future costs. These included:

- Establishing unique invoice-processing procedures and related controls to ensure appropriate accounting for costs.
- Developing methodologies for estimating the various elements of accruals and provisions and instituting related controls to validate assumptions and ensure adequate management review.
- Creating period-end financial reporting processes and related controls, including management and analytical review.
- Hiring additional resources to process and account for the significant level of expenditure.

Although the new controls are consistent with the company's established framework, they represent changes that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting. Despite the impact of this event, as stated above, management has concluded that the company's disclosure controls and procedures and internal control over financial reporting were effective as of 31 December 2010.

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 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 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; and 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. Additionally, any proposed service not included in the pre-approved services, must be approved in advance prior to commencement of the engagement. 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.

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 17 on page 176 and Audit committee report on page 98 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 137.

At the AGMs held on 17 April 2008 and 15 April 2010, 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 our AGM held on 15 April 2010. These amendments reflect the full implementation of the Act, among other matters.

Objects and purposes

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 company's last AGM 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.

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.
- Proposals concerning the modification of certain retirement benefits schemes under which the director may benefit and that have been approved by either the UK Board of Inland Revenue or by the shareholders.
- 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 last AGM, 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, 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. In certain circumstances, BP may give notices to shareholders by advertisement in UK newspapers. 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 above under the heading Voting rights.

Under the Articles of Association, the AGM of shareholders will 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, on written notice, to require 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, 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.

Directors' remuneration report

Directors' remuneration report

Part 1 Summary

Dr DeAnne S Julius
Chairman, Remuneration Committee
2 March 2011

Remuneration decisions for 2010 were dominated by the scale and impact of the accident in the Gulf of Mexico.

The remuneration committee shared the group chief executive's view that no bonuses should be paid on group-level results. Thus Mr Dudley received no bonus for the year. There is also no vesting of the 2008-2010 share element for any executive director.

Dr Hayward and Mr Inglis, who left BP during the course of the year, received their contractual entitlements of one year's salary on termination, together with other limited entitlements. Outstanding share element awards were preserved on a pro rata basis, with vesting being conditional on meeting applicable performance targets. Neither was awarded any annual bonus for 2010.

While the tragedy of lost lives and environmental damage remains foremost in everyone's minds, the committee also wished to fairly acknowledge the good business results in many parts of BP, delivered in the most testing of times. Mr Conn and Dr Grote met or exceeded their specific segment/functional targets for the year and were awarded 30% of their overall 'on-target' bonuses, including the deferred element. This reflected no payout on the portion related to group results (as with all executive directors) and was limited to 'on-target' for the portion related to their strong segment/functional results. A third of their bonus is deferred into shares on a mandatory basis, matched, and will vest in three years subject to meeting a safety and environmental hurdle during the period. Both individuals may elect to defer an additional third into shares on the same basis as the mandatory deferral. Both will receive salary increases in 2011 as noted in the table opposite.

Full details of executive director remuneration are set out in the table below.

For 2011 the overall policy for executive directors will remain largely unchanged, as summarized opposite. However, the committee will take a more active role in the oversight of pay policy and practice below the board. Together with the group chief executive, the committee will be reviewing the overall policy for senior executives to ensure that it promotes long-term sustainable success for shareholders as well as rewarding appropriately the many talented people leading the company.

Finally, as I retire after five years as remuneration committee chairman and 10 years on the board, I would like to thank the shareholders both for their challenge and their support as the company has navigated through difficult, as well as successful, times.

Summary of remuneration of executive directors in 2010 (information subject to audit)

	Annual remuneration								Long-term remuneration (EDIP)				
									2010 deferred annual bonus		Share element of EDIP: 2008-2010 plan (vested in Feb 2011)		Share element of EDIP: 2010-2012 plan
	Salary[a] (thousand)		Annual cash performance bonus (thousand)		Non-cash benefits and other emoluments (thousand)		Total (thousand)						
	2009	2010	2009	2010	2009	2010	2009	2010	Mandatory deferral[b]	Potential voluntary deferral[c]	Actual shares vested	Value (thousand)	Potential maximum performance shares[d]
R W Dudley[e]	$750	**$1,175**	$1,125	**0**	$304[f]	**$564[f]**	$2,179	**$1,739**	0	0	0	0	581,084
I C Conn	£690	**£690**	£1,104	**£104**	£46	**£34**	£1,840	**£828**	£104	£104	0	0	656,813
Dr B E Grote[e]	$1,380	**$1,380**	$2,070	**$207**	$8	**$10**	$3,458	**$1,597**	$207	$207	0	0	801,894
Directors leaving the board in 2010													
Dr A B Hayward[g]	£1,045	**£958**	£2,090	**0**	£23	**£95**	£3,158	**£1,053**	0	0	0	0	303,948
A G Inglis[h]	£690	**£575**	£1,311	**0**	£216[f]	**£168[f i]**	£2,217	**£743**	0	0	0	0	218,938

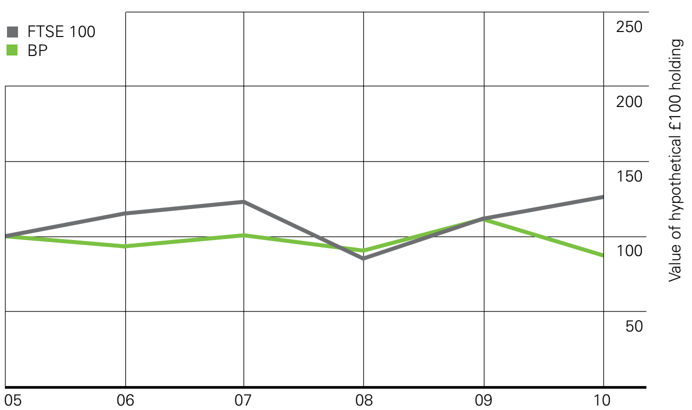
Amounts shown are in the currency received by executive directors. Annual bonuses are shown in the year they were earned.

[a] Figures show the total salary received during the calendar year. The last salary increase was in July 2008 other than on promotion of Mr Dudley to group chief executive.
[b] This amount will be converted to deferred shares at the three-day average share price following the full-year results announcement (£4.84, $46.68). Deferred shares will be matched one-for-one and both deferred and matched shares are subject to a safety and environmental hurdle over the three-year deferral period.
[c] Executive directors have the choice to have this portion either paid in cash or deferred voluntarily into shares on the same basis as the mandatory deferral.
[d] Maximum potential shares that could vest at the end of the three-year period depending on performance – reduced pro-rata for Dr Hayward and Mr Inglis to reflect actual service during performance period.
[e] Mr Dudley and Dr Grote hold shares in the form of ADSs. The above number reflects calculated equivalent in ordinary shares.
[f] 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 and Mr Inglis's retirement from the board.
[g] Dr Hayward left the board on 30 November 2010. In addition to the above he was awarded compensation for loss of office equal to one year's salary (£1,045,000) and a further £30,000 in respect of UK statutory compensation rights.
[h] Mr Inglis left the board on 31 October 2010. In addition to the above he was awarded compensation for loss of office equal to one year's salary (£690,000) and a further £200,000 to cover various repatriation and relocation costs in accordance with his international assignment arrangements.
[i] In addition to this amount, under a tax equalization arrangement, BP discharged a US tax liability arising from the participation by Mr Inglis in the UK pension scheme amounting to $1,260,000.

Summary of future remuneration components

Salary	• Mr Dudley's salary remains at $1,700,000. Both Mr Conn and Dr Grote, who last received salary increases in July 2008, will have their salaries increased effective 1 April 2011. Mr Conn's new salary will be £730,000 (from £690,000) and Dr Grote's will be $1,442,000 (from $1,380,000).
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 deferred shares with three-year deferral, with ability to voluntarily defer an additional one-third. • All deferred shares matched one-for-one, both subject to an assessment of safety and environmental performance 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.

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 £87.46 and £126.25 respectively.

Remuneration of non-executive directors in 2010[a]

		£ thousand
	2009	**2010**
P Anderson[b]	–	**118**
F Bowman[c]	–	**17**
A Burgmans	93	**90**
C B Carroll	90	**90**
Sir William Castell	115	**147**
G David[d]	118	**135**
I Davis[e]	–	**69**
D J Flint	85	**108**
Dr D S Julius	105	**100**
B Nelson[f]	–	**17**
C-H Svanberg[g]	30	**750**
Directors leaving the board in 2010		
E B Davis, Jr[h]	105	**33**
Sir Ian Prosser[i]	165	**52**

[a] This information has been subject to audit.
[b] Appointed on 1 February 2010.
[c] Appointed on 8 November 2010.
[d] Also received £28,000 for serving as a member of BP's technology advisory council.
[e] Appointed on 2 April 2010.
[f] Appointed on 8 November 2010.
[g] Also received a relocation allowance of £90,000.
[h] Also received a superannuation gratuity of £21,000.
[i] Also received a superannuation gratuity of £43,945.

No share or share option awards were made to any non-executive director in respect of service on the board during 2010.

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.

Part 2 Executive directors' remuneration

2010 remuneration

Salary

Mr Dudley's salary was increased to $1,700,000 on his promotion to group chief executive in October 2010. The London accommodation provided to him ceased at the end of 2010. No other executive director had a salary increase in 2010.

Annual bonus

The 2010 annual bonus results were dramatically affected by the Gulf of Mexico accident. In the judgement of the committee and the group chief executive this overrode the normal metrics for bonus outcomes. As indicated in the table on page 112, no bonus was paid to Mr Dudley, Dr Hayward or Mr Inglis for 2010. Mr Conn and Dr Grote similarly received no bonus for their group portion and were limited to an 'on-target' level for their segment/functional portion (accounting for 30% of their overall bonus opportunity). Both of these met or exceeded targets and made important contributions to the stabilization of the business following the accident.

The total bonus to Mr Conn was £310,500 and to Dr Grote $621,000. Of the total for each, 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. These amounts are shown in the table on page 112.

Deferred bonus

One-third of the bonus awarded to Dr Grote and Mr Conn 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.

Both individuals may elect to defer an additional third into shares on the same basis as the mandatory deferral.

All deferred bonuses are converted to shares based on an average price of BP shares over the three days following the company's announcement of 2010 results (£4.84/share, $46.68/ADS).

2008-2010 share element

Results for the 2008-2010 share element were also strongly affected by the Gulf of Mexico accident. BP's Total Shareholder Return (TSR) for the three-year period was lowest among the peer group of oil majors. The company's underlying performance relative to the peer group actually remained quite strong on the metrics historically used to test the fairness of the TSR result. The committee felt, however, that because of the seriousness of the Gulf of Mexico accident, the TSR ranking was an appropriate result. No shares, therefore, vested under the plan for any executive director.

2011 remuneration policy

The basic principles that guide remuneration policy for executive directors in BP include:

- A substantial portion of executive remuneration should be linked to success in implementing the company's business strategy to maximize long-term shareholder value.
- The structure of pay should reflect the long-term nature of BP's business and the significance of safety and environmental risks.
- Performance conditions for variable pay should be set independently by the committee at the outset of each year and assessed by the committee both quantitatively and qualitatively at the end of each performance period.
- Performance 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).
- 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.
- 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.
- The remuneration committee will actively seek to understand shareholder preferences and be as transparent as possible in explaining its remuneration policy and practices.

The majority of total remuneration is long term and varies with performance, with the largest elements share based, further aligning interests with shareholders.

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.

Salary

The committee normally reviews salaries annually, taking into account other large Europe-based global companies as well as relevant US companies. These groups are each defined and analysed by the committee's independent remuneration advisers.

Mr Dudley's current salary of $1,700,000 will remain unchanged in 2011. Both Mr Conn and Dr Grote, who last received salary increases in July 2008, will have their salaries increased effective 1 April 2011. Mr Conn's new salary will be £730,000 (from £690,000) and Dr Grote's will be $1,442,000 (from $1,380,000).

Annual bonus

Bonus measures and levels of eligibility are set at the start of the year for the senior leadership including executive directors. The approach for 2011 aligns closely with the group template for reinforcing safety and risk management, rebuilding trust and reinforcing value creation. There is a balance of long-term and near-term objectives weighted towards the top priorities of risk identification and management, safety and compliance, and talent and capability development. Group measures for executive directors will focus on:

- Safety and operational risk metrics – including full implementation of the S&OR functional model.
- Short-term performance – including key financial and operating metrics.
- Long-term performance – including progress on key projects and reserves replacement.
- People – including a new performance and reward framework.

Mr Dudley's bonus in 2011 will be based entirely on group measures. Mr Conn and Dr Grote will have 70% of their bonus based on group measures and 30% on the results of their respective segments. For Mr Conn these will include refining availability, safety and cost efficiency. For Dr Grote they will focus on functional costs and succession.

As in past years, in addition to the specific bonus metrics, the committee will also review the underlying performance of the group in light of the overall business plan, competitors' results, analysts' reports and the views of the chairmen of the other committees.

Based on this broader view, the committee can decide to reduce bonuses where this is warranted and, in exceptional circumstances, to pay no bonuses.

Deferred bonus

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 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.

This structure of deferred bonuses, paid in shares, places increased focus on long-term alignment and reinforces the critical importance of maintaining high safety and environmental standards.

Performance shares

The share element of the EDIP has been a feature of the plan, with some modifications, since its inception in 2000. The maximum number of shares that can be awarded will be 5.5 times salary for the group chief executive and four times salary for the other executive directors.

Performance shares will only vest to the extent that a performance condition is met, as described under performance conditions. In addition, the committee will have an overriding discretion, in exceptional circumstances (relating to either the company or a particular participant) to reduce the number of shares that vest (or to provide that no shares vest).

The compulsory retention period will also be decided by the committee and will not normally be less than three years. Together with the performance period, 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 committee's policy, reflected in the EDIP, continues to be that each executive director builds a significant personal shareholding, with a target of shares equivalent in value to five times salary, within a reasonable time from appointment as an executive director.

Performance conditions

Performance conditions for the 2011-2013 share element will be aligned with the strategic agenda that has evolved in response to last year's events. This focuses on value creation, reinforcing safety and risk management, and rebuilding trust.

Vesting of shares will be based 50% 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 20% will be based on the reserves replacement ratio, also relative to the other oil majors, reflecting a central element of value creation. The final 30% will be based on a set of strategic imperatives for rebuilding trust; in particular, reinforcing safety and risk management culture, rebuilding BP's external reputation, and reinforcing staff alignment and morale.

For the relative measures, TSR and the reserve replacement ratio, the comparator group will consist of ExxonMobil, Shell, Total, ConocoPhillips 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 reserve 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 competitors on each measure. BP's performance will then be compared to the other five. 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. For performance between second and third or first and second, the vesting percentage will be interpolated based on BP's performance relative to the company ranked directly above and below it.

The remaining 30% of vesting will be based on a balanced scorecard of strategic imperatives. These will comprise safety and risk management culture, external reputation, and internal staff alignment and morale. For each of these, specific metrics derived from externally tabulated surveys will be used to track progress. This evidence will be used by the committee, along with input from the other board committees, to judge performance on each metric. The results will be explained in the subsequent directors' remuneration report.

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.

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.

Pension benefits in excess of the individual lifetime allowance set by legislation are paid via an unapproved, unfunded pension arrangement provided directly by the company.

In the light of the reduced annual allowance tax regime being implemented from April 2011, the company is considering alternative approaches to the provision of pension benefits for future service for UK directors and other senior staff impacted by the change.

Although Mr Inglis was, like other UK directors, a member of the BP Pension Scheme, his participation gave rise to a US federal tax liability as he was based in Houston. During 2010, pursuant to a tax equalization arrangement that applied in respect of the period since Mr Inglis became a director in February 2007, under his international assignment arrangements, the committee approved the discharge of this US tax liability amounting to $1.26 million in respect of 2010. This figure included an element in respect of the additional value of Mr Inglis's accrued pension as a result of crystallization of early retirement rights on the termination of his employment with BP.

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. In addition, 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 higher benefit of the plans produced by the two formulas will be payable and this is currently the benefit determined under the Amoco heritage terms.

In addition, BP 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.

Their pension accrual for 2010, 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. BP provided accommodation in London for Mr Dudley and for Mr Inglis during 2010. This provision ceased for both individuals at the end of 2010.

Pensions[a] (information subject to audit)

thousand

	Service at 31 Dec 2010	Accrued pension entitlement at 31 Dec 2010	Additional pension earned during the year ended 31 Dec 2010[a]	Transfer value of accrued benefit[b] at 31 Dec 2009 (A)	Transfer value of accrued benefit[b] at 31 Dec 2010 (B)	Amount of B-A less contributions made by the director in 2010
R W Dudley (US)	31 years	$704	$298	$4,353	$10,336	$5,983
I C Conn (UK)	25 years	£287	£12	£4,508	£5,373	£865
Dr B E Grote (US)	31 years	$1,281	$270	$12,047	$16,501	$4,454
Directors leaving the board in 2010						
Dr A B Hayward (UK)[c]	29 years	£605	£21	£10,840	£13,677	£2,837
A G Inglis (UK)[c]	30 years	£349	£12	£6,000	£7,633	£1,633

[a] Additional pension earned during the year includes an inflation increase of 2.4% for UK directors and 1.5% for US directors.
[b] Transfer values have been calculated in accordance with guidance issued by the actuarial profession.
[c] Figures are calculated to end of 2010.

Performance share element of EDIP (information subject to audit)

	Performance period	Date of award of performance shares	Market price of each share at date of award of performance shares £	Share element interests: Potential maximum performance shares[a] At 1 Jan 2010	Awarded 2010	At 31 Dec 2010	Interests vested in 2010 and 2011: Number of ordinary shares vested[b]	Vesting date	Market price of each share at vesting £
R W Dudley[c]	2009-2011	06 May 2009	5.00	539,634	–	539,634	–	–	–
	2010-2012	09 Feb 2010	5.64	–	581,082	581,082	–	–	–
I C Conn	2007-2009	06 Mar 2007	5.12	456,748	–	–	95,697	3 Feb 2010	5.76
	2008-2010	13 Feb 2008	5.61	578,376	–	578,376	0	–	–
	2008-2011[d]	13 Feb 2008	5.61	133,452	–	133,452	155,695	22 Feb 2011	4.91
	2008-2013[d]	13 Feb 2008	5.61	133,452	–	133,452	–	–	–
	2009-2011	11 Feb 2009	5.10	780,816	–	780,816	–	–	–
	2010-2012	09 Feb 2010	5.64	–	656,813	656,813	–	–	–
Dr B E Grote[c]	2007-2009	06 Mar 2007	5.12	491,640	–	–	101,502	3 Feb 2010	5.76
	2008-2010	13 Feb 2008	5.61	581,748	–	581,748	0	–	–
	2009-2011	11 Feb 2009	5.10	992,928	–	992,928	–	–	–
	2010-2012	09 Feb 2010	5.64	–	801,894	801,894	–	–	–
Directors leaving the board in 2010									
Dr A B Hayward	2007-2009	06 Mar 2007	5.12	706,311	–	–	147,985	3 Feb 2010	5.76
	2008-2010	13 Feb 2008	5.61	845,319	–	821,838[e]	0	–	–
	2009-2011	11 Feb 2009	5.10	1,182,540	–	755,512[e]	–	–	–
	2010-2012	09 Feb 2010	5.64	–	994,739	303,948[e]	–	–	–
A G Inglis	2007-2009	06 Mar 2007	5.12	400,243	–	–	83,859	3 Feb 2010	5.76
	2008-2010	13 Feb 2008	5.61	578,376	–	578,376	0	–	–
	2008-2011[d]	13 Feb 2008	5.61	133,452	–	–	0	–	–
	2008-2013[d]	13 Feb 2008	5.61	133,452	–	–	0	–	–
	2009-2011	11 Feb 2009	5.10	780,816	–	520,544[e]	–	–	–
	2010-2012	09 Feb 2010	5.64	–	656,813	218,938[e]	–	–	–

[a] BP's performance is measured against the oil sector. For awards under the 2007-2009 and 2008-2010 plans, the performance condition is TSR measured against ExxonMobil, Shell, Total and Chevron. 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. Each performance period ends on 31 December of the third year.
[b] Represents awards 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 awarded.
[c] Dr Grote and Mr Dudley receive awards in the form of ADSs. The above numbers reflect calculated equivalents in ordinary shares.
[d] Restricted award under share element of EDIP. As reported in the 2007 directors' remuneration report in February 2008, the committee awarded both Mr Inglis and Mr Conn restricted shares, as set out above. These one-off awards will vest on the third and 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. Mr Inglis left the company on 31 December 2010 and accordingly his restricted awards lapsed.
[e] Potential maximum of performance shares has been reduced to reflect actual service during performance period on a pro-rated basis.

Share options (information subject to audit)

	Option type	At 1 Jan 2010	Granted	Exercised	At 31 Dec 2010	Option price	Market price at date of exercise	Date from which first exercisable	Expiry date
R W Dudley[a]	BP SOP	1,800	–	1,800	–	$48.94	$58.15[b]	28 Mar 2003	27 Mar 2010
	BP SOP	6,460	–	–	6,460	$49.65		23 Feb 2004	22 Feb 2011
	BP SOP	1,073	–	–	1,073	$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[d]	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
	EXEC	72,250	–	–	72,250	£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]	BPA	12,600	–	12,600	–	$48.94	$58.40-$58.42	28 Mar 2001	27 Mar 2010
	EDIP	13,173	–	13,173	–	$37.76	$54.36	17 Feb 2004	17 Feb 2010
	EDIP	58,333	–	–	58,333	$48.53		25 Feb 2005	25 Feb 2011
Directors leaving the board in 2010									
Dr A B Hayward	SAYE	3,220	–	–	3,220	£5.00		01 Sep 2011	29 Feb 2012
	EXEC	34,000	–	–	–[c]	£5.99	n/a	15 May 2003	15 May 2010
	EXEC	77,400	–	–	77,400	£5.67		23 Feb 2004	23 Feb 2011
	EXEC	160,000	–	–	160,000	£5.72		18 Feb 2005	18 Feb 2012
	EDIP	275,000	–	275,000	–	£4.22	£6.31[b]	25 Feb 2005	25 Feb 2011
A G Inglis	EXEC	72,250	–	–	72,250	£5.67		23 Feb 2004	22 Feb 2011
	EXEC	119,000	–	–	119,000	£5.72		18 Feb 2005	17 Feb 2012
	EXEC	119,000	–	119,000	–	£3.88	£6.31	17 Feb 2006	16 Feb 2013
	EXEC	100,500	–	100,500	–	£4.22	£6.31	25 Feb 2007	24 Feb 2014

The closing market prices of an ordinary share and of an ADS on 31 December 2010 were £4.66 and $44.17 respectively.
During 2010, the highest market prices were £6.55 and $62.32 respectively and the lowest market prices were £3.03 and $27.02 respectively.

BPA = BP Amoco share option plan, which applied to US executive directors prior to the adoption of the EDIP.
EDIP = Executive Directors' Incentive Plan adopted by shareholders in 2010 as described on page 114.
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] Closing market price for information. Shares were retained after exercise of options.
[c] Options lapsed.
[d] Options exercised on 22 February 2011. Closing market price for information only, as shares were retained after exercise of options.

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:

Executive director

	Appointee company	Additional position held at appointee company	Total fees
I C Conn	Rolls-Royce	Senior Independent Director	£65,000
Dr B E Grote	Unilever	Audit committee member	Unilever PLC £33,000 Unilever NV €47,500
A G Inglis[a]	BAE Systems	Chair of Corporate Responsibility Committee	£49,280

[a] Member of BAE Systems Board until 9 July 2010.

Service contracts

Director

	Contract date	Salary as at 31 Dec 2010
R W Dudley	6 Apr 2009	$1,700,000
I C Conn	22 Jul 2004	£690,000
Dr B E Grote	7 Aug 2000	$1,380,000

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. The service contracts are expressed to expire at a normal retirement age of 60 (subject to age discrimination).

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 2012 AGM. 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. 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.

Directors leaving the board

Mr Inglis and Dr Hayward stepped down from the board on 31 October 2010 and 30 November 2010 respectively. Mr Inglis remained in employment on his existing salary and benefits until ceasing employment on 31 December 2010; Dr Hayward ceased employment on 30 November 2010.

Mr Inglis and Dr Hayward, who were employed under service contracts with the company dated 1 February 2007 and 29 January 2003 respectively, were each entitled to one year's salary (£690,000 and £1,045,000 respectively) on termination as compensation in accordance with their contractual entitlements. Dr Hayward was paid a further £30,000 compensation in respect of UK statutory employment rights. As Mr Inglis was based in Houston, the company agreed, in accordance with his international assignment arrangements, to make a payment of £200,000 to cover various repatriation and relocation costs. The company reimbursed both individuals' legal fees in connection with their termination arrangements, and agreed to pay certain outplacement fees in the case of Mr Inglis.

Both individuals were eligible for a bonus for 2010 based on the achievement of bonus targets and their period of service during the year. The committee considered bonuses for these individuals at the same time as for the remaining executive directors and, for the reasons explained above, determined that no bonuses should be awarded.

As regards long-term incentives, both individuals retained their unvested performance awards under the EDIP in respect of the 2008-10, 2009-11 and 2010-12 share elements and these will vest at the normal time to the extent the performance targets are met (but subject to pro-rating for service during the performance period). Further details of these awards are set out on page 117. Both individuals retained their outstanding share options as set out in the table on page 118. The retention share award granted under the EDIP to Mr Inglis in 2008 lapsed as a result of the termination of his employment.

With effect from 1 December 2010, Dr Hayward has been engaged by BP to serve as a non-executive director of TNK-BP, for which he will be paid a fee of $150,000 per annum.

Remuneration committee

Dr Julius (chairman), Mr Burgmans, Mr David and Mr Davis are independent non-executive directors and were committee members during the year. The chairman of the board also attends meetings. The group chief executive was consulted on matters relating to the other executive directors who report to him and on matters relating to the performance of the company; neither he nor the chairman were present when matters affecting their own remuneration were discussed. Mr Burgmans will become chairman of the committee following Dr Julius's retirement at the 2011 AGM.

The remuneration committee's tasks are:

- 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 scheme of which the executive directors are members.
- To nominate, on behalf of the board, any trustees (or directors of corporate trustees) of the scheme.
- 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.

Constitution and operation

Each member of the remuneration committee is subject to annual re-election as a director of the company. The board considers all committee members to be independent (*see page 95*).

They have no personal financial interest, other than as shareholders, in the committee's decisions.

The committee met six times in the period under review.

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. The committee values its dialogue with major shareholders on remuneration matters.

Advice

Mr Aronson, an independent consultant, is the committee's secretary and independent adviser. Advice was also received from Mr 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 annual review.

In 2010, the committee continued to engage Towers Watson as its principal external adviser. 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.

Part 3 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 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 and non-executive remuneration on an annual basis. The chairman's remuneration is reviewed by the remuneration committee, which 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 a review, the decision was taken not to increase the fee levels of BP non-executive directors. However, it was decided that members of the Gulf of Mexico committee would receive a committee membership fee of £5,000 (the same fee level as the other main board committees) and that the chair of the Gulf of Mexico committee would receive a committee chairmanship fee of £30,000.

Fee structure

The table below shows the current fee structure for non-executive directors on 1 January 2011.

	£ 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 (SEEAC) chairmanship fees[c]	30
Remuneration committee chairmanship fee[c]	20
Committee membership fee[d]	5
Transatlantic attendance allowance	5

[a] The chairman remains ineligible for committee chairmanship and membership fees or transatlantic 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 and a relocation allowance for expenses incurred in relocating to London.
[b] The senior independent director is still eligible for committee chairmanship fees and transatlantic 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 SEEAC, the audit, the Gulf of Mexico and the remuneration committees.

Remuneration of non-executive directors in 2010[a]

		£ thousand
	2009	**2010**
P Anderson[b]	–	**118**
F Bowman[c]	–	**17**
A Burgmans	93	**90**
C B Carroll	90	**90**
Sir William Castell	115	**147**
G David[d]	118	**135**
I Davis[e]	–	**69**
D J Flint	85	**108**
Dr D S Julius	105	**100**
B Nelson[f]	–	**17**
C-H Svanberg[g]	30	**750**
Directors leaving the board in 2010		
E B Davis, Jr[h]	105	**33**
Sir Ian Prosser[i]	165	**52**

[a] This information has been subject to audit.
[b] Appointed on 1 February 2010.
[c] Appointed on 8 November 2010.
[d] Also received £28,000 for serving as a member of BP's technology advisory council.
[e] Appointed on 2 April 2010.
[f] Appointed on 8 November 2010.
[g] Also received a relocation allowance of £90,000.
[h] Also received a superannuation gratuity of £21,000.
[i] Also received a superannuation gratuity of £43,945.

No share or share option awards were made to any non-executive director in respect of service on the board during 2010.

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.

Sir Ian Prosser and Erroll Davis, Jr, who both retired on 15 April 2010, were paid superannuation gratuities of £43,945 and £21,000 respectively. This is in line with the policy arrangements agreed in 2002 and outlined above.

Non-executive directors of Amoco Corporation

Non-executive directors who were formerly non-executive directors of Amoco Corporation have residual entitlements under the Amoco Non-Employee Directors' Restricted Stock Plan. Directors were allocated restricted stock in remuneration for their service on the board of Amoco Corporation prior to its merger with BP in 1998. On merger, interests in Amoco shares in the plan were converted into interests in BP ADSs. The restricted stock will vest on the retirement of the non-executive director at the age of 70 (or earlier at the discretion of the board). Since the merger, no further entitlements have accrued to any director under the plan. The residual interests, as interests in a long-term incentive scheme, are set out in the table below:

	Interest in BP ADSs at 1 Jan 2010[a]	Date on which director reaches age 70[b]
Director leaving the board in 2010		
E B Davis, Jr[c]	4,490	5 August 2014

[a] No awards were granted and no awards lapsed during the year. The awards were granted over Amoco stock prior to the merger but their notional weighted average market value at the date of grant (applying the subsequent merger ratio of 0.66167 of a BP ADS for every Amoco share) was $27.87 per BP ADS.

[b] For the purposes of the regulations, the date on which the director retires from the board at or after the age of 70 is the end of the qualifying period. If the director retires prior to this date, the board may waive the restrictions.

[c] Erroll Davis, Jr retired from the board on 15 April 2010. He had received awards of Amoco shares under the plan between 23 April 1991 and 28 April 1998 prior to the merger. These interests had been converted into BP ADSs at the time of the merger. In accordance with the terms of the plan, the board exercised its discretion over this award and the shares vested on 21 May 2010 (when the BP ADS market price was $43.86) without payment by him.

With the retirement of Erroll Davis, Jr, no former Amoco non-executives now serve on the BP p.l.c. board.

Past directors

Mr Miles (who was a non-executive director of BP until April 2006) was appointed as a director and non-executive chairman of BP Pension Trustees Limited (BPPT) in October 2006, retiring from BPPT on 29 September 2010. During 2010 he received £112,500 for this role.

Sir Ian Prosser (who retired as a non-executive director of BP in April 2010) was appointed as a director of BPPT on 24 June 2010, and appointed non-executive chairman of BPPT on 29 September 2010. During 2010 he received £51,923 for this role.

Dr Walter Massey (who retired as a non-executive director of BP in April 2008) was appointed to the BP America External Advisory Council in April 2008 for a period of two years. During 2010 he received $31,250 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. During 2010 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 2 March 2011.

Additional information for shareholders

Critical accounting policies

The significant accounting policies of the group are summarized in Financial statements – Note 1 on page 150.

Inherent in the application of many of the accounting policies used in preparing the financial statements is the need for BP management to make 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 reporting period. Actual outcomes could differ from the estimates and assumptions used. The following summary provides more information about the critical accounting policies that could have a significant impact on the results of the group and should be read in conjunction with the Notes on financial statements.

The accounting policies and areas that require the most significant judgements and estimates used 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, 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 and production activities.

The acquisition of geological and geophysical seismic information, prior to the discovery of proved reserves, is expensed as incurred.

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.

Once a project is sanctioned for development, the carrying values of exploration licence and leasehold property acquisition costs and costs associated with exploration wells and exploratory-type stratigraphic test wells, are transferred to production assets within property, plant and equipment.

The capitalized exploration and development costs for proved oil and natural gas properties (which include the costs of drilling unsuccessful appraisal and development wells) are amortized on the basis of oil-equivalent barrels that are produced in a period as a percentage of the estimated proved reserves. Costs of common facilities subject to depreciation are expenditures incurred to date, together with future capital expenditure expected to be incurred in relation to these common facilities and excluding future drilling costs.

The estimated proved reserves used in these unit-of-production calculations vary with the nature of the capitalized expenditure. The reserves used in the calculation of the unit-of-production amortization are as follows:

- Cost of producing wells – proved developed reserves.
- Licence and property acquisition, common facilities and future decommissioning costs – total proved reserves.

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. 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*).

On 31 December 2008, the SEC published a revision of Rule 4-10 (a) of Regulation S-X for the estimation of reserves. In 2009, the application of the technical aspects of these revised rules resulted in an immaterial increase of less than 1% to BP's total proved reserves. 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 50, which is unaudited. As discussed below, oil and natural gas reserves have a direct impact on the assessment of the recoverability of asset carrying values reported in the financial statements.

The 2010 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 228-248.

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. 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 planning assumptions thereafter. As at 31 December 2010, the group's long-term planning assumptions were $75 per barrel for Brent and $6.50/mmBtu for Henry Hub (2009 $75 per barrel and $7.50/mmBtu). These long-term planning 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 2010 the rates ranged from 11% to 14% nominal (2009 9% to 13% nominal). The rate applied in each country is re-assessed 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 $8.6 billion on its balance sheet (2009 $8.6 billion), principally relating to the Atlantic Richfield and Burmah Castrol acquisitions. 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.

Taxation

The computation of the group's income tax expense 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 may arise in future periods. For more information see Financial statements – Note 19 on page 177 and Note 44 on page 218.

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 models and other valuation methods due to the absence of quoted prices or other observable, market-corroborated data. In particular, this applies to the majority of the group's natural gas embedded derivatives. These are primarily 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 gains and losses on embedded derivatives recognized in the income statement. For more information see Financial statements – Note 34 on page 192. 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 27 on page 185.

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. 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 2010 was 1.5% (2009 1.75%). 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 2010 was 1.5% (2009 1.75%).

As further described in Financial statements – Note 44 on page 218, 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 adjusted. Accordingly, significant management judgement relating to contingent liabilities is required, since the outcome of litigation is difficult to predict.

Gulf of Mexico oil spill

As a consequence of the Gulf of Mexico oil spill, as described on pages 34-39, BP has incurred costs during the year and has 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 during the year have been 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. Furthermore, the amount of claims that become payable by BP, the amount of fines ultimately levied on BP (including any determination of BP's negligence), the outcome of litigation, 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 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 27-32. Any such possible obligations are therefore contingent liabilities and, at present, it is not practicable to estimate their magnitude or possible timing of payment. Furthermore, other material unanticipated obligations may arise in future in relation to the incident. Refer to Financial statements – Note 44 on page 218 for further information.

Expenditure to be met from the $20-billion trust fund

In June 2010 BP agreed with the US government that it would establish a trust fund of $20 billion to be 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. BP's obligation to make contributions to the trust fund was recognized in full and 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. BP will not actually receive any reimbursements from the trust fund, but rather payments will be made directly to claimants from the trust fund.

BP has provided for its best estimate of items that will be paid through the $20-billion trust fund. 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, and claims asserted in civil litigation, 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 has been expensed in the income statement, taking account of the time value of money.

Other expenditure not covered by the $20-billion 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 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. 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.

Contingent assets relating to the Gulf of Mexico oil spill

BP is the operator of the Macondo well and holds a 65% working interest, with the remaining 35% interest held by two co-owners, Anadarko Petroleum Corporation (APC) and MOEX Offshore 2007 LLC (MOEX). Under the Operating Agreement, MOEX and APC are responsible for reimbursing BP for their proportionate shares of the costs of all operations and activities conducted under the Operating Agreement. In addition, the parties are responsible for their proportionate shares of all liabilities resulting from operations or activities conducted under the Operating Agreement, except where liability results from a party's gross negligence or wilful misconduct, in which case that party is solely responsible. BP does not believe that it has been grossly negligent under the terms of the Operating Agreement or at law.

As at 31 December 2010, $6 billion had been billed to the co-owners, which BP believes to be contractually recoverable. As further costs are incurred, BP believes that additional amounts are billable to our co-owners under the Operating Agreement.

Our co-owners have each written to BP indicating that they are withholding payment in light of the investigations surrounding, and determination of the root causes of, the incident. In addition, APC has publicly accused BP of having been grossly negligent and stated it has no liability for the incident, both of which claims BP refutes and intends to challenge in any legal proceedings. There are also audit rights concerning billings under the Operating Agreement which may be exercised by APC and MOEX, and which may or may not lead to an adjustment of the amount billed. BP may ultimately need to enforce its rights to collect payment from the co-owners through an arbitration proceeding as provided for in the Operating Agreement. There is a risk that amounts billed to co-owners may not ultimately be recovered should our co-owners be found not liable for these costs or be unable to pay them.

BP believes that it has a contractual right to recover the co-owners' shares of the costs incurred; however, no recovery amounts have been recognized in the financial statements as at 31 December 2010.

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 2010, 2009 and 2008 are provided in Financial statements – Note 38 on page 202.

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 38 on page 202.

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 38 on page 202.

Actuarial gains and losses are recognized in full within other comprehensive income in the year in which they occur.

Property, plants 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 40 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 24 February 2011, 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	925,000	–	–
R W Dudley	280,799[c]	1,120,716[c]	–
P M Anderson	6,000[c]	–	–
F L Bowman	7,320[c]	–	–
A Burgmans	10,156	–	–
C B Carroll	10,500[c]	–	–
Sir William Castell	82,500	–	–
I C Conn	417,553[d]	2,016,005	133,452
G David	159,000[c]	–	–
I E L Davis	10,000	–	–
D J Flint	15,000	–	–
Dr B E Grote	1,372,643[e]	2,376,570[c]	–
Dr D S Julius	15,000	–	–
B R Nelson	–	–	–
F P Nhleko	–	–	–

[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 ADSs, except for 94 shares held as ordinary shares.

As at 24 February 2011, 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]	259,218
I C Conn	203,472
Dr B E Grote[a b]	349,998

[a] Held as ADSs.
[b] These options lapsed on 25 February 2011.

There are no directors or members of senior management who own more than 1% of the ordinary shares outstanding. At 24 February 2011, all directors and senior management as a group held interests in 9,736,214 ordinary shares or their calculated equivalent, 6,045,743 performance shares or their calculated equivalent and 1,479,297 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 117-118.

Employee share plans

The following table shows employee share options granted.

			Options thousands
	2010	2009	2008
Employee share options granted during the year[a]	**10,420**	9,680	8,063

[a] For the options outstanding at 31 December 2010, the exercise price ranges and weighted average remaining contractual lives are shown in Financial statements – Note 41 on page 214.

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 (*see Financial statements – Note 41 on page 214*) 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.

Savings and matching plans

BP ShareSave Plan

This is a savings-related share option plan under which employees save on a monthly basis, over a three- or five-year period, towards the purchase of shares at a fixed price determined when the option is granted. This price is usually set at a 20% discount to the market price at the time of grant. 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 will have six months in which to use their savings to exercise their options on a pro-rated basis.

BP ShareMatch plans

These are matching share plans under which BP matches employees' own contributions of shares up to a predetermined limit. The plans are run in the UK and in more than 60 other countries. The UK plan is run on a monthly basis with shares being held in trust for five years before they can be released free of any income tax and national insurance liability. 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.

Local plans

In some countries, BP provides local scheme benefits, the rules and qualifications for which vary according to local circumstances.

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 plans (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 plans. 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 ESOP trusts vest unconditionally in employees, the amount paid for those shares is deducted in arriving at shareholders' equity (*see Financial statements – Note 40 on page 210*). Assets and liabilities of the ESOPs are recognized as assets and liabilities of the group.

At 31 December 2010, the ESOPs held 11,477,253 shares (2009 18,062,246 shares and 2008 29,051,082 shares) for potential future awards, which had a market value of $82 million (2009 $174 million and 2008 $220 million).

Pursuant to the various BP group share option schemes, the following options for ordinary shares of the company were outstanding at 18 February 2011:

Options outstanding (shares)	Expiry dates of options	Exercise price per share
261,526,262	2011-2016	$6.09-$11.92

More details on share options appear in Financial statements – Note 41 on page 214.

Major shareholders and related party transactions

Register of members holding BP ordinary shares as at 31 December 2010

Range of holdings	Number of ordinary shareholders	Percentage of total ordinary shareholders	Percentage of total ordinary share capital
1-200	59,514	18.86	0.02
201-1,000	118,266	37.48	0.30
1,001-10,000	124,516	39.46	1.80
10,001-100,000	11,488	3.64	1.12
100,001-1,000,000	960	0.30	1.72
Over 1,000,000[a]	809	0.26	95.04
Totals	315,553	100.00	100.00

[a] Includes JPMorgan Chase Bank holding 25.88% 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 2010[a]

Range of holdings	Number of ADS holders	Percentage of total ADS holders	Percentage of total ADSs
1-200	64,433	55.73	0.46
201-1,000	32,209	27.85	1.89
1,001-10,000	17,933	15.51	5.85
10,001-100,000	1,051	0.91	2.18
100,001-1,000,000	11	0.00	0.21
Over 1,000,000[b]	1	0.00	89.41
Totals	115,638	100.00	100.00

[a] One ADS represents six 25 cent ordinary shares.
[b] One holder of ADSs represents some 795,382 underlying shareholders.

As at 31 December 2010, there were also 1,630 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.

Substantial shareholdings and other information

The disclosure of certain major interests in the share capital of the company is governed by the Disclosure and Transparency Rules (DTR) made by the UK Financial Services Authority and the US Securities Exchange Act of 1934. Under DTR 5, we have received notification that BlackRock, Inc. holds 5.72% of the voting rights of the issued share capital of the company; and Legal & General Group Plc holds 3.72% of the voting rights of the issued share capital of the company.

The company has been notified that JPMorgan Chase Bank, as depositary for American depositary shares (ADSs) holds interests through its nominee, Guaranty Nominees Limited, in 4,888,530,141 ordinary shares (26.01% of the company's ordinary share capital excluding shares held in treasury and shares bought back for cancellation). During 2009, BlackRock, Inc. acquired Barclays Global Investors, resulting in an increase in the share interest of BlackRock, Inc. BlackRock, Inc. holds interests in 1,078,318,880 ordinary shares (5.74% of the ordinary share capital excluding shares held in treasury and shares bought back for cancellation). Legal & General Group plc hold interests in 701,642,238 ordinary shares (3.73% of the company's ordinary share capital excluding shares held in treasury and shares bought back for cancellation). The company's major shareholders do not have different voting rights.

As part of an agreed strategic alliance with Rosneft Oil Company (Rosneft), the company has agreed to issue 5% of its ordinary share capital (excluding shares held in treasury and shares bought back for cancellation) to Rosneft in exchange for the receipt of approximately 9.5% of Rosneft's ordinary share capital. Once issued, these shares are subject to mutual lock-up arrangements. Neither party can, subject to certain exceptions, dispose of the other party's shares for a period of two years. The lock-up does not prevent Rosneft from accepting a takeover offer for the whole of the company's share capital or from providing an irrevocable undertaking to accept a takeover offer which has been recommended by the company. Following the expiration of the lock-up period, orderly marketing provisions will apply to the disposal of either party's shares.

See Legal proceedings on page 133 for information on an interim injunction, granted by the English High Court on 1 February 2011, restraining BP from taking any further steps in relation to the Rosneft transactions pending the outcome of arbitration proceedings.

The company has also been notified of the following interests in preference shares: The National Farmers Union Mutual Insurance Society Limited holds interests in 945,000 8% cumulative first preference shares (13.07% of that class) and 987,000 9% cumulative second preference shares (18.03% of that class). M & G Investment Management Ltd. holds interests in 528,150 8% cumulative first preference shares (7.30% of that class) and 644,450 9% cumulative second preference shares (11.77% of that class). Duncan Lawrie Ltd. holds interests in 459,876 8% cumulative first preference shares (6.36% of that class). Lazard Asset Management Ltd. holds interests in 374,000 8% cumulative first preference shares (5.17% of that class) and 404,500 9% cumulative second preference shares (7.39% of that class). Royal London Asset Management Ltd. holds interests in 438,000 9% cumulative second preference shares (8.00% of that class). Ruffer LLP holds interests in 398,000 9% cumulative second preference shares (7.27% of that class). 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.

The total preference shares in issue comprise only 0.44% of the company's total issued nominal share capital (excluding shares held in treasury), the rest being ordinary shares.

Related party transactions

Transactions between the group and its significant jointly controlled entities and associates are summarized in Financial statements – Note 25 on page 183 and Note 26 on page 184. 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 2010 to 18 February 2011.

Dividends

When dividends are paid on its ordinary shares, BP's policy is to pay interim dividends on a quarterly basis. During 2010 the BP board announced an agreed package of measures to meet its obligations as a responsible party arising from the Gulf of Mexico incident. As a consequence of this agreement, the BP board reviewed its dividend policy and decided that, in the circumstances, it would be prudent to cancel the previously announced first-quarter dividend and that no interim dividends would be announced in respect of the second and third quarters of 2010. On 1 February 2011 the BP board announced that it would pay a dividend for the fourth quarter 2010.

BP policy is to announce dividends for ordinary shares in US dollars and state an equivalent pounds sterling dividend. Dividends on BP ordinary shares will be paid in pounds 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.

The following table shows dividends announced and paid by the company per ADS for each of the past five years.

		March	June	September	December	Total
Dividends per American depositary share						
2006	UK pence	31.7	31.5	31.9	31.4	126.5
	US cents	56.25	56.25	58.95	58.95	230.4
	Canadian cents	64.5	64.1	67.4	66.5	262.5
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	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
	Canadian cents[a]	n/a	n/a	n/a	n/a	n/a
2010	**UK pence**	**52.07**	**–**	**–**	**–**	**52.07**
	US cents	**84**	**–**	**–**	**–**	**84**

[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.

Additional information for shareholders

A dividend reinvestment plan (DRIP) was in place for the fourth-quarter dividend paid in March 2010, allowing holders of BP ordinary shares to elect to reinvest the net cash dividend in shares purchased on the London Stock Exchange. Following shareholder approval at BP's AGM on 15 April 2010, a Scrip Dividend Programme (Programme) was introduced and the DRIP was withdrawn. The Programme 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 27-32 and other matters that may affect the business of the group set out in Our strategy on pages 19-20 and in Liquidity and capital resources on page 64.

Legal proceedings

Proceedings and investigations relating to the Gulf of Mexico 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 more than 400 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, where the Deepwater Horizon was deployed at the time of the Incident, and holds a 65% working interest. The other working interest owners are Anadarko Petroleum Company and MOEX Offshore 2007 LLC. 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 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, and wrongful death, commercial or 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, injunctive 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 and others who are property and/or business owners alleged to have suffered economic loss. Shareholder derivative lawsuits 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. Purported class action lawsuits have also been filed in US federal courts against BP entities and various current and former officers and directors alleging securities fraud claims and violations of the Employee Retirement Income Security Act (ERISA). 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 and ERISA cases and another in federal court in New Orleans for the remaining cases. Since late September, most of the Deepwater Horizon related cases have been pending before these courts. On 18 February 2011, certain Transocean affiliates filed a third party complaint against BP, the US government, and other corporations involved in the Incident, thereby naming those entities as formal parties in Transocean's Limitation of Liability action pending in federal court in New Orleans.

Under OPA 90, BP E&P has been designated as one of the 'responsible parties' for the oil spill resulting from the Incident. Accordingly, BP E&P is one of the parties that the US government alleges is financially responsible for the clean-up of the spill and for economic damages as provided by OPA 90. In addition, pursuant to OPA 90, the US Coast Guard has requested reimbursement from BP and the other responsible parties for its costs of responding to the Incident, and BP has paid all amounts so billed to date. Continuing requests for cost reimbursement are expected from the US Coast Guard and other governmental authorities. In addition, BP is participating with federal and state trustees in a co-operative assessment of potential natural resource damages associated with the spill. Under OPA 90, the US government alleges that BP E&P is one of the parties financially responsible for paying the reasonable assessment costs incurred by these trustees as well as natural resource damages that result from the Incident.

BP E&P has established and committed to fund the Deepwater Horizon Oil Spill Trust, a $20-billion trust fund to pay costs and satisfy legitimate claims. BP E&P contributed $5 billion to the trust fund in 2010. This will be supplemented by additional payments of $1.25 billion per quarter until a total of $20 billion has been paid into the trust fund. While the trust fund is building, BP E&P has pledged collateral consisting of an overriding royalty interest in oil and gas production from certain assets in the Gulf of Mexico sufficient at any time to secure the difference between the amount deposited as of that date and $20 billion. The establishment of this trust does not represent a cap on BP's liabilities, and BP does not admit to a liability of this amount. The trust fund will pay claims administered by the GCCF, state and local government claims resolved by BP, final judgments, settlements, state and local response costs, and natural resource damages and related costs. Payments from the trust fund will be made upon adjudication or resolution of claims or the final determination of other costs covered by the account. There will be a sunset on the trust fund, and funds, if any, remaining once the claims process has been completed will revert to BP E&P.

BP is subject to a number of investigations related to the Incident by numerous agencies of the US government. On 27 April 2010, the US Coast Guard and the Minerals Management Service (renamed the Bureau of Ocean Energy Management, Regulation and Enforcement in June 2010) convened a joint investigation of the Incident by establishing a Marine Board of Investigation aimed at determining the causes of the Incident and recommending safety improvements. BP was designated as one of several Parties in Interest in the investigation.

On 21 May 2010, President Obama signed an executive order establishing the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (National Commission) to examine and report on, within six months of the date of the Commission's first meeting, the relevant facts and circumstances concerning the causes of the Gulf of Mexico oil spill incident and develop options for guarding against, and mitigating the impact of, oil spills associated with offshore drilling, taking into consideration the environmental, public health, and economic effects of such options. On 11 January 2011, the National Commission published its final 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 about the causes of the Incident.

On 7 July 2010, the US Chemical Safety and Hazard Investigation Board (CSB) informed BP of its intent to conduct an investigation of the Incident. The investigation is focused on the 20 April 2010 explosions and fire, and not the resulting oil spill or response efforts. The CSB is expected to issue within two years several investigation reports 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 explosion, including the performance of the blowout preventer and related technology features, and to identify and recommend available technology, industry best practices, best available standards, and other measures in the US and around the world related to oil and gas deepwater exploratory drilling and well completion to avoid future occurrence of such events. On 17 November 2010 the Committee issued 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. We expect that the Committee will issue its final report that presents the Committee's final analysis, including findings and/or recommendations, by 1 June 2011 (a pre-publication version of report), with further peer review and a final published version to follow by 30 December 2011.

A second, unrelated National Academies' Committee will be looking at the methodologies available for assessing spill impacts on ecosystems in the Gulf of Mexico, and a summary of the known effects of the spill, the impacts in the context of stresses from other human activities in the Gulf, and identification of research and monitoring needs to more fully understand the effects of the spill and gauge progress towards recovery and restoration. On 14 June 2010, the US Coast Guard initiated an Incident Specific Preparedness Review (ISPR) to examine the implementation and effectiveness of the response and recovery operations relating to the spill. We understand that the ISPR process has been completed and a Report (Report) has been generated; however the Report has not yet been made publicly available. We expect that the Report will be made publicly available sometime in the first quarter of 2011. Additionally, BP representatives have appeared before multiple committees of the US Congress that have been conducting inquiries into the Incident. BP has provided documents and written information in response to requests by these committees and will continue to do so. See Risk factors – Compliance and control risks on page 29.

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 United States filed a civil complaint against BP E&P and others on 15 December 2010. The complaint seeks a declaration of liability under OPA 90 and civil penalties under the Clean Water Act. Paragraph 92 of the complaint sets forth a purported 'reservation of rights' on behalf of the United States to amend the complaint or file additional complaints seeking various remedies under various laws and regulations, including but not limited to eight specifically mentioned federal statutes. Paragraph 92 of the complaint likewise contains a similar 'reservation of rights' regarding the conduct of 'administrative proceedings' under 'the Outer Continental Shelf Lands Act, 43 U.S.C. §§ 1301 *et seq.*, and the Federal Oil and Gas Royalty Management Act, 30 U.S.C. §§ 1701 *et seq.*'

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. 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.

The Attorney General for the State of Alabama has filed a lawsuit seeking damages for alleged economic and environmental harms, including natural resource damages, as a result of the Incident. It is possible that the State Attorneys General of Louisiana, Mississippi, Florida, Texas or other states and/or local governments, such as coastal municipalities also may initiate investigations and bring civil or criminal actions seeking damages, penalties and fines for violating state or local statutes. The Louisiana Department of Environmental Quality has issued an administrative order seeking injunctive relief and environmental civil penalties under state law, and several local governments in 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 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 oil spill 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 oil spill.

BP's potential liabilities resulting from pending and 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. Furthermore, BP has taken a pre-tax charge in its income statement of $40.9 billion in total during 2010, and these potential liabilities may continue to have a material adverse effect on the group's results and financial condition.

Other legal proceedings

From 25 October 2007 to 23 October 2010, BP America Inc. (BP America) was subject to oversight by an independent monitor, who had authority to investigate and report alleged violations of the US Commodity Exchange Act or US Commodity Futures Trading Commission (CFTC) regulations and to recommend corrective action. The appointment of the independent monitor was a condition of the deferred prosecution agreement (DPA) entered into with the DoJ on 25 October 2007 relating to allegations that BP America manipulated the price of February 2004 TET physical propane and attempted to manipulate the price of TET propane in April 2003 and the companion consent order with the CFTC, entered the same day, resolving all criminal and civil enforcement matters pending at that time concerning propane trading by BP Products North America Inc. (BP Products). The DPA required BP America's and certain of its affiliates' continued co-operation with the US government's investigation and prosecution of the trades in question, as well as other trading matters that may arise. The DPA had a term of three years but could be extended by two additional one-year periods, and contemplated dismissal of all charges at the end of the term following the DoJ's determination that BP America has complied with the terms of the DPA. The initial three year term has expired and the DoJ's motion to dismiss the action underlying the DPA was granted on 31 January 2011. Investigations into BP's trading activities continue to be conducted from time to time. 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 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. The FERC staff will determine whether to pursue the investigation, to close the investigation, or to seek authority to pursue resolution by settlement. 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. BP submitted responses to both notices on 23 December 2010 providing a detailed response that it did not engage in any inappropriate or unlawful activity. Private complaints, including class actions, were also filed against BP Products and affiliates alleging propane price manipulation. The complaints contained allegations similar to those in the CFTC action as well as of violations of federal and state antitrust and unfair competition laws and state consumer protection statutes and unjust enrichment. The complaints sought actual and punitive damages and injunctive relief. Settlement in both groups of the class actions (the direct and indirect purchasers) has received final court approval. Two independent lawsuits from class members who opted out of the direct purchaser settlement are still pending.

On 23 March 2005, an explosion and fire occurred in the isomerization unit of 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 TCEQ, has filed a petition against BP Products asserting certain air emissions and reporting violations at the Texas City refinery from 2005 to 2010, including in relation to the March 2005 explosion and fire. BP is contesting the petition in a pending civil proceeding. In March 2010, TCEQ notified the DoJ of its belief that certain of the alleged violations may violate the 25 October 2007 plea agreement.

On 9 August 2010, the Texas Attorney General filed a separate petition against BP Products asserting emissions violations relating to a 6 April 2010 compressor fire and subsequent flaring event at the Texas City refinery's ultracracker unit. 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 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. BP Products contested these citations. These matters were subsequently transferred for review to the Occupational Safety and Health (OSH) Review Commission.

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 CAA and 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 has filed a motion to dismiss the shareholder derivative action.

On 29 November 2007, BP Exploration (Alaska) Inc. (BPXA) entered into a criminal plea agreement with the DoJ relating to leaks of crude oil in March and August 2006. 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 an allegation that the Lisburne event was a criminal violation of state or federal law. A hearing is scheduled for the week of 25 April 2011. 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. Briefing is complete and we await oral argument.

On 31 March 2009, the DoJ filed a complaint against BPXA seeking civil penalties and injunctive relief relating to the 2006 oil releases. The complaint alleges that BPXA violated various federal environmental and pipeline safety statutes and associated regulations in connection with the two releases and its maintenance and operation of North Slope pipelines. The State of Alaska also filed a complaint on 31 March 2009 against BPXA 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.

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 before the OSH Review Commission which has assigned an Administrative Law Judge for purposes of mediation.

BP is the operator and 56% interest owner of the Atlantis unit in production in the Gulf of Mexico. 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. That complaint was unsealed in May 2010 and served on BP in June 2010. 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.

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. The agreement requires that BP Products pays a $15-million civil penalty and that the Texas City refinery 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 operating permit 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. The EPA, either through the IDEM or directly, can cause the permit to be modified, reissued, terminated or revoked. BP is in discussions with the EPA and the IDEM over these and other CAA issues relating to the Whiting refinery.

BP is also in settlement negotiations with EPA to resolve alleged CAA violations at the Whiting, 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 the shareholders agreement on the part of BP and seeking an interim injunction restraining BP from taking steps to conclude, implement or perform the previously announced transactions with Rosneft Oil Company relating to oil and gas exploration, production, refining and marketing in Russia. Those transactions include the issue or transfer of shares between Rosneft Oil Company and any BP group company. 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 injunction has been extended until 11 March 2011 pending an expedited hearing in relation to matters in dispute between the parties on a final basis during the week commencing 7 March 2011. The expedited hearing will decide, among other matters, whether the injunction will be extended beyond 11 March 2011.

On 9 February 2011, Apache Canada Ltd commenced an arbitration against BP Canada Energy. Apache alleges that in the future various of the sites that it acquired from BP Canada Energy pursuant to the parties' July 2010 Purchase and Sale Agreement will have to have work carried out to bring the sites into compliance with applicable Alberta environmental laws, and Apache Canada Ltd 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 process of selecting the arbitrator has begun. No hearing dates have been set.

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 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, Floor 58, 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 New York Stock Exchange (NYSE), respectively.

	Pence		Dollars	
	Ordinary shares		American depositary shares[a]	
	High	Low	High	Low
Year ended 31 December				
2006	723.00	558.50	76.85	63.52
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**
Year ended 31 December				
2009: First quarter	566.50	400.00	49.83	33.71
Second quarter	543.75	426.50	53.24	38.50
Third quarter	568.50	459.25	55.61	44.63
Fourth quarter	613.40	528.00	60.00	50.60
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 (to 18 February)	**514.90**	**471.65**	**49.50**	**44.83**
Month of				
September 2010	**436.15**	**375.75**	**41.30**	**35.67**
October 2010	**443.50**	**418.25**	**42.08**	**39.58**
November 2010	**459.20**	**420.70**	**44.37**	**39.76**
December 2010	**479.00**	**426.15**	**44.83**	**40.15**
January 2011	**514.90**	**479.00**	**49.50**	**44.83**
February 2011 (to 18 February)	**495.60**	**471.65**	**48.28**	**45.46**

[a] An 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 18 February 2011, 814,755,024 ADSs (equivalent to approximately 4,888,530,144 ordinary shares or some 26.01% of the total issued share capital, excluding shares held in treasury and shares bought back for cancellation) were outstanding and were held by approximately 114,834 ADS holders. Of these, about 113,490 had registered addresses in the US at that date. One of the registered holders of ADSs represents some 795,382 underlying holders.

On 18 February 2011, there were approximately 314,847 holders of record of ordinary shares. Of these holders, around 1,574 had registered addresses in the US and held a total of some 4,289,836 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 is capped at $1.25 billion per quarter and $17 billion in total. Verano has pledged the overriding royalty interest to the Trust as collateral for BP's remaining contribution obligations to the Trust. BP contributed a further $2 billion to the trust fund since this arrangement was established, thereby reducing the amount of the pledge to $15 billion at the end of the year. An event of default under the Pledge Agreement will arise if BP fails to make any contribution under the Trust Agreement when due or otherwise fails to observe certain other obligations, subject to specified cure periods. Following an event of default, the trustees will be 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 is governed by the laws of the State of Texas.

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 are 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, the 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.

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. Capital gain of a non-corporate US holder that is recognized in taxable years beginning before 1 January 2013 is generally taxed at a maximum rate of 15% 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, 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 ratably 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 2010 is also available online at *www.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 or log on to *www.sec.gov*. In addition, BP's SEC filings are available to the public at the SEC's website *www.sec.gov*. BP discloses on its website at *www.bp.com/NYSEcorporategovernancerules*, and in this report (see *Corporate governance practices (Form 20-F Item 16G) on page 105*) 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 15 April 2010, authorization was given to repurchase up to 1.9 billion ordinary shares in the period to the next AGM in 2011 or 15 July 2011, 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 2010 to 18 February 2011.

The following table provides details of share purchases made by ESOP trusts.

	Total number of shares purchased	Average paid per share $	Total number of shares purchased as part of publicly announced programmes	Maximum number of shares that may yet be purchased under the programme[a]
2010				
January	**51**	**10.36**		
February	**144,523**	**11.41**		
March	**626**	**8.41**		
April	**5,001,610**	**11.41**		
May	**1,941,069**	**11.41**		
June	**181,384**	**11.41**		
July	**4,550,658**	**6.25**		
August	**849**	**6.82**		
September	**817,606**	**6.32**		
October	**nil**			
November	**280,559**	**7.20**		
December	**38**	**7.18**		
2011				
January	**338,506**	**7.86**		
February (to 18 February)	**311,362**	**7.60**		

[a] No shares were repurchased pursuant to a publicly announced plan. Transactions represent the purchase of ordinary shares by ESOP trusts to satisfy future requirements of employee share schemes.

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 serviceDepositary 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 $4,647,254 for the year ended 31 December 2010.

The table below sets forth the types of expenses that the Depositary has agreed to reimburse, and the invoices relating to the year ended 31 December 2010 that were reimbursed:

Category of expense reimbursed to the company	Amount reimbursed for the year ended 31 December 2010
NYSE listing fees	$500,000
Total	$500,000

The Depositary has also agreed to waive fees for standard costs associated with the administration of the ADS programme and has paid certain expenses directly to third parties on behalf of the company. The table below sets forth those expenses that the Depositary waived or paid directly to third parties relating to the year ended 31 December 2010:

Category of expense waived or paid directly to third parties	Amount reimbursed for the year ended 31 December 2010
Service fees and out of pocket expenses waived[a]	$2,802,482
Broker reimbursements[b]	$1,150,475
Other third-party mailing costs[c]	$136,542
Legal advice[d]	$26,391
Other third-party expenses paid directly	$31,364
Total	$4,147,254

[a] Includes fees in relation to transfer agent costs and costs of the of BP Direct Access Plan operated by JPMorgan Chase.
[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 and CIBC Mellon for distribution of hard copy materials to ADR beneficial holders, 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.

Called-up share capital

Details of the allotted, called-up and fully-paid share capital at 31 December 2010 are set out in Financial statements – Note 39 on page 209.

At the AGM on 15 April 2010, authorization was given to the directors to allot shares up to an aggregate nominal amount equal to $3,143 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 $236 million, without having to offer such shares to existing shareholders. These authorities are given for the period until the next AGM in 2011 or 15 July 2011, whichever is the earlier. These authorities are renewed annually at the AGM.

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 ADS Depositary.

UK – Registrar's Office
The BP Registrar, Equiniti
Aspect House, Spencer Road, Lancing, West Sussex BN99 6DA
Freephone in UK 0800 701107; tel +44 (0)121 415 7005
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.

US – ADS Depositary
JPMorgan Chase Bank, N.A.
PO Box 64504, St Paul, MN 55164-0504
Toll-free in US and Canada +1 877 638 5672; tel +1 651 306 4383
For the hearing impaired +1 651 453 2133

Annual general meeting

The 2011 AGM will be held on Thursday, 14 April 2011 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 2011*.

By order of the board
David J Jackson
Secretary
2 March 2011

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	Amended Director's Service Contract and Secondment Agreement for R W Dudley†
Exhibit 4.3	Amended Director's Service Contract and Secondment Agreement for B E Grote†
Exhibit 7.	Computation of Ratio of Earnings to Fixed Charges (Unaudited)†
Exhibit 8.	Subsidiaries (included as Note 46 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	Pledge and Collateral Agreement dated as of 30 September 2010 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#†
Exhibit 99.	Deepwater Horizon Accident Investigation Report**

* Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2009.

** Incorporated by reference to the Company's Report on Form 6-K filed on 24 September 2010 (File No. 001-06262).

\# 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.

Financial statements

142 Consolidated financial statements of the BP group

150 Notes on financial statements

228 Supplementary information on oil and natural gas (unaudited)

PC1 Parent company financial statements of BP p.l.c.

Consolidated financial statements of the BP group

Statement of directors' responsibilities in respect of the consolidated financial statements

The directors are responsible for preparing the Annual Report and the consolidated financial statements in accordance with applicable United Kingdom law, International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board and IFRS as adopted by the European Union.

The directors are required to prepare financial statements for each financial year that present fairly the financial position of the group and the financial performance and cash flows of the group for that period. In preparing those financial statements, the directors are required to:

- Select suitable accounting policies and then apply them consistently.
- Present information, including accounting policies, in a manner that provides relevant, reliable, comparable and understandable information.
- Provide additional disclosure when compliance with the specific requirements of IFRS is insufficient to enable users to understand the impact of particular transactions, other events and conditions on the group's financial position and financial performance.
- State that the company has complied with IFRS, subject to any material departures disclosed and explained in the consolidated financial statements.

The directors are responsible for keeping proper accounting records that disclose with reasonable accuracy at any time the financial position of the group and enable them to ensure that the consolidated financial statements comply with the Companies Act 2006 and Article 4 of the IAS Regulation. They are also responsible for safeguarding the assets of the group and hence for taking reasonable steps for the prevention and detection of fraud and other irregularities.

The directors draw attention to Notes 2, 37 and 44 on the financial statements which describe the uncertainties surrounding the amounts and timings of liabilities arising from the Gulf of Mexico oil spill.

The group's business activities, performance, position and risks are set out in this report. The financial position of the group, its cash flows, liquidity position and borrowing facilities are detailed in the appropriate sections on pages 63 to 67 and elsewhere in the notes on financial statements. The report also includes details of the group's risk mitigation and management. Information on the Gulf of Mexico oil spill and BP's response is included on pages 34 to 39 and elsewhere in this report, including Corporate responsibility on pages 68 to 76. The group has considerable financial resources, and the directors believe that the group is well placed to manage its business risks successfully. After making enquiries, the directors have a reasonable expectation that the company and the group have adequate resources to continue in operational existence for the foreseeable future. Accordingly, they continue to adopt the going concern basis in preparing the annual report and accounts.

Having made the requisite enquiries, so far as the directors are aware, there is no relevant audit information (as defined by Section 418(3) of the Companies Act 2006) of which the group's auditors are unaware, and the directors have taken all the steps they ought to have taken to make themselves aware of any relevant audit information and to establish that the group's auditors are aware of that information.

The directors confirm that to the best of their knowledge:

- The consolidated financial statements, prepared in accordance with IFRS as issued by the International Accounting Standards Board, IFRS as adopted by the European Union and in accordance with the provisions of the Companies Act 2006, give a true and fair view of the assets, liabilities, financial position and profit or loss of the group; and
- The management report, which is incorporated in the directors' report, includes a fair review of the development and performance of the business and the position of the group, together with a description of the principal risks and uncertainties.

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

Independent auditor's report on the Annual Report and Accounts to the members of BP p.l.c.

We have audited the consolidated financial statements of BP p.l.c. for the year ended 31 December 2010 which comprise the group income statement, the group statement of comprehensive income, the group statement of changes in equity, the group balance sheet, the group cash flow statement and the related notes 1 to 46. The financial reporting framework that has been applied in their preparation is applicable law and International Financial Reporting Standards (IFRS) as adopted by the European Union.

This report is made solely to the company's members, as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for this report, or for the opinions we have formed.

Respective responsibilities of directors and auditors

As explained more fully in the Statement of directors' responsibilities in respect of the consolidated financial statements set out on page 142, the directors are responsible for the preparation of the consolidated financial statements and for being satisfied that they give a true and fair view. Our responsibility is to audit and express an opinion on the consolidated financial statements in accordance with applicable law and International Standards on Auditing (UK and Ireland). Those standards require us to comply with the Auditing Practices Board's Ethical Standards for Auditors.

Scope of the audit of the financial statements

An audit involves obtaining evidence about the amounts and disclosures in the financial statements sufficient to give reasonable assurance that the financial statements are free from material misstatement, whether caused by fraud or error. This includes an assessment of: whether the accounting policies are appropriate to the group's circumstances and have been consistently applied and adequately disclosed; the reasonableness of significant accounting estimates made by the directors; and the overall presentation of the financial statements.

Opinion on financial statements

In our opinion the consolidated financial statements:

- give a true and fair view of the state of the group's affairs as at 31 December 2010 and of its loss for the year then ended;
- have been properly prepared in accordance with IFRS as adopted by the European Union; and
- have been prepared in accordance with the requirements of the Companies Act 2006 and Article 4 of the IAS Regulation.

Separate opinion in relation to IFRS as issued by the International Accounting Standards Board

As explained in Note 1 to the consolidated financial statements, the group in addition to applying IFRS as adopted by the European Union, has also applied IFRS as issued by the International Accounting Standards Board (IASB).

In our opinion the consolidated financial statements comply with IFRS as issued by the IASB.

Emphasis of matter – significant uncertainty over provisions and contingencies related to the Gulf of Mexico oil spill

In forming our opinion we have considered the adequacy of the disclosures made in Notes 2, 37 and 44 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. Actual costs could ultimately be significantly higher or lower than those recorded as the claims and settlement process progresses. Our opinion is not qualified in respect of these matters.

Opinion on other matter prescribed by the Companies Act 2006

In our opinion the information given in the Directors' Report for the financial year for which the consolidated financial statements are prepared is consistent with the consolidated financial statements.

Matters on which we are required to report by exception

We have nothing to report in respect of the following:

Under the Companies Act 2006 we are required to report to you if, in our opinion:

- certain disclosures of directors' remuneration specified by law are not made; or
- we have not received all the information and explanations we require for our audit.

Under the Listing Rules we are required to review:

- the directors' statement, set out on page 142, in relation to going concern;
- the part of the BP board performance report relating to the company's compliance with the nine provisions of the June 2008 Combined Code specified for our review; and
- certain elements of the report to shareholders by the Board on directors' remuneration.

Other matter

We have reported separately on the parent company financial statements of BP p.l.c. for the year ended 31 December 2010 and on the information in the Directors' Remuneration Report that is described as having been audited.

Ernst & Young LLP
Allister Wilson (Senior Statutory Auditor)
for and on behalf of Ernst & Young LLP, Statutory Auditor
London
2 March 2011

Financial statements

The maintenance and integrity of the BP p.l.c. website are the responsibility of the directors; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the website.
Legislation in the United Kingdom governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

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

Report of Independent Registered Public Accounting Firm 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 2010 and 2009, and the related group income statement, group cash flow statement, group statement of comprehensive income and group statement of changes in equity, for each of the three years in the period ended 31 December 2010. 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 2010 and 2009, and the group results of operations and cash flows for each of the three years in the period ended 31 December 2010, 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, 37 and 44 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. Actual costs could ultimately be significantly higher or lower than those recorded as the claims and settlement process progresses. 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 2010, 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 2 March 2011 expressed an unqualified opinion thereon.

/s/ERNST & YOUNG LLP
Ernst & Young LLP
London, England
2 March 2011

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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 BP p.l.c.'s internal control over financial reporting as of 31 December 2010, 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 106. 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 2010, 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 2010 and 2009, and the related group income statement, group cash flow statement, group statement of comprehensive income and group statement of changes in equity, for each of the three years in the period ended 31 December 2010, and our report dated 2 March 2011 expressed an unqualified opinion thereon.

/s/ERNST & YOUNG LLP
Ernst & Young LLP
London, England
2 March 2011

Consent of independent registered public accounting firm

We consent to the incorporation by reference of our reports dated 2 March 2011 with respect to the group financial statements of BP p.l.c., and the effectiveness of internal control over financial reporting of BP p.l.c., included in this Annual Report (Form 20-F) for the year ended 31 December 2010 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 and 333-132619) of BP p.l.c.

/s/ERNST & YOUNG LLP
Ernst & Young LLP
London, England
2 March 2011

The maintenance and integrity of the BP p.l.c. website are the responsibility of the directors; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the website.
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Group income statement

For the year ended 31 December				$ million
	Note	**2010**	2009	2008
Sales and other operating revenues	7	**297,107**	239,272	361,143
Earnings from jointly controlled entities – after interest and tax		**1,175**	1,286	3,023
Earnings from associates – after interest and tax		**3,582**	2,615	798
Interest and other income	8	**681**	792	736
Gains on sale of businesses and fixed assets	5	**6,383**	2,173	1,353
Total revenues and other income		**308,928**	246,138	367,053
Purchases		**216,211**	163,772	266,982
Production and manufacturing expenses[a]		**64,615**	23,202	26,756
Production and similar taxes	9	**5,244**	3,752	8,953
Depreciation, depletion and amortization	10	**11,164**	12,106	10,985
Impairment and losses on sale of businesses and fixed assets	5	**1,689**	2,333	1,733
Exploration expense	16	**843**	1,116	882
Distribution and administration expenses	12	**12,555**	14,038	15,412
Fair value (gain) loss on embedded derivatives	34	**309**	(607)	111
Profit (loss) before interest and taxation		**(3,702)**	26,426	35,239
Finance costs[a]	18	**1,170**	1,110	1,547
Net finance expense (income) relating to pensions and other post-retirement benefits	38	**(47)**	192	(591)
Profit (loss) before taxation		**(4,825)**	25,124	34,283
Taxation[a]	19	**(1,501)**	8,365	12,617
Profit (loss) for the year		**(3,324)**	16,759	21,666
Attributable to				
BP shareholders		**(3,719)**	16,578	21,157
Minority interest		**395**	181	509
		(3,324)	16,759	21,666
Earnings per share – cents				
Profit (loss) for the year attributable to BP shareholders				
Basic	21	**(19.81)**	88.49	112.59
Diluted	21	**(19.81)**	87.54	111.56

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

Group statement of comprehensive income

For the year ended 31 December	Note	2010	2009	2008
				$ million
Profit (loss) for the year		**(3,324)**	16,759	21,666
Currency translation differences		**259**	1,826	(4,362)
Exchange gains on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets		**(20)**	(27)	–
Actuarial loss relating to pensions and other post-retirement benefits	38	**(320)**	(682)	(8,430)
Available-for-sale investments marked to market		**(191)**	705	(994)
Available-for-sale investments – recycled to the income statement		**(150)**	2	526
Cash flow hedges marked to market		**(65)**	652	(1,173)
Cash flow hedges – recycled to the income statement		**(25)**	366	45
Cash flow hedges – recycled to the balance sheet		**53**	136	(38)
Taxation	19	**(137)**	525	2,946
Other comprehensive income		**(596)**	3,503	(11,480)
Total comprehensive income		**(3,920)**	20,262	10,186
Attributable to				
BP shareholders		**(4,318)**	20,137	9,752
Minority interest		**398**	125	434
		(3,920)	20,262	10,186

Group statement of changes in equity

	2010 BP shareholders' equity	2010 Minority interest	2010 Total equity	2009 BP shareholders' equity	2009 Minority interest	2009 Total equity	2008 BP shareholders' equity	2008 Minority interest	2008 Total equity
									$ million
At 1 January	**101,613**	**500**	**102,113**	91,303	806	92,109	93,690	962	94,652
Total comprehensive income	**(4,318)**	**398**	**(3,920)**	20,137	125	20,262	9,752	434	10,186
Dividends	**(2,627)**	**(315)**	**(2,942)**	(10,483)	(416)	(10,899)	(10,342)	(425)	(10,767)
Repurchase of ordinary share capital	**–**	**–**	**–**	–	–	–	(2,414)	–	(2,414)
Share-based payments (net of tax)	**339**	**–**	**339**	721	–	721	617	–	617
Changes in associates' equity	**–**	**–**	**–**	(43)	–	(43)	–	–	–
Transactions involving minority interests	**(20)**	**321**	**301**	(22)	(15)	(37)	–	(165)	(165)
At 31 December	**94,987**	**904**	**95,891**	101,613	500	102,113	91,303	806	92,109

Financial statements

Group balance sheet

At 31 December			$ million
	Note	**2010**	2009
Non-current assets			
Property, plant and equipment	22	**110,163**	108,275
Goodwill	23	**8,598**	8,620
Intangible assets	24	**14,298**	11,548
Investments in jointly controlled entities	25	**12,286**	15,296
Investments in associates	26	**13,335**	12,963
Other investments	28	**1,191**	1,567
Fixed assets		**159,871**	158,269
Loans		**894**	1,039
Other receivables	30	**6,298**	1,729
Derivative financial instruments	34	**4,210**	3,965
Prepayments		**1,432**	1,407
Deferred tax assets	19	**528**	516
Defined benefit pension plan surpluses	38	**2,176**	1,390
		175,409	168,315
Current assets			
Loans		**247**	249
Inventories	29	**26,218**	22,605
Trade and other receivables	30	**36,549**	29,531
Derivative financial instruments	34	**4,356**	4,967
Prepayments		**1,574**	1,753
Current tax receivable		**693**	209
Other investments	28	**1,532**	–
Cash and cash equivalents	31	**18,556**	8,339
		89,725	67,653
Assets classified as held for sale	4	**7,128**	–
		96,853	67,653
Total assets		**272,262**	235,968
Current liabilities			
Trade and other payables	33	**46,329**	35,204
Derivative financial instruments	34	**3,856**	4,681
Accruals		**5,612**	6,202
Finance debt	35	**14,626**	9,109
Current tax payable		**2,920**	2,464
Provisions	37	**9,489**	1,660
		82,832	59,320
Liabilities directly associated with assets classified as held for sale	4	**1,047**	–
		83,879	59,320
Non-current liabilities			
Other payables	33	**14,285**	3,198
Derivative financial instruments	34	**3,677**	3,474
Accruals		**637**	703
Finance debt	35	**30,710**	25,518
Deferred tax liabilities	19	**10,908**	18,662
Provisions	37	**22,418**	12,970
Defined benefit pension plan and other post-retirement benefit plan deficits	38	**9,857**	10,010
		92,492	74,535
Total liabilities		**176,371**	133,855
Net assets		**95,891**	102,113
Equity			
Share capital	39	**5,183**	5,179
Reserves		**89,804**	96,434
BP shareholders' equity	40	**94,987**	101,613
Minority interest	40	**904**	500
Total equity	40	**95,891**	102,113

C-H Svanberg Chairman
R W Dudley Group Chief Executive
2 March 2011

Group cash flow statement

For the year ended 31 December				$ million
	Note	**2010**	2009	2008
Operating activities				
Profit (loss) before taxation		**(4,825)**	25,124	34,283
Adjustments to reconcile profit (loss) before taxation to net cash provided by operating activities				
Exploration expenditure written off	16	**375**	593	385
Depreciation, depletion and amortization	10	**11,164**	12,106	10,985
Impairment and (gain) loss on sale of businesses and fixed assets	5	**(4,694)**	160	380
Earnings from jointly controlled entities and associates		**(4,757)**	(3,901)	(3,821)
Dividends received from jointly controlled entities and associates		**3,277**	3,003	3,728
Interest receivable		**(277)**	(258)	(407)
Interest received		**205**	203	385
Finance costs	18	**1,170**	1,110	1,547
Interest paid		**(912)**	(909)	(1,291)
Net finance expense (income) relating to pensions and other post-retirement benefits	38	**(47)**	192	(591)
Share-based payments		**197**	450	459
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans		**(959)**	(887)	(173)
Net charge for provisions, less payments		**19,217**	650	(298)
(Increase) decrease in inventories		**(3,895)**	(5,363)	9,010
(Increase) decrease in other current and non-current assets		**(15,620)**	7,595	2,439
Increase (decrease) in other current and non-current liabilities		**20,607**	(5,828)	(6,101)
Income taxes paid		**(6,610)**	(6,324)	(12,824)
Net cash provided by operating activities		**13,616**	27,716	38,095
Investing activities				
Capital expenditure		**(18,421)**	(20,650)	(22,658)
Acquisitions, net of cash acquired		**(2,468)**	1	(395)
Investment in jointly controlled entities		**(461)**	(578)	(1,009)
Investment in associates		**(65)**	(164)	(81)
Proceeds from disposals of fixed assets	5	**7,492**	1,715	918
Proceeds from disposals of businesses, net of cash disposed	5	**9,462**	966	11
Proceeds from loan repayments		**501**	530	647
Other		**–**	47	(200)
Net cash used in investing activities		**(3,960)**	(18,133)	(22,767)
Financing activities				
Net issue (repurchase) of shares		**169**	207	(2,567)
Proceeds from long-term financing		**11,934**	11,567	7,961
Repayments of long-term financing		**(4,702)**	(6,021)	(3,821)
Net decrease in short-term debt		**(3,619)**	(4,405)	(1,315)
Dividends paid				
BP shareholders		**(2,627)**	(10,483)	(10,342)
Minority interest		**(315)**	(416)	(425)
Net cash provided by (used in) financing activities		**840**	(9,551)	(10,509)
Currency translation differences relating to cash and cash equivalents		**(279)**	110	(184)
Increase in cash and cash equivalents		**10,217**	142	4,635
Cash and cash equivalents at beginning of year		**8,339**	8,197	3,562
Cash and cash equivalents at end of year		**18,556**	8,339	8,197

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 2010 were approved and signed by the chairman and group chief executive on 2 March 2011 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 2010, or issued and early adopted. The standards and interpretations adopted in the year are described further on page 157.

The accounting policies that follow have been consistently applied to all years presented. The group balance sheet as at 1 January 2009 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 124 to 127, 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 7.

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's 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

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 equity. On 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 the income statement.

Business combinations and goodwill

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 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.

At the acquisition date, any goodwill acquired is allocated to each of the cash-generating units expected to benefit from the combination's synergies. For this purpose, cash-generating units are set at one level below a business segment.

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.

Business combinations undertaken prior to 2010 were accounted for using the acquisition method of accounting but there were some differences in the accounting treatment compared to what is required for 2010. See *Impact of new International Financial Reporting Standards* on page 157 for further information. There were no material business combinations undertaken prior to 2010 in the periods covered by these financial statements.

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.

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 expenditure 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.

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.

1. Significant accounting policies continued

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 and excluding future drilling costs.

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 value 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 value 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 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 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.

1. Significant accounting policies continued

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 revenues 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.
- Hedges of a net investment in a foreign operation.

At the inception of a hedge relationship the group formally designates and documents the hedge relationship for which the group wishes to claim hedge accounting, 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 rate 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 equity 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.

Hedges of a net investment in a foreign operation

For hedges of a net investment in a foreign operation, 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 equity are transferred to the income statement when the foreign operation is sold or partially disposed of.

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.

1. Significant accounting policies continued

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.

Amounts that BP has a contractual right to recover from third parties are contingent assets. Such amounts are not recognized in the accounts unless they are virtually certain to be received.

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 will be 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.

1. Significant accounting policies continued

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 effect on the fair value of plan assets 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.

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 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 the accounting profit nor taxable profit or loss.
- In respect of taxable temporary differences associated with investments in subsidiaries, jointly controlled entities and associates, except 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 the 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 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 as part of 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 Plans (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.

1. Significant accounting policies continued

Revenue

Revenue arising from the sale of goods is recognized when the significant risks and rewards of ownership have passed to the buyer and it 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.

Revenues associated with the sale of oil, natural gas, natural gas liquids, liquefied natural gas, petroleum and petrochemicals products and all other items are recognized when the title passes to the customer. 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 2010

The following revised or amended IFRSs were adopted by the group with effect from 1 January 2010.

In January 2008, the IASB issued a revised version of IFRS 3 'Business Combinations'. The revised standard still requires the purchase method of accounting to be applied to business combinations but introduces some changes to the accounting treatment. For example, contingent consideration is measured at fair value at the date of acquisition and subsequently remeasured to fair value with changes recognized in profit or loss. Goodwill may be calculated based on the parent's share of net assets or it may include goodwill related to the minority interest. All transaction costs are expensed. Assets and liabilities arising from business combinations that occurred before 1 January 2010 were not required to be restated and thus, on adoption there was no effect on the group's reported income or net assets.

In January 2008, the IASB issued a revised version of IAS 27 'Consolidated and Separate Financial Statements', which requires the effects of all transactions with minority interests to be recorded in equity if there is no change in control. When control is lost, any remaining interest in the entity is remeasured to fair value and a gain or loss recognized in profit or loss. There was no effect on the group's reported income or net assets on adoption.

In addition, several other standards and interpretations were adopted in the year which had no significant impact on the financial statements.

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.

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 new standard is effective for annual periods beginning on or after 1 January 2013 with transitional arrangements depending upon the date of initial application. BP has not yet decided the date of initial application 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.

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 34 to 39, BP has incurred costs during the year and has 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 37 for provisions and Note 44 for contingent liabilities. BP's rights and obligations in relation to the $20-billion trust fund which was established during the year have been 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
		2010
	Total	Of which: amount related to the trust fund
Income statement		
Production and manufacturing expenses	**40,858**	**7,261**
Profit (loss) before interest and taxation	**(40,858)**	**(7,261)**
Finance costs	**77**	**73**
Profit (loss) before taxation	**(40,935)**	**(7,334)**
Less: Taxation	**12,894**	**–**
Profit (loss) for the period	**(28,041)**	**(7,334)**
Balance sheet		
Current assets		
Trade and other receivables	**5,943**	**5,943**
Current liabilities		
Trade and other payables	**(6,587)**	**(5,002)**
Provisions	**(7,938)**	**–**
Net current liabilities	**(8,582)**	**941**
Non-current assets		
Other receivables	**3,601**	**3,601**
Non-current liabilities		
Other payables	**(9,899)**	**(9,899)**
Provisions	**(8,397)**	**–**
Deferred tax	**11,255**	**–**
Net non-current liabilities	**(3,440)**	**(6,298)**
Net assets	**(12,022)**	**(5,357)**
Cash flow statement		
Profit (loss) before taxation	**(40,935)**	**(7,334)**
Finance costs	**77**	**73**
Net charge for provisions, less payments	**19,354**	**–**
Increase in other current and non-current assets	**(12,567)**	**(12,567)**
Increase in other current and non-current liabilities	**16,413**	**14,828**
Pre-tax cash flows	**(17,658)**	**(5,000)**

Trust fund

BP has 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 quarterly contributions of $1.25 billion are to be made during 2011 to 2013. The income statement charge for 2010 includes $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. 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. BP will not settle any such items directly or receive reimbursement from the trust fund for such items.

2. Significant event – Gulf of Mexico oil spill continued

BP's obligation to make contributions to the trust fund was recognized in full, 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 $5 billion to the trust fund during 2010, and adjustments for discounting, the remaining liability as at 31 December 2010 was $14,901 million. This liability is recorded within other payables on the balance sheet, apportioned between current and non-current elements according to the agreed schedule of contributions.

The table below shows movements in the funding obligation, recognized within other payables on the balance sheet, during the period to 31 December 2010.

	$ million
Trust fund liability initially recognized – discounted	**19,580**
Unwinding of discount	**73**
Change in discount rate	**240**
Contributions	**(5,000)**
Other	**8**
At 31 December 2010	**14,901**
Of which – current	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.

The portion of the provision recognized during the year for items that will be covered by the trust fund was $12,567 million. Of this amount, payments of $3,023 million were made during the year from the trust fund. The remaining reimbursement asset as at 31 December 2010 was $9,544 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 2010 that will be covered by the trust fund – see Note 37 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
Increase in provision for items covered by the trust fund	**12,567**
Amounts paid directly by the trust fund	**(3,023)**
At 31 December 2010	**9,544**
Of which – current	5,943
– non-current	3,601

The amount of the income statement charge related to the trust fund comprises:

	$ million
Trust fund liability – discounted	**19,580**
Change in discount rate relating to trust fund liability	**240**
Recognition of reimbursement asset	**(12,567)**
Other	**8**
Total charge relating to the trust fund	**7,261**

As noted above, the obligation to fund the $20-billion trust fund has been recognized in full. Any increases in the provision that will be 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. These charges for provisions, and the associated reimbursement asset, recognized during the year amounted to $12,567 million. Thus, a further $7,433 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 44.

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, 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.

On 30 September 2010, BP 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 is capped at $1.25 billion per quarter and $17 billion in total. Verano has pledged the overriding royalty interest to the Trust as collateral for BP's remaining contribution obligations to the Trust. BP contributed a further $2 billion to the trust fund since this arrangement was established, thereby reducing the amount of the pledge to $15 billion at the end of the year. There is 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.

2. Significant event – Gulf of Mexico oil spill continued

Provisions and contingencies

At 31 December 2010 BP has recorded certain provisions and disclosed certain contingencies 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. A provision has also been recorded for claims administration costs and natural resource damage assessment costs.

BP considers that it is not possible to measure reliably any obligation in relation to Natural Resource Damages claims under OPA 90 or litigation for violations of OPA 90. 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 with the exception of claims administration costs which are borne separately by BP. 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. The establishment of the trust fund does not represent a cap or floor on BP's liabilities and BP does not admit liability for this amount.

Other items

Provisions at 31 December 2010 also include amounts in relation to offshore and onshore 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 legal fees where we have been able to estimate reliably those which will arise in the next two years. 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 or any obligation in relation to legal fees beyond two years. These items are therefore disclosed as contingent liabilities.

No amounts have been recognized for recovery of costs from our co-owners of the Macondo well because under IFRS recovery must be virtually certain for receivables to be recognized. All of these items are therefore disclosed as contingent assets.

Further information on provisions is provided below and in Note 37. Further information on contingent liabilities and contingent assets is provided in Note 44.

A provision has been recognized for estimated future expenditure relating to the oil spill, for items that can be reliably measured at this time, 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 $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 $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 2010 was $16,335 million.

Movements in the provision are presented in the table below.

	$ million
Increase in provision – items not covered by the trust fund	**17,694**
– items covered by the trust fund	**12,567**
Unwinding of discount	**4**
Change in discount rate	**5**
Utilization – paid by BP	**(10,912)**
– paid by the trust fund	**(3,023)**
At 31 December 2010	**16,335**
Of which – current	7,938
– non-current	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. Furthermore, the amount of claims that become payable by BP, the amount of fines ultimately levied on BP (including any determination of BP's negligence), the outcome of litigation, 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 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.

2. Significant event – Gulf of Mexico oil spill continued

Impact upon the group income statement and cash flow statement

The group income statement for 2010 includes a pre-tax charge of $40,935 million in relation to the Gulf of Mexico oil spill. This comprises costs incurred up to 31 December 2010, 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 $77 million reflect the unwinding of discount on the trust fund liability and provisions.

The amount of the provision recognized during the year can be reconciled to the income statement charge as follows:

	$ million
Increase in provision	**30,261**
Change in discount rate relating to provisions	**5**
Costs charged directly to the income statement	**3,339**
Trust fund liability – discounted	**19,580**
Change in discount rate relating to trust fund liability	**240**
Recognition of reimbursement asset	**(12,567)**
(Profit) loss before interest and taxation	**40,858**

Costs charged directly to the income statement relate to expenditure incurred prior to the establishment of a provision at the end of the second quarter and ongoing operating costs of the 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.

The total charge in the income statement is analysed in the table below. Costs charged directly to the income statement 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 the year.

	$ million
Trust fund liability – discounted	**19,580**
Change in discount rate relating to trust fund liability	**240**
Recognition of reimbursement asset	**(12,567)**
Other	**8**
Total charge relating to the trust fund	**7,261**
Spill response – amount provided	**10,883**
– costs charged directly to the income statement	**2,745**
Total charge relating to spill response	**13,628**
Environmental – amount provided	**929**
– change in discount rate relating to provisions	**5**
– costs charged directly to the income statement	**70**
Total charge relating to environmental	**1,004**
Litigation and claims – amount provided	**14,939**
– costs charged directly to the income statement	**184**
Total charge relating to litigation and claims	**15,123**
Clean Water Act penalties – amount provided	**3,510**
Other costs charged directly to the income statement	**332**
(Profit) loss before interest and taxation	**40,858**
Finance costs	**77**
(Profit) loss before taxation	**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.

Response operations following the Deepwater Horizon incident in April 2010 have been managed by the federal government's response framework, which transitioned on 17 December from the Unified Area Command (UAC) to the Gulf Coast incident management team (GC-IMT). Both the UAC and now the GC-IMT link the organizations responding to the incident and provide a forum for those organizations to make consensus decisions. If consensus cannot be reached the US Coast Guard co-ordinator carries the final decision on response related actions deemed necessary. As such, the activities undertaken by BP and its sub-contractors, and the associated costs, are not wholly within BP's control. This will continue to be the case until control of the response operations transitions to the Gulf Coast Restoration Organization.

In particular, the centralized approval process established for the procurement of materials, equipment and personnel has not been used for all of the procurement activity that has taken place. The types of activity that fell outside the centralized approval process included aspects of the surface and shoreline response. Numerous personnel and vessels were involved in activities which included skimming, boom deployment and shoreline clean up. Due to the scale of the incident and the need to respond rapidly, procurement authority was vested with state on-scene co-ordinators, various responsible parties and various state and local government authorities. So long as the expenses incurred are found to be consistent with the National Contingency Plan, the responsible parties will be expected to pay these costs, regardless of whether or not they were involved in or approved the decision to procure the resource. With the large number of parties involved, the resulting funding flows are complex and resulted in difficulty maintaining real time monitoring of expenses.

Pre-tax cash flows amounted to $17,658 million and the impact on net cash provided by operating activities, on a post-tax basis, amounted to $16,019 million.

3. Acquisitions

Acquisitions in 2010

BP made a number of acquisitions 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 Energy (Devon), undertaken in a number of stages during 2010. 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 acquisition has been accounted for using the acquisition method. The acquisition date fair values are provisional and may be adjusted once the transaction is finalized. Goodwill of $332 million has been recognized on this acquisition 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 $3.2 billion, is expected to complete in early 2011.

In addition to the Devon transaction, BP made a number of other minor acquisitions 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.

Acquisitions in 2009

BP made no significant acquisitions in 2009.

Acquisitions in 2008

BP made a number of acquisitions in 2008 for a total consideration of $403 million. These business combinations were in the Exploration and Production segment and Other businesses and corporate and the most significant was the acquisition of Whiting Clean Energy, a cogeneration power plant. Fair value adjustments were made to the acquired assets and liabilities.

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 2010. The carrying amount of the assets held for sale is $7,128 million, with associated liabilities of $1,047 million. Included within these amounts are the following items, all of which relate to the Exploration and Production segment.

In July 2010, BP announced the start of active marketing of its assets in Pakistan and Vietnam. On 14 December 2010, BP announced that it had reached agreement to sell its exploration and production assets in Pakistan to United Energy Group Limited for $775 million in cash. These assets, and associated liabilities, have been classified as held for sale in the group balance sheet at 31 December 2010. The sale is expected to be completed in the first half of 2011, subject to closing conditions and government and regulatory approvals.

In Vietnam, BP is seeking to divest its interests in offshore gas production (Block 06.1), a receiving terminal and associated pipelines and a power generation asset (Phu My 3). On 18 October 2010, BP announced that it had reached agreement to sell the 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 Venezuelan assets include BP's interests in the Petroperijá, Boquerón and PetroMonagas joint ventures. These assets, and associated liabilities, have been classified as held for sale in the group balance sheet at 31 December 2010. The sales of the Vietnam and Venezuela businesses are expected to be completed in the first half of 2011, subject to regulatory and other approvals and conditions.

On 3 August 2010, BP announced an agreement to dispose of its oil and gas exploration, production and transportation business in Colombia to a consortium of Ecopetrol, Colombia's national oil company (51%), and Talisman of Canada (49%) for $1.9 billion in cash, subject to post-closing adjustments. These assets and associated liabilities have been classified as held for sale in the group balance sheet at 31 December 2010. The sale completed on 24 January 2011.

On 25 October 2010, BP announced that it had reached agreement to sell its recently acquired interests in four mature producing deepwater oil and gas fields in the US Gulf of Mexico to Marubeni Oil and Gas for $650 million in cash, subject to post-closing adjustments. BP acquired the interests in these fields from Devon Energy earlier in 2010 as part of a wider acquisition of assets in the Gulf of Mexico, Brazil and Azerbaijan. These assets, and associated liabilities, have been classified as held for sale in the group balance sheet at 31 December 2010. The sale completed on 20 January 2011.

On 28 November 2010, BP announced that it had reached agreement to sell its interests in Pan American Energy (PAE) to Bridas Corporation for $7.06 billion in cash. PAE is an Argentina-based oil and gas company owned by BP (60%) and Bridas Corporation (40%). The transaction excludes the shares of PAE E&P Bolivia Ltd. BP's investment in PAE has been classified as held for sale in the group balance sheet at 31 December 2010. The sale is expected to be completed in 2011, subject to closing conditions and government and regulatory approvals.

Impairment losses amounting to $192 million have been recognized in relation to certain assets reclassified 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 $162 million in 2010. Similarly, equity accounting ceases for any equity-method investment upon reclassification as an asset held for sale. It is estimated that profits of approximately $9 million were not recognized in 2010 as a result of the discontinuance of equity accounting.

Disposal proceeds of $6,197 million received in advance of completion of these transactions have been classified as finance debt on the group balance sheet and of this, $4,780 million has been secured on the assets held for sale. See Note 35 for further information.

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 2010 are as follows:

	$ million
	2010
Assets	
Property, plant and equipment	**2,971**
Goodwill	**87**
Intangible assets	**135**
Investments in jointly controlled entities	**3,108**
Investments in associates	**333**
Loans	**12**
Cash	**34**
Other current assets	**448**
Assets classified as held for sale	**7,128**
Liabilities	
Trade and other payables	**597**
Provisions	**383**
Deferred tax liabilities	**67**
Liabilities directly associated with assets classified as held for sale	**1,047**

There were no accumulated foreign exchange gains or losses recognized directly in equity relating to the assets held for sale at 31 December 2010.

5. Disposals and impairment

	2010	2009	2008
			$ million
Proceeds from disposal of businesses, net of cash disposed	**9,462**	966	11
Proceeds from disposal of fixed assets	**7,492**	1,715	918
	16,954	2,681	929
By business			
Exploration and Production	**14,392**	940	19
Refining and Marketing	**1,840**	1,294	813
Other businesses and corporate	**722**	447	97
	16,954	2,681	929

Included in proceeds from disposal 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 (2009 and 2008 nil). 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 2010 amounted to $562 million receivable within one year (2009 $807 million and 2008 $15 million) and $271 million receivable after one year (2009 $691 million and 2008 $64 million).

	2010	2009	2008
			$ million
Gains on sale of businesses and fixed assets			
Exploration and Production	**5,267**	1,717	34
Refining and Marketing	**999**	384	1,258
Other businesses and corporate	**117**	72	61
	6,383	2,173	1,353

	2010	2009	2008
			$ million
Losses on sale of businesses and fixed assets			
Exploration and Production	**196**	28	18
Refining and Marketing	**119**	154	297
Other businesses and corporate	**6**	21	1
	321	203	316
Impairment losses			
Exploration and Production	**1,259**	118	1,186
Refining and Marketing	**144**	1,834	159
Other businesses and corporate	**113**	189	227
	1,516	2,141	1,572
Impairment reversals			
Exploration and Production	**–**	(3)	(155)
Refining and Marketing	**(141)**	–	–
Other businesses and corporate	**(7)**	(8)	–
	(148)	(11)	(155)
Impairment and losses on sale of businesses and fixed assets	**1,689**	2,333	1,733

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. 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 2010.

Exploration and Production

In 2010, the major transactions were the sale to Apache Corporation of Permian Basin assets in the US, Canadian upstream gas assets and exploration concessions in Egypt and the sale to Devon Energy, as part of an acquisition transaction described in Note 3, of 50% of our interests in Kirby oil sands in Canada. 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.

There were no significant disposals in 2008.

5. Disposals and impairment continued

Refining and Marketing

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 continued 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.

In 2008, the major transactions resulting in gains were the contribution of our Toledo refinery to a US jointly controlled entity in an exchange transaction with Husky Energy and the disposals of our interest in the Dixie Pipeline and certain retail assets in the US. The losses on sale related mainly to the disposal of retail assets in the US and Europe. In addition, certain assets at our Acetyls plant in Hull, UK, and other interests in the UK and Europe were sold.

Other businesses and corporate

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 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
	2010	2009	2008
Non-current assets	**2,319**	536	759
Current assets	**310**	444	485
Non-current liabilities	**(303)**	(146)	–
Current liabilities	**(124)**	(152)	(134)
Total carrying amount of net assets disposed	**2,202**	682	1,110
Recycling of foreign exchange on disposal	**(52)**	(27)	–
Costs on disposal	**18**	3	7
	2,168	658	1,117
Profit on sale of businesses[a]	**1,968**	314	1,721
Total consideration	**4,136**	972	2,838
Fair value of interest received in a jointly controlled entity	**–**	–	(2,838)
Consideration received (receivable)[b]	**20**	(6)	11
Proceeds from the sale of businesses related to completed transactions	**4,156**	966	11
Deposits received related to assets classified as held for sale	**5,306**	–	–
Proceeds from the sale of businesses[c]	**9,462**	966	11

[a] Of which $929 million gain was not recognized in the income statement in 2008 as it represented an unrealized gain on the transfer of the Toledo refinery into a jointly controlled entity.
[b] Consideration received from prior year business disposals or not yet received from current year disposals.
[c] Net of cash and cash equivalents disposed of $55 million (2009 $91 million and 2008 nil).

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 charges 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 2010 the rates used ranged from 11-14% (2009 9-13%). The rate applied in each country is re-assessed 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 2010, the Exploration and Production segment recognized impairment losses of $1,259 million. The main elements were the write-down of assets in the Gulf of Mexico of $501 million triggered by an increase in the decommissioning asset 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 write-down of accumulated costs in Sakhalin, Russia by $341 million, triggered by a change in the outlook on the future recoverability of the investment; and several other individually insignificant impairment charges amounting to $27 million.

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 charges amounting to $14 million.

During 2008, the Exploration and Production segment recognized impairment losses of $1,186 million. The main elements were the write-down of our investment in Rosneft by $517 million, to its fair value determined by reference to an active market, due to a significant decline in the market value of the investment, impairment of oil and gas properties in the Gulf of Mexico of $270 million triggered by downward revisions of reserves, an impairment of exploration assets in Vietnam of $210 million following BP's decision to withdraw from activities in the area concerned, impairment of oil and gas properties in Egypt of $85 million triggered by cost increases, and several other individually insignificant impairment charges amounting to $104 million.

These charges were partly offset by reversals of previously recognized impairment losses amounting to $155 million. Of this total, $122 million resulted from a reassessment of the economics of Rhourde El Baguel in Algeria.

Refining and Marketing

During 2010, the Refining and Marketing segment recognized impairment losses amounting to $144 million relating to retail churn in European businesses and other minor asset disposals. These losses were largely offset by the reversal of a previously recognized impairment charge of $141 million relating to the investment in our associate 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, has 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.

During 2008, the Refining and Marketing segment recognized impairment losses on a number of assets which amounted to $159 million.

Other businesses and corporate

During 2010, 2009 and 2008, Other businesses and corporate recognized impairment losses totalling $113 million, $189 million and $227 million respectively related to various assets in the Alternative Energy business.

6. Events after the reporting period

On 22 February 2011, BP announced its intention to sell its interests in a number of operated oil and gas fields in the UK. The assets involved are 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. BP aims to complete the divestments around the end of 2011, subject to receipt of suitable offers and regulatory and third-party approvals. 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 these intended transactions.

On 21 February 2011, BP announced a major strategic alliance with Reliance Industries Limited (Reliance) in India. As part of this alliance, BP will purchase a 30 per cent stake in 23 oil and gas production-sharing contracts that Reliance operates in India, including the producing KG D6 block, and the formation of a 50:50 joint venture between the two companies for the sourcing and marketing of gas in India. The upstream joint venture will combine BP's deepwater exploration and development capabilities with Reliance's project management and operations expertise. The 23 oil and gas blocks together cover approximately 270,000 square kilometres, and Reliance will continue to be the operator under the production-sharing contracts. BP will pay Reliance an aggregate consideration of $7.2 billion, and completion adjustments, for the interests to be acquired in the 23 production-sharing contracts. Future performance payments of up to $1.8 billion could be paid based on exploration success that results in development of commercial discoveries. Completion of the transactions is subject to Indian regulatory approvals and other customary conditions.

On 1 February 2011, BP announced that, following a strategic review, it intends to divest the Texas City refinery and the southern part of its US West Coast fuels value chain, including the Carson refinery, by the end of 2012 subject to all necessary legal and regulatory approvals. BP will ensure current obligations at Texas City are fulfilled. 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 these intended transactions.

On 14 January 2011, BP entered into a share swap agreement with Rosneft Oil Company whereby BP will receive approximately 9.5% of Rosneft's shares in exchange for BP issuing new ordinary shares to Rosneft, resulting in Rosneft holding 5% of BP's ordinary voting shares. The aggregate value of the shares in BP to be issued to Rosneft is approximately $7.8 billion (as at close of trading in London on 14 January 2011). BP has agreed to issue 988,694,683 ordinary shares to Rosneft; Rosneft has agreed to transfer 1,010,158,003 ordinary shares to BP. Completion of the transaction is subject to the outcome of the court application referred to in the paragraph below, and related pending arbitral proceedings. After completion, BP's increased investment in Rosneft will continue to be recognized as an available-for-sale financial asset. During the period from entering into the agreement until completion, the agreement represents a derivative financial instrument and changes in its fair value will be recognized in BP's income statement in 2011.

6. Events after the reporting period continued

An application was brought in the English High Court on 1 February 2011 by Alfa Petroleum Holdings Limited (APH) and OGIP Ventures Limited (OGIP) against BP International Limited and BP Russian Investments Limited. APH is a company owned by Alpha Group. APH and OGIP each own 25% of TNK-BP, in which BP also has a 50% shareholding. This application alleges breach of the shareholders agreement on the part of BP and seeks an interim injunction restraining BP from taking steps to conclude, implement or perform the previously announced transactions with Rosneft Oil Company relating to oil and gas exploration, production, refining and marketing in Russia. Those transactions include the issue or transfer of shares between Rosneft Oil Company and any BP group company. 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 injunction has been extended until 11 March 2011 pending an expedited hearing in relation to matters in dispute between the parties on a final basis during the week commencing 7 March 2011. The expedited hearing will decide, among other matters, whether the injunction will be extended beyond 11 March 2011.

7. Segmental analysis

The group's organizational structure reflects the various activities in which BP is engaged. In 2010, 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).

BP announced that in 2011 it intends to organize its Exploration and Production segment in three functional divisions – Exploration, Developments and Production, integrated through a Strategy and Integration organization. This will not affect the group's reportable segments and Exploration and Production will continue to be reported as a single operating segment.

Refining and Marketing's activities include the supply and trading, refining, manufacturing, marketing and transportation of crude oil, petroleum and petrochemicals products and related services.

Other businesses and corporate comprises the Alternative Energy business, Shipping, the group's aluminium business, Treasury (which in the segmental analysis includes all of the group's cash, cash equivalents and associated interest income), and corporate activities worldwide. 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 specific new 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.

7. 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	17,738	7,043	840	–	–	25,621
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] 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.

7. Segmental analysis continued

By business	Exploration and Production	Refining and Marketing	Other businesses and corporate	Consolidation adjustment and eliminations	Total group
					$ million
					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] 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.

7. Segmental analysis continued

					$ million
					2008
By business	Exploration and Production	Refining and Marketing	Other businesses and corporate	Consolidation adjustment and eliminations	Total group
Segment revenues					
Sales and other operating revenues	86,170	320,039	4,634	(49,700)	361,143
Less: sales between businesses	(45,931)	(1,918)	(1,851)	49,700	–
Third party sales and other operating revenues	40,239	318,121	2,783	–	361,143
Equity-accounted earnings	3,565	131	125	–	3,821
Interest revenues	114	35	220	–	369
Segment results					
Replacement cost profit (loss) before interest and taxation	38,308	4,176	(1,223)	466	41,727
Inventory holding losses[a]	(393)	(6,060)	(35)	–	(6,488)
Profit (loss) before interest and taxation	37,915	(1,884)	(1,258)	466	35,239
Finance costs					(1,547)
Net finance income relating to pensions and other post-retirement benefits					591
Profit before taxation					34,283
Other income statement items					
Depreciation, depletion and amortization	8,440	2,208	337	–	10,985
Impairment losses	1,186	159	227	–	1,572
Impairment reversals	155	–	–	–	155
Fair value (gain) loss on embedded derivatives	163	(57)	5	–	111
Charges for provisions, net of write-back of unused provisions	573	479	657	–	1,709
Segment assets					
Equity-accounted investments	20,131	6,622	1,073	–	27,826
Additions to non-current assets	21,584	6,636	1,802	–	30,022
Additions to other investments					52
Element of acquisitions not related to non-current assets					11
Additions to decommissioning asset					615
Capital expenditure and acquisitions	22,227	6,634	1,839	–	30,700

[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.

7. Segmental analysis continued

By geographical area	US	Non-US	$ million 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]	**67,498**	**92,614**	**160,112**
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			**175,409**
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-employment benefit plan surpluses.

By geographical area	US	Non-US	$ million 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-employment benefit plan surpluses.

By geographical area	US	Non-US	$ million 2008 Total
Revenues			
Third party sales and other operating revenues[a]	123,364	237,779	361,143
Results			
Replacement cost profit before interest and taxation	10,678	31,049	41,727
Non-current assets			
Other non-current assets[b c]	62,679	89,823	152,502
Other investments			855
Loans			995
Other receivables			710
Derivative financial instruments			5,054
Defined benefit pension plan surpluses			1,738
Total non-current assets			161,854
Capital expenditure and acquisitions	16,046	14,654	30,700

[a] Non-US region includes UK $81,773 million.
[b] Non-US region includes UK $15,990 million.
[c] Excluding financial instruments, and post-employment benefit plan surpluses.

8. Interest and other income

			$ million
	2010	2009	2008
Interest income			
Interest income from available-for-sale financial assets[a]	**23**	15	32
Interest income from loans and receivables[a]	**88**	69	163
Interest from loans to equity-accounted entities	**36**	53	115
Other interest	**91**	88	59
	238	225	369
Other income			
Dividend income from available-for-sale financial assets[a]	**37**	32	37
Other income	**406**	535	330
	443	567	367
	681	792	736

[a] Total interest and other income related to financial instruments amounted to $148 million (2009 $116 million and 2008 $232 million).

9. Production and similar taxes

			$ million
	2010	2009	2008
US	**1,093**	649	2,602
Non-US	**4,151**	3,103	6,351
	5,244	3,752	8,953

10. Depreciation, depletion and amortization

			$ million
By business	**2010**	2009	2008
Exploration and Production			
US	**3,751**	4,150	3,012
Non-US	**4,865**	5,407	5,428
	8,616	9,557	8,440
Refining and Marketing			
US	**955**	919	825
Non-US[a]	**1,303**	1,317	1,383
	2,258	2,236	2,208
Other businesses and corporate			
US	**140**	136	132
Non-US	**150**	177	205
	290	313	337
By geographical area			
US	**4,846**	5,205	3,969
Non-US[a]	**6,318**	6,901	7,016
	11,164	12,106	10,985

[a] Non-US area includes the UK-based international activities of Refining and Marketing.

11. Impairment review of goodwill

		$ million
Goodwill at 31 December	**2010**	2009
Exploration and Production	**4,450**	4,297
Refining and Marketing	**4,074**	4,245
Other businesses and corporate	**74**	78
	8,598	8,620

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 has been allocated to each geographic region, that is UK, US and Rest of World, and 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 2010 (2009 11% and 13%).

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
				2010				2009
	UK	**US**	**Rest of World**	**Total**	UK	US	Rest of World	Total
Goodwill	**341**	**3,479**	**630**	**4,450**	341	3,441	515	4,297
Excess of recoverable amount over carrying amount	**7,556**	**18,968**	**41,714**	**n/a**	7,721	15,528	n/a	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 the company'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.

Consistent with prior years, the 2010 review for impairment was carried out during the fourth quarter.

The table above shows the carrying amount of the goodwill allocated to each of the regions of the Exploration and Production segment and the excess of the recoverable amount over the carrying amount (the headroom) in the cash-generating units to which the goodwill has been allocated. Consistent with prior periods, midstream and intangible oil and gas assets were excluded from the headroom calculation.

For 2010, the Brent oil price assumption was an average $85 per barrel in 2011, $88 per barrel in 2012, $89 per barrel in 2013, $89 per barrel in 2014, $90 per barrel in 2015 and $75 per barrel in 2016 and beyond. The Henry Hub natural gas price assumption was an average of $4.25/mmBtu in 2011, $4.96/mmBtu in 2012, $5.29/mmBtu in 2013, $5.49/mmBtu in 2014, $5.67/mmBtu in 2015 and $6.50/mmBtu in 2016 and beyond. The prices for the first five years were derived from forward price curves in the fourth quarter. Prices in 2016 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.

In 2009, as permitted by IAS 36, the detailed calculations of recoverable amount performed in 2008 for the US and the UK, and the calculations performed in 2005 for the Rest of World, were used for the 2009 impairment test as the criteria of IAS 36 were considered to be satisfied: the headroom was substantial in 2008 (for the US and the UK) and 2005 (for the Rest of World); there had been no significant change 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. For 2008, the Brent oil assumption was an average $49 per barrel in 2009, $59 per barrel in 2010, $65 per barrel in 2011, $68 per barrel in 2012, $70 per barrel in 2013 and $75 per barrel in 2014 and beyond. The Henry Hub natural gas price assumption was an average of $6.16/mmBtu in 2009, $7.15/mmBtu in 2010, $7.34/mmBtu in 2011, $7.62/mmBtu in 2012, $7.60/mmBtu in 2013 and $7.50/mmBtu in 2014 and beyond. The prices for the first five years were derived from forward price curves at the year-end. Prices in 2014 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.

11. 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 done 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 for 2016 and beyond was around 20% lower for the UK and US, and around one-third lower for Rest of World, this would cause the recoverable amount to be equal to the carrying amount of goodwill and related non-current assets for each cash-generating unit. It was estimated that no reasonably possible change in the long-term price of gas would cause the headroom in the UK, US or Rest of World 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 2010, 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 amounts of each cash-generating unit to zero. Consequently, management believes no reasonably possible change in the production assumption would cause the carrying amounts to exceed the recoverable amounts.

Management also believes that currently there is no reasonably possible change in discount rate that would cause the carrying amounts in the UK, US or Rest of World to exceed the recoverable amounts.

Refining and Marketing

								$ million
				2010				2009
	Rhine FVC	**Lubricants**	**Other**	**Total**	Rhine FVC	Lubricants	Other	Total
Goodwill	**629**	**3,285**	**160**	**4,074**	655	3,416	174	4,245
Excess of recoverable amount over carrying amount	**4,091**	**n/a**	**n/a**	**n/a**	2,034	n/a	n/a	n/a

Cash flows for each cash-generating unit are derived from the business segment plan. 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, production volumes, and discount rate. In 2010 the method used to calculate the margin per barrel presented has been updated and comparative figures presented have also been updated. The revised margin measure, the regional Refinery Marker Margin (RMM), is based on a single representative crude with product yields characteristic of the typical level of upgrading complexity available in the region. Gross margin assumptions used in the Rhine FVC plan are consistent with those used to develop the regional RMM. The average values assigned to the regional RMM and refinery production volume over the plan period are $11.05 per barrel and 248mmbbl a year (2009 $10.60 per barrel and 254mmbbl a 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 (2009 cash flows beyond the five-year plan period were extrapolated using a nominal 2.4% growth rate).

	2010
Sensitivity analysis	
Sensitivity of value in use to a change in refinery margins of $1 per barrel ($ billion)	**1.6**
Adverse change in refinery margins to reduce recoverable amount to carrying amount ($ per barrel)	**2.6**
Sensitivity of value in use to a 5% change in production volume ($ billion)	**0.9**
Adverse change in production volume to reduce recoverable amount to carrying amount (mmbbl per year)	**54**
Sensitivity of value in use to a change in the discount rate of 1% ($ billion)	**0.8**
Discount rate to reduce recoverable amount to carrying amount	**19%**

Lubricants

As permitted by IAS 36, the detailed calculations of recoverable amount performed in 2009 were used for the 2010 impairment test as the criteria in that standard were considered to be satisfied: the headroom was substantial in 2009; there had been no significant change 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 change in any of these key assumptions would cause the unit's carrying amount to exceed its recoverable amount. Cash flows beyond the two-year plan period were extrapolated using a nominal 3% growth rate.

US West Coast FVC

As disclosed in Note 5, the impairment review of goodwill allocated to the US West Coast FVC resulted in the recognition of an impairment loss in 2009 to write off the entire balance of $1,579 million.

12. Distribution and administration expenses

			$ million
	2010	2009	2008
Distribution	**11,393**	12,798	14,075
Administration	**1,162**	1,240	1,337
	12,555	14,038	15,412

13. Currency exchange gains and losses

			$ million
	2010	2009	2008
Currency exchange losses charged to income[a]	**218**	193	156

[a] Excludes exchange gains and losses arising on financial instruments measured at fair value through profit or loss.

14. Research and development

			$ million
	2010	2009	2008
Expenditure on research and development	**780**	587	595

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 72. These donations are not included in the amounts reported above.

15. 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
	2010	2009	2008
Minimum lease payments	**5,371**	4,109	4,114
Contingent rentals	**(60)**	(9)	97
Sub-lease rentals	**(121)**	(133)	(194)
	5,190	3,967	4,017

The future minimum lease payments at 31 December, before deducting related rental income from operating sub-leases of $365 million (2009 $379 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	**2010**	2009
Payable within		
1 year	**3,521**	3,251
2 to 5 years	**6,798**	7,334
Thereafter	**3,654**	4,131
	13,973	14,716

15. Operating leases continued

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 2010 the future minimum lease payments relating to drilling rigs amounted to $4,515 million (2009 $4,919 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.

16. 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
	2010	2009	2008
Exploration and evaluation costs			
Exploration expenditure written off[a]	**375**	593	385
Other exploration costs	**468**	523	497
Exploration expense for the year[b]	**843**	1,116	882
Intangible assets – exploration and appraisal expenditure	**13,126**	10,388	9,031
Net assets	**13,126**	10,388	9,031
Capital expenditure	**6,422**	2,715	4,780
Net cash used in operating activities	**468**	523	497
Net cash used in investing activities	**6,428**	3,306	4,163

[a] 2010 includes $157 million related to decommissioning provisions for idle infrastructure, as required by BOEMRE's Notice of Lessees 2010 GO5 issued in October 2010.
[b] In addition to these amounts, an impairment charge of $210 million was recognized in 2008 relating to exploration assets in Vietnam following BP's decision to withdraw from activities in the area concerned.

17. Auditor's remuneration

			$ million
Fees – Ernst & Young	**2010**	2009	2008
Fees payable to the company's auditors for the audit of the company's accounts[a]	**13**	13	16
Fees payable to the company's auditors and its associates for other services			
Audit of the company's subsidiaries pursuant to legislation	**22**	22	28
Other services pursuant to legislation	**12**	11	13
	47	46	57
Tax services	**2**	1	2
Services relating to corporate finance transactions	**1**	–	2
All other services	**4**	6	5
Audit fees in respect of the BP pension plans	**1**	1	1
	55	54	67

[a] Fees in respect of the audit of the accounts of BP p.l.c. including the group's consolidated financial statements.

2010 includes $1 million of additional fees for 2009 and 2008 includes $3 million of additional fees for 2007. Auditors' remuneration is included in the income statement within distribution and administration expenses.

The tax services relate to income tax and indirect tax compliance, employee tax services and tax advisory services.

17. Auditor's remuneration continued

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 (2009 $54 million and 2008 $67 million) is required to be presented as follows: audit services $47 million (2009 $46 million and 2008 $57 million); other audit related services $1 million (2009 $2 million and 2008 $1 million); tax services $2 million (2009 $1 million and 2008 $2 million); and fees for all other services $5 million (2009 $5 million and 2008 $7 million).

18. Finance costs

			$ million
	2010	2009	2008
Interest payable	**955**	906	1,319
Capitalized at 2.75% (2009 2.75% and 2008 4.00%)[a]	**(254)**	(188)	(162)
Unwinding of discount on provisions[b]	**234**	247	287
Unwinding of discount on other payables[b]	**235**	145	103
	1,170	1,110	1,547

[a] Tax relief on capitalized interest is $71 million (2009 $63 million and 2008 $42 million).
[b] Unwinding of discount on provisions relating to the Gulf of Mexico oil spill was $4 million and unwinding of discount on other payables relating to the Gulf of Mexico oil spill was $73 million. See Note 2 for further information on the financial impacts of the Gulf of Mexico oil spill.

19. Taxation

Tax on profit

			$ million
	2010	2009	2008
Current tax			
Charge for the year	**6,766**	6,045	13,468
Adjustment in respect of prior years	**(74)**	(300)	(85)
	6,692	5,745	13,383
Deferred tax			
Origination and reversal of temporary differences in the current year	**(8,157)**	2,131	(324)
Adjustment in respect of prior years	**(36)**	489	(442)
	(8,193)	2,620	(766)
Tax on profit (loss)	**(1,501)**	8,365	12,617

Tax included in other comprehensive income

			$ million
	2010	2009	2008
Current tax	**(107)**	–	(264)
Deferred tax	**244**	(525)	(2,682)
	137	(525)	(2,946)

Tax included directly in equity

			$ million
	2010	2009	2008
Current tax	**(37)**	–	–
Deferred tax	**64**	(65)	190
	27	(65)	190

19. Taxation continued

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.

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, 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.

					$ million
	2010 excluding impacts of Gulf of Mexico oil spill	**2010 impacts of Gulf of Mexico oil spill**	**2010**	2009	2008
Profit (loss) before taxation	**36,110**	**(40,935)**	**(4,825)**	25,124	34,283
Tax charge (credit) on profit (loss)	**11,393**	**(12,894)**	**(1,501)**	8,365	12,617
Effective tax rate	**32%**	**31%**	**31%**	33%	37%

					% of profit or loss before taxation
UK statutory corporation tax rate	**28**	**28**	**28**	28	28
Increase (decrease) resulting from					
UK supplementary and overseas taxes at higher rates	**9**	**7**	**(6)**	8	14
Tax reported in equity-accounted entities	**(3)**	**–**	**23**	(3)	(2)
Adjustments in respect of prior years	**–**	**–**	**2**	1	(2)
Current year losses unrelieved (prior year losses utilized)	**–**	**–**	**1**	–	(1)
Goodwill impairment	**–**	**–**	**–**	2	–
Tax incentives for investment	**(1)**	**–**	**9**	(2)	(1)
Gulf of Mexico oil spill non-deductible costs	**–**	**(4)**	**(30)**	–	–
Other	**(1)**	**–**	**4**	(1)	1
Effective tax rate	**32**	**31**	**31**	33	37

Deferred tax

					$ million
		Income statement			Balance sheet
	2010	2009	2008	**2010**	2009
Deferred tax liability					
Depreciation	**1,565**	1,983	1,248	**27,309**	25,398
Pension plan surpluses	**38**	(6)	108	**469**	271
Other taxable temporary differences	**1,178**	978	(2,471)	**5,538**	4,307
	2,781	2,955	(1,115)	**33,316**	29,976
Deferred tax asset					
Pension plan and other post-retirement benefit plan deficits	**179**	180	104	**(2,155)**	(2,269)
Decommissioning, environmental and other provisions	**(8,151)**	86	(333)	**(13,296)**	(4,930)
Derivative financial instruments	**(56)**	80	228	**(298)**	(243)
Tax credit	**(1,088)**	(516)	330	**(2,118)**	(1,034)
Loss carry forward	**24**	402	(212)	**(943)**	(1,014)
Other deductible temporary differences	**(1,882)**	(567)	232	**(4,126)**	(2,340)
	(10,974)	(335)	349	**(22,936)**	(11,830)
Net deferred tax (credit) charge and net deferred tax liability	**(8,193)**	2,620	(766)	**10,380**	18,146
Of which – deferred tax liabilities				**10,908**	18,662
– deferred tax assets				**528**	516

		$ million
Analysis of movements during the year	**2010**	2009
At 1 January	**18,146**	16,198
Exchange adjustments	**3**	(7)
Charge (credit) for the year on profit (loss)	**(8,193)**	2,620
Charge (credit) for the year in other comprehensive income	**244**	(525)
Charge (credit) for the year in equity	**64**	(65)
Acquisitions	**187**	–
Reclassified as liabilities directly associated with assets held for sale	**(67)**	–
Deletions	**(4)**	(75)
At 31 December	**10,380**	18,146

19. Taxation continued

The group has recognized significant costs in the year in relation to the Gulf of Mexico oil spill. Tax has been calculated on the expenditures that qualify for tax relief 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 and has resulted in a significant reduction in the overall deferred tax liability of the group compared to 2009.

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 2010, the group had approximately $3.9 billion (2009 $4.8 billion[a]) of carry-forward tax losses, predominantly in Europe, that would be available to offset against future taxable profit. A deferred tax asset has been recognized in respect of $3.0 billion of losses (2009 $3.2 billion). No deferred tax asset has been recognized in respect of $0.9 billion of losses (2009 $1.6 billion[a]). Substantially all the tax losses have no fixed expiry date.

At 31 December 2010, the group had approximately $13.9 billion of unused tax credits predominantly in the UK and US (2009 $12.5 billion). At 31 December 2010 there is a deferred tax asset of $2.1 billion in respect of unused tax credits (2009 $1.0 billion). No deferred tax asset has been recognized in respect of $11.8 billion of tax credits (2009 $11.5 billion). In 2010 $0.3 billion of tax credits were utilized on which a deferred tax asset had not previously been recognized.

In 2009 a change in UK legislation repealed double taxation relief in relation to foreign dividends, onshore pooling and utilization of eligible unrelieved foreign tax eliminating the associated tax credits. The UK tax credits, arising in UK branches overseas, with no deferred tax asset, amounting to $9.9 billion (2009 $9.5 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 2010 the unrecognized deferred tax amounted to $0.9 billion (2009 $0.5 billion). These credits and temporary differences arise in UK branches predominantly based in high tax rate jurisdictions so are unlikely to have value in the future as UK taxes on these overseas branches are largely mitigated by double tax relief on the local foreign tax.

The US tax credits with no deferred tax asset, amounting to $1.9 billion (2009 $2.0 billion) expire 10 years after generation, and the majority expire in the period 2014-2018.

The other major components of temporary differences at the end of 2010 are tax depreciation, provisions and other items in relation 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.

In 2010 there are no material temporary differences associated with investments in subsidiaries and equity accounted entities for which deferred tax liabilities have not been recognized.

In 2010 the enactment of a 1% reduction in the rate of UK corporation tax on profits arising from activities outside the North Sea has reduced the deferred tax charge by $86 million. In 2009 there were no changes in the statutory tax rates that materially impacted the group's tax charge.

[a]2009 comparative data has been amended.

20. Dividends

Following the Gulf of Mexico oil spill and the agreement to establish the $20-billion trust fund, the BP board reviewed its dividend policy and decided to cancel the previously announced first-quarter 2010 ordinary share dividend scheduled for payment on 21 June 2010, and further decided that no ordinary share dividends would be paid in respect of the second and third quarters of 2010. On 1 February 2011, BP announced the resumption of quarterly dividend payments. The quarterly dividend to be paid on 28 March 2011 is 7 cents per ordinary share ($0.42 per American Depositary Share (ADS)). The corresponding amount in sterling will be announced on 14 March 2011. A scrip dividend alternative is available, allowing shareholders to elect to receive their dividend in the form of new ordinary shares and ADS holders in the form of new ADSs.

	pence per share			cents per share			$ million		
	2010	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Dividends announced and paid									
Preference shares							**2**	2	2
Ordinary shares									
March	**8.679**	9.818	6.813	**14.000**	14.000	13.525	**2,625**	2,619	2,553
June	**–**	9.584	6.830	**–**	14.000	13.525	**–**	2,619	2,545
September	**–**	8.503	7.039	**–**	14.000	14.000	**–**	2,620	2,623
December	**–**	8.512	8.705	**–**	14.000	14.000	**–**	2,623	2,619
	8.679	36.417	29.387	**14.000**	56.000	55.050	**2,627**	10,483	10,342
Dividend announced per ordinary share, payable in March 2011[a]				**7.000**			**1,315**		

[a]The amount in sterling will be announced on 14 March 2011.

The group does not account for dividends until they are paid. The financial statements for the year ended 31 December 2010 do not reflect the dividend announced on 1 February 2011 and payable in March 2011; this will be treated as an appropriation of profit in the year ended 31 December 2011.

21. Earnings per ordinary share

			cents per share
	2010	2009	2008
Basic earnings per share	**(19.81)**	88.49	112.59
Diluted earnings per share	**(19.81)**	87.54	111.56

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 Plans (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
	2010	2009	2008
Profit (loss) attributable to BP shareholders	**(3,719)**	16,578	21,157
Less dividend requirements on preference shares	**2**	2	2
Profit (loss) for the year attributable to BP ordinary shareholders	**(3,721)**	16,576	21,155

			shares thousand
	2010	2009	2008
Basic weighted average number of ordinary shares	**18,785,912**	18,732,459	18,789,827
Potential dilutive effect of ordinary shares issuable under employee share schemes	**211,895**	203,232	172,690
	18,997,807	18,935,691	18,962,517

The number of ordinary shares outstanding at 31 December 2010, 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 18,796,497,760. Between 31 December 2010 and 18 February 2011, the latest practicable date before the completion of these financial statements, there was a net increase of 2,303,313 in the number of ordinary shares outstanding as a result of share issues in relation to employee share schemes. The number of potential ordinary shares issuable through the exercise of employee share schemes was 208,667,985 at 31 December 2010. There has been an decrease of 35,044,060 in the number of potential ordinary shares between 31 December 2010 and 18 February 2011.

On 14 January 2011, BP entered into a share swap agreement with Rosneft Oil Company that, subject to the outcome of the court application referred to in Note 6, would result in BP issuing 988,694,683 new ordinary shares to Rosneft when the transaction completes. See Note 6 for further information regarding this transaction.

22. Property, plant and equipment

$ million

	Land and land improvements	Buildings	Oil and gas properties	Plant, machinery and equipment	Fixtures, fittings and office equipment	Transport-ation	Oil depots, storage tanks and service stations	Total
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**
Cost								
At 1 January 2009	3,964	2,742	146,813	37,905	3,045	12,295	10,345	217,109
Exchange adjustments	148	85	2	877	83	66	546	1,807
Additions	59	313	11,928	3,743	145	115	739	17,042
Transfers	–	–	745	–	–	–	–	745
Deletions	(385)	(222)	(2,291)	(926)	(251)	(35)	(1,335)	(5,445)
At 31 December 2009	3,786	2,918	157,197	41,599	3,022	12,441	10,295	231,258
Depreciation								
At 1 January 2009	598	1,313	79,955	17,298	1,696	7,542	5,507	113,909
Exchange adjustments	19	38	–	446	54	30	272	859
Charge for the year	31	102	8,951	1,372	302	289	618	11,665
Impairment losses	88	53	10	185	10	8	52	406
Deletions	(165)	(117)	(1,941)	(398)	(169)	(17)	(1,049)	(3,856)
At 31 December 2009	571	1,389	86,975	18,903	1,893	7,852	5,400	122,983
Net book amount at 31 December 2009	3,215	1,529	70,222	22,696	1,129	4,589	4,895	108,275
Net book amount at 1 January 2009	3,366	1,429	66,858	20,607	1,349	4,753	4,838	103,200

Assets held under finance leases at net book amount included above								
At 31 December 2010	**–**	**14**	**236**	**386**	**–**	**7**	**18**	**661**
At 31 December 2009	–	14	225	110	–	7	19	375

Decommissioning asset at net book amount included above	Cost	Depreciation	Net
At 31 December 2010	**9,237**	**4,585**	**4,652**
At 31 December 2009	7,968	4,129	3,839

Assets under construction included above	
At 31 December 2010	**23,055**
At 31 December 2009	19,120

23. Goodwill

		$ million
	2010	2009
Cost		
At 1 January	**10,199**	9,878
Exchange adjustments	**(154)**	350
Acquisitions	**335**	–
Reclassified as assets held for sale	**(87)**	–
Deletions	**(116)**	(29)
At 31 December	**10,177**	10,199
Impairment losses		
At 1 January	**(1,579)**	–
Impairment losses for the year	**–**	(1,579)
At 31 December	**(1,579)**	(1,579)
Net book amount at 31 December	**8,598**	8,620
Net book amount at 1 January	**8,620**	9,878

24. Intangible assets

						$ million
			2010			2009
	Exploration and appraisal expenditure	**Other intangibles**	**Total**	Exploration and appraisal expenditure	Other intangibles	Total
Cost						
At 1 January	**10,713**	**3,284**	**13,997**	9,425	2,927	12,352
Exchange adjustments	**6**	**(29)**	**(23)**	8	75	83
Acquisitions	**982**	**118**	**1,100**	–	–	–
Additions	**5,440**	**297**	**5,737**	2,715	441	3,156
Transfers	**(2,633)**	**–**	**(2,633)**	(745)	–	(745)
Reclassified as assets held for sale	**(134)**	**(4)**	**(138)**	–	–	–
Deletions	**(898)**	**(263)**	**(1,161)**	(690)	(159)	(849)
At 31 December	**13,476**	**3,403**	**16,879**	10,713	3,284	13,997
Amortization						
At 1 January	**325**	**2,124**	**2,449**	394	1,698	2,092
Exchange adjustments	**–**	**(11)**	**(11)**	–	32	32
Charge for the year	**375**	**367**	**742**	593	441	1,034
Impairment losses	**–**	**–**	**–**	–	90	90
Reclassified as assets held for sale	**–**	**(3)**	**(3)**	–	–	–
Deletions	**(350)**	**(246)**	**(596)**	(662)	(137)	(799)
At 31 December	**350**	**2,231**	**2,581**	325	2,124	2,449
Net book amount at 31 December	**13,126**	**1,172**	**14,298**	10,388	1,160	11,548
Net book amount at 1 January	**10,388**	**1,160**	**11,548**	9,031	1,229	10,260

Intangible assets with a carrying amount of $66 million (2009 $66 million) have been pledged to secure certain group liabilities.

25. Investments in jointly controlled entities

The significant jointly controlled entities of the BP group at 31 December 2010 are shown in Note 46. Summarized financial information for the group's share of jointly controlled entities is shown below.

					$ million
	2010[a]	2009			2008
			TNK-BP	Other	Total
Sales and other operating revenues	**11,679**	9,396	25,936	10,796	36,732
Profit before interest and taxation	**1,730**	1,815	3,588	1,343	4,931
Finance costs	**122**	155	275	185	460
Profit before taxation	**1,608**	1,660	3,313	1,158	4,471
Taxation	**433**	374	882	397	1,279
Minority interest	**–**	–	169	–	169
Profit for the year	**1,175**	1,286	2,262	761	3,023
Non-current assets	**12,054**	15,857			
Current assets	**3,595**	4,124			
Total assets	**15,649**	19,981			
Current liabilities	**1,615**	2,276			
Non-current liabilities	**2,701**	3,768			
Total liabilities	**4,316**	6,044			
	11,333	13,937			
Group investment in jointly controlled entities					
Group share of net assets (as above)	**11,333**	13,937			
Loans made by group companies to jointly controlled entities	**953**	1,359			
	12,286	15,296			

[a]Balance sheet information shown above excludes data relating to jointly controlled entities reclassified as assets held for sale as at 31 December 2010. Income statement information shown above includes data relating to jointly controlled entities reclassified as assets held for sale during 2010 for the period from 1 January 2010 up until their date of reclassification as held for sale.

Our investment in TNK-BP was reclassified from a jointly controlled entity to an associate with effect from 9 January 2009, the date that BP finalized a revised shareholder agreement with its Russian partners in TNK-BP, Alfa Access-Renova (AAR). The formerly evenly-balanced main board structure was replaced by one with four representatives each from BP and AAR, plus three independent directors. The change in accounting classification from a jointly controlled entity to an associate reflected the ability of the independent directors of TNK-BP to decide on certain matters in the event of disagreement between the shareholder representatives on the board. The group's investment continues to be accounted for using the equity method.

Transactions between the group and its jointly controlled entities are summarized below.

						$ million
Sales to jointly controlled entities		**2010**		2009		2008
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	**3,804**	**1,352**	2,182	1,328	2,971	1,036

						$ million
Purchases from jointly controlled entities		**2010**		2009		2008
Product	**Purchases**	**Amount payable at 31 December[a]**	Purchases	Amount payable at 31 December[a]	Purchases	Amount payable at 31 December[a]
LNG, crude oil and oil products, natural gas, refinery operating costs, plant processing fees	**8,063**	**683**	5,377	214	9,115	182

[a]Amounts payable to jointly controlled entities shown above exclude $2,583 million (2009 $2,509 million and 2008 $2,365 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 $585 million (2009 $419 million), which will be paid over several years as it relates partly to pension payments. 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.

26. Investments in associates

The significant associates of the group are shown in Note 46. The principal associate in 2010 and 2009 is TNK-BP. Summarized financial information for the group's share of associates is set out below.

							$ million
			2010[a]			2009	2008
	TNK-BP	**Other**	**Total**	TNK-BP	Other	Total	
Sales and other operating revenues	**22,323**	**10,031**	**32,354**	17,377	8,301	25,678	11,709
Profit before interest and taxation	**3,866**	**1,215**	**5,081**	3,178	811	3,989	1,065
Finance costs	**128**	**22**	**150**	220	19	239	33
Profit before taxation	**3,738**	**1,193**	**4,931**	2,958	792	3,750	1,032
Taxation	**913**	**228**	**1,141**	871	125	996	234
Minority interest	**208**	**–**	**208**	139	–	139	–
Profit for the year	**2,617**	**965**	**3,582**	1,948	667	2,615	798
Non-current assets	**14,686**	**4,024**	**18,710**	13,437	4,573	18,010	
Current assets	**4,500**	**1,989**	**6,489**	4,205	1,887	6,092	
Total assets	**19,186**	**6,013**	**25,199**	17,642	6,460	24,102	
Current liabilities	**3,284**	**1,888**	**5,172**	3,122	1,640	4,762	
Non-current liabilities	**5,283**	**1,914**	**7,197**	4,797	2,277	7,074	
Total liabilities	**8,567**	**3,802**	**12,369**	7,919	3,917	11,836	
Minority interest	**624**	**–**	**624**	582	–	582	
	9,995	**2,211**	**12,206**	9,141	2,543	11,684	
Group investment in associates							
Group share of net assets (as above)	**9,995**	**2,211**	**12,206**	9,141	2,543	11,684	
Loans made by group companies to associates	**–**	**1,129**	**1,129**	–	1,279	1,279	
	9,995	**3,340**	**13,335**	9,141	3,822	12,963	

[a] Balance sheet information shown above excludes data relating to associates reclassified as held for sale as at 31 December 2010. Income statement information shown above includes data relating to associates reclassified as assets held for sale during 2010 for the period from 1 January 2010 up until the date of reclassification as held for sale.

Our investment in TNK-BP was reclassified from a jointly controlled entity to an associate with effect from 9 January 2009. See Note 25 for further information.

Transactions between the group and its associates are summarized below.

						$ million
Sales to associates		**2010**		2009		2008
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	**3,561**	**330**	2,801	320	3,248	219

Purchases from associates		**2010**		2009		2008
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	**4,889**	**633**	5,110	614	4,635	295

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 2010, as shown in the table above, exclude $299 million (2009 $376 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 2010 of $39 million (2009 $19 million) are also excluded from the table above.

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. See Note 4 for further information. As at 31 December 2010, a deposit of $972 million had been received from TNK-BP in advance of completion of this transaction and is reported within finance debt on the group balance sheet. This disposal deposit is not reflected in the amount payable in the table above. See Note 35 for further information.

27. Financial instruments and financial risk factors

The accounting classification of each category of financial instruments, and their carrying amounts, are set out below.

							$ million
At 31 December							**2010**
	Note	**Loans and receivables**	**Available-for-sale financial assets**	**At fair value through profit and loss**	**Derivative hedging instruments**	**Financial liabilities measured at amortized cost**	**Total carrying amount**
Financial assets							
Other investments – equity shares	**28**	**–**	**1,191**	**–**	**–**	**–**	**1,191**
– other	**28**	**–**	**1,532**	**–**	**–**	**–**	**1,532**
Loans		**1,141**	**–**	**–**	**–**	**–**	**1,141**
Trade and other receivables	**30**	**32,380**	**–**	**–**	**–**	**–**	**32,380**
Derivative financial instruments	**34**	**–**	**–**	**7,222**	**1,344**	**–**	**8,566**
Cash and cash equivalents	**31**	**13,462**	**5,094**	**–**	**–**	**–**	**18,556**
Financial liabilities							
Trade and other payables	**33**	**–**	**–**	**–**	**–**	**(56,499)**	**(56,499)**
Derivative financial instruments	**34**	**–**	**–**	**(7,254)**	**(279)**	**–**	**(7,533)**
Accruals		**–**	**–**	**–**	**–**	**(6,249)**	**(6,249)**
Finance debt	**35**	**–**	**–**	**–**	**–**	**(39,139)**	**(39,139)**
		46,983	**7,817**	**(32)**	**1,065**	**(101,887)**	**(46,054)**

							$ million
At 31 December							2009
	Note	Loans and receivables	Available-for-sale financial assets	At fair value through profit and loss	Derivative hedging instruments	Financial liabilities measured at amortized cost	Total carrying amount
Financial assets							
Other investments	28	–	1,567	–	–	–	1,567
Loans		1,288	–	–	–	–	1,288
Trade and other receivables	30	31,016	–	–	–	–	31,016
Derivative financial instruments	34	–	–	7,960	972	–	8,932
Cash and cash equivalents	31	6,570	1,769	–	–	–	8,339
Financial liabilities							
Trade and other payables	33	–	–	–	–	(34,325)	(34,325)
Derivative financial instruments	34	–	–	(7,389)	(766)	–	(8,155)
Accruals		–	–	–	–	(6,905)	(6,905)
Finance debt	35	–	–	–	–	(34,627)	(34,627)
		38,874	3,336	571	206	(75,857)	(32,870)

The fair value of finance debt is shown in Note 35. 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 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.

27. Financial instruments and financial risk factors continued

(a) Market risk

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

The group measures market risk exposure arising from its trading positions using value-at-risk techniques. For 2010, the various value-at-risk models used in prior years were consolidated as part of a process simplification into a Monte Carlo framework. This makes 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. The results of the gas price trading are included within Exploration and Production segment results, and the gas price trading value-at-risk includes gas and power trading. The results of the oil price trading are included within Refining and Marketing segment results, and the oil price trading value-at-risk includes oil, interest rate and currency trading. Market risk exposure in respect of embedded derivatives is also not included in the value-at-risk table. Instead separate sensitivity analyses are disclosed below.

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				**2010**				2009
	High	**Low**	**Average**	**Year end**	High	Low	Average	Year end
Group trading	**70**	**15**	**34**	**33**	79	24	45	30
Gas price trading	**62**	**7**	**27**	**18**	62	11	28	26
Oil price trading	**39**	**10**	**19**	**25**	75	11	29	13

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 $104 million at 31 December 2010 (2009 $73 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 $1,607 million at 31 December 2010 (2009 liability of $1,331 million). Key information on the natural gas contracts is given below.

At 31 December	**2010**	2009
Remaining contract terms	**4 years and 5 months to 7 years and 9 months**	9 months to 8 years 9 months
Contractual/notional amount	**1,688 million therms**	2,460 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				**2010**				2009
	Gas price	**Oil price**	**Power price**	**Discount rate**	Gas price	Oil price	Power price	Discount rate
Favourable 10% change	**145**	**48**	**10**	**10**	175	26	23	20
Unfavourable 10% change	**(180)**	**(68)**	**(10)**	**(10)**	(215)	(43)	(19)	(20)

27. 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 2010, the foreign currency value at risk was $81 million (2009 $140 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 34.

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, Korean won and Singapore dollar and at 31 December 2010 open contracts were in place for $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 (2009 $800 million sterling, $491 million Canadian dollar, $299 million euro, $240 million Norwegian krone, $215 million Australian dollar, $51 million Korean won and $41 million Singapore dollar capital expenditures maturing within six years with over 65% of the deals maturing within two years).

For other UK, European, Canadian 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 2010, the open positions relating to cylinders consisted of receive sterling, pay US dollar, purchased call and sold put options (cylinders) for $1,340 million (2009 $1,887 million); receive euro, pay US dollar cylinders for $650 million (2009 $1,716 million); receive Australian dollar, pay US dollar cylinders for $286 million (2009 $297 million). At 31 December 2010 the open positions relating to currency forwards consisted of buy sterling, sell US dollar currency forwards for $925 million (2009 nil); buy Euro, sell US dollar currency forwards for $630 million (2009 nil); and buy Canadian dollar, sell US dollar, currency forwards for $162 million (2009 nil).

In addition, most of the group's borrowings are in US dollars or are hedged with respect to the US dollar. At 31 December 2010, the total foreign currency net borrowings not swapped into US dollars amounted to $652 million (2009 $465 million). Of this total, $125 million was denominated in currencies other than the functional currency of the individual operating unit being entirely Canadian dollars (2009 $113 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 $12 million (2009 $11 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 at 31 December 2010 was 67% of total finance debt outstanding (2009 63%). The weighted average interest rate on finance debt at 31 December 2010 is 2% (2009 2%) and the weighted average maturity of fixed rate debt is five years (2009 four 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 2011, it is estimated that the group's profit before taxation for 2011 would decrease by approximately $303 million (2009 $219 million decrease in 2010). 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 2010 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 in 2010 (2009 nil and 2008 $546 million) relating to listed non-current available-for-sale investments. For further information see Note 28.

At 31 December 2010, it is estimated that an increase of 10% in quoted equity prices would result in an immediate credit to other comprehensive income of $95 million (2009 $130 million credit to other comprehensive income), whilst a decrease of 10% in quoted equity prices would result in an immediate charge to other comprehensive income of $95 million (2009 $130 million charge to other comprehensive income). BP has derivative positions that result in opposite impacts such that a 10% increase in equity prices would result in a charge to profit or loss of $70 million (2009 nil) and a 10% decrease in equity prices would result in a gain to profit or loss of $67 million (2009 nil).

27. Financial instruments and financial risk factors continued

At 31 December 2010, a single equity investment made up 80% (2009 73%) of the carrying amount of non-current available-for-sale financial assets thus the group's exposure is concentrated on changes in the share price of this equity 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.

While the global credit environment showed signs of stabilization and improvement in 2010, economic and political uncertainties continue to drive heightened awareness, discussion and co-ordination around the credit risks arising from the group's 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 or letters of credit and parent company guarantees. 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. At 31 December 2010, the maximum credit exposure was $60,643 million (2009 $49,575 million). Collateral received and recognized in the balance sheet at the year end was $313 million (2009 $549 million) and collateral held off balance sheet was $52 million (2009 $48 million). Credit exposure exists in relation to guarantees issued by group companies under which amounts outstanding at 31 December 2010 were $404 million (2009 $319 million) in respect of liabilities of jointly controlled entities and associates and $664 million (2009 $667 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.

Some mitigation of credit exposure is achieved by: netting arrangements; credit support agreements which require the counterparty to provide collateral or other credit risk mitigation; and credit insurance and other risk transfer instruments.

For the contracts comprising derivative financial instruments in an asset position at 31 December 2010, it is estimated that over 80% (2009 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 avoid concentration risks. At 31 December 2010, over 80% of the cash and cash equivalents balance was deposited with financial institutions rated A+ or higher.

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 50-60% (2009 approximately 55-60%) 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.

The group does not typically renegotiate the terms of trade receivables; however, if a renegotiation does take place, the outstanding balance is included in the analysis based on the original payment terms. There were no significant renegotiated balances outstanding at 31 December 2010 or 31 December 2009.

		$ million
Trade and other receivables at 31 December	**2010**	2009
Neither impaired nor past due	**30,181**	29,426
Impaired (net of valuation allowance)	**67**	91
Not impaired and past due in the following periods		
within 30 days	**1,358**	808
31 to 60 days	**249**	151
61 to 90 days	**101**	76
over 90 days	**424**	464
	32,380	31,016

27. Financial instruments and financial risk factors continued

The movement in the valuation allowance for trade receivables is set out below.

		$ million
	2010	2009
At 1 January	**430**	391
Exchange adjustments	**(9)**	12
Charge for the year	**150**	157
Utilization	**(143)**	(130)
At 31 December	**428**	430

(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.

Following the Gulf of Mexico oil spill, the group faced significant challenges in managing liquidity risk. The group was required to make substantial cash payments in connection with the oil spill and also experienced increased requirements during the year to post letters of credit to collateralize a number of environmental liabilities totalling $624 million and post further cash collateral under trading agreements totalling $728 million. Further informaton is provided in Liquidity and capital resources on pages 63 to 67.

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. At 31 December 2010, the group had substantial amounts of undrawn borrowing facilities available, including committed facilities of $12,500 million (2009 $4,950 million), consisting of $5,250 million of standby facilities (of which $400 million is available to draw and repay by mid-September 2011, $4,550 million until mid-October 2011, and $300 million until mid-January 2013) and $7,250 million of 364-day facilities (of which $4,000 million can be drawn until late May 2011 and is repayable up to 364 days from the date of drawing, $2,000 million drawn until the end of June 2011, $750 million drawn until early July 2011, and $500 million drawn until late August 2011). These facilities are with a number of international banks and borrowings under them would be at pre-agreed rates.

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 2010, the amount drawn down against the DIP was $12,272 million (2009 $11,403 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 and A (negative outlook) assigned by Standard & Poor's, a downgrading from Aa1 (stable outlook) and AA (stable outlook), respectively assigned prior to the Gulf of Mexico oil spill.

Since the credit rating downgrading, we have issued $6.2 billion of long-term debt early in the fourth quarter 2010, and issued short-term commercial paper at competitive rates, as and when required. As an additional measure, we have increased and maintained the cash and cash equivalents held by the group to $18.6 billion at the end of 2010, compared with $8.3 billion at the end of 2009.

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.

Included within current finance debt are US Industrial Revenue/Municipal bonds where bondholders have the option to tender the bonds for repayment at interest reset dates, and the next reset date falls within 12 months of the balance sheet date. The amounts at the end of 2010 totalled $379 million, down from $2,895 million at the end of 2009. The reduction largely reflects the initial failure to re-market the bonds following the Gulf of Mexico oil spill, as well as active management by BP to withdraw or re-negotiate term-out of the bonds on reset dates to further remove the uncertainty of the liquidity risk. Also included within current finance debt at the end of 2009 was an amount of $1,622 million for loans associated with long-term gas supply contracts backed by gas pre-paid bonds with tender options at interest rate resets with BP as the liquidity provider. Following the Gulf of Mexico oil spill the bonds failed re-marketing requiring BP to acquire and hold all of the bonds, with corresponding reduction to nil in the amount reflected in finance debt at the end of 2010.

Current finance debt on the group balance sheet at 31 December 2010 includes $6,197 million (2009 nil) in respect of cash deposits received for disposals expected to complete in 2011 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
			2010			2009
	Trade and other payables[a]	**Accruals**	**Finance debt**	Trade and other payables	Accruals	Finance debt
Within one year	**42,691**	**5,612**	**9,353**	31,413	6,202	9,790
1 to 2 years	**6,549**	**278**	**6,816**	1,059	231	6,861
2 to 3 years	**6,242**	**125**	**7,542**	1,089	106	5,359
3 to 4 years	**411**	**42**	**6,105**	566	78	5,528
4 to 5 years	**365**	**28**	**5,494**	67	49	3,151
5 to 10 years	**323**	**110**	**6,642**	85	163	5,723
Over 10 years	**25**	**54**	**724**	46	76	1,150
	56,606	**6,249**	**42,676**	34,325	6,905	37,562

[a] Trade and other payables at 31 December 2010 includes the Gulf of Mexico oil spill trust fund liability which is payable as follows: $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.

Financial statements

27. 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 34. 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 $6,725 million at 31 December 2010 (2009 $7,999 million) to be received on the same day as the related cash outflows.

		$ million
	2010	2009
Within one year	**986**	2,826
1 to 2 years	**1,682**	1,395
2 to 3 years	**1,358**	1,669
3 to 4 years	**1,124**	1,349
4 to 5 years	**295**	1,104
5 to 10 years	**947**	322
	6,392	8,665

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.

28. Other investments

			$ million
		2010	2009
	Current	**Non-current**	Non-current
Listed	**–**	**953**	1,296
Unlisted	**1,532**	**238**	271
	1,532	**1,191**	1,567

Other non-current investments comprise equity investments that have no fixed maturity date or coupon rate. These investments are classified as available-for-sale financial assets and as such are recorded at fair value with the gain or loss arising as a result of changes in fair value recorded directly in equity. 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 and are in level 3 of the fair value hierarchy.

At 31 December 2010, current unlisted investments relate to repurchased gas pre-paid bonds – see Note 35 for further information.

In 2010, no impairment losses were incurred relating to either unlisted investments or other listed investments. In 2009, impairment losses were incurred of $13 million relating to unlisted investments and nil relating to other listed investments.

BP has pledged listed equity investments with a carrying value of $948 million as part of a financing arrangement. As BP has retained substantially all the risks and rewards associated with the shares they continue to be reflected as an asset on the balance sheet, with a liability being reflected within finance debt. BP can 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.

29. Inventories

		$ million
	2010	2009
Crude oil	**8,969**	6,237
Natural gas	**112**	105
Refined petroleum and petrochemical products	**13,997**	12,337
	23,078	18,679
Supplies	**1,669**	1,661
	24,747	20,340
Trading inventories	**1,471**	2,265
	26,218	22,605
Cost of inventories expensed in the income statement	**216,211**	163,772

The inventory valuation at 31 December 2010 is stated net of a provision of $41 million (2009 $46 million) to write inventories down to their net realizable value. The net movement in the year in respect of inventory net realizable value provisions was $5 million credit (2009 $1,366 million credit).

30. Trade and other receivables

				$ million
		2010		2009
	Current	**Non-current**	Current	Non-current
Financial assets				
Trade receivables	**24,255**	**–**	22,604	–
Amounts receivable from jointly controlled entities	**751**	**601**	1,317	11
Amounts receivable from associates	**448**	**220**	417	298
Other receivables	**4,763**	**1,342**	4,949	1,420
	30,217	**2,163**	29,287	1,729
Non-financial assets				
Gulf of Mexico oil spill trust fund reimbursement asset[a]	**5,943**	**3,601**	–	–
Other receivables	**389**	**534**	244	–
	6,332	**4,135**	244	–
	36,549	**6,298**	29,531	1,729

[a] See Note 2 for further information.

Trade and other receivables are predominantly non-interest bearing. See Note 27 for further information.

Receivables with a carrying value of $18 million (2009 nil) have been pledged as security for certain of the group's liabilities.

31. Cash and cash equivalents

		$ million
	2010	2009
Cash at bank and in hand	**8,209**	3,359
Term bank deposits	**5,253**	3,211
Other cash equivalents	**5,094**	1,769
	18,556	8,339

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. Substantially all of the other cash equivalents are categorized within level 1 of the fair value hierarchy.

Cash and cash equivalents at 31 December 2010 includes $1,089 million (2009 $1,095 million) that is restricted. This relates principally to amounts required to cover initial margins on trading exchanges.

See Note 27 for further information.

32. Valuation and qualifying accounts

						$ million
		2010		2009		2008
	Doubtful debts	**Fixed assets – investments**	Doubtful debts	Fixed assets – investments	Doubtful debts	Fixed assets – investments
At 1 January	**430**	**349**	391	935	406	146
Charged to costs and expenses	**150**	**376**	157	66	191	647
Charged to other accounts[a]	**(9)**	**(3)**	12	6	(32)	143
Deductions	**(143)**	**(182)**	(130)	(658)	(174)	(1)
At 31 December	**428**	**540**	430	349	391	935

[a] Principally currency transactions.

Valuation and qualifying accounts are deducted in the balance sheet from the assets to which they apply.

Financial statements

33. Trade and other payables

				$ million
		2010		2009
	Current	**Non-current**	Current	Non-current
Financial liabilities				
Trade payables	**27,510**	**–**	22,886	–
Amounts payable to jointly controlled entities	**1,361**	**1,905**	304	2,419
Amounts payable to associates	**712**	**220**	692	298
Gulf of Mexico oil spill trust fund liability[a]	**5,002**	**9,899**	–	–
Other payables	**8,100**	**1,790**	7,531	195
	42,685	**13,814**	31,413	2,912
Non-financial liabilities				
Other payables	**3,644**	**471**	3,791	286
	46,329	**14,285**	35,204	3,198

[a]See Note 2 for further information.

Trade and other payables are predominantly interest free, however the Gulf of Mexico oil spill trust fund is recorded on a discounted basis. See Note 27 for further information.

34. 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 27.

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
		2010		2009
	Fair value asset	**Fair value liability**	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	**194**	**(280)**	318	(226)
Oil price derivatives	**1,099**	**(877)**	1,140	(1,191)
Natural gas price derivatives	**5,350**	**(3,951)**	5,636	(3,960)
Power price derivatives	**561**	**(432)**	682	(497)
Other derivatives	**–**	**(89)**	47	(47)
	7,204	**(5,629)**	7,823	(5,921)
Embedded derivative commodity price contracts	**18**	**(1,625)**	137	(1,468)
Cash flow hedges				
Currency forwards, futures and cylinders	**134**	**(124)**	182	(114)
Cross-currency interest rate swaps	**101**	**(1)**	44	(298)
	235	**(125)**	226	(412)
Fair value hedges				
Currency forwards, futures and swaps	**772**	**(80)**	490	(232)
Interest rate swaps	**337**	**(74)**	256	(122)
	1,109	**(154)**	746	(354)
	8,566	**(7,533)**	8,932	(8,155)
Of which – current	**4,356**	**(3,856)**	4,967	(4,681)
– non-current	**4,210**	**(3,677)**	3,965	(3,474)

34. 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 27.

The following tables show further information on the fair value of derivatives and other financial instruments held for trading purposes. Derivative assets held for trading have the following fair values and maturities.

							$ million
							2010
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**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**

							$ million
							2009
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	162	83	33	22	16	2	318
Oil price derivatives	814	136	69	59	44	18	1,140
Natural gas price derivatives	2,958	1,059	582	354	186	497	5,636
Power price derivatives	496	139	32	12	3	–	682
Other derivatives	47	–	–	–	–	–	47
	4,477	1,417	716	447	249	517	7,823

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

							$ million
							2010
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**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)**
Other derivatives	**–**	**(29)**	**(60)**	**–**	**–**	**–**	**(89)**
	(3,483)	**(955)**	**(628)**	**(171)**	**(115)**	**(277)**	**(5,629)**

							$ million
							2009
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(110)	(58)	(20)	(32)	(4)	(2)	(226)
Oil price derivatives	(1,083)	(67)	(29)	(11)	(1)	–	(1,191)
Natural gas price derivatives	(2,381)	(607)	(248)	(222)	(78)	(424)	(3,960)
Power price derivatives	(335)	(109)	(39)	(11)	(3)	–	(497)
Other derivatives	(47)	–	–	–	–	–	(47)
	(3,956)	(841)	(336)	(276)	(86)	(426)	(5,921)

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.

34. Derivative financial instruments continued

The following table shows the changes in the day-one profits and losses deferred on the balance sheet.

				$ million
		2010		2009
	Oil price	**Natural gas price**	Oil price	Natural gas price
Fair value of contracts not recognized through the income statement at 1 January	**21**	**33**	32	83
Fair value of new contracts at inception not recognized in the income statement	**–**	**39**	–	(14)
Fair value recognized in the income statement	**(21)**	**(3)**	(11)	(36)
Fair value of contracts not recognized through profit at 31 December	**–**	**69**	21	33

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
							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**

							$ million
							2009
	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	163	76	23	17	10	1	290
Level 2	9,544	2,182	915	357	146	–	13,144
Level 3	264	188	162	148	128	527	1,417
	9,971	2,446	1,100	522	284	528	14,851
Less: netting by counterparty	(5,494)	(1,029)	(384)	(75)	(35)	(11)	(7,028)
	4,477	1,417	716	447	249	517	7,823
Fair value of derivative liabilities							
Level 1	(95)	(39)	(14)	(24)	–	(1)	(173)
Level 2	(9,086)	(1,681)	(597)	(234)	(47)	–	(11,645)
Level 3	(269)	(150)	(109)	(93)	(74)	(436)	(1,131)
	(9,450)	(1,870)	(720)	(351)	(121)	(437)	(12,949)
Less: netting by counterparty	5,494	1,029	384	75	35	11	7,028
	(3,956)	(841)	(336)	(276)	(86)	(426)	(5,921)
Net fair value	521	576	380	171	163	91	1,902

34. 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 2010	**215**	**72**	**(1)**	**286**
Gains (losses) recognized in the income statement	**21**	**637**	**(1)**	**657**
Settlements	**(54)**	**(11)**	**1**	**(64)**
Purchases	**–**	**–**	**–**	**–**
Sales	**–**	**–**	**–**	**–**
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**

						$ million
	Currency	Oil price	Natural gas price	Power price	Other	Total
Net fair value of contracts at 1 January 2009	3	149	17	–	–	169
Gains (losses) recognized in the income statement	(1)	205	91	–	(1)	294
Settlements	–	(91)	(5)	–	–	(96)
Purchases	–	–	–	1	–	1
Sales	–	–	–	(2)	1	(1)
Transfers out of level 3	(2)	(50)	(4)	–	–	(56)
Transfers into level 3	–	2	(25)	–	–	(23)
Exchange adjustments	–	–	(2)	–	–	(2)
Net fair value of contracts at 31 December 2009	–	215	72	(1)	–	286

The amount recognized in the income statement for the year relating to level 3 held-for-trading derivatives still held at 31 December 2010 was a $651 million gain (2009 $278 million gain relating to derivatives still held at 31 December 2009).

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. 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 gain of $1,428 million (2009 $3,735 million net gain and 2008 $6,721 million net gain).

Embedded derivatives

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 embedded derivatives relate to commodity prices, 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.

Embedded derivative assets and liabilities have the following fair values and maturities.

							$ million
							2010
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Assets	**18**	**–**	**–**	**–**	**–**	**–**	**18**
Liabilities	**(325)**	**(326)**	**(285)**	**(281)**	**(212)**	**(196)**	**(1,625)**
Net fair value	**(307)**	**(326)**	**(285)**	**(281)**	**(212)**	**(196)**	**(1,607)**

							$ million
							2009
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Assets	134	–	–	–	–	3	137
Liabilities	(154)	(236)	(231)	(227)	(232)	(388)	(1,468)
Net fair value	(20)	(236)	(231)	(227)	(232)	(385)	(1,331)

34. Derivative financial instruments continued

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
	2010	2009
	Commodity price	Commodity price
Net fair value of contracts at 1 January	**(1,331)**	(1,892)
Settlements	**37**	221
Gains (losses) recognized in the income statement[a]	**(350)**	535
Exchange adjustments	**37**	(195)
Net fair value of contracts at 31 December	**(1,607)**	(1,331)

[a] The amount for gains (losses) recognized in the income statement for 2009 includes a loss of $224 million arising as a result of refinements in the modelling and valuation methods used for these contracts.

The amount recognized in the income statement for the year relating to level 3 embedded derivatives still held at 31 December 2010 was a $350 million loss (2009 $347 million gain relating to embedded derivatives still held at 31 December 2009).

The fair value gain (loss) on embedded derivatives is shown below.

			$ million
	2010	2009	2008
Commodity price embedded derivatives	**(309)**	607	(106)
Interest rate embedded derivatives	**–**	–	(5)
Fair value (loss) gain	**(309)**	607	(111)

Cash flow hedges

At 31 December 2010, 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, as well as cross-currency interest rate swaps to fix the US dollar interest rate and US dollar redemption value, with matching critical terms on the currency leg of the swap with the underlying non-US dollar debt issuance. Note 27 outlines the management of risk aspects for currency and interest rate 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 $25 million (2009 loss of $366 million and 2008 loss of $45 million). The entire gain of $25 million is included in production and manufacturing expenses (2009 $332 million loss in production and manufacturing expense and $34 million loss in finance costs; 2008 $1 million loss in production and manufacturing expense and $44 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 loss of $53 million (2009 $136 million loss and 2008 $38 million gain).

The amounts retained in equity at 31 December 2010 are expected to mature and impact the income statement by a gain of $89 million in 2011, a loss of $23 million in 2012 and a loss of $50 million in 2013 and beyond.

Fair value hedges

At 31 December 2010, 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 2010 was $563 million (2009 $98 million loss and 2008 $2 million gain) offset by a loss on the fair value of the finance debt of $554 million (2009 $117 million gain and 2008 $20 million loss).

The interest rate and cross-currency interest rate swaps have an average maturity of four to five years, (2009 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 27 outlines the group's approach to interest rate risk management.

Hedges of net investments in foreign operations

The group held currency swap contracts as a hedge of a long-term investment in a UK subsidiary that expired in 2009. The loss on the hedge recognized in equity in 2008 was $38 million. US dollars had been sold forward for sterling purchased and matched the underlying liability with no significant ineffectiveness reflected in the income statement.

35. Finance debt

						$ million
			2010			2009
	Current	**Non-current**	**Total**	Current	Non-current	Total
Borrowings	**8,312**	**30,017**	**38,329**	9,018	25,020	34,038
Net obligations under finance leases	**117**	**693**	**810**	91	498	589
	8,429	**30,710**	**39,139**	9,109	25,518	34,627
Disposal deposits	**6,197**	**–**	**6,197**	–	–	–
	14,626	**30,710**	**45,336**	9,109	25,518	34,627

Current finance debt includes the portion of long-term debt that will mature in the next 12 months, amounting to $6,976 million (2009 $3,965 million). Deposits for disposal transactions expected to complete in 2011 of $6,197 million (2009 nil) are also included. This debt will be considered extinguished on completion of the transactions.

Current finance debt also includes US Industrial Revenue/Municipal bonds of $379 million (2009 $2,895 million) with earliest contractual repayment dates within one year, and the 2009 balance included $1,622 million for loans associated with long-term gas supply contracts backed by gas pre-paid bonds. The bondholders typically have the option to tender these bonds for repayment on interest reset dates with any bonds that are tendered being remarketed. The reduction in current finance debt in 2010 attributable to such bonds largely reflects the unsuccessful remarketing of the bonds during the year. BP has repaid $2,460 million of US Industrial Revenue/Municipal bonds and at 31 December 2010 either held or had retired the bonds. All of the outstanding bonds associated with long-term gas supply contracts, amounting to $1,527 million were held by BP with the liability now recorded within other payables on the balance sheet and the bonds recorded within other current investments.

At 31 December 2010 $790 million (2009 $113 million) of finance debt was secured by the pledging of assets, and $4,780 million was secured in connection with deposits received relating to certain disposal transactions expected to complete in 2011 (2009 nil). In addition, in connection with $4,588 million (2009 nil) 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**
						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**
						2009
US dollar	4	4	12,525	1	20,566	33,091
Euro	4	2	63	2	1,199	1,262
Other currencies	6	14	171	3	103	274
			12,759		21,868	34,627

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. Future minimum lease payments under finance leases are set out below.

		$ million
	2010	2009
Future minimum lease payments payable within		
1 year	**153**	109
2 to 5 years	**535**	329
Thereafter	**438**	407
	1,126	845
Less finance charges	**316**	256
Net obligations	**810**	589
Of which – payable within 1 year	**117**	91
– payable within 2 to 5 years	**404**	202
– payable thereafter	**289**	296

35. 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 2010, 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, bank loans, overdrafts and US Industrial Revenue/Municipal bonds, 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
		2010		2009
	Fair value	**Carrying amount**	Fair value	Carrying amount
Short-term borrowings	**1,453**	**1,453**	5,144	5,144
Long-term borrowings	**37,600**	**36,876**	29,918	28,894
Net obligations under finance leases	**928**	**810**	599	589
Total finance debt	**39,981**	**39,139**	35,661	34,627

36. Capital disclosures and analysis of changes in net debt

The group defines capital as the total equity of the group. The group's approach to managing capital is set out in its financial framework which was revised during 2010, with the objective of maintaining a capital structure that allows the group to execute its strategy and is resilient to inherent volatility. The group intends to invest to grow the company and shareholder value sustainably through the business cycle, whilst providing the group with financial flexibility in the medium term as the disposal programme is completed and commitments to the Deepwater Horizon Oil Spill Trust are fulfilled.

In the light of the Gulf of Mexico oil spill and the agreement to establish the $20-billion trust fund, the BP board reviewed its dividend policy and decided that no ordinary share dividends would be paid in respect of the first three quarters of 2010. On 1 February 2011, BP announced the resumption of quarterly dividend payments, with a fourth quarter dividend of 7 cents per share. We believe this level is supported by the success of our disposal programme thus far, and by the improving business environment, but is balanced by the recognition of our continuing obligation to fund the trust until the end of 2013 and the need to retain financial flexibility. We intend to increase the dividend level over time in line with the circumstances of the company.

Going forward, the group intends to maintain a significant cash liquidity buffer and reduce the net debt ratio to within a range of 10-20%.

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 claimed, less cash and cash equivalents. Net debt and net debt ratio are non-GAAP measures. BP uses these measures to 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 2010 the net debt ratio was 21% (2009 20%).

During 2010, the company did not repurchase any of its own shares.

		$ million
At 31 December	**2010**	2009
Gross debt	**45,336**	34,627
Less: Cash and cash equivalents	**18,556**	8,339
Less: Fair value asset of hedges related to finance debt	**916**	127
Net debt	**25,864**	26,161
Equity	**95,891**	102,113
Net debt ratio	**21%**	20%

An analysis of changes in net debt is provided below.

						$ million
			2010			2009
Movement in net debt	**Finance debt[a]**	**Cash and cash equivalents**	**Net debt**	Finance debt[a]	Cash and cash equivalents	Net debt
At 1 January	**(34,500)**	**8,339**	**(26,161)**	(33,238)	8,197	(25,041)
Exchange adjustments	**194**	**(279)**	**(85)**	(60)	110	50
Net cash flow	**(3,613)**	**10,496**	**6,883**	(1,141)	32	(1,109)
Movement in finance debt relating to investing activities[b]	**(6,197)**	**–**	**(6,197)**	–	–	–
Other movements	**(304)**	**–**	**(304)**	(61)	–	(61)
At 31 December	**(44,420)**	**18,556**	**(25,864)**	(34,500)	8,339	(26,161)

[a] Including fair value of associated derivative financial instruments.
[b] See Note 35 for further information.

37. Provisions

$ 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**

$ million

	Decommissioning	Environmental	Litigation	Other	Total
At 1 January 2009	8,418	1,691	1,446	2,098	13,653
Exchange adjustments	398	15	22	29	464
New or increased provisions	169	588	302	1,256	2,315
Write-back of unused provisions	–	(259)	(99)	(228)	(586)
Unwinding of discount	184	32	15	16	247
Change in discount rate	324	18	(35)	8	315
Utilization	(383)	(308)	(574)	(361)	(1,626)
Deletions	(90)	(58)	(1)	(3)	(152)
At 31 December 2009	9,020	1,719	1,076	2,815	14,630
Of which – current	287	368	433	572	1,660
– non-current	8,733	1,351	643	2,243	12,970

The group makes full provision for the future cost of decommissioning oil and natural gas production facilities and related pipelines on a discounted basis on the installation of those facilities. The provision for the costs of decommissioning these 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 1.5% (2009 1.75%). 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 1.5% (2009 1.75%). 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 2010 are provisions for deferred employee compensation of $728 million (2009 $789 million) and for expected rental shortfalls on surplus properties of $45 million (2009 $246 million). These provisions are discounted using either a nominal discount rate of 3.75% (2009 4.0%) or a real discount rate of 1.5% (2009 1.75%), as appropriate.

37. Provisions continued

Provisions relating to the Gulf of Mexico oil spill

The Gulf of Mexico oil spill is described on pages 34 to 39 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 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 2010 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.

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 $427 million was included in provisions at 31 December 2010. This amount is expected to be spent evenly over the 10-year period.

As a responsible party under the 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, amongst 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. A provision of $382 million has been established for these items. 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, therefore no amounts have been provided for these items and they are disclosed as a contingent liability. See Note 44 for further information.

Spill response

The remaining provision for spill response includes the estimated future costs of both subsea operations as well as surface and shoreline work.

The subsea response provision is based on the remaining activities expected to be undertaken and has been calculated using daily rates of costs incurred to date. This includes the rig costs to complete the plugging and abandonment of the second relief well, which is in progress and is expected to complete in early March 2011, and the recovery of the subsea infrastructure used as part of the various containment systems. The majority of the vessels involved in the response have now been decontaminated. The provision includes the costs of decontaminating the remaining 25 vessels, which is expected to be complete by the end of April 2011.

The provision for surface and shoreline response is based on the daily costs currently being incurred which are underpinned by headcount, equipment and the number of vessels on hire. At the end of the year, there were approximately 360 vessels on hire and the number of personnel involved in response activities was approximately 6,200. BP and the US Coast Guard are working closely with state and local officials to clean Gulf Coast beaches before the 2011 spring and summer tourism seasons and this is the basis on which the provision at 31 December 2010 has been calculated. The provision also includes an estimate of future federal response costs and ongoing monitoring that will be required until the end of the second quarter of 2012.

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 have also been provided for.

BP believes that the history of claims received to date, and settlements made, provides 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 has been determined in accordance with IFRS and represents BP's current best estimate of the expenditure required to settle its obligations at the balance sheet date. The measurement of this provision is subject to significant uncertainty. Actual costs could ultimately be significantly higher or lower than those recorded as the claims and settlement process progresses.

In estimating the amount of the provision, BP has determined a range of possible outcomes for Individual and Business Claims, and State and Local Claims. These determinations are based on BP's claims payment experience, the application of insurance industry benchmark data, the use of a combination of actuarial and statistical methods and management judgements where appropriate. The methods selected are consistent with those used by the insurance industry to estimate a range of total expenditures for both reported and unreported claims. These methods have been adopted on the basis that, at this stage of development, the application of insurance industry standard techniques for the estimation of ultimate losses is an appropriate approach for the costs arising from the Deepwater Horizon oil spill.

37. Provisions continued

Through the application of this approach, BP has concluded that a reasonable range of possible outcomes for the amount of the provision as at 31 December 2010 is $6 billion to $13 billion. BP believes that the provision recorded at 31 December 2010 of $9.2 billion represents a reliable best estimate from within this range of possible outcomes. This amount is shown as payable from the trust fund under *Litigation and claims* in the table above. The provision is in addition to the $3.4 billion of claims paid in 2010. Of this total paid, $3.2 billion is included within utilization of provision in the table, 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 total utilization of provision of $4 billion under *Litigation and claims* are amounts relating to claims administration costs and legal fees. Of the total payments of $3.4 billion during the year, $3 billion was paid out of the trust fund and $0.4 billion was paid by BP.

BP's management has utilized actuarial techniques and its judgement in determining this reliable best estimate. However, it is possible that the final outcome could lie outside this range.

Many key assumptions underlie and influence both the range of possible outcomes and the reliable best estimates of total expenditures derived for both categories of claims. These 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 scope and number of claims that can be resolved successfully in the claims process, the resolution of rejected claims, the outcomes of any litigation, the effects on tourism and fisheries and other economic and environmental factors.

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 44 for further information.

Legal fees

Estimated legal fees have been provided for where we have been able to estimate reliably those which will arise in the next two years.

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 (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, the company 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. The company 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) the company'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, based on the analysis of available data by its experts, 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, the company 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.

37. Provisions continued

Therefore, for the purposes of calculating a provision for fines and penalties under Section 311 of the Clean Water Act, the company 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 approximately 850,000 barrels captured by vessels on the surface. In utilizing this estimate, the company 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. One factor that would impact the flow rate estimate is the completion of the analysis on the blowout preventer which is now in the custody of the federal government. Similar situations exist with regard to other pieces of physical evidence critical to the flow rate analysis. 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 the company'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 2010 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.

38. Pensions and other post-retirement benefits

Most group companies have pension plans, the forms and benefits of which vary with conditions and practices in the countries concerned. Pension benefits may be provided through defined contribution plans (money purchase schemes) or defined benefit plans (final salary and other types of schemes with committed pension 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 SPU. 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 are provided. These include 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 2010, contributions of $411 million (2009 $9 million and 2008 $6 million) and $694 million (2009 $795 million and 2008 $362 million) were made to the UK plans and US plans respectively. In addition, contributions of $188 million (2009 $204 million and 2008 $130 million) were made to other funded defined benefit plans. The aggregate level of contributions in 2011 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 plans are funded to a limited extent.

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 2010. 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 2010 are used to determine the pension liabilities at that date and the pension expense for 2011.

									%
Financial assumptions			UK			US			Other
	2010	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Discount rate for pension plan liabilities	**5.5**	5.8	6.3	**4.7**	5.4	6.3	**5.3**	5.8	5.7
Discount rate for other post-retirement benefit plans	**n/a**	n/a	n/a	**5.3**	5.8	6.2	**n/a**	n/a	n/a
Rate of increase in salaries	**5.4**	5.3	4.9	**4.1**	4.2	2.2	**3.8**	3.8	3.5
Rate of increase for pensions in payment	**3.5**	3.4	3.0	**–**	–	–	**1.8**	1.8	1.7
Rate of increase in deferred pensions	**3.5**	3.4	3.0	**–**	–	–	**1.3**	1.2	1.0
Inflation	**3.5**	3.4	3.0	**2.3**	2.4	0.4	**2.3**	2.3	2.0

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 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.

38. Pensions and other post-retirement benefits continued

Our assumptions for the rate of increase in salaries are based on our inflation 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:

									Years
Mortality assumptions			UK			US			Germany
	2010	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Life expectancy at age 60 for a male currently aged 60	**26.1**	26.0	25.9	**24.7**	24.6	24.4	**23.3**	23.2	23.0
Life expectancy at age 60 for a male currently aged 40	**29.1**	29.0	28.9	**26.2**	26.1	25.9	**26.2**	26.1	25.9
Life expectancy at age 60 for a female currently aged 60	**28.7**	28.6	28.5	**26.3**	26.3	26.1	**27.9**	27.8	27.6
Life expectancy at age 60 for a female currently aged 40	**31.6**	31.5	31.4	**27.2**	27.2	27.0	**30.6**	30.4	30.3

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:

			%
	2010	2009	2008
First year's US healthcare cost trend rate	**7.8**	8.0	8.1
Ultimate US healthcare cost trend rate	**5.0**	5.0	5.0
Year in which ultimate trend rate is reached	**2018**	2016	2014

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:

	Policy range
Asset category	%
Total equity	45-75
Bonds/cash	17.5-50
Property/real estate	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.

38. 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. The market value of unlisted investments at 31 December 2010 was $3,348 million (2009 $2,956 million and 2008 $2,819 million). The market value of pension assets at the end of 2010 was higher than at the end of 2009 due to a rise in the market value of investments when expressed in their local currencies partially offset by a decrease in value that arises from changes in exchange rates (decreasing the reported value of investments when expressed in US dollars). Movements in the value of plan assets during the year are shown in detail in the table on page 206.

		2010		2009		2008
	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	**8.0**	**18,546**	8.0	16,945	8.0	13,704
Bonds	**5.0**	**3,866**	5.3	3,701	6.1	3,258
Property	**6.5**	**1,462**	6.5	1,269	6.5	978
Cash	**1.4**	**406**	1.1	634	2.9	299
	7.2	**24,280**	7.3	22,549	7.4	18,239
US pension plans						
Equities	**8.5**	**5,058**	8.5	4,326	8.5	3,991
Bonds	**4.5**	**1,419**	4.8	1,218	3.7	1,247
Property	**8.0**	**7**	8.0	8	8.0	8
Cash	**0.3**	**165**	0.9	271	1.9	131
	8.0	**6,649**	8.0	5,823	8.0	5,377
US other post-retirement benefit plans						
Equities	**–**	**–**	8.5	8	8.5	9
Bonds	**–**	**–**	4.8	4	3.7	4
Cash	**0.3**	**8**	–	–	–	–
	0.3	**8**	7.6	12	7.3	13
Other plans						
Equities	**8.0**	**1,182**	8.6	1,091	8.4	799
Bonds	**4.2**	**1,874**	4.4	1,651	4.2	1,481
Property	**6.3**	**83**	6.5	82	6.3	127
Cash	**2.7**	**155**	2.0	245	3.1	118
	5.4	**3,294**	5.9	3,069	5.8	2,525

38. 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 2011 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 2011	**(343)**	**343**
Discount rate		
Effect on pension and other post-retirement benefit expense in 2011	**(76)**	**101**
Effect on pension and other post-retirement benefit obligation at 31 December 2010	**(5,370)**	**6,864**
Inflation rate		
Effect on pension and other post-retirement benefit expense in 2011	**470**	**(364)**
Effect on pension and other post-retirement benefit obligation at 31 December 2010	**5,060**	**(4,135)**
US healthcare cost trend rate		
Effect on US other post-retirement benefit expense in 2011	**31**	**(24)**
Effect on US other post-retirement benefit obligation at 31 December 2010	**401**	**(328)**

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 2011 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 2011	**41**	**4**	**4**	**9**
Effect on pension and other post-retirement benefit obligation at 31 December 2010	**581**	**73**	**72**	**187**

38. 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 (loss) 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 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.
[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.

38. 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)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	16,655	7,534	3,003	7,655	34,847
Exchange adjustments	1,896	–	–	363	2,259
Current service cost[a]	311	243	48	117	719
Past service cost	–	–	(22)	1	(21)
Interest cost	1,112	456	183	420	2,171
Curtailment	–	–	–	11	11
Settlement	–	–	–	(3)	(3)
Special termination benefits[c]	37	–	–	45	82
Contributions by plan participants	37	–	–	10	47
Benefit payments (funded plans)[d]	(977)	(1,371)	(4)	(209)	(2,561)
Benefit payments (unfunded plans)[d]	(4)	(73)	(191)	(399)	(667)
Disposals	–	–	–	(42)	(42)
Actuarial (gain) loss on obligation	2,358	730	(21)	164	3,231
Benefit obligation at 31 December[a e]	21,425	7,519	2,996	8,133	40,073
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	18,239	5,377	13	2,525	26,154
Exchange adjustments	2,054	–	–	242	2,296
Expected return on plan assets[a f]	1,426	405	1	147	1,979
Contributions by plan participants	37	–	–	10	47
Contributions by employers (funded plans)	9	795	–	204	1,008
Benefit payments (funded plans)[d]	(977)	(1,371)	(4)	(209)	(2,561)
Disposals	–	–	–	(19)	(19)
Actuarial gain on plan assets[f]	1,761	617	2	169	2,549
Fair value of plan assets at 31 December	22,549	5,823	12	3,069	31,453
Surplus (deficit) at 31 December	1,124	(1,696)	(2,984)	(5,064)	(8,620)
Represented by					
Asset recognized	1,290	–	–	100	1,390
Liability recognized	(166)	(1,696)	(2,984)	(5,164)	(10,010)
	1,124	(1,696)	(2,984)	(5,064)	(8,620)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	1,287	(1,280)	(33)	(164)	(190)
Unfunded	(163)	(416)	(2,951)	(4,900)	(8,430)
	1,124	(1,696)	(2,984)	(5,064)	(8,620)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(21,262)	(7,103)	(45)	(3,233)	(31,643)
Unfunded	(163)	(416)	(2,951)	(4,900)	(8,430)
	(21,425)	(7,519)	(2,996)	(8,133)	(40,073)

[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] The benefit payments amount shown above comprises $3,174 million benefits plus $54 million of plan expenses incurred in the administration of the benefit.
[e] The benefit obligation for other plans includes $3,880 million for the German plan, which is largely unfunded.
[f] 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.

38. Pensions and other post-retirement benefits continued

					$ million
					2008
	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]	448	235	40	128	851
Past service cost	7	74	–	1	82
Settlement, curtailment and special termination benefits	30	–	–	12	42
Payments to defined contribution plans	–	170	–	25	195
Total operating charge[b]	485	479	40	166	1,170
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	2,094	632	2	194	2,922
Interest on plan liabilities	(1,239)	(444)	(198)	(450)	(2,331)
Other finance income (expense)	855	188	(196)	(256)	591
Analysis of the amount recognized in other comprehensive income					
Actual return less expected return on pension plan assets	(6,946)	(2,895)	(8)	(404)	(10,253)
Change in assumptions underlying the present value of the plan liabilities	1,570	3	215	214	2,002
Experience gains and losses arising on the plan liabilities	(73)	(194)	18	70	(179)
Actuarial (loss) gain recognized in other comprehensive income	(5,449)	(3,086)	225	(120)	(8,430)

[a] The costs of managing the plan's investments are treated as being part of the investment return, the costs of administering our pensions fund 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 2010, reimbursement balances due from or to other companies in respect of pensions amounted to $483 million reimbursement assets (2009 $443 million) and $13 million reimbursement liabilities (2009 $14 million). These balances are not included as part of the pension liability, but are reflected elsewhere in the group balance sheet.

					$ million
	2010	2009	2008	2007	2006
History of surplus (deficit) and of experience gains and losses					
Benefit obligation at 31 December	**41,912**	40,073	34,847	43,100	42,433
Fair value of plan assets at 31 December	**34,231**	31,453	26,154	42,799	39,910
Deficit	**(7,681)**	(8,620)	(8,693)	(301)	(2,523)
Experience losses on plan liabilities	**(94)**	(421)	(178)	(200)	(124)
Actual return less expected return on pension plan assets	**2,037**	2,549	(10,253)	302	1,967
Actual return on plan assets	**4,261**	4,528	(7,331)	3,157	4,377
Actuarial (loss) gain recognized in other comprehensive income	**(320)**	(682)	(8,430)	1,717	2,615
Cumulative amount recognized in other comprehensive income	**(3,942)**	(3,622)	(2,940)	5,490	3,773

Estimated future benefit payments

The expected benefit payments, which reflect expected future service, as appropriate, but exclude plan expenses, up until 2020 are as follows:

					$ million
	UK pension plans	**US pension plans**	**US other post-retirement benefit plans**	**Other plans**	**Total**
2011	**994**	**805**	**207**	**612**	**2,618**
2012	**1,035**	**807**	**209**	**581**	**2,632**
2013	**1,069**	**810**	**213**	**584**	**2,676**
2014	**1,122**	**808**	**217**	**588**	**2,735**
2015	**1,167**	**788**	**221**	**576**	**2,752**
2016-2020	**6,581**	**3,636**	**1,132**	**2,815**	**14,164**

39. Called-up share capital

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

	2010		2009		2008	
Issued	**Shares (thousand)**	**$ million**	Shares (thousand)	$ million	Shares (thousand)	$ million
8% cumulative first preference shares of £1 each	**7,233**	**12**	7,233	12	7,233	12
9% cumulative second preference shares of £1 each	**5,473**	**9**	5,473	9	5,473	9
		21		21		21
Ordinary shares of 25 cents each						
At 1 January	**20,629,665**	**5,158**	20,618,458	5,155	20,863,424	5,216
Issue of new shares for employee share schemes[a]	**17,495**	**4**	11,207	3	24,791	6
Repurchase of ordinary share capital[b]	**–**	**–**	–	–	(269,757)	(67)
At 31 December	**20,647,160**	**5,162**	20,629,665	5,158	20,618,458	5,155
		5,183		5,179		5,176
Authorized						
8% cumulative first preference shares of £1 each	**7,250**	**12**	7,250	12	7,250	12
9% cumulative second preference shares of £1 each	**5,500**	**9**	5,500	9	5,500	9
Ordinary shares of 25 cents each	**36,000,000**	**9,000**	36,000,000	9,000	36,000,000	9,000

[a] Consideration received relating to the issue of new shares for employee share schemes amounted to $138 million (2009 $84 million and 2008 $180 million).
[b] Purchased for a total consideration of nil (2009 nil and 2008 $2,914 million), all of which were for cancellation. At 31 December 2010, 112,803,287 (2009 112,803,287 and 2008 150,444,408) ordinary shares bought back were awaiting cancellation. These shares have been excluded from ordinary shares in issue shown above. Transaction costs of share repurchases amounted to nil (2009 nil and 2008 $16 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

	2010		2009		2008	
	Shares (thousand)	**Nominal value $ million**	Shares (thousand)	Nominal value $ million	Shares (thousand)	Nominal value $ million
At 1 January	**1,869,777**	**467**	1,888,151	472	1,940,639	485
Shares gifted to the Employee Share Ownership Plans	**–**	**–**	(1,265)	(1)	(10,000)	(2)
Shares transferred at market price to the Employee Share Ownership Plans	**(7,125)**	**(2)**	–	–	(20,000)	(5)
Shares re-issued to employee share schemes	**(11,953)**	**(3)**	(17,109)	(4)	(22,488)	(6)
At 31 December	**1,850,699**	**462**	1,869,777	467	1,888,151	472

For each year presented, the balance at 1 January represents the maximum number of shares held in treasury during the year, representing 9.1% (2009 9.2% and 2008 9.3%) of the called-up ordinary share capital of the company.

During 2010, the movement in treasury shares represented less than 0.1% (2009 less than 0.1% and 2008 0.25%) of the ordinary share capital of the company.

On 14 January 2011, BP entered into a share swap agreement with Rosneft Oil Company that would result in BP issuing 988,694,683 new ordinary shares to Rosneft when the transaction completes, which is subject to the matters disclosed in Note 6.

40. Capital and reserves

	Share capital	**Share premium account**	**Capital redemption reserve**	**Merger reserve**
At 1 January 2010	**5,179**	**9,847**	**1,072**	**27,206**
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**	**–**	**–**
Transactions involving minority interests	**–**	**–**	**–**	**–**
At 31 December 2010	**5,183**	**9,987**	**1,072**	**27,206**

	Share capital	Share premium account	Capital redemption reserve	Merger reserve
At 1 January 2009	5,176	9,763	1,072	27,206
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	–	–
Changes in associates' equity	–	–	–	–
Transactions involving minority interests	–	–	–	–
At 31 December 2009	5,179	9,847	1,072	27,206

	Share capital	Share premium account	Capital redemption reserve	Merger reserve
At 1 January 2008	5,237	9,581	1,005	27,206
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	–	–	–	–
Repurchase of ordinary share capital	(67)	–	67	–
Share-based payments[a]	6	182	–	–
Transactions involving minority interests	–	–	–	–
At 31 December 2008	5,176	9,763	1,072	27,206

[a] Includes new share issues and movements in own shares and treasury shares where these relate to share-based payment plans.

$ million

	Own shares	Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
	(214)	**(21,303)**	**4,811**	**754**	**22**	**1,584**	**72,655**	**101,613**	**500**	**102,113**
	–	**–**	**126**	**–**	**2**	**–**	**–**	**128**	**3**	**131**
	–	**–**	**–**	**–**	**–**	**–**	**(418)**	**(418)**	**–**	**(418)**
	–	**–**	**–**	**(291)**	**–**	**–**	**–**	**(291)**	**–**	**(291)**
	–	**–**	**–**	**–**	**(18)**	**–**	**–**	**(18)**	**–**	**(18)**
	–	**–**	**–**	**–**	**–**	**–**	**(3,719)**	**(3,719)**	**395**	**(3,324)**
	–	**–**	**126**	**(291)**	**(16)**	**–**	**(4,137)**	**(4,318)**	**398**	**(3,920)**
	–	**–**	**–**	**–**	**–**	**–**	**(2,627)**	**(2,627)**	**(315)**	**(2,942)**
	88	**218**	**–**	**–**	**–**	**2**	**(113)**	**339**	**–**	**339**
	–	**–**	**–**	**–**	**–**	**–**	**(20)**	**(20)**	**321**	**301**
	(126)	**(21,085)**	**4,937**	**463**	**6**	**1,586**	**65,758**	**94,987**	**904**	**95,891**

	Own shares	Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
	(326)	(21,513)	2,353	63	(866)	1,295	67,080	91,303	806	92,109
	–	–	2,458	(2)	(37)	–	–	2,419	(56)	2,363
	–	–	–	–	–	–	(478)	(478)	–	(478)
	–	–	–	693	–	–	–	693	–	693
	–	–	–	–	925	–	–	925	–	925
	–	–	–	–	–	–	16,578	16,578	181	16,759
	–	–	2,458	691	888	–	16,100	20,137	125	20,262
	–	–	–	–	–	–	(10,483)	(10,483)	(416)	(10,899)
	112	210	–	–	–	289	23	721	–	721
	–	–	–	–	–	–	(43)	(43)	–	(43)
	–	–	–	–	–	–	(22)	(22)	(15)	(37)
	(214)	(21,303)	4,811	754	22	1,584	72,655	101,613	500	102,113

	Own shares	Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
	(60)	(22,112)	6,540	481	106	1,196	64,510	93,690	962	94,652
	–	–	(4,187)	–	–	–	–	(4,187)	(75)	(4,262)
	–	–	–	–	–	–	(5,828)	(5,828)	–	(5,828)
	–	–	–	(418)	–	–	–	(418)	–	(418)
	–	–	–	–	(972)	–	–	(972)	–	(972)
	–	–	–	–	–	–	21,157	21,157	509	21,666
	–	–	(4,187)	(418)	(972)	–	15,329	9,752	434	10,186
	–	–	–	–	–	–	(10,342)	(10,342)	(425)	(10,767)
	–	–	–	–	–	–	(2,414)	(2,414)	–	(2,414)
	(266)	599	–	–	–	99	(3)	617	–	617
	–	–	–	–	–	–	–	–	(165)	(165)
	(326)	(21,513)	2,353	63	(866)	1,295	67,080	91,303	806	92,109

40. 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 Plans (ESOPs) to meet the future requirements of the employee share-based payment plans.

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 affects profit or loss, 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.

40. 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
			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

			$ million
			2008
	Pre-tax	Tax	Net of tax
Currency translation differences (including recycling)	(4,362)	100	(4,262)
Actuarial loss relating to pensions and other post-retirement benefits	(8,430)	2,602	(5,828)
Available-for-sale investments (including recycling)	(468)	50	(418)
Cash flow hedges (including recycling)	(1,166)	194	(972)
Other comprehensive income	(14,426)	2,946	(11,480)

41. Share-based payments

Effect of share-based payment transactions on the group's result and financial position

			$ million
	2010	2009	2008
Total expense recognized for equity-settled share-based payment transactions	**577**	506	524
Total (credit) expense recognized for cash-settled share-based payment transactions	**(1)**	15	(16)
Total expense recognized for share-based payment transactions	**576**	521	508
Closing balance of liability for cash-settled share-based payment transactions	**16**	32	21
Total intrinsic value for vested cash-settled share-based payments	**1**	7	2

For ease of presentation, option and share holdings 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 share-based payment plans that existed during the year are detailed below. All plans are ongoing unless otherwise stated.

Plans for executive directors

Executive Directors' Incentive Plan (EDIP) – share element

An equity-settled incentive plan for executive directors with a three-year performance period. For share plan performance periods 2008-2010 the award of shares is determined by comparing BP's total shareholder return (TSR) against the other oil majors (ExxonMobil, Shell, Total and Chevron). For the performance period 2009-2011 the award of shares is determined 50% on TSR versus a competitor group of oil majors (which in this period also included ConocoPhillips) and 50% on a balanced scorecard (BSC) of three underlying performance measures versus the same competitor group. For the period 2010-2012 the award of shares is determined one third on TSR versus a competitor group of oil majors (identical to the 2009-2011 plan group) and two thirds on a BSC of three underlying performance factors. After the performance period, the shares that vest (net of tax) are then subject to a three-year retention period. The directors' remuneration report on pages 112 to 121 includes full details of the plan.

Executive Directors' Incentive Plan (EDIP) – deferred matching share element

Following the renewal of the EDIP at the 2010 Annual General Meeting, a deferred matching share element is in place requiring a mandatory one third of directors' annual bonus to be deferred into shares for three years. The shares are matched by the company on a one-for-one basis. Vesting of both deferred and matching shares is contingent on an assessment of safety and environmental sustainability over the three-year deferral period and a director may voluntarily defer an additional one third of bonus into shares on the same terms.

Executive Directors' Incentive Plan (EDIP) – share option element

An equity-settled share option plan for executive directors that permits options to be granted at an exercise price no lower than the market price of a share on the date that the option is granted. The options are exercisable up to the seventh anniversary of the grant date and the last grants were made in 2004. From 2005 onwards the remuneration committee's policy is not to make further grants of share options to executive directors.

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 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 during the three-year period will normally preclude the conversion of units into shares, but special arrangements apply where the participant leaves for a qualifying reason.

Grants are settled in cash where participants are located in a country whose regulatory environment prohibits the holding of BP shares.

Performance unit plans

The number of units granted is made by reference to level of seniority of the 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 TSR compared against the other oil majors. In addition, free cash flow (FCF) is used as a performance measure for one of the performance plans. Plans included in this category are the Competitive Performance Plan (CPP), the Medium Term Performance Plan (MTPP) 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 long-term potential. One restricted share unit plan used in special circumstances for senior employees, 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 share immediately preceding the date of grant were granted to participants annually until 2006. There were no performance conditions and the options are exercisable between the third and tenth anniversaries of the grant date.

Savings and matching plans

BP ShareSave Plan

This is a savings-related share option plan under which employees save on a monthly basis, over a three- or five-year period, towards the purchase of shares at a fixed price determined when the option is granted. This price is usually set at a 20% discount to the market price at the time of grant. 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 will have six months in which to use their savings to exercise their options on a pro-rated basis.

41. Share-based payments continued

BP ShareMatch Plans

These are matching share plans under which BP matches employees' own contributions of shares up to a predetermined limit. The plans are run in the UK and in more than 60 other countries. The UK plan is run on a monthly basis with shares being held in trust for five years before they can be released free of any income tax and national insurance liability. 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.

Local plans

In some countries BP provides local scheme benefits, the rules and qualifications for which vary according to local circumstances.

Employee Share Ownership Plans (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 ESOP trusts vest unconditionally to employees, the amount paid for those shares is deducted in arriving at shareholders' equity (see Note 40). Assets and liabilities of the ESOPs are recognized as assets and liabilities of the group.

At 31 December 2010 the ESOPs held 11,477,253 shares (2009 18,062,246 shares and 2008 29,051,082 shares) for potential future awards, which had a market value of $82 million (2009 $174 million and 2008 $220 million).

Share option transactions

Details of share option transactions for the year under the share option plans are as follows:

	2010 Number of options	2010 Weighted average exercise price $	2009 Number of options	2009 Weighted average exercise price $	2008 Number of options	2008 Weighted average exercise price $
Outstanding at 1 January	**295,895,357**	**8.73**	326,254,599	8.70	358,094,243	8.51
Granted	**10,420,287**	**6.08**	9,679,836	6.55	8,062,899	8.96
Forfeited	**(9,499,661)**	**7.88**	(5,954,325)	8.81	(2,502,784)	8.50
Exercised	**(31,839,034)**	**7.97**	(21,293,871)	7.53	(37,277,895)	6.97
Expired	**(1,670,227)**	**8.71**	(12,790,882)	8.01	(121,864)	7.00
Outstanding at 31 December	**263,306,722**	**8.75**	295,895,357	8.73	326,254,599	8.70
Exercisable at 31 December	**242,530,635**	**8.90**	274,685,068	8.80	260,178,938	8.22

The weighted average share price at the date of exercise was $9.54 (2009 $9.10 and 2008 $10.87). For the options outstanding at 31 December 2010, the exercise price ranges and weighted average remaining contractual lives are shown below.

Range of exercise prices	Options outstanding Number of shares	Options outstanding Weighted average remaining life Years	Options outstanding Weighted average exercise price $	Options exercisable Number of shares	Options exercisable Weighted average exercise price $
$6.09 – $7.53	**54,821,144**	**2.68**	**6.36**	**39,231,453**	**6.40**
$7.54 – $8.99	**115,187,261**	**1.71**	**8.19**	**112,551,834**	**8.17**
$9.00 – $10.45	**21,827,393**	**3.54**	**9.88**	**19,276,424**	**9.98**
$10.46 – $11.92	**71,470,924**	**4.81**	**11.14**	**71,470,924**	**11.14**
	263,306,722	**2.90**	**8.75**	**242,530,635**	**8.90**

Fair values and associated details for options and shares granted

	2010 ShareSave 3 year	2010 ShareSave 5 year	2009 ShareSave 3 year	2009 ShareSave 5 year	2008 ShareSave 3 year	2008 ShareSave 5 year
Option pricing model used	**Binomial**	**Binomial**	Binomial	Binomial	Binomial	Binomial
Weighted average fair value	**$0.06**	**$0.08**	$1.07	$1.07	$1.82	$1.74
Weighted average share price	**$4.58**	**$4.58**	$7.87	$7.87	$11.26	$11.26
Weighted average exercise price	**$5.90**	**$5.90**	$6.92	$6.92	$9.70	$9.70
Expected volatility	**22%**	**23%**	32%	32%	23%	23%
Option life	**3.5 years**	**5.5 years**	3.5 years	5.5 years	3.5 years	5.5 years
Expected dividends	**8.40%**	**8.40%**	7.40%	7.40%	4.60%	4.60%
Risk free interest rate	**1.25%**	**2.00%**	3.00%	3.75%	5.00%	5.00%
Expected exercise behaviour	**100% year 4**	**100% year 6**	100% year 4	100% year 6	100% year 4	100% year 6

The group uses a valuation model to determine the fair value of options granted. The model uses the implied volatility of ordinary share price for the quarter within which the grant date of the relevant plan falls. The fair value is adjusted for the expected rates of early cancellation. Management is responsible for all inputs and assumptions in relation to the model, including the determination of expected volatility.

41. Share-based payments continued

Shares granted in 2010	CPP	EPP	EDIP-TSR	EDIP-BSC	RSP	DAB	PSP
Number of equity instruments granted (million)	**1.3**	**7.6**	**1.2**	**2.5**	**21.4**	**24.5**	**16.0**
Weighted average fair value	**$19.81**	**$9.43**	**$4.42**	**$8.94**	**$6.78**	**$9.43**	**$9.43**
Fair value measurement basis	**Monte Carlo**	**Market value**	**Monte Carlo**	**Market value**	**Market value**	**Market value**	**Market value**

Shares granted in 2009	CPP	EPP	EDIP-TSR	EDIP-BSC	RSP	DAB	PSP
Number of equity instruments granted (million)	1.4	7.6	2.1	2.1	2.4	38.9	16.5
Weighted average fair value	$9.76	$6.56	$2.74	$7.27	$8.76	$6.56	$8.32
Fair value measurement basis	Monte Carlo	Market value	Monte Carlo	Market value	Market value	Market value	Monte Carlo

Shares granted in 2008	MTPP-TSR	MTPP-FCF	EDIP-TSR	EDIP-RET[a]	RSP	DAB	PSP
Number of equity instruments granted (million)	9.1	9.1	2.6	0.5	7.7	5.8	16.7
Weighted average fair value	$5.07	$10.34	$4.55	$11.13	$8.83	$10.34	$12.89
Fair value measurement basis	Monte Carlo	Market value	Monte Carlo	Market value	Market value	Market value	Monte Carlo

[a]EDIP – retention element.

The group used a Monte Carlo simulation to determine the fair value of the TSR element of the 2010, 2009 and 2008 CPP, MTPP, and EDIP plans, and in 2009 and 2008 for the PSP plan. In accordance with the rules of the plans the model simulates BP's TSR and compares it against our principal strategic competitors over the three-year period of the plans. The model takes into account the historic 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.

42. Employee costs and numbers

Employee costs	2010	2009	2008
			$ million
Wages and salaries[a]	**9,242**	9,702	10,388
Social security costs	**789**	780	805
Share-based payments	**576**	521	508
Pension and other post-retirement benefit costs	**1,166**	1,213	579
	11,773	12,216	12,280

Number of employees at 31 December	2010	2009	2008
Exploration and Production	**21,100**	21,500	21,400
Refining and Marketing[b]	**52,300**	51,600	61,500
Other businesses and corporate	**6,200**	7,200	9,100
Gulf Coast Restoration Organization	**100**	–	–
	79,700	80,300	92,000
By geographical area			
US	**22,100**	22,800	29,300
Non-US[b]	**57,600**	57,500	62,700
	79,700	80,300	92,000

			2010			2009			2008
Average number of employees	US	Non-US	Total	US	Non-US	Total	US	Non-US	Total
Exploration and Production	**8,100**	**13,500**	**21,600**	7,900	13,800	21,700	7,800	13,800	21,600
Refining and Marketing	**12,600**	**38,300**	**50,900**	14,700	40,700	55,400	21,600	43,400	65,000
Other businesses and corporate	**1,900**	**5,000**	**6,900**	2,300	5,800	8,100	2,600	6,500	9,100
	22,600	**56,800**	**79,400**	24,900	60,300	85,200	32,000	63,700	95,700

[a]Includes termination payments of $166 million (2009 $945 million and 2008 $669 million).
[b]Includes 15,200 (2009 13,900 and 2008 21,200) service station staff.

43. Remuneration of directors and senior management

Remuneration of directors

			$ million
	2010	2009	2008
Total for all directors			
Emoluments	**15**	19	19
Gains made on the exercise of share options	**2**	2	1
Amounts awarded under incentive schemes	**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. Also included was compensation for loss of office of $3 million in 2010 (2009 nil and 2008 $1 million).

Pension contributions

During 2010 three executive directors participated in a non-contributory pension scheme 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 2010.

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 112 to 121.

Remuneration of directors and senior management

			$ million
	2010	2009	2008
Total for all senior management			
Short-term employee benefits	**25**	36	34
Post-retirement benefits	**3**	3	4
Share-based payments	**29**	20	20

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 $3 million (2009 $6 million and 2008 $3 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 41.

44. Contingent liabilities and contingent assets

Contingent liabilities relating to the Gulf of Mexico oil spill

As a consequence of the Gulf of Mexico oil spill, as described on pages 34 to 39, BP has incurred costs during the year and recognized provisions for certain future costs. Further information is provided in Note 2 and Note 37.

BP has provided for its best estimate of certain claims under the Oil Pollution Act of 1990 (OPA 90) that will be paid through the $20-billion trust fund. 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, and claims asserted in civil litigation, 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 37 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 anticipate that we will need at least a full year, and perhaps materially longer, after the initial oil impacts to gain an understanding of the natural resource damages. In addition, if 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 determined and the effects of early restoration projects are 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 or timing of the remaining Natural Resource Damages claims.

BP is named as a defendant in more than 400 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, 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. These pending lawsuits are at the very early stages of proceedings and most of the claims have been consolidated into one of two multi-district litigation proceedings. A trial of liability issues in the pending multi-district litigation is currently scheduled for February 2012. 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. See *Legal proceedings* on page 130 for further information.

Therefore no amounts have been provided for these items as of 31 December 2010. 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 37, for those relating to the Clean Water Act. It is also not possible to reliably estimate legal fees beyond two years. 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.

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 27 to 32. Any such possible obligations are therefore contingent liabilities and, at present, it is not practicable to estimate their magnitude or possible timing of payment. Furthermore, other material unanticipated obligations may arise in future in relation to the incident.

Contingent assets relating to the Gulf of Mexico oil spill

BP is the operator of the Macondo well and holds a 65% working interest, with the remaining 35% interest held by two co-owners, Anadarko Petroleum Corporation (APC) and MOEX Offshore 2007 LLC (MOEX). Under the Operating Agreement, MOEX and APC are responsible for reimbursing BP for their proportionate shares of the costs of all operations and activities conducted under the Operating Agreement. In addition, the parties are responsible for their proportionate shares of all liabilities resulting from operations or activities conducted under the Operating Agreement, except where liability results from a party's gross negligence or wilful misconduct, in which case that party is solely responsible. BP does not believe that it has been grossly negligent nor has it engaged in wilful misconduct under the terms of the Operating Agreement or at law.

As of 31 December 2010, $6 billion had been billed to the co-owners, which BP believes to be contractually recoverable. Billings to co-owners are based upon costs incurred to date rather than amounts provided in the period. As further costs are incurred, BP believes that certain of the costs will be billable to our co-owners under the Operating Agreement.

Our co-owners have each written to BP indicating that they are withholding payment in light of the investigations surrounding, and pending determination of the root causes of, the incident. In addition, APC has publicly accused BP of having been grossly negligent and stated it has no liability for the incident, both of which claims BP refutes and intends to challenge in any legal proceedings. There are also audit rights concerning billings under the Operating Agreement which may be exercised by APC and MOEX, and which may or may not lead to an adjustment of the amount billed. BP may ultimately need to enforce its rights to collect payment from the co-owners through an arbitration proceeding as provided for in the Operating Agreement. There is a risk that amounts billed to co-owners may not ultimately be recovered should our co-owners be found not liable for these costs or be unable to pay them.

BP believes that it has a contractual right to recover the co-owners' shares of the costs incurred, however, no recovery amounts have been recognized in the financial statements as at 31 December 2010.

44. Contingent liabilities and contingent assets continued

Other contingent liabilities

There were contingent liabilities at 31 December 2010 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 27.

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, oil fields, 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.

45. Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been placed at 31 December 2010 amounted to $11,279 million (2009 $9,812 million). In addition, at 31 December 2010, the group had contracts in place for future capital expenditure relating to investments in jointly controlled entities of $437 million (2009 $622 million) and investments in associates of $80 million (2009 $170 million).

BP's share of capital commitments of jointly controlled entities amounted to $1,117 million (2009 $926 million).

46. Subsidiaries, jointly controlled entities and associates

The more important subsidiaries, jointly controlled entities and associates of the group at 31 December 2010 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 Op. Co.	100	England & Wales	Exploration and production
*BP Global Investments	100	England & Wales	Investment holding
*BP International	100	England & Wales	Integrated oil operations, investment holding, finance
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 Oil Australia	100	Australia	Integrated oil operations
BP Australia Capital Markets	100	Australia	Finance
BP Developments Australia	100	Australia	Exploration and production
BP Finance Australia	100	Australia	Finance
Azerbaijan			
Amoco Caspian Sea Petroleum	100	British Virgin Islands	Exploration and production
BP Exploration (Caspian Sea)	100	England & Wales	Exploration and production
Canada			
BP Canada Energy	100	Canada	Exploration and production
BP Canada Finance	100	Canada	Finance
Egypt			
BP Egypt Co.	100	US	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 Co.	100	US	Exploration and production, refining and marketing, pipelines and petrochemicals
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	
BP Exploration and Production	100	US	
BP Exploration (Alaska)	100	US	
BP Products North America	100	US	
BP West Coast Products	100	US	
Standard Oil Co.	100	US	
Verano Collateral Holdings	100	US	
BP Capital Markets America	100	US	Finance

46. Subsidiaries, jointly controlled entities and associates continued

Jointly controlled entities	%	Country of incorporation or registration	Principal activities
Angola			
Angola LNG Supply Services	14	US	LNG processing and transportation
Argentina			
Pan American Energy[a b]	60	US	Exploration and production
Canada			
Sunrise Oil Sands	50	Canada	Exploration and production
China			
Shanghai SECCO Petrochemical Co.	50	China	Petrochemicals
Germany			
Ruhr Oel	50	Germany	Refining and marketing and petrochemicals
Russia			
Elvary Neftegaz Holdings BV	49	Netherlands	Exploration and appraisal
Trinidad & Tobago			
Atlantic 4 Holdings	38	US	LNG manufacture
Atlantic LNG 2/3 Company of Trinidad and Tobago	43	Trinidad & Tobago	LNG manufacture
US			
BP-Husky Refining	50	US	Refining
Watson Cogeneration[a]	51	US	Power generation
Venezuela			
Petromonagas[b]	17	Venezuela	Exploration and production

[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 2010 the group's interests in Pan American Energy and Petromonagas have been reclassified as assets held for sale. See Note 4 for further information.

Associates	%	Country of incorporation	Principal activities
Abu Dhabi			
Abu Dhabi Marine Areas	37	England & Wales	Crude oil production
Abu Dhabi Petroleum Co.	24	England & Wales	Crude oil production
Azerbaijan			
The Baku-Tbilisi-Ceyhan Pipeline Co.	30	Cayman Islands	Pipelines
South Caucasus Pipeline Co.	26	Cayman Islands	Pipelines
Russia			
TNK-BP	50	British Virgin Islands	Integrated oil operations

47. 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					**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)

47. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

					$ million
For the year ended 31 December					2009
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	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

47. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	$ million 2008 BP group
Sales and other operating revenues	6,782	–	361,143	(6,782)	361,143
Earnings from jointly controlled entities – after interest and tax	–	–	3,023	–	3,023
Earnings from associates – after interest and tax	–	–	798	–	798
Equity-accounted income of subsidiaries – after interest and tax	469	20,295	–	(20,764)	–
Interest and other revenues	514	173	1,025	(976)	736
Gains on sale of businesses and fixed assets	–	–	1,353	–	1,353
Total revenues and other income	7,765	20,468	367,342	(28,522)	367,053
Purchases	895	–	272,869	(6,782)	266,982
Production and manufacturing expenses	1,083	–	25,673	–	26,756
Production and similar taxes	2,343	–	6,610	–	8,953
Depreciation, depletion and amortization	365	–	10,620	–	10,985
Impairment and losses on sale of businesses and fixed assets	–	–	1,733	–	1,733
Exploration expense	–	–	882	–	882
Distribution and administration expenses	22	28	15,469	(107)	15,412
Fair value loss on embedded derivatives	–	–	111	–	111
Profit before interest and taxation	3,057	20,440	33,375	(21,633)	35,239
Finance costs	158	169	2,089	(869)	1,547
Net finance (income) expense relating to pensions and other post-retirement benefits	–	(822)	231	–	(591)
Profit before taxation	2,899	21,093	31,055	(20,764)	34,283
Taxation	944	(64)	11,737	–	12,617
Profit for the year	1,955	21,157	19,318	(20,764)	21,666
Attributable to					
BP shareholders	1,955	21,157	18,809	(20,764)	21,157
Minority interest	–	–	509	–	509
	1,955	21,157	19,318	(20,764)	21,666

47. 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	BP group
					$ million 2010
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	–	–	12,286	–	12,286
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	151,765	(116,716)	159,871
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	169,700	(121,021)	175,409
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	–	–	7,128	–	7,128
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

Financial statements

47. 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	Eliminations and reclassifications	$ million 2009 BP group
Non-current assets					
Property, plant and equipment	7,366	–	100,909	–	108,275
Goodwill	–	–	8,620	–	8,620
Intangible assets	321	–	11,227	–	11,548
Investments in jointly controlled entities	–	–	15,296	–	15,296
Investments in associates	–	2	12,961	–	12,963
Other investments	–	–	1,567	–	1,567
Subsidiaries - equity-accounted basis	4,424	101,760	–	(106,184)	–
Fixed assets	12,111	101,762	150,580	(106,184)	158,269
Loans	283	1,178	5,490	(5,912)	1,039
Other receivables	–	–	1,729	–	1,729
Derivative financial instruments	–	–	3,965	–	3,965
Prepayments	–	–	1,407	–	1,407
Deferred tax assets	–	–	516	–	516
Defined benefit pension plan surpluses	–	1,071	319	–	1,390
	12,394	104,011	164,006	(112,096)	168,315
Current assets					
Loans	–	–	249	–	249
Inventories	221	–	22,384	–	22,605
Trade and other receivables	18,529	30,707	35,852	(55,557)	29,531
Derivative financial instruments	–	–	4,967	–	4,967
Prepayments	8	2	1,743	–	1,753
Current tax receivable	–	–	209	–	209
Cash and cash equivalents	(22)	28	8,333	–	8,339
	18,736	30,737	73,737	(55,557)	67,653
Total assets	31,130	134,748	237,743	(167,653)	235,968
Current liabilities					
Trade and other payables	4,662	2,374	83,725	(55,557)	35,204
Derivative financial instruments	–	–	4,681	–	4,681
Accruals	–	27	6,175	–	6,202
Finance debt	55	–	9,054	–	9,109
Current tax payable	172	–	2,292	–	2,464
Provisions	–	–	1,660	–	1,660
	4,889	2,401	107,587	(55,557)	59,320
Non-current liabilities					
Other payables	229	4,254	4,627	(5,912)	3,198
Derivative financial instruments	–	–	3,474	–	3,474
Accruals	–	74	629	–	703
Finance debt	–	–	25,518	–	25,518
Deferred tax liabilities	1,872	149	16,641	–	18,662
Provisions	1,048	–	11,922	–	12,970
Defined benefit pension plan and other post-retirement benefit plan deficits	–	–	10,010	–	10,010
	3,149	4,477	72,821	(5,912)	74,535
Total liabilities	8,038	6,878	180,408	(61,469)	133,855
Net assets	23,092	127,870	57,335	(106,184)	102,113
Equity					
BP shareholders' equity	23,092	127,870	56,835	(106,184)	101,613
Minority interest	–	–	500	–	500
Total equity	23,092	127,870	57,335	(106,184)	102,113

47. Condensed consolidating information on certain US subsidiaries continued

Cash flow statement

For the year ended 31 December	Issuer: BP Exploration (Alaska) Inc.	Guarantor: BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					$ million
					2010
Net cash provided by operating activities	**829**	**32,111**	**(4,584)**	**(14,740)**	**13,616**
Net cash used in 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)**
(Decrease) increase 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**

For the year ended 31 December	Issuer: BP Exploration (Alaska) Inc.	Guarantor: BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					$ million
					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

For the year ended 31 December	Issuer: BP Exploration (Alaska) Inc.	Guarantor: BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					$ million
					2008
Net cash provided by operating activities	1,105	12,665	41,600	(17,275)	38,095
Net cash used in investing activities	(896)	–	(21,871)	–	(22,767)
Net cash used in financing activities	(209)	(12,898)	(14,677)	17,275	(10,509)
Currency translation differences relating to cash and cash equivalents	–	–	(184)	–	(184)
(Decrease) increase in cash and cash equivalents	–	(233)	4,868	–	4,635
Cash and cash equivalents at beginning of year	(10)	244	3,328	–	3,562
Cash and cash equivalents at end of year	(10)	11	8,196	–	8,197

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. For 2009 and 2010, where relevant, information for equity-accounted entities is provided in the same level of detail as for subsidiaries. Also for 2009 and 2010, proved reserves are based on revised SEC definitions.

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 51 to 52.

Supplementary information on oil and natural gas (unaudited) continued

Oil and natural gas exploration and production activities

$ million

	Europe		North America		South America	Africa	Asia		Australasia	2010 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.

Financial statements

Supplementary information on oil and natural gas (unaudited) continued

Oil and natural gas exploration and production activities continued

$ million

	Europe		North America		South America	Africa	Asia		Australasia	2010 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	103	–	14,486	3,192	–	17,923
Unproved properties	–	–	–	1,284	–	–	652	–	–	1,936
	–	–	–	1,426	103	–	15,138	3,192	–	19,859
Accumulated depreciation	–	–	–	–	–	–	6,300	2,674	–	8,974
Net capitalized costs	–	–	–	1,426	103	–	8,838	518	–	10,885
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	87	–	7,965
Sales between businesses	–	–	–	–	–	–	3,432	460	–	3,892
	–	–	–	–	2,268	–	9,042	547	–	11,857
Exploration expenditure	–	–	–	–	22	–	40	–	–	62
Production costs	–	–	–	–	316	–	1,602	184	–	2,102
Production taxes	–	–	–	–	911	–	3,567	–	–	4,478
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	545	–	8,414
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) continued

Oil and natural gas exploration and production activities continued

										$ million
										2009
	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]										
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).

Supplementary information on oil and natural gas (unaudited) continued

Oil and natural gas exploration and production activities continued

										$ million
										2009
	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	–	–	–	–	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	351	–	7,247
Sales between businesses	–	–	–	–	–	–	2,838	–	–	2,838
	–	–	–	–	1,977	–	7,757	351	–	10,085
Exploration expenditure	–	–	–	–	23	–	37	–	–	60
Production costs	–	–	–	–	354	–	1,428	159	–	1,941
Production taxes	–	–	–	–	702	–	2,597	–	–	3,299
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	431	–	6,941
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) continued

Oil and natural gas exploration and production activities continued

										$ million
										2008
	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]										
Gross capitalized costs										
Proved properties	34,614	5,507	59,918	3,517	7,934	21,563	–	10,689	2,581	146,323
Unproved properties	626	–	5,006	165	134	2,011	–	465	1,018	9,425
	35,240	5,507	64,924	3,682	8,068	23,574	–	11,154	3,599	155,748
Accumulated depreciation	26,564	3,125	28,511	2,141	4,217	10,451	–	4,395	945	80,349
Net capitalized costs	8,676	2,382	36,413	1,541	3,851	13,123	–	6,759	2,654	75,399

The group's share of equity-accounted entities' net capitalized costs at 31 December 2008 was $13,393 million.

	UK	Rest of Europe	US	Rest of North America	South America	Africa	Russia	Rest of Asia	Australasia	Total
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved	–	–	1,374	2	–	–	–	136	–	1,512
Unproved	4	–	2,942	–	–	–	–	41	–	2,987
	4	–	4,316	2	–	–	–	177	–	4,499
Exploration and appraisal costs[d]	137	–	862	33	90	838	12	269	49	2,290
Development	907	695	4,914	309	768	2,966	–	859	349	11,767
Total costs	1,048	695	10,092	344	858	3,804	12	1,305	398	18,556

The group's share of equity-accounted entities' costs incurred in 2008 was $3,259 million: in Russia $1,921 million, South America $1,039 million, and Rest of Asia $299 million.

	UK	Rest of Europe	US	Rest of North America	South America	Africa	Russia	Rest of Asia	Australasia	Total
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	3,865	105	1,526	147	3,339	3,745	–	1,186	860	14,773
Sales between businesses	4,374	1,416	22,094	1,237	2,605	6,022	–	11,249	1,171	50,168
	8,239	1,521	23,620	1,384	5,944	9,767	–	12,435	2,031	64,941
Exploration expenditure	121	1	305	32	30	213	14	140	26	882
Production costs	1,357	150	3,002	289	429	875	18	485	62	6,667
Production taxes	503	–	2,603	2	358	–	–	5,510	110	9,086
Other costs (income)[f]	(28)	(43)	3,440	343	198	(122)	196	2,064	226	6,274
Depreciation, depletion and amortization	1,049	199	2,729	181	730	2,120	–	788	87	7,883
Impairments and losses on sale of businesses and fixed assets	–	–	308	2	4	8	–	219	–	541
	3,002	307	12,387	849	1,749	3,094	228	9,206	511	31,333
Profit (loss) before taxation[g]	5,237	1,214	11,233	535	4,195	6,673	(228)	3,229	1,520	33,608
Allocable taxes	2,280	883	3,857	205	2,218	2,672	(36)	984	513	13,576
Results of operations	2,957	331	7,376	330	1,977	4,001	(192)	2,245	1,007	20,032

The group's share of equity-accounted entities' results of operations (including the group's share of total TNK-BP results) in 2008 was a profit of $2,793 million after deducting interest of $355 million, taxation of $1,217 million and minority interest of $169 million.

	UK	Rest of Europe	US	Rest of North America	South America	Africa	Russia	Rest of Asia	Australasia	Total
Exploration and Production segment replacement cost profit before interest and tax										
Exploration and production activities										
Subsidiaries (as above)	5,237	1,214	11,233	535	4,195	6,673	(228)	3,229	1,520	33,608
Equity-accounted entities	(1)	–	1	40	304	(1)	2,259	191	–	2,793
Midstream activities[h i]	743	16	490	673	274	112	–	(272)	(129)	1,907
Total replacement cost profit before interest and tax	5,979	1,230	11,724	1,248	4,773	6,784	2,031	3,148	1,391	38,308

[a] These tables contain information relating to oil and natural gas exploration and production activities. 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. The group's share of equity-accounted entities' activities are excluded from the tables and included in the footnotes, with the exception of Abu Dhabi production taxes, which are included in the results of operations above.

[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 loss on embedded derivatives of $102 million. The UK region includes a $499 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 $285 million which is included in finance costs in the group income statement.

[h] Includes a $517 million write-down of our investment in Rosneft based on its quoted market price at the end of the year.

[i] Midstream activities exclude inventory holding gains and losses.

Supplementary information on oil and natural gas (unaudited) continued

Movements in estimated net proved reserves

Crude oil[a]	Europe		North America		South America	Africa	Asia		Australasia	million barrels 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 a 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 801 million barrels relating to assets held for sale at 31 December 2010.
[i] Includes 4 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 35 million barrels of crude oil sold relating to production from assets held for sale at 31 December 2010.

Supplementary information on oil and natural gas (unaudited) continued

Movements in estimated net proved reserves continued

Natural gas[a]	UK	Rest of Europe	US	Rest of North America	South America	Africa	Russia	Rest of Asia	Australasia	Total
										billion cubic feet
										2010
	Europe		North America		South America	Africa	Asia		Australasia	Total
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 1,819 billion cubic feet relating to assets held for sale at 31 December 2010.
[h] Includes 12 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 141 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) continued

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.

Supplementary information on oil and natural gas (unaudited) continued

Movements in estimated net proved reserves continued

million barrels of oil equivalent

Total hydrocarbons[a]										2010
	Europe		North America		South America	Africa	Asia		Australasia	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 a 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 1,114 million barrels of oil equivalent relating to assets held for sale at 31 December 2010.
[k] Includes 6 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 59 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) continued

Movements in estimated net proved reserves continued

million barrels

Crude oil[a]										2009
	Europe		North America		South America	Africa	Asia		Australasia	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 a 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) continued

Movements in estimated net proved reserves continued

billion cubic feet

Natural gas[a]	Europe		North America		South America	Africa	Asia		Australasia	2009 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
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) continued

Movements in estimated net proved reserves continued

million barrels of oil equivalent

Total hydrocarbons[a]	Europe UK	Europe Rest of Europe	North America US[e]	North America Rest of North America	South America	Africa	Asia Russia	Asia Rest of Asia	Australasia	2009 Total
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 a 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.

Supplementary information on oil and natural gas (unaudited) continued

Movements in estimated net proved reserves continued

										million barrels
Crude oil[a]										2008
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[e]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2008										
Developed	414	105	1,882	13	102	256	–	121	44	2,937
Undeveloped	123	169	1,265	1	202	350	–	372	73	2,555
	537	274	3,147	14	304	606	–	493	117	5,492
Changes attributable to										
Revisions of previous estimates	16	(11)	(212)	1	7	264	–	194	5	264
Improved recovery	39	28	182	–	8	18	–	43	3	321
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	64	–	5	173	–	–	–	242
Production[b]	(63)	(16)	(191)	(3)	(23)	(101)	–	(47)	(11)	(455)
Sales of reserves-in-place	–	–	–	–	(199)	–	–	–	–	(199)
	(8)	1	(157)	(2)	(202)	354	–	190	(3)	173
At 31 December 2008[c]										
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
Equity-accounted entities (BP share)[f]										
At 1 January 2008										
Developed	–	–	–	–	328	–	2,094	574	–	2,996
Undeveloped	–	–	–	–	243	–	1,137	205	–	1,585
	–	–	–	–	571	–	3,231	779	–	4,581
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(3)	11	217	(1)	–	224
Improved recovery	–	–	–	–	62	–	–	–	–	62
Purchases of reserves-in-place	–	–	–	–	199	–	–	–	–	199
Discoveries and extensions	–	–	–	–	13	–	26	–	–	39
Production	–	–	–	–	(34)	–	(302)	(80)	–	(416)
Sales of reserves-in-place	–	–	–	–	–	–	(1)	–	–	(1)
	–	–	–	–	237	11	(60)	(81)	–	107
At 31 December 2008[d]										
Developed	–	–	–	–	399	–	2,227	499	–	3,125
Undeveloped	–	–	–	–	409	11	944	199	–	1,563
	–	–	–	–	808	11	3,171	698	–	4,688
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2008										
Developed	414	105	1,882	13	430	256	2,094	695	44	5,933
Undeveloped	123	169	1,265	1	445	350	1,137	577	73	4,140
	537	274	3,147	14	875	606	3,231	1,272	117	10,073
At 31 December 2008										
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

[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 19 thousand barrels a day.
[c] Includes 807 million barrels of NGLs. Also includes 21 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 36 million barrels of NGLs. Also includes 216 million barrels of crude oil in respect of the 6.80% minority interest in TNK-BP.
[e] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 54 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) continued

Movements in estimated net proved reserves continued

Natural gas[a]										billion cubic feet 2008
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2008										
Developed	2,049	63	10,670	608	3,075	990	–	1,270	1,135	19,860
Undeveloped	553	410	4,705	421	7,973	1,410	–	1,269	4,529	21,270
	2,602	473	15,375	1,029	11,048	2,400	–	2,539	5,664	41,130
Changes attributable to										
Revisions of previous estimates	23	(8)	(2,063)	51	(456)	142	–	–	361	(1,950)
Improved recovery	77	9	1,322	16	159	6	–	108	2	1,699
Purchases of reserves-in-place	–	–	183	–	–	–	–	–	–	183
Discoveries and extensions	–	–	549	125	948	82	–	37	–	1,741
Production[b]	(298)	(11)	(834)	(94)	(946)	(198)	–	(274)	(140)	(2,795)
Sales of reserves-in-place	–	–	–	–	(3)	–	–	–	–	(3)
	(198)	(10)	(843)	98	(298)	32	–	(129)	223	(1,125)
At 31 December 2008[c]										
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
Equity-accounted entities (BP share)[e]										
At 1 January 2008										
Developed	–	–	–	–	1,478	–	808	187	–	2,473
Undeveloped	–	–	–	–	831	–	353	113	–	1,297
	–	–	–	–	2,309	–	1,161	300	–	3,770
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(96)	182	1,273	(2)	–	1,357
Improved recovery	–	–	–	–	301	–	–	11	–	312
Purchases of reserves-in-place	–	–	–	–	3	–	–	–	–	3
Discoveries and extensions	–	–	–	–	192	–	–	–	–	192
Production[b]	–	–	–	–	(188)	–	(221)	(22)	–	(431)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	212	182	1,052	(13)	–	1,433
At 31 December 2008[d]										
Developed	–	–	–	–	1,498	–	1,560	176	–	3,234
Undeveloped	–	–	–	–	1,023	182	653	111	–	1,969
	–	–	–	–	2,521	182	2,213	287	–	5,203
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2008										
Developed	2,049	63	10,670	608	4,553	990	808	1,457	1,135	22,333
Undeveloped	553	410	4,705	421	8,804	1,410	353	1,382	4,529	22,567
	2,602	473	15,375	1,029	13,357	2,400	1,161	2,839	5,664	44,900
At 31 December 2008										
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

[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 193 billion cubic feet of natural gas consumed in operations, 149 billion cubic feet in subsidiaries, 44 billion cubic feet in equity-accounted entities and excludes 17 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.
[c] Includes 3,108 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 5.92% 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) continued

Movements in estimated net proved reserves continued

million barrels of oil equivalent

Total hydrocarbons[a]										2008
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[e]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2008										
Developed	767	116	3,722	118	631	427	–	340	240	6,361
Undeveloped	219	239	2,077	74	1,576	593	–	591	853	6,222
	986	355	5,799	192	2,207	1,020	–	931	1,093	12,583
Changes attributable to										
Revisions of previous estimates	20	(12)	(569)	10	(71)	289	–	194	67	(72)
Improved recovery	52	30	410	3	36	18	–	61	4	614
Purchases of reserves-in-place	–	–	32	–	–	–	–	–	–	32
Discoveries and extensions	–	–	158	22	168	187	–	7	–	542
Production[b f]	(115)	(18)	(334)	(20)	(186)	(135)	–	(94)	(35)	(937)
Sales of reserves-in-place	–	–	–	–	(200)	–	–	–	–	(200)
	(43)	–	(303)	15	(253)	359	–	168	36	(21)
At 31 December 2008[c]										
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
Equity-accounted entities (BP share)[g]										
At 1 January 2008										
Developed	–	–	–	–	583	–	2,233	606	–	3,422
Undeveloped	–	–	–	–	386	–	1,199	224	–	1,809
	–	–	–	–	969	–	3,432	830	–	5,231
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(20)	42	436	(1)	–	457
Improved recovery	–	–	–	–	115	–	–	2	–	117
Purchases of reserves-in-place	–	–	–	–	200	–	–	–	–	200
Discoveries and extensions	–	–	–	–	46	–	26	–	–	72
Production[b f]	–	–	–	–	(66)	–	(341)	(84)	–	(491)
Sales of reserves-in-place	–	–	–	–	–	–	(1)	–	–	(1)
	–	–	–	–	275	42	120	(83)	–	354
At 31 December 2008[d]										
Developed	–	–	–	–	658	–	2,495	529	–	3,682
Undeveloped	–	–	–	–	586	42	1,057	218	–	1,903
	–	–	–	–	1,244	42	3,552	747	–	5,585
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2008										
Developed	767	116	3,722	118	1,214	427	2,233	946	240	9,783
Undeveloped	219	239	2,077	74	1,962	593	1,199	815	853	8,031
	986	355	5,799	192	3,176	1,020	3,432	1,761	1,093	17,814
At 31 December 2008										
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

[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 a day.
[c] Includes 807 million barrels of NGLs. Also includes 557 million barrels of oil equivalent in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 36 million barrels of NGLs. Also includes 239 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 54 million barrels of oil equivalent upon which a net profits royalty will be payable.
[f] Includes 33 million barrels of oil equivalent of natural gas consumed in operations, 25 million barrels of oil equivalent in subsidiaries, 8 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.

Supplementary information on oil and natural gas (unaudited) continued

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 there in, 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
										2010
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December 2010										
Subsidiaries										
Future cash inflows[a]	**73,100**	**25,800**	**264,800**	**200**	**29,300**	**70,800**	**–**	**52,500**	**42,300**	**558,800**
Future production cost[b]	**25,700**	**9,800**	**111,400**	**200**	**6,800**	**14,000**	**–**	**13,400**	**12,800**	**194,100**
Future development cost[b]	**7,400**	**2,500**	**24,300**	**–**	**6,100**	**14,600**	**–**	**9,900**	**3,100**	**67,900**
Future taxation[c]	**19,900**	**8,100**	**41,900**	**–**	**8,200**	**14,100**	**–**	**7,000**	**6,200**	**105,400**
Future net cash flows	**20,100**	**5,400**	**87,200**	**–**	**8,200**	**28,100**	**–**	**22,200**	**20,200**	**191,400**
10% annual discount[d]	**9,800**	**2,300**	**45,500**	**–**	**3,300**	**11,900**	**–**	**8,200**	**10,300**	**91,300**
Standardized measure of discounted future net cash flows[e]	**10,300**	**3,100**	**41,700**	**–**	**4,900**	**16,200**	**–**	**14,000**	**9,900**	**100,100**
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	**–**	**–**	**–**	**9,700**	**45,500**	**–**	**110,500**	**31,000**	**–**	**196,700**
Future production cost[b]	**–**	**–**	**–**	**4,500**	**19,200**	**–**	**80,900**	**26,500**	**–**	**131,100**
Future development cost[b]	**–**	**–**	**–**	**2,000**	**4,300**	**–**	**11,000**	**2,800**	**–**	**20,100**
Future taxation[c]	**–**	**–**	**–**	**800**	**7,500**	**–**	**3,900**	**200**	**–**	**12,400**
Future net cash flows	**–**	**–**	**–**	**2,400**	**14,500**	**–**	**14,700**	**1,500**	**–**	**33,100**
10% annual discount[d]	**–**	**–**	**–**	**2,400**	**8,700**	**–**	**6,100**	**700**	**–**	**17,900**
Standardized measure of discounted future net cash flows[g h]	**–**	**–**	**–**	**–**	**5,800**	**–**	**8,600**	**800**	**–**	**15,200**
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows[j]	**10,300**	**3,100**	**41,700**	**–**	**10,700**	**16,200**	**8,600**	**14,800**	**9,900**	**115,300**

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

			$ million
	Subsidiaries	Equity-accounted entities (BP share)	Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	**(26,600)**	**(4,900)**	**(31,500)**
Development costs for the current year as estimated in previous year	**10,400**	**2,000**	**12,400**
Extensions, discoveries and improved recovery, less related costs	**9,600**	**1,600**	**11,200**
Net changes in prices and production cost	**52,800**	**1,900**	**54,700**
Revisions of previous reserves estimates	**(9,200)**	**200**	**(9,000)**
Net change in taxation	**(13,400)**	**(300)**	**(13,700)**
Future development costs	**(4,300)**	**(1,400)**	**(5,700)**
Net change in purchase and sales of reserves-in-place	**(1,500)**	**–**	**(1,500)**
Addition of 10% annual discount	**7,500**	**1,500**	**9,000**
Total change in the standardized measure during the year[i]	**25,300**	**600**	**25,900**

[a] The marker prices used were Brent $79.02/bbl, Henry Hub $4.37/mmBtu.
[b] Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included.
[c] Taxation is computed using appropriate year-end statutory corporate income tax rates.
[d] Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.
[e] Minority interest in BP Trinidad and Tobago LLC amounted to $1,200 million.
[f] The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.
[g] Minority interest in TNK-BP amounted to $600 million.
[h] No equity-accounted future cash flows in Africa because proved reserves are received as a result of contractual arrangements, with no associated costs.
[i] Total change in the standardized measure during the year includes the effect of exchange rate movements.
[j] Includes future net cash flows for assets held for sale at 31 December 2010.

Supplementary information on oil and natural gas (unaudited) continued

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves 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		
At 31 December 2009										
Subsidiaries										
Future cash inflows[a]	50,800	17,700	204,000	4,900	26,400	58,400	–	36,100	32,500	430,800
Future production cost[b]	20,000	8,000	91,300	2,700	6,700	12,000	–	9,200	11,000	160,900
Future development cost[b]	5,000	2,500	24,900	1,000	5,600	12,200	–	6,400	3,100	60,700
Future taxation[c]	12,900	3,700	27,300	200	5,800	11,300	–	4,700	4,500	70,400
Future net cash flows	12,900	3,500	60,500	1,000	8,300	22,900	–	15,800	13,900	138,800
10% annual discount[d]	5,800	1,600	29,500	500	3,200	9,800	–	6,300	7,300	64,000
Standardized measure of discounted future net cash flows[e]	7,100	1,900	31,000	500	5,100	13,100	–	9,500	6,600	74,800
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	–	–	–	–	37,700	–	96,700	30,000	–	164,400
Future production cost[b]	–	–	–	–	17,000	–	65,200	25,200	–	107,400
Future development cost[b]	–	–	–	–	4,000	–	10,200	3,100	–	17,300
Future taxation[c]	–	–	–	–	5,200	–	4,300	100	–	9,600
Future net cash flows	–	–	–	–	11,500	–	17,000	1,600	–	30,100
10% annual discount[d]	–	–	–	–	6,800	–	7,900	800	–	15,500
Standardized measure of discounted future net cash flows[g h]	–	–	–	–	4,700	–	9,100	800	–	14,600
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	7,100	1,900	31,000	500	9,800	13,100	9,100	10,300	6,600	89,400

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

$ million

	Subsidiaries	Equity-accounted entities (BP share)	Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	(18,900)	(3,400)	(22,300)
Development costs for the current year as estimated in previous year	11,700	2,100	13,800
Extensions, discoveries and improved recovery, less related costs	8,500	1,600	10,100
Net changes in prices and production cost	37,200	5,900	43,100
Revisions of previous reserves estimates	(4,300)	(200)	(4,500)
Net change in taxation	(10,600)	(1,600)	(12,200)
Future development costs	(600)	900	300
Net change in purchase and sales of reserves-in-place	(100)	(900)	(1,000)
Addition of 10% annual discount	4,700	900	5,600
Total change in the standardized measure during the year[i]	27,600	5,300	32,900

[a] The marker prices used were Brent $59.91/bbl, Henry Hub $3.82/mmBtu.
[b] Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included.
[c] Taxation is computed using appropriate year-end statutory corporate income tax rates.
[d] Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.
[e] Minority interest in BP Trinidad and Tobago LLC amounted to $1,300 million.
[f] The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.
[g] Minority interest in TNK-BP amounted to $600 million.
[h] No equity-accounted future cash flows in Africa because proved reserves are received as a result of contractual arrangements, with no associated costs.
[i] Total change in the standardized measure during the year includes the effect of exchange rate movements.

Supplementary information on oil and natural gas (unaudited) continued

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves continued

										$ million
										2008
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December 2008										
Subsidiaries										
Future cash inflows[a]	36,400	13,800	165,800	6,400	26,300	40,400	–	31,400	24,200	344,700
Future production cost[b]	18,100	6,300	80,400	2,700	7,200	11,600	–	11,800	10,700	148,800
Future development cost[b]	3,300	2,900	25,600	1,300	7,200	10,900	–	7,500	3,200	61,900
Future taxation[c]	7,300	2,300	17,500	500	5,500	6,600	–	2,400	2,800	44,900
Future net cash flows	7,700	2,300	42,300	1,900	6,400	11,300	–	9,700	7,500	89,100
10% annual discount[d]	2,200	1,200	21,000	1,000	2,900	5,500	–	4,200	3,900	41,900
Standardized measure of discounted future net cash flows[e]	5,500	1,100	21,300	900	3,500	5,800	–	5,500	3,600	47,200
Equity-accounted entities (BP share)[g]										
Standardized measure of discounted future net cash flows[h]	–	–	–	–	3,600	–	4,800	900	–	9,300
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows[e]	5,500	1,100	21,300	900	7,100	5,800	4,800	6,400	3,600	56,500

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

	$ million
	2008
Sales and transfers of oil and gas produced, net of production costs	(43,600)
Development costs for the current year as estimated in previous year	9,400
Extensions, discoveries and improved recovery, less related costs	4,400
Net changes in prices and production cost	(146,800)
Revisions of previous reserves estimates	1,200
Net change in taxation	69,400
Future development costs	(7,400)
Net change in purchase and sales of reserves-in-place	(200)
Addition of 10% annual discount	14,600
Total change in the standardized measure during the year of subsidiaries[f]	(99,000)

[a] The year-end marker prices used were 2008 Brent $36.55/bbl, Henry Hub $5.63/mmBtu.
[b] Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on year-end cost levels and assume continuation of existing economic conditions. Future decommissioning costs are included.
[c] Taxation is computed using appropriate year-end statutory corporate income tax rates.
[d] Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.
[e] Minority interest in BP Trinidad and Tobago LLC amounted to $900 million at 31 December 2008.
[f] Total change in the standardized measure during the year includes the effect of exchange rate movements.
[g] The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.
[h] Minority interest in TNK-BP amounted to $300 million at 31 December 2008.

Supplementary information on oil and natural gas (unaudited) continued

Operational and statistical information

The following tables present operational and statistical information related to production, drilling, productive wells and acreage. Figures include amounts attributable to assets held for sale.

Crude oil and natural gas production

The following table shows crude oil and natural gas production for the years ended 31 December 2010, 2009 and 2008.

Production for the year[a]

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
Crude oil[b]										thousand barrels per day
2010	**137**	**40**	**594**	**7**	**54**	**246**	**–**	**119**	**32**	**1,229**
2009	168	40	665	8	61	304	–	123	31	1,400
2008	173	43	538	9	66	277	–	128	29	1,263
Natural gas[c]										million cubic feet per day
2010	**472**	**15**	**2,184**	**202**	**2,544**	**556**	**–**	**574**	**785**	**7,332**
2009	618	16	2,316	263	2,492	621	–	610	514	7,450
2008	759	23	2,157	245	2,532	484	–	696	381	7,277
Equity-accounted entities (BP share)										
Crude oil[b]										thousand barrels per day
2010	**–**	**–**	**–**	**–**	**98**	**–**	**856**	**191**	**–**	**1,145**
2009	–	–	–	–	101	–	840	194	–	1,135
2008	–	–	–	–	92	–	826	220	–	1,138
Natural gas[c]										million cubic feet per day
2010	**–**	**–**	**–**	**–**	**399**	**–**	**640**	**30**	**–**	**1,069**
2009	–	–	–	–	392	–	601	42	–	1,035
2008	–	–	–	–	454	–	564	39	–	1,057

[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] Crude oil includes natural gas liquids and condensate.
[c] Natural gas production excludes gas consumed in operations.

Productive oil and gas wells and acreage

The following tables show the number of gross and net productive oil and natural gas wells and total gross and net developed and undeveloped oil and natural gas acreage in which the group and its equity-accounted entities had interests as at 31 December 2010. A 'gross' well or acre is one in which a whole or fractional working interest is owned, while the number of 'net' wells or acres is the sum of the whole or fractional working interests in gross wells or acres. Productive wells are producing wells and wells capable of production. Developed acreage is the acreage within the boundary of a field, on which development wells have been drilled, which could produce the reserves; while undeveloped acres are those on which wells have not been drilled or completed to a point that would permit the production of commercial quantities, whether or not such acres contain proved reserves.

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Number of productive wells at 31 December 2010										
Oil wells[a] – gross	**251**	**84**	**2,709**	**7**	**3,705**	**596**	**20,235**	**1,889**	**13**	**29,489**
– net	**130**	**32**	**1,121**	**3**	**2,063**	**454**	**9,081**	**424**	**2**	**13,310**
Gas wells[b] – gross	**281**	**–**	**23,041**	**366**	**498**	**106**	**63**	**639**	**68**	**25,062**
– net	**138**	**–**	**12,581**	**285**	**167**	**42**	**31**	**284**	**13**	**13,541**

[a] Includes approximately 3,989 gross (1,730 net) multiple completion wells (more than one formation producing into the same well bore).
[b] Includes approximately 2,623 gross (1,673 net) multiple completion wells. If one of the multiple completions in a well is an oil completion, the well is classified as an oil well.

Financial statements

Supplementary information on oil and natural gas (unaudited) continued

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Oil and natural gas acreage at 31 December 2010										Thousands of acres
Developed – gross	**346**	**65**	**6,920**	**198**	**1,738**	**497**	**2,282**	**2,434**	**162**	**14,642**
– net	**189**	**21**	**4,184**	**157**	**471**	**195**	**885**	**935**	**35**	**7,072**
Undeveloped[a] – gross	**1,311**	**186**	**6,970**	**7,185**	**12,434**	**21,373**	**32,137**	**18,366**	**7,330**	**107,292**
– net	**775**	**79**	**4,663**	**4,380**	**6,398**	**16,072**	**15,475**	**8,955**	**2,796**	**59,593**

[a] Undeveloped acreage includes leases and concessions.

Net oil and gas wells completed or abandoned

The following table shows the number of net productive and dry exploratory and development oil and natural gas wells completed or abandoned in the years indicated by the group and its equity-accounted entities. Productive wells include wells in which hydrocarbons were encountered and the drilling or completion of which, in the case of exploratory wells, has been suspended pending further drilling or evaluation. A dry well is one found to be incapable of producing hydrocarbons in sufficient quantities to justify completion.

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
2010										
Exploratory										
Productive	**–**	**0.2**	**39.3**	**–**	**1.3**	**1.2**	**10.5**	**2.8**	**0.3**	**55.6**
Dry	**0.7**	**–**	**0.3**	**–**	**0.9**	**1.4**	**4.0**	**–**	**–**	**7.3**
Development										
Productive	**6.4**	**1.2**	**260.0**	**31.7**	**105.7**	**18.9**	**364.3**	**53.3**	**–**	**841.5**
Dry	**1.7**	**–**	**0.5**	**–**	**1.2**	**2.7**	**–**	**2.4**	**–**	**8.5**
2009										
Exploratory										
Productive	0.1	–	47.2	–	3.0	4.5	7.0	5.3	0.6	67.7
Dry	0.2	–	4.2	–	–	1.4	4.5	6.0	0.2	16.5
Development										
Productive	9.3	1.5	403.8	17.9	135.4	20.8	293.0	45.8	1.6	929.1
Dry	–	–	3.3	–	–	0.5	4.0	0.4	0.6	8.8
2008										
Exploratory										
Productive	0.8	–	2.4	–	4.4	4.3	12.5	0.5	0.6	25.5
Dry	–	0.5	0.9	0.1	0.4	2.6	23.0	0.5	0.4	28.4
Development										
Productive	6.6	0.5	379.8	28.3	112.5	18.6	10.0	45.4	4.5	606.2
Dry	0.2	–	1.1	0.9	2.9	1.5	19.5	2.1	–	28.2

Drilling and production activities in progress

The following table shows the number of exploratory and development oil and natural gas wells in the process of being drilled by the group and its equity-accounted entities as of 31 December 2010. Suspended development wells and long-term suspended exploratory wells are also included in the table.

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December 2010										
Exploratory										
Gross		**1.0**	**–**	**211.0**	**3.0**	**1.0**	**3.0**	**11.0**	**3.0**	**–**
233.0										
Net	**0.2**	**–**	**45.2**	**1.5**	**–**	**1.6**	**5.5**	**1.2**	**–**	**55.2**
Development										
Gross	**11.0**	**–**	**375.0**	**–**	**23.0**	**34.0**	**88.0**	**20.0**	**–**	**551.0**
Net	**5.5**	**–**	**140.6**	**–**	**9.5**	**10.8**	**39.7**	**6.6**	**–**	**212.7**

Signatures

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

BP p.l.c.
(Registrant)

/s/D.J. JACKSON
D.J. Jackson
Company Secretary

Dated 2 March 2011

Parent company financial statements of BP p.l.c.

Statement of directors' responsibilities in respect of the parent company financial statements

The directors are responsible for preparing the financial statements in accordance with applicable United Kingdom law and United Kingdom generally accepted accounting practice.

Company law requires the directors to prepare financial statements for each financial year that give a true and fair view of the state of affairs of the company. In preparing these financial statements, the directors are required:

- To select suitable accounting policies and then apply them consistently.
- To make judgements and estimates that are reasonable and prudent.
- To state whether applicable accounting standards have been followed, subject to any material departures disclosed and explained in the financial statements.
- To prepare the financial statements on the going concern basis unless it is inappropriate to presume that the company will continue in business. The directors are also responsible for keeping proper accounting records that disclose with reasonable accuracy at any time the financial position of the company and enable them to ensure that the financial statements comply with the Companies Act 2006. They are also responsible for safeguarding the assets of the company and hence for taking reasonable steps for the prevention and detection of fraud and other irregularities.

Having made the requisite enquiries, so far as the directors are aware, there is no relevant audit information (as defined by Section 418(3) of the Companies Act 2006) of which the company's auditors are unaware, and the directors have taken all the steps they ought to have taken to make themselves aware of any relevant audit information and to establish that the company's auditors are aware of that information.

The parent company financial statements of BP p.l.c. on pages PC1 – PC16 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Independent auditor's report to the members of BP p.l.c.

We have audited the parent company financial statements of BP p.l.c. for the year ended 31 December 2010 which comprise the company balance sheet, the company cash flow statement, the company statement of total recognized gains and losses and the related notes 1 to 14. The financial reporting framework that has been applied in their preparation is applicable law and United Kingdom accounting standards (United Kingdom generally accepted accounting practice).

This report is made solely to the company's members, as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for this report, or for the opinions we have formed.

Respective responsibilities of directors and auditors

As explained more fully in the Statement of directors' responsibilities in respect of the parent company financial statements set out on page PC1, the directors are responsible for the preparation of the parent company financial statements and for being satisfied that they give a true and fair view. Our responsibility is to audit the parent company financial statements in accordance with applicable law and International Standards on Auditing (UK and Ireland). Those standards require us to comply with the Auditing Practices Board's Ethical Standards for Auditors.

Scope of the audit of the financial statements

An audit involves obtaining evidence about the amounts and disclosures in the financial statements sufficient to give reasonable assurance that the financial statements are free from material misstatement, whether caused by fraud or error. This includes an assessment of: whether the accounting policies are appropriate to the parent company's circumstances and have been consistently applied and adequately disclosed; the reasonableness of significant accounting estimates made by the directors; and the overall presentation of the financial statements.

Opinion on financial statements

In our opinion the parent company financial statements:
- give a true and fair view of the state of the company's affairs as at 31 December 2010;
- have been properly prepared in accordance with United Kingdom generally accepted accounting practice; and
- have been prepared in accordance with the requirements of the Companies Act 2006.

Opinion on other matters prescribed by the Companies Act 2006

In our opinion:
- the part of the Directors' remuneration report to be audited has been properly prepared in accordance with the Companies Act 2006; and
- the information given in the Directors' Report for the financial year for which the parent company financial statements are prepared is consistent with the parent company financial statements.

Matters on which we are required to report by exception

We have nothing to report in respect of the following matters where the Companies Act 2006 requires us to report to you if, in our opinion:
- adequate accounting records have not been kept by the parent company, or returns adequate for our audit have not been received from branches not visited by us; or
- the parent company financial statements and the part of the Directors' remuneration report to be audited are not in agreement with the accounting records and returns; or
- certain disclosures of directors' remuneration specified by law are not made; or
- we have not received all the information and explanations we require for our audit.

Other matter

We have reported separately on the consolidated financial statements of BP p.l.c. for the year ended 31 December 2010. That report includes an emphasis of matter on the significant uncertainty over provisions and contingencies related to the Gulf of Mexico oil spill.

Ernst & Young LLP
Allister Wilson (Senior statutory auditor)
for and on behalf of Ernst & Young LLP, Statutory Auditor
London
2 March 2011

The maintenance and integrity of the BP p.l.c. website are the responsibility of the directors; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the website.
Legislation in the United Kingdom governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

The parent company financial statements of BP p.l.c. on pages PC1 – PC16 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Company balance sheet

At 31 December			$ million
	Note	2010	2009
Fixed assets			
Investments			
Subsidiary undertakings	3	**122,649**	93,063
Associated undertakings	3	**2**	2
Total fixed assets		**122,651**	93,065
Current assets			
Debtors – amounts falling due:			
Within one year	4	**14,444**	30,709
After more than one year	4	**38**	1,178
Deferred taxation	2	**70**	130
Cash at bank and in hand		**4**	28
		14,556	32,045
Creditors – amounts falling due within one year	5	**2,385**	2,401
Net current assets		**12,171**	29,644
Total assets less current liabilities		**134,822**	122,709
Creditors – amounts falling due after more than one year	5	**4,293**	4,328
Net assets excluding pension plan surplus		**130,529**	118,381
Defined benefit pension plan surplus	6	**1,537**	912
Defined benefit pension plan deficit	6	**(147)**	(120)
Net assets		**131,919**	119,173
Represented by			
Capital and reserves			
Called-up share capital	7	**5,183**	5,179
Share premium account	8	**9,987**	9,847
Capital redemption reserve	8	**1,072**	1,072
Merger reserve	8	**26,509**	26,509
Own shares	8	**(126)**	(214)
Treasury shares	8	**(21,085)**	(21,303)
Share-based payment reserve	8	**1,585**	1,519
Profit and loss account	8	**108,794**	96,564
		131,919	119,173

The financial statements on pages PC3-PC16 were approved and signed by the chairman and group chief executive on 2 March 2011 having been duly authorized to do so by the board of directors:

C-H Svanberg Chairman
R W Dudley Group Chief Executive

Financial statements

The parent company financial statements of BP p.l.c. on pages PC1 – PC16 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Company cash flow statement

For the year ended 31 December				$ million
	Note	**2010**	2009	2008
Net cash (outflow) inflow from operating activities	9	**17,231**	(20,773)	(4,399)
Servicing of finance and returns on investments				
Interest received		**175**	137	167
Interest paid		**(31)**	(26)	(167)
Dividends received		**14,739**	35,187	17,066
Net cash inflow from servicing of finance and returns on investments		**14,883**	35,298	17,066
Tax paid	**(3)**	(11)	(2)	
Capital expenditure and financial investment				
Payments for fixed assets – investments		**(29,636)**	(4,236)	–
Proceeds from sale of fixed assets – investments		**311**	9	–
Net cash outflow for capital expenditure and financial investment		**(29,325)**	(4,227)	–
Equity dividends paid		**(2,627)**	(10,483)	(10,342)
Net cash (outflow) inflow before financing		**159**	(196)	2,323
Financing				
Other share-based payment movements		**(183)**	213	358
Repurchase of ordinary share capital		**–**	–	(2,914)
Net cash inflow (outflow) from financing		**(183)**	213	(2,556)
Increase (decrease) in cash	9	**(24)**	17	(233)

Company statement of total recognized gains and losses

For the year ended 31 December				$ million
	Note	**2010**	2009	2008
Profit for the year		**14,776**	34,524	17,715
Currency translation differences		**(45)**	104	(710)
Actuarial gain (loss) relating to pensions	6	**457**	(585)	(5,122)
Tax on actuarial (gain) loss relating to pensions	2	**(123)**	164	1,434
Total recognized gains and losses relating to the year		**15,065**	34,207	13,317

The parent company financial statements of BP p.l.c. on pages PC1 – PC16 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Notes on financial statements

1. Accounting policies

Accounting standards
These financial statements are prepared in accordance with applicable UK accounting standards.

Accounting convention
The financial statements are prepared under the historical cost convention.

Foreign currency transactions
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. 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 profit for the year. Exchange adjustments arising when the opening net assets and the profits for the year retained by non-US dollar functional currency branches are translated into US dollars are taken to a separate component of equity and reported in the statement of total recognized gains and losses.

Investments
Investments in subsidiaries and associated undertakings are recorded at cost. The company assesses investments for impairment whenever events or changes in circumstances indicate that the carrying value of an investment may not be recoverable. If any such indication of impairment exists, the company makes an estimate of its recoverable amount. Where the carrying amount of an investment exceeds its recoverable amount, the investment is considered impaired and is written down to its recoverable amount.

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
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 effect on the fair value of plan assets 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 the statement of total recognized gains and losses 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. The surplus or deficit, net of taxation thereon, is presented separately above the total for net assets on the face of the balance sheet.

The parent company financial statements of BP p.l.c. on pages PC1 – PC16 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

1. Accounting policies continued

Deferred taxation

Deferred tax is recognized in respect of all timing differences that have originated but not reversed at the balance sheet date where transactions or events have occurred at that date that will result in an obligation to pay more, or a right to pay less, tax in the future.

Deferred tax assets are recognized only to the extent that it is considered more likely than not that there will be suitable taxable profits from which the underlying timing differences can be deducted.

Deferred tax is measured on an undiscounted basis at the tax rates that are expected to apply in the periods in which timing differences reverse, based on tax rates and laws enacted or substantively enacted at the balance sheet date.

Use of estimates

The preparation of accounts in conformity with generally accepted accounting practice requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the accounts and the reported amounts of revenues and expenses during the reporting period. Actual outcomes could differ from these estimates.

2. Taxation

			$ million
Tax included in the statement of total recognized gains and losses	**2010**	2009	2008
Deferred tax			
Origination and reversal of timing differences in the current year	**123**	(164)	(1,434)
This comprises:			
Actuarial (loss) gain relating to pensions and other post-retirement benefits	**123**	(164)	(1,434)
Deferred tax			
Deferred tax liability			
Pensions	**480**	279	399
Deferred tax asset			
Other taxable timing differences	**70**	130	77
Net deferred tax liability	**410**	149	322
Analysis of movements during the year			
At 1 January	**149**	322	1,885
Exchange adjustments	**45**	47	(276)
Charge (credit) for the year on ordinary activities	**93**	(56)	147
Charge (credit) for the year in the statement of total recognized gains and losses	**123**	(164)	(1,434)
At 31 December	**410**	149	322

3. Fixed assets – investments

				$ million
	Subsidiary undertakings	**Associated undertakings**		
	Shares	**Shares**	**Loans**	**Total**
Cost				
At 1 January 2010	**93,137**	**2**	**2**	**93,141**
Additions[a]	**29,637**	**–**	**–**	**29,637**
Disposals	**(51)**	**–**	**–**	**(51)**
At 31 December 2010	**122,723**	**2**	**2**	**122,727**
Amounts provided				
At 1 January 2010	**74**	**–**	**2**	**76**
At 31 December 2010	**74**	**–**	**2**	**76**
Cost				
At 1 January 2009	89,045	2	2	89,049
Adjustments	(116)	–	–	(116)
Additions	4,208	–	–	4,208
At 31 December 2009	93,137	2	2	93,141
Amounts provided				
At 1 January 2009	74	–	2	76
At 31 December 2009	74	–	2	76
Net book amount				
At 31 December 2010	**122,649**	**2**	**–**	**122,651**
At 31 December 2009	93,063	2	–	93,065

[a] Includes $29,375 million related to an equity injection in BP International Ltd.

The parent company financial statements of BP p.l.c. on pages PC1 – PC16 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

3. Fixed assets – investments continued

The more important subsidiary undertakings of the company at 31 December 2010 and the percentage holding of ordinary share capital (to the nearest whole number) are set out below. The principal country of operation is generally indicated by the company's country of incorporation or by its name. A complete list of investments in subsidiary undertakings, joint ventures and associated undertakings will be attached to the company's annual return made to the Registrar of Companies.

Subsidiary undertakings	%	Country of incorporation	Principal activities
International			
BP Global Investments	100	England & Wales	Investment holding
BP International	100	England & Wales	Integrated oil operations
BP Holdings North America	100	England & Wales	Investment holding
BP Corporate Holdings	100	England & Wales	Investment holding
Burmah Castrol	100	Scotland	Lubricants

The carrying value of BP International Ltd in the accounts of the company at 31 December 2010 was $59.63 billion (2009 $30.25 billion and 2008 $30.25 billion).

4. Debtors

				$ million
	2010			2009
	Within 1 year	**After 1 year**	Within 1 year	After 1 year
Group undertakings	**14,440**	**38**	30,704	1,150
Other	**4**	**–**	5	28
	14,444	**38**	30,709	1,178

The carrying amounts of debtors approximate their fair value.

5. Creditors

				$ million
	2010			2009
	Within 1 year	**After 1 year**	Within 1 year	After 1 year
Group undertakings	**2,343**	**4,258**	2,343	4,236
Accruals and deferred income	**23**	**35**	27	74
Dividends	**1**	**–**	1	–
Other	**18**	**–**	30	18
	2,385	**4,293**	2,401	4,328

The carrying amounts of creditors approximate their fair value.

The maturity profile of the financial liabilities included in the balance sheet at 31 December is shown in the table below. These amounts are included within Creditors – amounts falling due after more than one year, and are denominated in US dollars.

Amounts falling due after one year include $4,236 million payable to a group undertaking. This amount is subject to interest payable quarterly at LIBOR plus 55 basis points.

		$ million
	2010	2009
Due within		
1 to 2 years	**41**	33
2 to 5 years	**16**	51
More than 5 years	**4,236**	4,244
	4,293	4,328

The parent company financial statements of BP p.l.c. on pages PC1 – PC16 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

6. Pensions

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 SPU. 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 have the option to join a defined contribution plan.

The obligation and cost of providing the pension benefits is assessed annually using the projected unit credit method. The date of the most recent actuarial review was 31 December 2010. The principal plans are subject to a formal actuarial valuation every three years in the UK. The most recent formal actuarial valuation of the main UK pension plan was as at 31 December 2008.

The material financial assumptions used for estimating the benefit obligations of the plans are set out below. The assumptions used to evaluate accrued pension at 31 December in any year are used to determine pension expense for the following year, that is, the assumptions at 31 December 2010 are used to determine the pension liabilities at that date and the pension cost for 2011.

			%
Financial assumptions	**2010**	2009	2008
Expected long-term rate of return	**7.3**	7.4	7.5
Discount rate for plan liabilities	**5.5**	5.8	6.3
Rate of increase in salaries	**5.4**	5.3	4.9
Rate of increase for pensions in payment	**3.5**	3.4	3.0
Rate of increase in deferred pensions	**3.5**	3.4	3.0
Inflation	**3.5**	3.4	3.0

Our discount rate assumption is based on third-party AA corporate bond indices and we use yields that reflect the maturity profile of the expected benefit payments. The inflation rate assumption is based on the difference between the yields on index-linked and fixed-interest long-term government bonds. The inflation assumptions are used to determine the rate of increase for pensions in payment and the rate of increase in deferred pensions.

Our assumption for the rate of increase in salaries is based on our inflation assumption plus an allowance for expected long-term real salary growth. This includes allowance for promotion-related salary growth of 0.4%. In addition to the financial assumptions, we regularly review the demographic and mortality assumptions. The mortality assumptions reflect best practice in the UK, and have been chosen with regard to the latest available published tables adjusted where appropriate to reflect the experience of the group and an extrapolation of past longevity improvements into the future.

			Years
Mortality assumptions	**2010**	2009	2008
Life expectancy at age 60 for a male currently aged 60	**26.1**	26.0	25.9
Life expectancy at age 60 for a male currently aged 40	**29.1**	29.0	28.9
Life expectancy at age 60 for a female currently aged 60	**28.7**	28.6	28.5
Life expectancy at age 60 for a female currently aged 40	**31.6**	31.5	31.4

The market values of the various categories of asset held by the pension plan at 31 December are set out below.

The market value of pension assets at the end of 2010 is higher when compared with 2009 due to an increase in the market value of investments when expressed in their local currencies and partially offset by a decrease in value that arises from changes in exchange rates (decreasing the reported value of investments when expressed in US dollars). Movements in the value of plan assets during the year are shown in detail below.

						$ million
		2010		2009		2008
	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
Equities	**8.0**	**17,703**	8.0	16,148	8.0	13,106
Bonds	**5.1**	**3,128**	5.4	2,989	6.3	2,610
Property	**6.5**	**1,412**	6.5	1,221	6.5	932
Cash	**1.4**	**369**	1.1	595	2.9	282
	7.3	**22,612**	7.4	20,953	7.5	16,930
Present value of plan liabilities		**20,742**		19,882		15,414
Surplus in the plan		**1,870**		1,071		1,516

The parent company financial statements of BP p.l.c. on pages PC1 – PC16 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

6. Pensions continued

			$ million
	2010	2009	2008
Analysis of the amount charged to operating profit			
Current service cost[a]	**381**	300	434
Past service cost	**–**	–	7
Settlement, curtailment and special termination benefits	**21**	34	29
Total operating charge	**402**	334	470
Analysis of the amount credited (charged) to other finance income			
Expected return on pension plan assets	**1,486**	1,339	1,969
Interest on pension plan liabilities	**(1,098)**	(1,029)	(1,146)
Other finance income	**388**	310	823
Analysis of the amount recognized in the statement of total recognized gains and losses			
Actual return less expected return on pension plan assets	**1,479**	1,634	(6,533)
Change in assumptions underlying the present value of the plan liabilities	**(1,034)**	(2,073)	1,476
Experience gains (losses) arising on the plan liabilities	**12**	(146)	(65)
Actuarial (loss) gain recognized in statement of total recognized gains and losses	**457**	(585)	(5,122)

	2010	2009
Movements in benefit obligation during the year		
Benefit obligation at 1 January	**19,882**	15,414
Exchange adjustment	**(775)**	1,756
Current service cost[a]	**381**	300
Interest cost	**1,098**	1,029
Special termination benefits[b]	**21**	34
Contributions by plan participants[c]	**38**	36
Benefit payments (funded plans)[d]	**(879)**	(902)
Benefit payments (unfunded plans)[d]	**(3)**	(4)
Disposals	**(43)**	–
Actuarial loss on obligation	**1,022**	2,219
Benefit obligation at 31 December	**20,742**	19,882
Movements in fair value of plan assets during the year		
Fair value of plan assets at 1 January	**20,953**	16,930
Exchange adjustment	**(819)**	1,907
Expected return on plan assets[a e]	**1,486**	1,339
Contributions by plan participants[c]	**38**	36
Contributions by employers (funded plans)	**397**	9
Benefit payments (funded plans)	**(879)**	(902)
Disposals	**(43)**	–
Actuarial gain on plan assets[e]	**1,479**	1,634
Fair value of plan assets at 31 December[f]	**22,612**	20,953
Surplus at 31 December	**1,870**	1,071

[a] The costs of managing the fund's investments are treated as being part of the investment return, the costs of administering our pensions plan benefits are included in current service cost.
[b] The charge for special termination benefits represents the increased liability arising as a result of early retirements occurring as part of restructuring programmes.
[c] The contributions by plan participants are mostly comprised of contributions made under salary sacrifice with effect from January 2010.
[d] The benefit payments amount shown above comprises $867 million benefits plus $15 million of plan expenses incurred in the administration of the benefit.
[e] 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.
[f] Reflects $22,516 million of assets held in the BP Pension Fund (2009 $20,895 million) and $68 million held in the BP Global Pension Trust (2009 $58 million), with $28 million representing the company's share of the Merchant Navy Officers Pension Fund (2009 nil).

6. Pensions continued

	$ million 2010	2009
Represented by		
Asset recognized	**2,069**	1,234
Liability recognized	**(199)**	(163)
	1,870	1,071
The surplus (deficit) may be analysed between funded and unfunded plans as follows		
Funded	**2,064**	1,231
Unfunded	**(194)**	(160)
	1,870	1,071
The defined benefit obligation may be analysed between funded and unfunded plans as follows		
Funded[a]	**(20,548)**	(19,722)
Unfunded	**(194)**	(160)
	(20,742)	(19,882)

[a] Reflects $20,448 million of liabilities of the BP Pension Fund (2009 $19,661 million), $67 million of liabilities of the BP Global Pension Trust (2009 $61 million) and $33 million of liabilities representing the company's share of the Merchant Navy Officers Pension Fund (2009 nil).

	$ million 2010	2009
Reconciliation of plan surplus to balance sheet		
Surplus at 31 December	**1,870**	1,071
Deferred tax	**(480)**	(279)
	1,390	792
Represented by		
Asset recognized on balance sheet	**1,537**	912
Liability recognized on balance sheet	**(147)**	(120)
	1,390	792

The aggregate level of employer contributions into the BP Pension Fund in 2011 is expected to be $404 million.

	2010	2009	2008	2007	$ million 2006
History of surplus and of experience gains and losses					
Benefit obligation at 31 December	**20,742**	19,882	15,414	22,146	21,507
Fair value of plan assets at 31 December	**22,612**	20,953	16,930	29,411	27,169
Surplus	**1,870**	1,071	1,516	7,265	5,662
Experience gains (losses) on plan liabilities					
Amount ($ million)	**12**	(146)	(65)	(155)	(211)
Percentage of benefit obligation	**0%**	(1)%	0%	(1)%	(1)%
Actual return less expected return on pension plan assets					
Amount ($ million)	**1,479**	1,634	(6,533)	404	1,252
Percentage of plan assets	**7%**	8%	(39)%	1%	5%
Actuarial (loss) gain recognized in statement of total recognized gains and losses					
Amount ($ million)	**457**	(585)	(5,122)	698	1,120
Percentage of benefit obligation	**2%**	(3)%	(33)%	3%	6%
Cumulative amount recognized in statement of total recognized gains and losses	**(1,235)**	(1,692)	(1,107)	4,015	3,317

The parent company financial statements of BP p.l.c. on pages PC1 – PC16 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

7. Called-up share capital

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

		2010		2009
Issued	**Shares (thousand)**	**$ million**	Shares (thousand)	$ million
8% cumulative first preference shares of £1 each	**7,233**	**12**	7,233	12
9% cumulative second preference shares of £1 each	**5,473**	**9**	5,473	9
		21		21
Ordinary shares of 25 cents each				
At 1 January	**20,629,665**	**5,158**	20,618,458	5,155
Issue of new shares for employee share schemes	**17,495**	**4**	11,207	3
31 December	**20,647,160**	**5,162**	20,629,665	5,158
		5,183		5,179
Authorized				
8% cumulative first preference shares of £1 each	**7,250**	**12**	7,250	12
9% cumulative second preference shares of £1 each	**5,500**	**9**	5,500	9
Ordinary shares of 25 cents each	**36,000,000**	**9,000**	36,000,000	9,000

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.

Repurchase of ordinary share capital

The company did not purchase any ordinary shares in 2010 (2009 no ordinary shares were purchased and 2008 269,757,188 ordinary shares were purchased for total consideration of $2,914 million of which all were for cancellation). At 31 December 2010, 1,850,698,774 shares of nominal value $462 million were held in treasury (2009 1,869,777,323 shares of nominal value $467 million and 2008 1,888,151,157 shares of nominal value $472 million). There were no transaction costs for share purchases in 2010 (2009 nil and 2008 $16 million).

8. Capital and reserves

$ million

	Share capital	**Share premium account**	**Capital redemption reserve**	**Merger reserve**	**Own shares**	**Treasury shares**	**Share-based payment reserve**	**Profit and loss account**	**Total**
At 1 January 2010	**5,179**	**9,847**	**1,072**	**26,509**	**(214)**	**(21,303)**	**1,519**	**96,564**	**119,173**
Currency translation differences	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(45)**	**(45)**
Actuarial gain on pensions (net of tax)	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**276**	**276**
Share-based payments	**4**	**140**	**–**	**–**	**88**	**218**	**66**	**(150)**	**366**
Profit for the year	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**14,776**	**14,776**
Dividends	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(2,627)**	**(2,627)**
At 31 December 2010	**5,183**	**9,987**	**1,072**	**26,509**	**(126)**	**(21,085)**	**1,585**	**108,794**	**131,919**

$ million

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Own shares	Treasury shares	Share-based payment reserve	Profit and loss account	Total
At 1 January 2009	5,176	9,763	1,072	26,509	(326)	(21,513)	1,271	72,840	94,792
Currency translation differences	–	–	–	–	–	–	–	104	104
Actuarial loss on pensions (net of tax)	–	–	–	–	–	–	–	(421)	(421)
Share-based payments	3	84	–	–	112	210	248	–	657
Profit for the year	–	–	–	–	–	–	–	34,524	34,524
Dividends	–	–	–	–	–	–	–	(10,483)	(10,483)
At 31 December 2009	5,179	9,847	1,072	26,509	(214)	(21,303)	1,519	96,564	119,173

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8. Capital and reserves continued

As a consolidated income statement is presented for the group, a separate income statement for the parent company is not required to be published.

The profit and loss account reserve includes $24,107 million (2009 $24,107 million and 2008 $24,107 million), the distribution of which is limited by statutory or other restrictions.

The company does not account for dividends until they are paid. The financial statements for the year ended 31 December 2010 do not reflect the dividend announced on 1 February 2011 and payable in March 2011; this will be treated as an appropriation of profit in the year ended 31 December 2011.

Managing capital

The company defines capital as the total equity of the company. The company's approach to managing capital is set out in its financial framework which was revised during 2010, with the objective of maintaining a capital structure that allows the company to execute its strategy and is resilient to inherent volatility. During 2010, the company did not repurchase any of its own shares.

9. Cash flow

			$ million
	2010	2009	2008
Reconciliation of net cash flow to movement of funds			
Increase (decrease) in cash	**(24)**	17	(233)
Movement of funds	**(24)**	17	(233)
Net cash at 1 January	**28**	11	244
Net cash at 31 December	**4**	28	11

Notes on cash flow statement

(a) Reconciliation of operating profit to net cash (outflow) inflow from operating activities	**2010**	2009	2008
Operating profit	**14,514**	34,195	17,211
Net operating charge for pensions and other post-retirement benefits, less contributions	**2**	321	461
Dividends, interest and other income	**(15,188)**	(35,189)	(17,239)
Share-based payments	**549**	444	446
(Increase) decrease in debtors	**17,405**	(24,584)	(5,271)
Increase (decrease) in creditors	**(51)**	4,040	(7)
Net cash inflow (outflow) from operating activities	**17,231**	(20,773)	(4,399)

			$ million
(b) Analysis of movements of funds	**At 1 January 2010**	**Cash flow**	**At 31 December 2010**
Cash at bank	**28**	**(24)**	**4**

10. Contingent liabilities

The parent company has issued guarantees under which amounts outstanding at 31 December 2010 were $36,777 million (2009 $30,158 million and 2008 $30,063 million), of which $36,747 million (2009 $30,126 million and 2008 $30,008 million) related to guarantees in respect of subsidiary undertakings, including $36,006 million (2009 $29,385 million and 2008 $29,267 million) in respect of borrowings by subsidiary undertakings and $30 million (2009 $32 million and 2008 $55 million) in respect of liabilities of other third parties.

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11. Share-based payments

Effect of share-based payment transactions on the company's result and financial position

			$ million
	2010	2009	2008
Total expense recognized for equity-settled share-based payment transactions	**577**	506	524
Total expense (credit) recognized for cash-settled share-based payment transactions	**(1)**	15	(16)
Total expense recognized for share-based payment transactions	**576**	521	508
Closing balance of liability for cash-settled share-based payment transactions	**16**	32	21
Total intrinsic value for vested cash-settled share-based payments	**1**	7	2

For ease of presentation, option and share holdings 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 share-based payment plans that existed during the year are detailed below. All plans are ongoing unless otherwise stated.

Plans for executive directors

Executive Directors' Incentive Plan (EDIP) – share element

An equity-settled incentive plan for executive directors with a three-year performance period. For share plan performance periods 2008-2010 the award of shares is determined by comparing BP's total shareholder return (TSR) against the other oil majors (ExxonMobil, Shell, Total and Chevron). For the performance period 2009-2011 the award of shares is determined 50% on TSR versus a competitor group of oil majors (which in this period also included ConocoPhillips) and 50% on a balanced scorecard (BSC) of three underlying performance measures versus the same competitor group. For the period 2010-2012 the award of shares is determined one third on TSR versus a competitor group of oil majors (identical to the 2009-2011 plan group) and two thirds on a BSC of three underlying performance indicators. After the performance period, the shares that vest (net of tax) are then subject to a three-year retention period. The directors' remuneration report on pages 112 to 121 includes full details of the plan.

Executive Directors' Incentive Plan (EDIP) – deferred matching share element

Following the renewal of the EDIP at the 2010 Annual General Meeting, a deferred matching share element is in place requiring a mandatory one third of directors' annual bonus to be deferred into shares for three years. The shares are matched by the company on a one-for-one basis. Vesting of both deferred and matching shares is contingent on an assessment of safety and environmental sustainability over the three-year deferral period and a director may voluntarily defer an additional one third of bonus into shares on the same terms.

Executive Directors' Incentive Plan (EDIP) – share option element

An equity-settled share option plan for executive directors that permits options to be granted at an exercise price no lower than the market price of a share on the date that the option is granted. The options are exercisable up to the seventh anniversary of the grant date and the last grants were made in 2004. From 2005 onwards the remuneration committee's policy is not to make further grants of share options to executive directors.

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 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 during the three-year period will normally preclude the conversion of units into shares, but special arrangements apply where the participant leaves for a qualifying reason.

Grants are settled in cash where participants are located in a country whose regulatory environment prohibits the holding of BP shares.

Performance unit plans

The number of units granted is made by reference to level of seniority of the 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 TSR compared against the other oil majors. In addition, free cash flow (FCF) is used as a performance measure for one of the performance plans. Plans included in this category are the Competitive Performance Plan (CPP), the Medium Term Performance Plan (MTPP) 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 long-term potential. One restricted share unit plan used in special circumstances for senior employees, 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 share immediately preceding the date of grant were granted to participants annually until 2006. There were no performance conditions and the options are exercisable between the third and tenth anniversaries of the grant date.

Savings and matching plans

BP ShareSave Plan

This is a savings-related share option plan under which employees save on a monthly basis, over a three- or five-year period, towards the purchase of shares at a fixed price determined when the option is granted. This price is usually set at a 20% discount to the market price at the time of grant. 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 have six months in which to use their savings to exercise their options on a pro-rated basis.

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11. Share-based payments continued

BP ShareMatch Plans

These are matching share plans under which BP matches employees' own contributions of shares up to a predetermined limit. The plans are run in the UK and in more than 60 other countries. The UK plan is run on a monthly basis with shares being held in trust for five years before they can be released free of any income tax and national insurance liability. 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.

Local plans

In some countries BP provides local scheme benefits, the rules and qualifications for which vary according to local circumstances.

Employee Share Ownership Plans (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 ESOP trusts vest unconditionally to employees, the amount paid for those shares is deducted in arriving at shareholders' equity (see Note 8). Assets and liabilities of the ESOPs are recognized as assets and liabilities of the group.

At 31 December 2010 the ESOPs held 11,477,253 shares (2009 18,062,246 shares and 2008 29,051,082 shares) for potential future awards, which had a market value of $82 million (2009 $174 million and 2008 $220 million).

Share option transactions

Details of share option transactions for the year under the share option plans are as follows:

	2010		2009		2008	
	Number of options	**Weighted average exercise price $**	Number of options	Weighted average exercise price $	Number of options	Weighted average exercise price $
Outstanding at 1 January	**295,895,357**	**8.73**	326,254,599	8.70	358,094,243	8.51
Granted	**10,420,287**	**6.08**	9,679,836	6.55	8,062,899	8.96
Forfeited	**(9,499,661)**	**7.88**	(5,954,325)	8.81	(2,502,784)	8.50
Exercised	**(31,839,034)**	**7.97**	(21,293,871)	7.53	(37,277,895)	6.97
Expired	**(1,670,227)**	**8.71**	(12,790,882)	8.01	(121,864)	7.00
Outstanding at 31 December	**263,306,722**	**8.75**	295,895,357	8.73	326,254,599	8.70
Exercisable at 31 December	**242,530,635**	**8.90**	274,685,068	8.80	260,178,938	8.22

The weighted average share price at the date of exercise was $9.54 (2009 $9.10 and 2008 $10.87). For the options outstanding at 31 December 2010, the exercise price ranges and weighted average remaining contractual lives are shown below.

	Options outstanding			**Options exercisable**	
Range of exercise prices	**Number of shares**	**Weighted average remaining life years**	**Weighted average exercise price $**	**Number of shares**	**Weighted average exercise price $**
$6.09 – $7.53	**54,821,144**	**2.68**	**6.36**	**39,231,453**	**6.40**
$7.54 – $8.99	**115,187,261**	**1.71**	**8.19**	**112,551,834**	**8.17**
$9.00 – $10.45	**21,827,393**	**3.54**	**9.88**	**19,276,424**	**9.98**
$10.46 – $11.92	**71,470,924**	**4.81**	**11.14**	**71,470,924**	**11.14**
	263,306,722	**2.90**	**8.75**	**242,530,635**	**8.90**

Fair values and associated details for options and shares granted

	2010		2009		2008	
	ShareSave 3 year	**ShareSave 5 year**	ShareSave 3 year	ShareSave 5 year	ShareSave 3 year	ShareSave 5 year
Option pricing model used	**Binomial**	**Binomial**	Binomial	Binomial	Binomial	Binomial
Weighted average fair value	**$0.06**	**$0.08**	$1.07	$1.07	$1.82	$1.74
Weighted average share price	**$4.58**	**$4.58**	$7.87	$7.87	$11.26	$11.26
Weighted average exercise price	**$5.90**	**$5.90**	$6.92	$6.92	$9.70	$9.70
Expected volatility	**22%**	**23%**	32%	32%	23%	23%
Option life	**3.5 years**	**5.5 years**	3.5 years	5.5 years	3.5 years	5.5 years
Expected dividends	**8.40%**	**8.40%**	7.40%	7.40%	4.60%	4.60%
Risk free interest rate	**1.25%**	**2.00%**	3.00%	3.75%	5.00%	5.00%
Expected exercise behaviour	**100% year 4**	**100% year 6**	100% year 4	100% year 6	100% year 4	100% year 6

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11. Share-based payments continued

The group uses a valuation model to determine the fair value of options granted. The model uses the implied volatility of ordinary share price for the quarter within which the grant date of the relevant plan falls. The fair value is adjusted for the expected rates of early cancellation. Management is responsible for all inputs and assumptions in relation to the model, including the determination of expected volatility.

Shares granted in 2010	**CPP**	**EPP**	**EDIP-TSR**	**EDIP-BSC**	**RSP**	**DAB**	**PSP**
Number of equity instruments granted (million)	**1.3**	**7.6**	**1.2**	**2.5**	**21.4**	**24.5**	**16.0**
Weighted average fair value	**$19.81**	**$9.43**	**$4.42**	**$8.94**	**$6.78**	**$9.43**	**$9.43**
Fair value measurement basis	**Monte Carlo**	**Market value**	**Monte Carlo**	**Market value**	**Market value**	**Market value**	**Market value**

Shares granted in 2009	CPP	EPP	EDIP-TSR	EDIP-BSC	RSP	DAB	PSP
Number of equity instruments granted (million)	1.4	7.6	2.1	2.1	2.4	38.9	16.5
Weighted average fair value	$9.76	$6.56	$2.74	$7.27	$8.76	$6.56	$8.32
Fair value measurement basis	Monte Carlo	Market value	Monte Carlo	Market value	Market value	Market value	Monte Carlo

Shares granted in 2008	MTPP-TSR	MTPP-FCF	EDIP-TSR	EDIP-RET[a]	RSP	DAB	PSP
Number of equity instruments granted (million)	9.1	9.1	2.6	0.5	7.7	5.8	16.7
Weighted average fair value	$5.07	$10.34	$4.55	$11.13	$8.83	$10.34	$12.89
Fair value measurement basis	Monte Carlo	Market value	Monte Carlo	Market value	Market value	Market value	Monte Carlo

[a] EDIP – retention element.

The group used a Monte Carlo simulation to determine the fair value of the TSR element of the 2010, 2009 and 2008 CPP, MTPP and EDIP plans, and in 2009 and 2008 for the PSP plan. In accordance with the rules of the plans the model simulates BP's TSR and compares it against our principal strategic competitors over the three-year period of the plans. The model takes into account the historic 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.

12. Auditor's remuneration

Fees payable to the company's auditor for the audit of the company's accounts were $17 million (2009 $13 million and 2008 $16 million).

Remuneration receivable by the company's auditor for the supply of other services to the company is not presented in the parent company financial statements as this information is provided in the consolidated financial statements.

13. Directors' remuneration

			$ million
Remuneration of directors	**2010**	2009	2008
Total for all directors			
Emoluments	**15**	19	19
Gains made on the exercise of share options	**2**	2	1
Amounts awarded under incentive schemes	**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. Also included was compensation for loss of office, of $3 million in 2010, (2009 nil and 2008 $1 million).

Pension contributions

During 2010 three executive directors participated in a non-contributory pension scheme established for UK staff 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 2010.

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 112 to 121.

The parent company financial statements of BP p.l.c. on pages PC1 – PC16 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

14. Post balance sheet events

On 14 January 2011, BP entered into a share swap agreement with Rosneft Oil Company whereby BP will receive approximately 9.5% of Rosneft's shares in exchange for BP issuing new ordinary shares to Rosneft, resulting in Rosneft holding 5% of BP's ordinary voting shares. The aggregate value of the shares in BP to be issued to Rosneft is approximately $7.8 billion (as at close of trading in London on 14 January 2011). BP has agreed to issue 988,694,683 ordinary shares to Rosneft; Rosneft has agreed to transfer 1,010,158,003 ordinary shares to BP. Completion of the transaction is subject to the outcome of the court application referred to in the paragraph below, and related pending arbitral proceedings. After completion, BP's increased investment in Rosneft will continue to be recognized as an available-for-sale financial asset. During the period from entering into the agreement until completion, the agreement represents a derivative financial instrument and changes in its fair value will be recognized in BP's income statement in 2011.

An application was brought in the English High Court on 1 February 2011 by Alfa Petroleum Holdings Limited (APH) and OGIP Ventures Limited (OGIP) against BP International Limited and BP Russian Investments Limited. APH is a company owned by Alpha Group. APH and OGIP each own 25% of TNK-BP, in which BP also has a 50% shareholding. This application alleges breach of the shareholders agreement on the part of BP and seeks an interim injunction restraining BP from taking steps to conclude, implement or perform the previously announced transactions with Rosneft Oil Company relating to oil and gas exploration, production, refining and marketing in Russia. Those transactions include the issue or transfer of shares between Rosneft Oil Company and any BP group company. 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 injunction has been extended until 11 March 2011 pending an expedited hearing in relation to matters in dispute between the parties on a final basis during the week commencing 7 March 2011. The expedited hearing will decide, among other matters, whether the injunction will be extended beyond 11 March 2011.

The parent company financial statements of BP p.l.c. on pages PC1 – PC16 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Information for shareholders

Reports and publications

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Summary Review 2010
Read a summary of our financial and operating performance in *BP Summary Review 2010* in print or online.
www.bp.com/summaryreview

Sustainability Review
Read the summary *BP Sustainability Review 2010* in print or read more online from late March 2011.
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