BP PLC
Form 20-F
March 04, 2008

# 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 December 31, 2007**
**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 plc**
**1 St James  s Square**
**London**
**SW1Y 4PD**
**United Kingdom**
**Tel +44 (0)20 7496 4263**
**Fax +44 (0)20 7496 4242**

(Name, Telephone, Email 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*** <br> **Chicago Stock Exchange*** |
| **4 7/8% Guaranteed Notes due 2010** | **New York Stock Exchange** |

| | |
|---|---|
| **Floating Rate Guaranteed Extendible Notes** | **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**

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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** | **18,922,785,598** |
| **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 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

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# Cross reference to Form 20-F

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# Certain definitions

Unless the context indicates otherwise, the following terms have the meanings shown below:

### Oil and natural gas reserves

**Oil and gas reserves** Proved reserves are defined by the Securities and Exchange Commission (SEC) in Rule 410(a) of Regulation S-X, paragraphs (2), (2i), (2ii) and (2iii). Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes: (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed programme in the reservoir, provides support for the engineering analysis on which the project or programme was based.

(iii) Estimates of proved reserves do not include the following:

- (a) oil that may become available from known reservoirs but is classified separately as indicated additional reserves ;
- (b) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;
- (c) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and
- (d) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

**Proved developed reserves** Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included as proved developed reserves only after testing by a pilot project or after the operation of an installed programme has confirmed through production response that increased recovery will be achieved.

**Proved undeveloped reserves** Proved reserves 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. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances are estimates for proved undeveloped reserves 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 tests in the area and in the same reservoir.

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## Miscellaneous terms

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

**ADR** American depositary receipt.

**ADS** American depositary share.

**AGM** Annual general meeting.

**Amoco** The former Amoco Corporation and its subsidiaries.

**Atlantic Richfield** Atlantic Richfield Company and its subsidiaries.

**Associate** An entity over which the group has significant influence and that is neither a subsidiary nor joint venture. Significant influence is the power to participate in the financial and operating policy decisions of an entity without having control or joint control over those policies.

**Baker Panel, or panel** BP US Refineries Independent Safety Review Panel.

**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.

**Gas** Natural gas.

**Hydrocarbons** Crude oil and natural gas.

**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.

**MTBE** Methyl tertiary butyl ether.

**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** Production-sharing agreement.

**IFRS** International Financial Reporting Standards.

**Joint venture** A contractual arrangement between the group and other venturers that undertake an economic activity that is subject to joint control. Joint control exists only where the strategic financial and operating decisions relating to the activity require the unanimous consent of the venturers.

**Jointly controlled asset** A joint venture where the venturers have a direct ownership interest in, and jointly control, the assets of the venture.

**Jointly controlled entity** 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 fellow venturers.

**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.

**UK** United Kingdom of Great Britain and Northern Ireland.

**US** United States of America.

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# Performance review

## Selected financial and operating information

This information, insofar as it relates to 2007, has been extracted or derived from the audited financial statements of the BP group presented on pages 93-180. 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.

BP sold its Innovene operations in December 2005. In the circumstances of discontinued operations, IFRS require that the profits earned by the discontinued operations, in this case the Innovene

operations, on sales to the continuing operations be eliminated on consolidation from the discontinued operations and attributed to the continuing operations and vice versa. This adjustment has two offsetting elements: the net margin on crude refined by Innovene, as substantially all crude for its refineries was supplied by BP and most of the refined products manufactured by Innovene were taken by BP; and the margin on sales of feedstock from BP s US refineries to Innovene s manufacturing plants. The profits attributable to individual segments are not affected by this adjustment. This representation does not indicate the profits earned by continuing or Innovene operations, as if they were standalone entities, for past periods or those likely to be earned in future periods.

$ million except per share amounts

| | | **2007** | 2006 | 2005 | 2004 | 2003 |
|---|---|---|---|---|---|---|
| **Income statement data** | | | | | | |
| Sales and other operating revenues from continuing operations[a] | | **284,365** | 265,906 | 239,792 | 192,024 | 164,653 |
| Profit before interest and taxation from continuing operations[a] | | **32,352** | 35,658 | 32,182 | 25,746 | 18,776 |
| Profit from continuing operations[a] | | **21,169** | 22,626 | 22,133 | 17,884 | 12,681 |
| Profit for the year | | **21,169** | 22,601 | 22,317 | 17,262 | 12,618 |
| Profit for the year attributable to BP shareholders | | **20,845** | 22,315 | 22,026 | 17,075 | 12,448 |
| Capital expenditure and acquisitions[b] | | **20,641** | 17,231 | 14,149 | 16,651 | 19,623 |
| Per ordinary share | cents | | | | | |
| Profit for the year attributable to BP shareholders | | | | | | |
| Basic | | **108.76** | 111.41 | 104.25 | 78.24 | 56.14 |
| Diluted | | **107.84** | 110.56 | 103.05 | 76.87 | 55.61 |
| Profit from continuing operations attributable to BP shareholders | | | | | | |
| Basic | | **108.76** | 111.54 | 103.38 | 81.09 | 56.42 |
| Diluted | | **107.84** | 110.68 | 102.19 | 79.66 | 55.89 |
| Dividends paid per share | cents | **42.30** | 38.40 | 34.85 | 27.70 | 25.50 |
| | pence | **20.995** | 21.104 | 19.152 | 15.251 | 15.658 |
| **Ordinary share data**[c] | | | | | | |
| Average number outstanding of 25 cent ordinary shares (shares million undiluted) | | **19,163** | 20,028 | 21,126 | 21,821 | 22,171 |

| | | | | | |
|---|---|---|---|---|---|
| Average number outstanding of 25 cent ordinary shares (shares million diluted) | **19,327** | 20,195 | 21,411 | 22,293 | 22,424 |
| **Balance sheet data** | | | | | |
| Total assets | **236,076** | 217,601 | 206,914 | 194,630 | 172,491 |
| Net assets | **94,652** | 85,465 | 80,450 | 78,235 | 70,264 |
| Share capital | **5,237** | 5,385 | 5,185 | 5,403 | 5,552 |
| BP shareholders equity | **93,690** | 84,624 | 79,661 | 76,892 | 69,139 |
| Finance debt due after more than one year | **15,651** | 11,086 | 10,230 | 12,907 | 12,869 |
| Net debt to net debt plus equity | **23%** | 20% | 17% | 22% | 22% |

[a] Excludes Innovene, which was treated as a discontinued operation in accordance with IFRS 5 Non-current Assets Held for Sale and Discontinued Operations . (*See Financial statements Note 3 on page 110.*)

[b] 2007 included $1,132 million for the acquisition of Chevron s Netherlands manufacturing company. There were no significant acquisitions in 2006 or in 2005. Capital expenditure in 2006 included $1 billion in respect of our investment in Rosneft. Capital expenditure and acquisitions for 2004 included $1,354 million for including TNK s interest in Slavneft within TNK-BP and $1,355 million for the acquisition of Solvay s interests in BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America.
Capital expenditure and acquisitions for 2003 included $5,794 million for the acquisition of our interest in TNK-BP. With the exception of the shares issued to Alfa Group and Access Renova (AAR) in connection with TNK-BP (2004-2006), all capital expenditure and acquisitions during the past five years have been financed from cash flow from operations, disposal proceeds and external financing.

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

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## Production and net proved oil and natural gas reserves

The following table shows our production for the past five years and the estimated net proved oil and natural gas reserves at the end of each of those years.

### Production and net proved reserves[a]

| | **2007** | 2006 | 2005 | 2004 | 2003 |
|---|---|---|---|---|---|
| Crude oil production for subsidiaries (thousand barrels per day) | **1,304** | 1,351 | 1,423 | 1,480 | 1,615 |
| Crude oil production for equity-accounted entities (thousand barrels per day) | **1,110** | 1,124 | 1,139 | 1,051 | 506 |
| Natural gas production for subsidiaries (million cubic feet per day) | **7,222** | 7,412 | 7,512 | 7,624 | 8,092 |
| Natural gas production for equity-accounted entities (million cubic feet per day) | **921** | 1,005 | 912 | 879 | 521 |
| Estimated net proved crude oil reserves for subsidiaries (million barrels)[b] | **5,492** | 5,893 | 6,360 | 6,755 | 7,214 |
| Estimated net proved crude oil reserves for equity-accounted entities (million barrels)[c] | **4,581** | 3,888 | 3,205 | 3,179 | 2,867 |
| Estimated net proved natural gas reserves for subsidiaries (billion cubic feet)[d] | **41,130** | 42,168 | 44,448 | 45,650 | 45,155 |
| Estimated net proved natural gas reserves for equity-accounted entities (billion cubic feet)[e] | **3,770** | 3,763 | 3,856 | 2,857 | 2,869 |

[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 to make lifting and sales arrangements independently, and include minority interests in consolidated operations.

[b] Includes 20 million barrels (23 million barrels at 31 December 2006 and 29 million barrels at 31 December 2005) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[c] Includes 210 million barrels (179 million barrels at 31 December 2006 and 95 million barrels at 31 December 2005) in respect of the 6.51% minority interest in TNK-BP (6.29% at 31 December 2006 and 4.47% at 31 December 2005).

[d] Includes 3,211 billion cubic feet of natural gas (3,537 billion cubic feet at 31 December 2006 and 3,812 billion cubic feet at 31 December 2005) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[e] Includes 68 billion cubic feet (99 billion cubic feet at 31 December 2006 and 57 billion cubic feet at 31 December 2005) in respect of the 5.88% minority interest in TNK-BP (7.77% at 31 December 2006 and 4.47% at 31 December 2005).

During 2007, 414 million barrels of oil and natural gas, on an oil equivalent* basis (mmboe), were added to BP s proved reserves for subsidiaries (excluding purchases and sales). After allowing for production, which amounted to 937mmboe, BP s proved reserves for subsidiaries were 12,583mmboe at 31 December 2007. These proved reserves are mainly located in the US (46%), Rest of Americas (19%), Asia Pacific (10%), Africa (8%) and the UK (8%).

For equity-accounted entities, 1,168mmboe were added to proved reserves (excluding purchases and sales), production was 470mmboe and proved reserves were 5,231mmboe at 31 December 2007.

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

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## Risk factors

We urge you to consider carefully the risks described below. If any of these risks occur, our business, financial condition and results of operations could suffer and the trading price and liquidity of our securities could decline, in which case you could lose all or part of your investment.

Our system of risk management provides the response to enduring risks of group significance through the establishment of standards and other controls. Inability to identify, assess and respond to risks through this and other controls could lead to inability to capture opportunities, threats materializing, inefficiency and legal non-compliance.

The risks are categorized against the following areas: Strategy; Compliance and ethics; Financial control; and Operations.

### Strategic risks

*Access and renewal*

Successful execution of our group plan depends critically 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. Lack of material positions in new markets and/or inability to complete disposals could result in an inability to capture above-average market growth.

*Prices and markets*

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 future fall in oil and natural gas prices, a prolonged period of low prices or other indicators would lead to a review for impairment of the group s oil and natural gas properties. This review would reflect management s view of long-term oil and natural gas prices. Such a review 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.

Refining profitability can be volatile, with both periodic oversupply and supply tightness in various regional markets. Sectors of the chemicals industry are also subject to fluctuations in supply and demand within the petrochemicals market, with consequent effect on prices and profitability.

*Climate change and carbon pricing*

Compliance with changes in laws, regulations and obligations relating to climate change could result in substantial capital expenditure, reduced profitability from changes in operating costs and revenue generation and strategic growth opportunities being impacted.

Socio-political

We have operations in countries where political, economic and social transition is taking place. Some countries have experienced political instability, changes to the regulatory environment, 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.

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*

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. The implementation of group strategy requires continued technological advances and innovation including advances in exploration, production, refining, petrochemical 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.

**Compliance and ethics risks**

*Regulatory*

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 protection 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. 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.

*Ethical misconduct and non-compliance*

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 non-compliance with applicable laws and regulation or ethical misconduct could be damaging to our reputation and shareholder value. Multiple events of non-compliance could call into question the integrity of our operations.

**Financial control risks**

*Liquidity, financial capacity and financial exposure*

The group has established a financial framework to ensure that it is able to maintain an appropriate level of liquidity and financial capacity and to constrain the level of assessed capital at risk for the purposes of positions taken in financial instruments. Failure to operate within our financial framework could lead to the group becoming financially distressed leading to a loss of shareholder value. 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. 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.

For further information on financial instruments and financial risk factors see Financial statements Note 28 on page 136 and Note 34 on page 143.

*Liabilities and provisions*

Changes in the external environment, such as new laws and regulations, market volatility or other factors, could affect the adequacy of our provisions for pensions, tax, environmental and legal liabilities.

**Operations risks**

Operations safety and operations

*Process safety*

Inherent in our operations are hazards that require continual oversight and control. There are risks of technical integrity failure and loss of containment of hydrocarbons and other hazardous material at operating sites or pipelines. Failure to manage these risks could result in injury or loss of life, environmental damage and/or loss of production.

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*Personal safety*

Inability to provide safe environments for our workforce and the public could lead to injuries or loss of life.

*Environmental*

If we do not apply our resources to overcome the perceived trade-off between global access to energy and the protection or improvement of the natural environment, we could fail to live up to our aspirations of no or minimal damage to the environment and contributing to human progress.

*Product quality*

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*

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. 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.

*Transportation*

All modes of transportation of hydrocarbons contain inherent risks. A loss of containment of hydrocarbons and 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.

Operations planning and performance management

*Investment efficiency*

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

*Major project delivery*

Successful execution of our group plan (see page 11) depends critically on implementing the activities to deliver the major projects over the plan period. Poor delivery of any major project that underpins production growth and/or a major programme designed to enhance shareholder value could adversely affect our financial performance.

*Reserves replacement*

Successful execution of our group plan depends critically on sustaining long-term reserves replacement. If upstream resources are not progressed to proved reserves in a timely and efficient manner, we will be unable to sustain long-term replacement of reserves.

Operations enterprise systems, security and continuity

*Digital infrastructure*

The reliability and security of our digital infrastructure are critical to maintaining our business applications availability. 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.

*Security*

Security threats require continual oversight and control. Acts of terrorism that threaten our plants and offices, pipelines, transportation or computer systems would severely disrupt business and operations and could cause harm to people.

*Business continuity and disaster recovery*

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 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.

Operations people management

*People and capability*

Employee training, development and successful recruitment of new staff are key to implementing our plans. Inability to develop the human capacity and capability across the organization could jeopardize performance delivery.

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## Forward-looking statements

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 , should , may , objective , is likely to , intends , believes , plans , we see or similar expressions. In particular, among other statements, ( statements in Performance review (pages 6-55) with regard to management aims and objectives, future capital expenditure, future hydrocarbon production volume, 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 Performance review (pages 6-44) with regard to planned expansion, investment or other projects and future regulatory actions; and (iii) the statements in Performance review (pages 45-55) with regard to the plans of the group, cash flows, opportunities for material acquisitions, the cost of and provision for future remediation programmes, liquidity and costs for providing pension and other post-retirement benefits; and including under Liquidity and capital resources with regard to future production, future refining availability, future capital expenditure, sources of funding, future revenues and financial performance, potential for cost efficiencies, level of free cash flow allocated to share buybacks, shareholder distributions and share buybacks, gearing, working capital and expected payments under contractual and commercial commitments; 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; 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 on pages 8-9. In addition to factors set forth elsewhere in this report, those set out above are important factors, although not exhaustive, that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements.

## Statements regarding competitive position

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

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## Information on the company

### General

*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. Also, unless otherwise indicated, figures for business sales and other operating revenues include sales between BP businesses.*

*The company, incorporated in 1909 in England and Wales, became known as BP Amoco p.l.c. following the merger with Amoco Corporation (incorporated in Indiana, US, in 1889). The company subsequently changed its name to BP p.l.c.*

*BP is one of the world s leading oil companies on the basis of market capitalization and proved reserves. Our worldwide headquarters is located at 1 St James s Square, London SW1Y 4PD, UK, tel +44 (0)20 7496 4000. Our agent in the US is BP America Inc., 4101 Winfield Road, Warrenville, Illinois 60555, tel +1 630 821 2222.*

### Overview of the group

BP is a global group, with interests and activities 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 three business segments in 2007, supported by a number of organizational elements comprising group functions and regions.

In 2007, the three business segments were Exploration and Production, Refining and Marketing and Gas, Power and Renewables. With effect from 1 January 2008, the Gas, Power and Renewables segment ceased to report separately *(see Resegmentation in 2008 on page 12)*. Exploration and Production s activities include oil and natural gas exploration, development and production (upstream activities), together with related pipeline, transportation and processing activities (midstream activities). The activities of Refining and Marketing include the supply and trading, refining, marketing and transportation of crude oil, petroleum and chemicals products. Gas, Power and Renewables activities included marketing and trading of gas and power, marketing of liquefied natural gas (LNG), natural gas liquids (NGLs), and low-carbon power generation through our Alternative Energy business. The group provides high-quality technological support for all its businesses through its research and engineering activities.

Group functions serve the business segments, aiming to achieve coherence across the group, manage risks effectively and achieve economies of scale. Each head of region ensures regional consistency of the activities of business segments and group functions and represents BP to external parties.

The group s system of internal control is described in the BP management framework. It is designed to meet the expectations of internal control of the Turnbull Guidance on the Combined Code in the UK and of COSO (committee of the sponsoring organization for the Treadway Commission in the US). The system of internal control is the complete set of management systems, organizational structures, processes, standards and behaviours that are employed to conduct the business of BP and deliver returns to shareholders. The design of the system of internal control addresses risks and how to respond to them. Each component of the system is in itself a device to respond to a particular type or collection of risks.

The group strategy describes the group s strategic objectives and the presumptions made by BP about the future. It describes strategic risks that arise from making such presumptions and the actions to be taken to manage or mitigate the risks. The board delegates to the group chief executive responsibility for developing BP s strategy and its implementation through the group plan that determine the setting of priorities and allocation of resources. The group chief executive is obliged to discuss with the board, on the basis of the strategy and group plan, all material matters currently or prospectively affecting BP s performance.

As the group s business segments are managed on a global, not regional, basis, geographical information for the group and segments is

given to provide additional information for investors but does not reflect the way BP manages its activities.

We have well-established operations in Europe, the US, Canada, Russia, South America, Australasia, Asia and parts of Africa. Currently, around 65% of the group s capital is invested in Organisation for Economic Co-operation and Development (OECD) countries, with just under 40% of our fixed assets located in the US and around 25% located in Europe.

We believe that BP has a strong portfolio of assets:

- In Exploration and Production, we have upstream interests in 29 countries. Exploration and Production activities are managed through operating units that are accountable for the day-to-day management of the segment s activities. An operating unit is accountable for one or more fields. Profit centres comprise one or more operating units.
  Profit centres are, or are expected to become, areas that provide significant production and income for the segment. Our current areas of major development include the deepwater Gulf of Mexico, Azerbaijan, Algeria, Angola, Egypt and Asia Pacific where we believe we have competitive advantage and that we believe provide the foundation for volume growth and

improved margins in the future. We also have significant midstream activities to support our upstream interests.

- In Refining and Marketing, we have a strong presence in the US and Europe. In the US, we market under the Amoco and BP brands in the Midwest, east and southeast and under the ARCO brand on the west coast, and under the BP and Aral brands in Europe. We have a long- established supply and trading activity responsible for delivering value across the crude and oil products supply chain. Our Aromatics & Acetyls business maintains a manufacturing position globally, with emphasis on growth in Asia. We also have, or are growing, businesses elsewhere in the world under the BP and Castrol brands, including a strong global lubricants portfolio and other business-to- business marketing businesses (aviation and marine) covering the mobility sectors. We continue to seek opportunities to broaden our activities in growth markets such as China and India.
- In our Gas, Power and Renewables businesses, marketing and trading is undertaken primarily in the US, Canada, the UK and the rest of Europe. Our marketing and trading activities include natural gas, power and NGLs. Our LNG activities identify and capture worldwide opportunities for our upstream natural gas resources and are focused on growing natural gas markets, including the US, the UK, Spain and key consuming countries of the Asia Pacific region. We have a significant NGLs processing and marketing business in North America. BP Alternative Energy, launched in November 2005, combines all of BP s interests in businesses that provide low-carbon energy solutions for power generation: solar, wind, gas-fired power generation and hydrogen power with carbon capture and storage. Alternative Energy has solar production facilities in the US, Spain, China, India and Australia; and wind farms in the Netherlands, India and the US. We are advancing development of hydrogen power plants and are involved in gas-fired power projects in the US, the UK, Spain, Vietnam, Trinidad & Tobago and South Korea.

Through non-US subsidiaries or other non-US entities, during the period covered by this report, BP conducted limited marketing, licensing and trading activities in, or with persons from, certain countries identified by the US Department of State as State Sponsors of Terrorism. BP believes that these activities are immaterial to the group.

BP has interests in, and is the operator of, two fields and a pipeline located outside of Iran in which the National Iranian Oil Company (NIOC) and an affiliated entity have interests. In Iran, BP buys small quantities of crude oil. This is primarily for sale to third parties in Europe and a small portion is used by BP in its own refineries in South Africa and Europe. In addition, BP sells small quantities of crude oil into Iran and blends and markets small quantities of lubricants for sale to domestic consumers through a joint venture there, which has a blending facility. However, 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 chemicals plants in Iran.

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BP sells small quantities of lubricants in Cuba through a 50/50 joint venture there. In Syria, small quantities of lubricants are sold through a distributor and BP obtains small volumes of crude oil supplies for sale to third parties in Europe. These sales and purchases are insignificant and BP does not provide other goods, technologies or services in these countries.

## Acquisitions and disposals

In 2007, BP acquired Chevron s Netherlands manufacturing company, Texaco Raffiniderij Pernis B.V. The acquisition included Chevron s 31% minority shareholding in Nerefco, its 31% shareholding in the 22.5 MW wind farm co-located at the refinery as well as a 22.8% shareholding in the TEAM joint venture terminal and shareholdings in two local pipelines linking the TEAM terminal to the refinery. Disposal proceeds were $4,267 million, which included $1,903 million from the sale of the Coryton refinery and $605 million from the sale of our exploration and production gas infrastructure business in the Netherlands.

In 2006, there were no significant acquisitions. BP purchased 9.6% of the shares issued under Rosneft s IPO for a consideration of $1 billion (included in capital expenditure). This represented an interest of around 1.4% in Rosneft. Disposal proceeds were $6,254 million, which included $2.1 billion on the sale of our interest in the Shenzi discovery and around $1.3 billion from the sale of our producing properties on the Outer Continental Shelf of the Gulf of Mexico to Apache Corporation.

In 2005, there were no significant acquisitions. Disposal proceeds were $11,200 million, which included net cash proceeds from the sale of Innovene to INEOS of $8,304 million after selling costs, closing adjustments and liabilities. Innovene represented the majority of the Olefins and Derivatives business. Additionally, disposal proceeds included proceeds from the sale of the group s interest in the Ormen Lange field in Norway.

## Resegmentation in 2008

On 11 October 2007, we announced our intention to simplify the organizational structure of BP. From 1 January 2008, there are only two business segments: Exploration and Production and Refining and Marketing. A separate business, Alternative Energy, handles BP s low-carbon businesses and future growth options outside oil and gas.

As a result, and with effect from 1 January 2008:

- The Gas, Power and Renewables segment ceased to report separately.
- The NGLs, LNG and gas and power marketing and trading businesses were transferred from the Gas, Power and Renewables segment to the Exploration and Production segment.
- The Alternative Energy business was transferred from the Gas, Power and Renewables segment to Other businesses and corporate.
- The Emerging Consumers Marketing Unit was transferred from Refining and Marketing to Alternative Energy (which is reported in Other businesses and corporate).
- The Biofuels business was transferred from Refining and Marketing to Alternative Energy (which is reported in Other businesses and corporate).
- The Shipping business was transferred from Refining and Marketing to Other businesses and corporate.

## Exploration and Production

Our Exploration and Production segment includes upstream and midstream activities in 29 countries, including the US, the UK, Angola, Azerbaijan, Canada, Egypt, Russia, Trinidad & Tobago (Trinidad) and locations within Asia Pacific, Latin America, North Africa and the Middle East. Upstream activities involve oil and natural gas exploration and field development and production. Our exploration programme is currently focused around the deepwater Gulf of Mexico, Algeria, Angola, Azerbaijan, Egypt and Russia. Major development areas include the deepwater Gulf of Mexico, Azerbaijan, Algeria, Angola, Egypt and Asia Pacific. During 2007, production came from 22 countries. The principal areas of production are Russia, the US, Trinidad, the UK, Latin America, the Middle East, Asia Pacific, Azerbaijan, Angola and Egypt.

Midstream activities involve the ownership and management of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation. Our most significant midstream pipeline interests include the Trans Alaska Pipeline System, the Forties Pipeline System and the Central Area Transmission System pipeline, both in the UK sector of the North Sea, and the Baku-Tbilisi-Ceyhan pipeline, running through Azerbaijan, Georgia and Turkey. Major LNG activities are located in Trinidad, Indonesia and Australia. Further LNG businesses with BP involvement are being built up in Egypt and Angola.

Our oil and gas production assets are located onshore or 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.

### Key statistics

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Sales and other operating revenues from continuing operations | **54,550** | 52,600 | 47,210 |
| Profit before interest and tax from continuing operations[a] | **26,938** | 29,629 | 25,502 |
| Total assets | **108,874** | 99,310 | 93,447 |
| Capital expenditure and acquisitions | **13,906** | 13,118 | 10,237 |
| | | | million barrels of oil equivalent |
| Net proved reserves group | **12,583** | 13,163 | 14,023 |
| Net proved reserves equity-accounted entities | **5,231** | 4,537 | 3,870 |
| | | | thousand barrels per day |
| Liquids production group | **1,304** | 1,351 | 1,423 |
| Liquids production equity-accounted entities | **1,110** | 1,124 | 1,139 |
| | | | million cubic feet per day |
| Natural gas production group | **7,222** | 7,412 | 7,512 |
| Natural gas production equity-accounted entities | **921** | 1,005 | 912 |
| | | | $ per barrel |
| Average BP crude oil realizations[b] | **69.98** | 61.91 | 50.27 |
| Average BP NGL realizations[b] | **46.20** | 37.17 | 33.23 |
| Average BP liquids realizations[b c] | **67.45** | 59.23 | 48.51 |

| | | | |
|---|---|---|---|
| Average West Texas Intermediate oil price | **72.20** | 66.02 | 56.58 |
| Average Brent oil price | **72.39** | 65.14 | 54.48 |
| | | | $ per thousand cubic feet |
| Average BP natural gas realizations[b] | **4.53** | 4.72 | 4.90 |
| Average BP US natural gas realizations[b] | **5.43** | 5.74 | 6.78 |
| | | | $ per million British thermal units |
| Average Henry Hub gas price[d] | **6.86** | 7.24 | 8.65 |
| | | | pence per therm |
| Average UK National Balancing Point gas price | **29.95** | 42.19 | 40.71 |

a Profit before interest and tax from continuing operations includes profit after interest and tax of equity-accounted entities.
b The Exploration and Production segment does not undertake any hedging activity. Consequently, realizations reflect the market price achieved. Realizations are based on sales of consolidated subsidiaries only, which excludes equity-accounted entities.
c Crude oil and natural gas liquids.
d Henry Hub First of Month Index.

Upstream operations in Argentina, Bolivia, Abu Dhabi, Kazakhstan and the TNK-BP and some of the Sakhalin operations in Russia, as well as some of our operations in Indonesia and Venezuela, are conducted through equity-accounted entities.

The Exploration and Production strategy is to build production by:

Focusing on finding the largest fields in the world s most prolific hydrocarbon basins.

Building leadership positions in these areas.

Managing the decline of existing producing assets and divesting assets when they no longer compete in our portfolio.

Through the application of advanced technology and significant investment, we have gained a strong position in many of our operating areas.

Total capital expenditure and acquisitions in 2007 was $13.9 billion (2006 $13.1 billion and 2005 $10.2 billion). There were no significant acquisitions in the period from 2005 to 2007. Capital expenditure in 2006 included our investment in Rosneft s IPO of $1 billion. Capital expenditure in 2008 is planned to be around $15 billion including approximately $0.5 billion in respect of the gas and power businesses that are now reported through Exploration and Production, as described below, and excluding the impact of our transaction with Husky Energy Inc., which is further described on page 21. This reflects our project programme, managed within the context of our disciplined approach to capital investment and taking into account sector-specific inflation.

Development expenditure incurred in 2007, excluding midstream activities, was $10,153 million, compared with $9,109 million in 2006 and $7,678 million in 2005.

## Resegmentation in 2008

With effect from 1 January 2008, the NGLs, LNG and the gas and power marketing and trading businesses were transferred from the Gas, Power and Renewables segment to the Exploration and Production segment.

## 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 in 2007 were $1,892 million, compared with $1,765 million in 2006 and $1,266 million in 2005. These costs include exploration and appraisal drilling expenditures, which are capitalized within intangible fixed assets, and geological and geophysical exploration costs, which are charged to income as incurred. Approximately 47% of 2007 exploration and appraisal costs were directed towards appraisal activity. In 2007, we participated in 86 gross (37 net) exploration and appraisal wells in 12 countries. The principal areas of activity were the deepwater Gulf of Mexico, Angola, Egypt, North Sea, Canada and Pakistan.

Total exploration expense in 2007 of $756 million (2006 $1,045 million and 2005 $684 million) included the write-off of expenses related to

unsuccessful drilling activities in Russia ($86 million excluding TNK-BP), Egypt ($49 million), Colombia ($49 million), the deepwater Gulf of Mexico ($36 million), onshore North America ($36 million), Angola ($27 million) and others ($11 million).

In 2007, we obtained upstream rights in several new tracts, which include the following:

- In the Gulf of Mexico, we have been awarded 171 blocks (BP average equity 100%) through the Outer Continental Shelf Lease Sales 204 and 205.
- In Oman, we signed a production-sharing agreement (PSA) to appraise and develop the Khazzan/Makarem gas fields.
- In Colombia, BP was awarded operatorship in two blocks, RC4 (BP 35%) and RC5 (BP 100%), which cover approximately 6,200 square kilometres in the Caribbean Sea, offshore northern Colombia.
- In Libya, BP signed a major exploration and production agreement with Libya s National Oil Company, covering over 53,000 square kilometres both onshore and offshore.

In 2007, we were involved in a number of discoveries. In most cases, reserves bookings from these fields will depend on the results of ongoing technical and commercial evaluations, including appraisal drilling. Our most significant discoveries in 2007 included the following:

- In Angola, we made further discoveries in the ultra deepwater (greater than 1,500 metres) Block 31 (BP 26.7% and operator) with the Miranda, Cordelia and Portia wells, bringing the total number of discoveries in Block 31 to 15.
- In Azerbaijan, we made a further discovery in a new reservoir in Shah Deniz (BP 25.5% and operator) with the SDX-04 well.
- In Egypt, we made three discoveries with the Giza North-1 (BP 60% and operator), Taurus Deep (BP 60% and operator) and Satis (BP 50% and operator) wells.
- In the deepwater Gulf of Mexico, we made a discovery with the Isabela well (BP 67% and operator).

## Reserves and production

### *Compliance*

IFRS does not provide specific guidance on reserves disclosures. BP estimates proved reserves in accordance with SEC Rule 4-10 (a) and relevant guidance notes and letters issued by the SEC staff.

By their nature, there is always some risk involved in the ultimate development and production of 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 and the continued availability of additional development capital.

All the group s oil and gas reserves held in consolidated companies have been estimated by the group s petroleum engineers. Of the equity-accounted volumes in 2007, 16% were based on estimates prepared by group petroleum engineers and 84% were based on estimates prepared by independent engineering consultants, although all of the group s oil and gas reserves held in equity-accounted entities are reviewed by the group s petroleum engineers before making the assessment of volumes to be booked by BP.

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 title to the hydrocarbons is not conferred, such as PSAs. In a concession, the consortium of which we are a part is entitled to the 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 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. Thirteen per cent of our proved reserves are associated with PSAs. The main countries in which we operate under PSAs are Algeria, Angola, Azerbaijan, Egypt, Indonesia and Vietnam.

We separately disclose our share of 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.

### *Resource progression*

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

Resources in a field will only be categorized as proved reserves when all the criteria for attribution of proved status have been met, including an internally imposed requirement for project sanction or for sanction expected within six months and, for additional reserves in existing fields, the requirement that the reserves be included in the business plan and scheduled for development, typically within three years. Where, on occasion, the group decides to book reserves where development is scheduled to commence beyond three years, these reserves will be booked only where they satisfy the SEC s criteria for attribution of proved status. Internal approval and final investment decision are what we refer to as project sanction.

At the point of sanction, all booked 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 reserves depends on a later phase of activity, only that portion of reserves associated with existing, available facilities and infrastructure moves to PD. The first PD bookings will 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 PUD reserves to the start of production. Changes to reserves bookings may be made due to analysis of new or existing data concerning production, reservoir performance, commercial factors, acquisition and divestment activity and additional reservoir development activity.

*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 includes systematically examining the effectiveness of the group s financial controls designed to assure the reliability of reporting and safeguarding of assets and examining the group s compliance with laws, regulations and internal standards.
- 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 reserves base undergoes central review every two years and more than 90% is reviewed every four years.

For the executive directors and senior management, no specific portion of compensation bonuses is directly related to oil and gas 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 and senior management. Other indicators include a number of financial and operational measures.

BP s variable pay programme for the other senior managers in the Exploration and Production segment is based on individual performance contracts. Individual performance contracts are based on agreed items from the business performance plan, one of which, if they choose, could relate to oil and gas reserves.

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*Reserve replacement*

Total hydrocarbon proved reserves, on an oil equivalent basis and excluding equity-accounted entities, comprised 12,583mmboe at 31 December 2007, a decrease of 4.4% compared with 31 December 2006. Natural gas represents about 56% of these reserves. The reduction includes net sales of 58mmboe, largely comprising a number of assets in the Netherlands, Pakistan, Canada and the US.

Total hydrocarbon proved reserves, on an oil equivalent basis for equity-accounted entities alone, comprised 5,231mmboe at 31 December 2007, an increase of 15.3% compared with 31 December 2006. Natural gas represents about 12% of these proved reserves. The increase includes net sales of 3mmboe, largely comprising a number of assets in Russia.

The proved reserves replacement ratio (also known as the production 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, and may be expressed as a replacement ratio excluding acquisitions and divestments or as a total replacement ratio including acquisitions and divestments.

| | | | % |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Proved reserves replacement ratio, excluding equity-accounted entities | **44** | 34 | 68 |
| Proved reserves replacement ratio, excluding equity-accounted entities, including sales and purchases of reserves-in-place | **38** | 11 | 40 |
| Proved reserves replacement ratio, for equity-accounted entities | **248** | 272 | 151 |
| Proved reserves replacement ratio, for equity-accounted entities, including sales and purchases of reserves-in-place | **248** | 239 | 141 |
| | | | million barrels of oil equivalent |
| Additions to proved developed reserves, excluding equity-accounted entities, including sales and purchases of reserves-in-place[a] | **929** | 675 | 632 |
| Additions to proved developed reserves, for equity-accounted entities, including sales and purchases of reserves-in-place[a] | **473** | 936 | 474 |
| | | | % |
| Proved developed reserves replacement ratio, excluding equity-accounted entities, including sales and purchases of reserves-in-place | **99** | 70 | 63 |
| Proved developed reserves replacement ratio, for equity-accounted entities, including sales and purchases of reserves-in-place | **101** | 195 | 99 |

a This includes some reserves that were previously classified as proved undeveloped.

In 2007, net additions to the group s proved reserves (excluding sales and purchases of reserves-in-place and equity-accounted entities) amounted to 414mmboe, principally through improved recovery from, and extensions to, existing fields and discoveries of new fields. Of the reserves additions through improved recovery from, and extensions to, existing fields and discoveries of new fields, 64% are associated with new projects and are proved undeveloped reserves additions. The remainder are in existing developments where they represent a mixture of proved developed and proved undeveloped reserves. The principal reserves additions were in the Norway (Skarv), the US (Liberty, Prudhoe Bay, Great White, Nakika, Thunder Horse), Trinidad (Immortelle, Manakin), Angola (Pazflor) and Canada (Noel).

*Production*

Our total hydrocarbon production during 2007 averaged 2,549 thousand barrels of oil equivalent per day (mboe/d) for subsidiaries and 1,269mboe/d for equity-accounted entities, a decrease of 3% and 2% respectively compared with 2006. For subsidiaries, 35% of our production was in the US and 13% in the UK. For equity-accounted entities, 72% of production was from TNK-BP.

Total production for 2008 is expected to be higher than in 2007. This is based on the group s asset portfolio at 1 January 2008, expected startups in 2008 and Brent at $60/bbl, before any 2008 disposal effects and before any effects of prices above $60/bbl on volumes in PSAs.

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The following tables show BP s estimated net proved reserves as at 31 December 2007.

## Estimated net proved reserves of liquids at 31 December 2007[a b c]

| | | | million barrels |
|---|---|---|---|
| | Developed | Undeveloped | Total |
| UK | 414 | 123 | 537 |
| Rest of Europe | 105 | 169 | 274 |
| US | 1,882 | 1,265 | 3,147[d] |
| Rest of Americas | 115 | 203 | 318[e] |
| Asia Pacific | 61 | 77 | 138 |
| Africa | 256 | 350 | 606 |
| Russia | | | |
| Other | 104 | 368 | 472 |
| Group | 2,937 | 2,555 | 5,492 |
| Equity-accounted entities | 2,996 | 1,585 | 4,581[f] |

## Estimated net proved reserves of natural gas at 31 December 2007[a b c]

| | | | billion cubic feet |
|---|---|---|---|
| | Developed | Undeveloped | Total |
| UK | 2,049 | 553 | 2,602 |
| Rest of Europe | 63 | 410 | 473 |
| US | 10,670 | 4,705 | 15,375 |
| Rest of Americas | 3,683 | 8,394 | 12,077[g] |
| Asia Pacific | 1,822 | 4,817 | 6,639 |
| Africa | 990 | 1,410 | 2,400 |
| Russia | | | |
| Other | 583 | 981 | 1,564 |
| Group | 19,860 | 21,270 | 41,130 |
| Equity-accounted entities | 2,473 | 1,297 | 3,770[h] |

## Net proved reserves on an oil equivalent basis (mmboe)

| | | | |
|---|---|---|---|
| Group | 6,361 | 6,222 | 12,583 |
| Equity-accounted entities | 3,422 | 1,809 | 5,231 |

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 joint ventures and associates that are accounted for by the equity method although we do not control these entities or the assets held by such entities.

[b] In certain deepwater fields, such as fields in the Gulf of Mexico, BP has claimed 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. The general method of reserves assessment to determine reasonable certainty of commercial recovery that BP employs 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 a better understanding of the 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. Historically, proved reserves recorded using these methods have been validated by actual production levels. As at the end of 2007, BP had proved reserves in 22 fields in the deepwater Gulf of Mexico that had been initially booked prior to production flow testing. Of these fields, 19 are in production and one, Thunder Horse, is expected to begin production by the end of 2008. Two other fields are in the early stages of development.

[c] The 2007 year-end marker prices used were Brent $96.02/bbl (2006 $58.93/bbl and 2005 $58.21/bbl) and Henry Hub $7.10/mmBtu (2006 $5.52/mmBtu and 2005 $9.52/mmBtu).

[d] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 98 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.

[e] Includes 20 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[f] Includes 210 million barrels of crude oil in respect of the 6.51% minority interest in TNK-BP.

[g] Includes 3,211 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[h] Includes 68 billion cubic feet of natural gas in respect of the 5.88% minority interest in TNK-BP.

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The following tables show BP s production by major field for 2007, 2006 and 2005.

| **Liquids** | | % | thousand barrels per day BP net share of production[a] | | |
|---|---|---|---|---|---|
| | Field or Area | Interest | **2007** | 2006 | 2005 |
| Alaska | Prudhoe Bay[b] | 26.4 | **74** | 71 | 89 |
| | Kuparuk | 39.2 | **52** | 57 | 62 |
| | Northstar[b] | 98.6 | **28** | 38 | 46 |
| | Milne Point[b] | 99.4 | **28** | 31 | 37 |
| | Other | Various | **27** | 27 | 34 |
| Total Alaska | | | **209** | 224 | 268 |
| Lower 48 onshore[c] | Various | Various | **108** | 125 | 130 |
| Gulf of Mexico deepwater[c] | Na Kika[b] | 50.0 | **32** | 41 | 44 |
| | Horn Mountain[b] | 100.0 | **18** | 23 | 26 |
| | King[b] | 100.0 | **22** | 28 | 24 |
| | Mars | 28.5 | **30** | 19 | 21 |
| | Mad Dog[b] | 61.0 | **25** | 17 | 13 |
| | Holstein[b] | 50.0 | **17** | 15 | 22 |
| | Other | Various | **52** | 52 | 48 |
| Gulf of Mexico Shelf[c] | Other | Various | | 3 | 16 |
| Total Gulf of Mexico | | | **196** | 198 | 214 |
| Total US | | | **513** | 547 | 612 |
| UK offshore[c] | ETAP[d] | Various | **32** | 49 | 49 |
| | Foinaven[b] | Various | **37** | 37 | 39 |
| | Magnus[b] | 85.0 | **16** | 30 | 30 |
| | Schiehallion/Loyal[b] | Various | **20** | 26 | 28 |
| | Harding[b] | 70.0 | **14** | 17 | 22 |
| | Andrew[b] | 62.8 | **8** | 7 | 12 |
| | Other | Various | **59** | 69 | 75 |
| Total UK offshore | | | **186** | 235 | 255 |
| Onshore | Wytch Farm[b] | 67.8 | **15** | 18 | 22 |
| Total UK | | | **201** | 253 | 277 |
| Netherlands[c] | Various | Various | | 1 | 1 |
| Norway | Valhall[b] | 28.1 | **17** | 21 | 25 |
| | Draugen | 18.4 | **14** | 15 | 20 |
| | Ula[b] | 80.0 | **12** | 14 | 17 |

| | | | | | |
|---|---|---|---|---|---|
| | Other | Various | **8** | 10 | 12 |
| Total Rest of Europe | | | **51** | 61 | 75 |
| Angola | Dalia | 16.7 | **31** | | |
| | Girassol | 16.7 | **14** | 17 | 34 |
| | Greater Plutonio[b] | 50.0 | **12** | | |
| | Kizomba A | 26.7 | **36** | 54 | 56 |
| | Kizomba B | 26.7 | **35** | 58 | 28 |
| | Other | Various | **11** | 4 | 10 |
| Australia | Various | 15.8 | **34** | 34 | 36 |
| Azerbaijan | Azeri-Chirag-Gunashli[b] | 34.1 | **200** | 145 | 76 |
| | Shah Deniz[b] | 25.5 | **5** | | |
| Canada[c] | Various[b] | Various | **8** | 8 | 10 |
| Colombia | Various[b] | Various | **28** | 34 | 41 |
| Egypt | Various | Various | **43** | 42 | 47 |
| Trinidad & Tobago[c] | Various[b] | 100.0 | **30** | 40 | 40 |
| Venezuela[c] | Various | Various | **16** | 26 | 55 |
| Other[c] | Various | Various | **36** | 28 | 26 |
| Total Rest of World | | | **539** | 490 | 459 |
| Total group[e] | | | **1,304** | 1,351 | 1,423 |
| Equity-accounted entities (BP share) | | | | | |
| Abu Dhabi[f] | Various | Various | **192** | 163 | 148 |
| Argentina Pan American Energy | Various | Various | **69** | 69 | 67 |
| Russia TNK-BP | Various | Various | **832** | 876 | 911 |
| Other[c] | Various | Various | **17** | 16 | 13 |
| Total equity-accounted entities | | | **1,110** | 1,124 | 1,139 |

[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] BP-operated.

[c] In 2007, BP divested its producing properties in the Netherlands and some producing properties in the US Lower 48 and Canada. TNK-BP disposed of its interests in several non-core properties. In 2006, BP divested its producing properties on the Outer Continental Shelf of the Gulf of Mexico and its interest in the Statfjord oil and gas field in the UK. Our interests in the Boqueron, Desarollo Zulia Occidental (DZO) and Jusepin projects in Venezuela were reduced following a decision by the Venezuelan government. TNK-BP disposed of its non-core interests in the Udmurtneft assets. In 2005, BP divested the Teak, Samaan and Poui assets in Trinidad and sold interests in certain properties in the Gulf of Mexico. In addition, BP exchanged the Gulf of Mexico deepwater Blind Faith prospect for Kerr McGee s interest in the Arkoma Red Oak and Williburton fields, and TNK-BP disposed of non-core producing assets in the Saratov region.

[d] Volumes relate to six BP-operated fields within ETAP. BP has no interests in the remaining three ETAP fields, which are operated by Shell.

[e] Includes 54 net mboe/d of NGLs from processing plants in which BP has an interest (2006 55mboe/d and 2005 58mboe/d).

[f] The BP group holds interests, through associates, in onshore and offshore concessions in Abu Dhabi, expiring in 2014 and 2018 respectively. During the second quarter of 2007, we updated our reporting policy in Abu Dhabi to be consistent with general industry practice and as a result have started reporting production and reserves there gross of production taxes. This change resulted in an increase in our reserves of 153 million barrels and in our production of 33 thousand barrels per day (mb/d).

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## Natural gas

| | Field or Area | Interest (%) | 2007 | 2006 | 2005 |
|---|---|---|---|---|---|
| | | | million cubic feet per day BP net share of production[a] | | |
| Lower 48 onshore[b] | San Juan[c] | Various | **694** | 765 | 753 |
| | Arkoma[c] | Various | **204** | 225 | 198 |
| | Hugoton[c] | Various | **123** | 137 | 151 |
| | Tuscaloosa[c] | Various | **78** | 86 | 111 |
| | Wamsutter[c] | 70.5 | **120** | 113 | 110 |
| | Jonah[c] | 65.0 | **173** | 133 | 97 |
| | Other | Various | **458** | 461 | 465 |
| Total Lower 48 onshore | | | **1,850** | 1,920 | 1,885 |
| Gulf of Mexico deepwater[b] | Na Kika[c] | 50.0 | **50** | 97 | 133 |
| | Marlin[c] | 78.2 | **13** | 16 | 52 |
| | Other | Various | **205** | 210 | 235 |
| Gulf of Mexico Shelf[b] | Other | Various | **1** | 66 | 160 |
| Total Gulf of Mexico | | | **269** | 389 | 580 |
| Alaska | Various | Various | **55** | 67 | 81 |
| Total US | | | **2,174** | 2,376 | 2,546 |
| UK offshore[b] | Braes[d] | Various | **69** | 101 | 165 |
| | Bruce[c] | 37.0 | **72** | 107 | 161 |
| | West Sole[c] | 100.0 | **55** | 56 | 55 |
| | Marnock[c] | 62.0 | **25** | 42 | 47 |
| | Britannia | 9.0 | **37** | 42 | 46 |
| | Shearwater | 27.5 | **19** | 31 | 37 |
| | Armada | 18.2 | **16** | 28 | 30 |
| | Other | Various | **475** | 529 | 549 |
| Total UK | | | **768** | 936 | 1,090 |
| Netherlands[b] | P/18-2[c] | 48.7 | | 23 | 25 |
| | Other | Various | **3** | 33 | 37 |
| Norway | Various | Various | **26** | 35 | 46 |
| Total Rest of Europe | | | **29** | 91 | 108 |
| Australia | Various | 15.8 | **376** | 364 | 367 |
| Canada[b] | Various[c] | Various | **255** | 282 | 307 |
| China | Yacheng[c] | 34.3 | **85** | 102 | 98 |

| | | | | | |
|---|---|---|---|---|---|
| Egypt | Hapy[c] | 50.0 | **108** | 99 | 106 |
| | Other | Various | **206** | 172 | 83 |
| Indonesia | Sanga-Sanga(direct)[c] | 26.3 | **75** | 84 | 110 |
| | Other[c] | 46.0 | **81** | 80 | 128 |
| Sharjah | Sajaa[c] | 40.0 | **83** | 111 | 113 |
| | Other | 40.0 | **9** | 9 | 10 |
| Azerbaijan | Shah Deniz[c] | 25.5 | **73** | | |
| Trinidad & Tobago[b] | Kapok[c] | 100.0 | **984** | 946 | 1,005 |
| | Mahogany[c] | 100.0 | **454** | 321 | 303 |
| | Amherstia[c] | 100.0 | **155** | 176 | 289 |
| | Parang[c] | 100.0 | | 120 | 154 |
| | Immortelle[c] | 100.0 | **153** | 219 | 132 |
| | Cassia[c] | 100.0 | **25** | 30 | 83 |
| | Other[c] | 100.0 | **663** | 453 | 21 |
| Other[b] | Various | Various | **466** | 441 | 459 |
| Total Rest of World | | | **4,251** | 4,009 | 3,768 |
| Total group[e] | | | **7,222** | 7,412 | 7,512 |
| Equity-accounted entities (BP share) | | | | | |
| Argentina Pan American Energy | Various | Various | **379** | 362 | 343 |
| Russia TNK-BP[b] | Various | Various | **451** | 544 | 482 |
| Other[b] | Various | Various | **91** | 99 | 87 |
| Total equity-accounted entities[e] | | | **921** | 1,005 | 912 |

[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 2007, BP divested its producing properties in the Netherlands and some producing properties in the US Lower 48 and Canada. TNK-BP disposed of its interests in several non-core properties. In 2006, BP divested its producing properties on the Outer Continental Shelf of the Gulf of Mexico and its interest in the Statfjord oil and gas field in the UK. Our interests in the Boqueron, Desarollo Zulia Occidental (DZO) and Jusepin projects in Venezuela were reduced following a decision by the Venezuelan government. TNK-BP disposed of its non-core interests in the Udmurtneft assets. In 2005, BP divested the Teak, Samaan and Poui assets in Trinidad and sold interests in certain properties in the Gulf of Mexico. In addition, BP exchanged the Gulf of Mexico deepwater Blind Faith prospect for Kerr McGee s interest in the Arkoma Red Oak and Williburton fields, and TNK-BP disposed of non-core producing assets in the Saratov region.

[c] BP-operated.

[d] Includes 4 million cubic feet per day (mmcf/d) of natural gas received as in-kind tariff payments in 2005. None received in 2006 and 2007.

[e] 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.

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## United States

2007 liquids production at 513mb/d decreased 6% from 2006, while natural gas production at 2,174mmcf/d decreased 8% compared with 2006.

Crude oil production showed a moderate decline of 18mb/d from 2006, with production from new projects (Gulf of Mexico) being offset by divestments and natural reservoir decline. The NGLs component of liquids production decreased by 15mb/d, driven mainly by commercial changes in NGL processing contracts, natural reservoir decline and divestments. Gas production was lower (201mmcf/d) because of divestments and natural reservoir decline.

Development expenditure in the US (excluding midstream) during 2007 was $3,861 million, compared with $3,579 million in 2006 and $2,965 million in 2005. The annual increase is the result of various development projects in progress.

Our activities within the US take place in three main areas. Significant events during 2007 within each of these are indicated below.

### *Deepwater Gulf of Mexico*

Deepwater Gulf of Mexico is our largest area of growth in the US. In 2007, our deepwater Gulf of Mexico liquids production was 196mb/d and gas production was 268mmcf/d.

Significant events were:

- The Atlantis platform (BP 56% and operator) was successfully commissioned and started producing oil and gas during the fourth quarter of 2007. Atlantis employs the deepest moored platform of its kind in the world and a separate semi-submersible drilling and construction rig. The versatile modular design of the platform provides potential to add wells to increase recovery.
- At Thunder Horse (BP 75% and operator), as a result of a metallurgical failure during pre-commissioning checks in 2006, the decision was taken to repair all at-risk subsea components. All relevant components have been removed from the sea floor and progress made in reinstalling the repaired equipment. In 2007, the platform s drilling rig was commissioned and its first well successfully drilled and completed. Thunder Horse is expected to start production by the end of 2008. Designed to process 250,000 barrels of oil per day and 200 million cubic feet per day of natural gas, Thunder Horse is expected to be the largest field in the Gulf of Mexico. The field will be supported by a network of 25 subsea wells.
- In November, BP started production from two multi-phase subsea pump stations in the King field (BP 100% and operator). At a depth of 1,700 metres and 15 miles away from the Marlin platform, this sets a double world record for both depth and distance. The two pumps are expected to enhance production from the King field by an average of 20% and to extend the production life of the field by five years through improved recovery.
- BP was awarded 88 blocks in the western Gulf of Mexico lease sale and 83 blocks in the central Gulf of Mexico lease sale.
- On 6 June 2007, a discovery was made with the Isabela well (BP 67% and operator), located on Mississippi Canyon Block 562 in approximately 2,000 metres of water about 150 miles south-east of New Orleans.
- During the second quarter, we increased our ownership in Horn Mountain to 100% as part of an asset exchange agreement with Occidental Petroleum Corporation (Occidental).
- In April 2007, BP disposed of its 80% interest in the Entrada field to Callon Petroleum Company for a total price of $190 million.

### *Lower 48 states*

In the Lower 48 states (onshore), our 2007 natural gas production was 1,850mmcf/d, which was down 4% compared with 2006. Liquids production was 108mb/d, down 14% compared with 2006. The year-on-year decrease in production is mainly attributed to normal field decline and divestment activity. In 2007, we drilled approximately 400 wells as operator and continued to maintain a stable programme of drilling activity throughout the year.

Production is derived primarily from two main areas:

- In the western basins (Colorado, New Mexico and Wyoming) our assets produced 222mboe/d in 2007.
- In the Gulf Coast and mid-continental basins (Kansas, Louisiana, Oklahoma and Texas) our assets produced 203mboe/d in 2007.

The development of recovery technology continues to be a fundamental strategy in accessing our North America tight gas resources. Through the use of horizontal drilling and advanced hydraulic fracturing techniques, we are achieving well rates up to 10 times higher than more conventional techniques and per-well recoveries some five times higher.

Significant events were:

- In January 2007, we announced our investment of up to $2.4 billion expected over 13 years in the coalbed methane field development project in the San Juan basin in Colorado. The project includes the drilling of more than 700 wells, nearly all from existing well sites, and the installation of associated field facilities.
- 

Drilling continued during 2007 on the Wamsutter natural gas expansion project. The multi-year drilling programme is expected to increase production significantly by the end of 2010. We are currently testing horizontal fracturing technology and carrying out wireless seismic studies on the reservoir.

– Significant progress has been made on decommissioning the Gulf of Mexico Shelf hurricane-damaged platforms, which is on track for completion in 2010. This work has been carried out almost exclusively using a diverless access approach, significantly reducing exposure to safety issues associated with diving. Late in 2007, we signed an agreement with Wild Well Control, an affiliate of Superior Energy Services, to sell seven damaged platforms and 59 associated wells and consequentially to transfer the decommissioning liability to them. They will assume responsibility for plugging and abandonment of all wells, salvage and removal or reefing of the damaged platforms and related facilities, and restoration of all sites.
– In 2007, BP divested its non-core Permian assets as part of the asset exchange agreement with Occidental. In consideration, BP received the remaining one-third interest in the Horn Mountain field in the Gulf of Mexico and approximately $100 million cash.
– In the third quarter of 2007, we ceased operations at the Whitney Canyon gas plant located near Evanston, Wyoming. By doing this we expect to extend the economic life of the field by re-routing the natural gas processed at the Whitney Canyon gas plant to Chevron s Carter Creek gas plant. BP intends to continue to operate the 28 wells in the Whitney Canyon field and the inlet facility, as well as the nearby Painter Complex gas plant.

*Alaska*

In Alaska, BP net oil production in 2007 was 209mboe/d, a decrease of 7% from 2006, due to normal decline in the large mature fields, partially offset by lower downtime.

BP operates 13 North Slope oil fields (including Prudhoe Bay, Northstar and Milne Point) and four North Slope pipelines and owns a significant interest in six other producing fields. BP s 26.4% interest in Prudhoe Bay also includes a large undeveloped natural gas resource. Developing viscous oil production and unlocking large undeveloped heavy oil resources through the application of advanced technology are important parts of the Alaska business strategy.

Significant events in 2007 were:

– On 20 June 2007, the Prudhoe Bay field and the Trans Alaska Pipeline System (TAPS) celebrated the 30th anniversary of first production from the North Slope of Alaska. The original expectations for Prudhoe Bay were to drill 500 wells, produce for 20 years and recover 9 billion boe of hydrocarbon resources. After 30 years, more than 2,500 wells have been drilled, more than 11.5 billion boe have been recovered to date, and the field is expected to continue to produce for another 50 years or more. Prudhoe Bay production averaged 400mboe/d (gross) in 2007, with BP s net share being 102mboe/d. Overall, downtime during the year was consistent with plans for normal maintenance activity and there were no large unplanned production disruptions.

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– In 2007, we spent more than $250 million (BP net) in Alaska on a programme to upgrade or replace pipelines, increase inspection and corrosion monitoring, carry out preventative maintenance and repairs, expand capacity, and improve the efficiency of major facilities in all BP-operated fields.
– We have also made progress on the replacement of sections of oil transit lines in the Prudhoe Bay field, which for these transit lines has included adding pipeline pigging facilities to clean and inspect pipelines, direct corrosion inhibitor injection, new leak detection and corrosion monitoring systems. We aim to complete this activity in 2008.
– On 16 February 2007, BP temporarily shut down its Northstar production facility for 18 days to repair welds in the low pressure gas piping system. The facility was restarted on 6 March. The full-year impact of the production disruption resulting from this shutdown was more than offset by the beneficial impacts of an earlier-than-planned restart of the Milne Point K Pad pipeline replacement and strong reservoir performance throughout 2007 at Prudhoe Bay and Kuparuk.
– On 25 October 2007, BP Exploration Alaska (BPXA) entered into a plea agreement with the US Department of Justice (DOJ), which ended both federal and state government criminal investigations of BPXA on matters related to the March and August 2006 oil transit line spills in Alaska. On 29 November 2007, in accordance with the agreement, BPXA pleaded guilty to a misdemeanour violation of the US Federal Water Pollution Control Act. BPXA paid a $12 million (gross) fine and is subject to one-to-three years probation. BPXA also paid restitution of $4 million (gross) to the State of Alaska and paid another $4 million (gross) to the National Fish and Wildlife Foundation for Arctic environmental research. The DOJ and the State of Alaska have agreed not to bring any further criminal charges against BPXA in connection with the March and August 2006 spills.
– On 2 June 2007, the Alaska Gasline Inducement Act (AGIA) was passed into law. AGIA sets out the terms and conditions for application for the exclusive right to build a natural gas pipeline to transport North Slope gas to market. BP stated publicly that it cannot submit a conforming bid under AGIA because of, in its view, unresolved risks and uncertainties related to project costs, fiscal terms and pipeline tariffs. BP continues to develop and assess options for commercializing the major undeveloped gas resources on Alaska s North Slope.
– On 16 November 2007, the Alaska State Legislature passed a new petroleum production tax law, which replaced the Petroleum Production Tax legislation enacted in 2006. The new legislation increases production taxes and is effective retrospectively from 1 July 2007. The key terms of the new production tax law include a base oil tax rate of 25% on net profits, with progressive increases expected in the oil tax rate as the net margin increases above $30/bbl. The new production tax law will be governed by regulations to be defined and promulgated in 2008 by the Alaska State Department of Revenue.
– On 26 December 2007, the Alaska Superior Court issued a ruling reversing the 2006 decision by the Department of Natural Resources (DNR) to terminate the Point Thomson Unit and remanded the matter to the DNR to provide the leaseholders their constitutional due process rights, including the right to a hearing. Although the judge s decision found that the DNR s rejection of the latest plan of development (POD) was supported by substantial evidence, the ruling reinstated the leaseholders interests in the Point Thomson leases and unit, and instructed the DNR to consider good and diligent oil and gas . . . production practices in shaping an appropriate remedy for the rejected POD. The DNR is expected to call a hearing during the first quarter of 2008.
– On 3 October 2007, the Endicott field achieved its 20th year of production. Since start-up in 1987, Endicott has produced 500mmboe. During 2007, Endicott commenced a technology trial programme that is expected to progress BP s LoSal™ Enhanced Oil Recovery process from technology development to technology deployment. LoSal™ is a patented technology that utililizes geochemically specific waters to attack the larger remaining residual oils present after conventional waterflooding. To gain partner approval for a full-field deployment, an

interwell programme has been started at Endicott. Results from this programme are expected in the second half of 2008 and are expected to lead to a full-field project commitment in 2009. The LoSal²™ technology has implications for many fields beyond BP s Alaska portfolio and the work at Endicott and in Alaska will be extrapolated to BP s global portfolio.
– On 3 January 2008, the US Minerals Management Service approved BP s development and production plan for the Liberty field. During 2007, $25 million was spent on pre-project planning for Liberty, including engineering, environmental studies and permit applications. Development plans for Liberty, which lies offshore to the east of the Endicott field, include ultra-extended reach wells to be drilled from pads at Endicott and processing Liberty oil production through existing Endicott facilities.

## United Kingdom

We are the largest producer of oil, second largest producer of gas and the largest overall producer of hydrocarbons in the UK. In 2007, total liquids production was 201mb/d, a 20% decrease on 2006, and gas production was 768mmcf/d, an 18% decrease on 2006. This decrease in production was driven by natural decline and the unplanned shutdown of the Central Area Transmission System (CATS) pipeline. Our activities in the North Sea are focused on safe operations, efficient delivery of production and midstream operations, in-field drilling and selected new field developments. Our development expenditure (excluding midstream) in the UK was $804 million in 2007, compared with $794 million in 2006 and $790 million in 2005.

Significant events in 2007 were:

– During the second quarter, we announced the decision not to proceed with the decarbonized fuel DF1 project in Scotland. This project was being led by BP, in partnership with Scottish and Southern Energy, and would have produced hydrogen as a decarbonized fuel for use in power generation, with the carbon dioxide ($CO_2$) gases being exported to the Miller oil reservoir in the North Sea for increased oil recovery and ultimate storage. Significant investment had been made in front- end engineering and design activity. Development of the project was originally planned to begin at the end of 2006 and required UK government support. In May, the UK government announced that it would not decide which carbon capture storage project to support until 2008 at the earliest. The timing of this decision did not fit with the DF1 project timeline, which was constrained by the maturity of the Miller oil field, and therefore the decision was taken not to proceed. The Miller field, which began production in 1992, has now ceased production and decommissioning activity is in the planning stage.
– We sanctioned the Dimlington Onshore Compression and Terminals Integration project, a $250-million investment in new gas compression facilities at the BP-operated Dimlington Terminal, which receives gas from fields in the southern North Sea. This new equipment is expected to reduce pipeline pressure between the offshore fields and the terminal, allowing the gas fields to increase production. BP expects remaining recoverable reserves in the West Sole and Amethyst fields to increase by around 30% as a result of this project.
– In October, we announced changes to the structure of the North Sea operations that are intended to simplify the organization and improve the efficiency of work processes in response to the challenges of the increasingly mature North Sea, where declining production and rapidly- rising costs have created business conditions that are not sustainable in the long term. The new structure will mean fewer organizational units and reduced management layers. This will allow consolidation of onshore non-technical support activities, leading to economies of scale and reduced complexity.

### Rest of Europe

Development expenditure (excluding midstream) in the Rest of Europe was $443 million, compared with $214 million in 2006 and $188 million in 2005.

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*Norway*

In 2007, our total production in Norway was 56mboe/d, a 15% decrease on 2006. This decrease in production was driven by natural decline.

Significant activities were:

– Progress on the Valhall (BP 28.1% and operator) redevelopment project continued during 2007. A new platform is scheduled to become operational in 2010, with expected oil production capacity of 150mb/d and gas handling capacity of 175mmcf/d.
– In June, we announced the sanction of the combined Skarv and Idun development. This development is located in the Norwegian Sea approximately 200 kilometres west of Sandnessjøen. The fields will be developed using a Floating Production Storage and Offloading vessel (FPSO), subsea wells and an 80-kilometre gas export pipeline connecting to the Asgard Transport System.

*Netherlands*

On 1 February 2007, we completed the sale of our exploration and production and gas infrastructure business in the Netherlands to the Abu Dhabi National Energy Company, TAQA. This included onshore and offshore production assets and the onshore gas storage facility, Piek Gas Installatie, at Alkmaar.

Rest of World

Development expenditure in Rest of World (excluding midstream) was $5,045 million in 2007, compared with $4,522 million in 2006 and $3,735 million in 2005.

*Rest of Americas*

Canada

In Canada, our natural gas and liquids production was 52mboe/d in 2007, a decrease of 9% compared with 2006. The year-on-year decrease in production is mainly due to natural field decline.

In January 2008, we sanctioned the Noel Cadomin sweet gas project. A total of 130 wells are planned to be drilled with first production expected in 2009.

The Mist Mountain coalbed gas project is in the appraisal stage, which is expected to last for a number of years. The purpose of this stage is to assess the viability of coalbed gas production in British Columbia s Crowsnest coalfield by proving technologies and practices that will allow for the design of an environmentally sustainable commercial project. We are seeking British Columbia government approval to access public land for this project.

On 5 December 2007, BP announced it had signed a memorandum of understanding with Husky Energy Inc. to form an integrated North American oil sands business. The transaction is expected to be completed by the end of March 2008.

Trinidad

In Trinidad, natural gas production volumes increased by 7.5% to 2,434mmcf/d in 2007. The increase was delivered as a result of improved operating efficiency leading to increased throughput for Atlantic LNG Train 4, increased demand from the domestic market, full ramp up of the Cannonball field and the start-up of two new fields in 2007. Liquids production declined by 10mb/d (25%) to 30mb/d in 2007 from 40mb/d in 2006 as a result of the natural decline from high condensate fields.

The Mango and Cashima fields reached first gas on 17 November 2007 and 15 December 2007 respectively. Mango and Cashima were designed and built in Trinidad using a standardized design with 85% of fabrication hours and 65% of project management hours contributed by local Trinidad workers.

Venezuela

In Venezuela, due to the transition to the incorporated joint venture (IJV) entities in accordance with Venezuelan regulations that came into force in 2006, 2007 was the first full year of reduced interest. As a result of the aforementioned, and the OPEC quotas, our 2007 liquids production decreased by 10mb/d compared with 2006.

– On 26 June 2007, BP agreed to the migration of the Cerro Negro operations to an IJV without diluting its interest and signed a binding memorandum of understanding reflecting agreement to the significant terms and conditions for migration to, and operation of, the IJV. Signature of the final conversion contract, and finalization of the rest of the required procedures, is expected to take place in the first quarter of 2008.

Colombia

In Colombia, BP s net production averaged 46mboe/d. The reduction of 4mboe/d compared with 2006 is mainly due to natural field decline, partially compensated by additional gas sales. The main part of the production comes from the Cusiana, Cupiagua and Cupiagua South fields, with increasing new production from the Cupiagua extension into the Recetor Association Contract and the Floreña and Pauto fields in the Piedemonte Association Contract.

In September, BP was awarded two offshore blocks in the Caribbean that cover approximately 6,200 square kilometres. One block, RC4 (BP 35% and operator), will be a joint venture with state-owned Ecopetrol and Petrobras, while BP will have sole rights to develop the other, RC5 (BP 100% and operator).

In December 2006, the Colombian Congress passed new legislation to reduce corporate income taxes from 35% to 34% in 2007 and 33% in 2008.

After months of negotiations with Ecopetrol, agreement around extension of the current association contracts was not reached. However, new commercial agreements are in the final stages of negotiation to allow partners to access new investment opportunities.

Argentina and Bolivia

In Argentina and Bolivia, activity is conducted through Pan American Energy (PAE), in which BP holds a 60% interest, and which is accounted for by the equity method since it is jointly controlled. In 2007, total PAE gross production of 264mboe/d represented an increase of 1% over 2006. This increase came from the continued focus on drilling in Golfo San Jorge in Argentina. The field is now producing at its highest level since inception in 1958 and further expansion programmes are planned. PAE also has interests in gas pipelines, electricity generation plants and other midstream infrastructure assets.

On 27 April, PAE entered into an agreement with the Argentine province of Chubut, which provides for the concession term extension and includes certain investment commitments related to exploration and production on the Cerro Dragón block, located in Golfo San Jorge basin. On 25 June, PAE signed a similar agreement with Santa Cruz province. These are the first agreements entered into to extend the term of concessions in Argentina, and were formalized under the framework established by a law recently passed by the Argentine Congress that will allow PAE to undertake long-term projects.

On 13 July, PAE signed a loan agreement with the International Finance Corporation (IFC) for the amount of $550 million. This loan will be used to finance a programme of capital investment in the Cerro Dragón block in Argentina. The last tranche will mature in April 2018.

On 2 May, following notarization, the new agreements entered into by PAE and other oil and gas companies with Yacimientos Petroliferos Fiscales Bolivianos (YPFB) in Bolivia in November 2006 became effective. These agreements are intended to run until 31 December 2026 and establish the commitment assumed by each of the companies to supply the Bolivian domestic gas market. YPFB will be responsible for marketing all hydrocarbons produced in Bolivia and for determining the terms of relevant gas sales contracts. Along with these changes, the volumes that Chaco (an exploration and production company operated in Bolivia owned 50% by PAE and 50% by YPFB, 30% BP net) is allowed to export have been significantly increased resulting in higher overall gas sales realizations for Chaco.

In a continuation of changes made to the export tax since its inception in 2002, the Argentine government issued a resolution in November 2007 increasing the export tax rate on oil when the international crude oil price is US$60.9/bbl or higher.

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*Africa*

Algeria

BP, through its joint operatorships of the In Salah Gas (33.15%) and In Amenas (12.50%) projects, supplied 83bcf (BP net) of gas to markets in Algeria and southern Europe during 2007, an increase of 33% from 2006 due to the ramp up of In Amenas during 2007. The $CO_2$ capture system, part of the In Salah project, is one of the world s largest $CO_2$ capture projects.

Angola

In Angola, BP net production in 2007 was 139mboe/d, an increase of 5% from 2006 due to the start up of the Greater Plutonio, Marimba and Rosa fields, and the ramp up of Dalia, more than offsetting PSA changes in the Kizomba A, Kizomba B and Girassol fields.

The first lifting from the Dalia field (BP 16.67%) was achieved during the first quarter of 2007, with gross field production ramping up to 245mb/d by the end of 2007. The Dalia field was discovered in 1997. It entered project execution phase in the first half of 2003 and production began on 13 December 2006.

During the second quarter, the Rosa project (BP 16.67%) achieved first production. Discovered in January 1998, some 135 kilometres off the coast of Angola in water depths of approximately 1,350 metres, the Rosa field is located 15 kilometres away from the Girassol FPSO to which it is tied back. It is the first deepwater field of this size to be tied back to such a remote installation and in such water depths. Rosa is expected to maintain the FPSO s production capacity above250mb/d until early in the next decade.

Oil production at the Greater Plutonio offshore development area in Block 18 began in October 2007. The five fields making up the Greater Plutonio development were discovered between 1999 and 2001 in water depths of up to 1,450 metres and it is the first BP-operated asset in Angola (BP 50% and operator). The development utilizes an FPSO connected to the wells by a large subsea system. The subsea system is expected to ultimately encompass 43 wells and the longest single-riser tower system of its kind in the world. Many components of the project were constructed in Angola including the world s largest Caternary Anchor Leg Mooring (CALM) buoy.

In October, production commenced from the Marimba North project (BP 26.67%), in Block 15. The field is in approximately 1,300 metres of water more than 145 kilometres off the coast of Angola. The Marimba North project is a tie-back to the Kizomba A development. The Marimba North production and control facilities have been integrated with the existing Kizomba A development to effectively and cost efficiently utilize the existing field facilities. Start-up of the field was achieved safely without any production impact to the Kizomba A operations.

In the ultra deepwater Block 31 there were three exploration successes, Miranda, Cordelia and Portia, bringing the total for Block 31 to 15. The Miranda well is located in a water depth of approximately 2,436 metres, some 375 kilometres northwest of Luanda. The Cordelia well is located in a water depth of approximately 2,308 metres, some 371 kilometres northwest of Luanda. The Portia well is located in a water depth of approximately 2,012 metres, some 386 kilometres northwest of Luanda.

In August, the Pazflor Project in Angola Block 17 (BP 16.67%) was sanctioned. Pazflor will be a standalone FPSO development, the third major production hub in Block 17, and is expected to deliver first oil in 2011. The development will be based on a new-build FPSO with subsea wells, rigid flowlines and subsea processing.

In January 2008, production began at the Mondo field (BP 26.67%) in Block 15. Located in water depths of approximately 800 metres, the field utilizes an FPSO and has a total of 36 subsea wells.

Egypt

In Egypt, BP net production was 97mboe/d, an increase of 10% from 88mboe/d in 2006. This increase was mainly due to an increase in the number of producing wells and the benefit of full-year production from producing wells drilled in 2006.

In Egypt, the Gulf of Suez Petroleum Company (GUPCO) (BP 50%), a joint venture operating company between BP and the Egyptian General Petroleum Corporation (EGPC), carries out our operated oil and gas production operations. GUPCO operates eight PSAs in the Gulf of Suez and Western Desert and one PSA in the Mediterranean Sea, encompassing a total of more than 40 fields.

Progress continued on the Saqqara field (BP 100%) development project, with first production expected in 2008.

Progress continued on the Egypt Gas Phase 1 (Taurt) (BP 50%) development project, with first production expected in 2008.
In January 2007, BP drilled a successful well, Giza North-1, in the North Alexandria concession (BP 60% and operator) held by BP, RWE DEA and EGPC/The Egyptian Natural Gas Holding Company (EGAS). The Giza North-1 was drilled in 668 metres of water, some 56 kilometres offshore in the Pliocene formation where BP has made three previous discoveries.
In May 2007, BP drilled a successful well, Taurus Deep, in the North Alexandria A Concession (BP 60% and operator) held by BP, RWE DEA and EGPC. The Taurus Deep well was drilled in approximately 400 metres of water, some 70 kilometres offshore, and is in the Middle Miocene formation.
In January 2008, BP finished drilling a successful well, Satis-1, in the North El Burg offshore concession (BP 50% and operator) held by BP, IEOC and EGAS. The Satis-1 well was drilled in approximately 90 metres of water, some 50 kilometres offshore, and is in the Oligocene formation.
In December 2007, BP had first production from the Denise field where it holds a 50% interest.

Libya

In May, BP and its partner, the Libyan Investment Corporation (LIC) signed a major exploration and production agreement with Libya sNational Oil Company. The initial exploration commitment is set at a minimum of $900 million with significant appraisal and development expenditures dependent on exploration success. BP and the LIC will explore over 53,000 square kilometres of the onshore Ghadames and offshore frontier Sirt basins. Successful exploration could lead to the drilling of around 20 appraisal wells. The agreement was ratified by the Libyan General People s Council on 23 December.

*Asia Pacific*

Indonesia

BP produces crude oil and supplies natural gas to the island of Java through its holding in the Offshore Northwest Java PSA (BP 46%). In 2007, BP net production was 39mboe/d, a decrease of 8.8% from 43mboe/d in 2006 as a result of a higher-than-forecasted base decline, unplanned losses and the impact of higher realizations on the PSA.
During 2007, development continued on the Tangguh LNG project (BP 37.2% and operator). The project development includes offshore platforms, pipelines and an LNG plant with two production trains. First commercial delivery is expected in early 2009.

Vietnam

BP participates in one of the country s largest projects with foreigninvestment, the Nam Con Son gas project. This is an integrated resource and infrastructure project, including offshore gas production, a pipeline transportation system and power plant. In 2007, BP net natural gas production was 82mmcf/d gross, a decrease of 15% over 2006. This decrease was mainly due to higher supply from another gas field brought onstream in late 2006. Gas sales from Block 6.1 (BP 35% and operator) are made under a long-term agreement for electricity generation in Vietnam, including the Phu My Phase 3 power plant (BP 33.3%).

China

In 2007, natural gas production was 85mmcf/d BP net, a decrease of 17% over 2006. This decrease was mainly due to the closure of a Rate Acceleration Agreement with a key customer at the end of 2006.

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The Yacheng offshore gas field (BP 34.3%) supplies, under a long-term contract, 100% of the natural gas requirement of Castle Peak Power Company, which provides around 50% of Hong Kong selectricity. Some natural gas is also piped to Hainan Island, where it is sold to the Fuel and Chemical Company of Hainan, also under a long- term contract.

In March, the National People s Congress reduced the rate ofcorporation tax from 33% to 25% with effect from 1 January 2008.

Australia

In Australia, BP net gas production in 2007 was 376mmcf/d, an increase of 3.3% from 2006 due to increased domestic gas demand in Western Australia. BP net liquids production at 34mb/d remained unchanged from 2006.

BP is one of seven partners in the North West Shelf (NWS) venture. Six partners (including BP) hold an equal 16.7% interest in the infrastructure and oil reserves and an equal 15.8% interest in the gas and condensate reserves with a seventh partner owning the remaining 5.32% of gas and condensate reserves. The operation covers offshore production platforms, an FPSO, trunklines and onshore gas processing plants. The NWS venture is currently the principal supplier to the domestic market in Western Australia. During 2007, progress continued on the construction of a fifth LNG train (4.7 million tonnes per year design capacity), with first throughput expected in the second half of 2008.

*Russia*

TNK-BP

TNK-BP, a joint venture between BP (50%) and Alfa Group and Access-Renova (AAR) (50%), is an integrated oil company operating in Russia and the Ukraine. The TNK-BP group s major assets are held inOAO TNK-BP Holding. Other assets include the BP-branded retail sites in Moscow and the Moscow region and interests in OAO Rusia Petroleum and the OAO Slavneft group. The workforce comprises more than 60,000 people.

BP s investment in TNK-BP is held by the Exploration and Productionsegment and the results of TNK-BP are accounted for under the equity method in this segment.

TNK-BP has proved reserves of 6.9 billion barrels of oil equivalent (including its 49.9% equity share of Slavneft), of which 4.5 billion are developed. In 2007, TNK-BP s average liquids production was1.7mmboe/d, a decrease of just over 5% compared with 2006, reflecting the disposal of the Udmurt asset in 2006. The production base is largely centred in West Siberia (Samotlor, Nyagan and Megion), which contributes about 1.2mmboe/d, together with Volga Urals (Orenburg) contributing some 0.4mmboe/d. About 44% of total oil production is currently exported as crude oil and 19% as refined product.

Downstream, TNK-BP has interests in six refineries in Russia and the Ukraine (including Ryazan and Lisichansk and Slavneft s Yaroslavl refinery), with throughput of approximately 35 million tonnes per year. During December 2007, TNK-BP agreed to purchase additional retail and other downstream assets in Russia and the Ukraine from a number of small companies with completion due in 2008. TNK-BP supplies approximately 1,600 branded filling stations in Russia and the Ukraine and, with the additional sites, is expected to have more than 20% market share of the Moscow retail market.

In January 2007, TNK-BP announced the purchase of Occidental s50% interest in the West Siberian joint venture, Vanyoganneft, for $485 million. The transaction closed during the first quarter of 2007 and TNK-BP now owns 100% of the Vanyoganneft asset.

On 22 June, BP and TNK-BP signed heads of terms to create strategic business alliances with OAO Gazprom. Under the terms of this agreement, TNK-BP agreed to sell to Gazprom its 62.89% stake in OAO Rusia Petroleum, the company that owns the licence for the Kovykta gas condensate field in East Siberia and its 50% interest in East Siberia Gas Company (ESGCo). BP and TNK-BP have an option to repurchase on market terms up to 25% + 1 share in OAO Rusia Petroleum and up to 25% of ESGCo in the event that a strategic business alliance is subsequently established with OAO Gazprom.

In November 2006, following a review of the results of an inspection by the licensing authorities that had resulted in a request for the revocation of the two licences held by TNK-BP subsidiary Rospan International, an agreed rectification plan was put in place. All the Rospan licence compliance issues arising from the inspection by the licensing authorities in 2006 are now substantially resolved.

Sakhalin

BP participates in the KV licence area in offshore Sakhalin where it conducts exploration activities through Elvaryneftegas (BP 49%), an equity-accounted joint venture with Rosneft. Two discoveries have been made to date in the KV licence area. BP also participates in joint operations in two licence areas with Rosneft in East and West Shmidt (BP 49%).

Exploratory drilling continued in 2007 with the drilling of two wells in the West Shmidt licence area. Both wells were found to be dry and, as a result, BP wrote off all expenditures related to the West Shmidt licence area.

The 2008 work programme for the Sakhalin licence includes seismic re-processing in the East Shmidt licence area and a 2D seismic acquisition programme in the KV licence area. No drilling is planned for 2008.

*Other*

Azerbaijan

In Azerbaijan, BP net production in 2007 was 218mboe/d, an increase of 50% from 2006 due to the ramping up of three Azeri oil producing platforms and the Shah Deniz condensate gas platform commencing production in 2007.

BP, as operator of the Azerbaijan International Operating Company (AIOC), manages and has a 34.1% interest in the Azeri-Chirag- Gunashli (ACG) oil fields in the Caspian Sea, offshore Azerbaijan. Phase 3 of the project, which will develop the deepwater Gunashli area of ACG, remains on schedule to begin production in 2008 with platform topsides having been completed in September 2007.

BP is the operator of Shah Deniz (BP 25.5%), which is in the Azerbaijan sector of the Caspian Sea and will deliver gas to markets in Azerbaijan, Georgia and Turkey. First gas to Turkey was achieved in July 2007. Production from the field is expected to continue to ramp up as further wells are brought onstream. Plateau production from Stage 1 is expected to be 6.9 billion cubic metres of gas per annum and approximately 30,000 barrels of condensate per day.

In November, we announced a further major new gas-condensate discovery in the Shah Deniz field in the Caspian Sea. The SDX-04 exploration and appraisal well, some 70 kilometres south-east of Baku, discovered a new deeper structure below the currently producing reservoir. Drilled to a Caspian-record depth of more than 7,300 metres in the south-western part of Shah Deniz, the well encountered gas condensate in the main target horizons extending the field to the south. The well also discovered a new high pressure reservoir in a deeper structure.

Middle East and south Asia

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 14.7% in onshore and offshore concessions respectively. In 2007, BP s share of production in Abu Dhabi was 192mb/d, down 3% from 2006 as a result of a major planned maintenance shutdown in the offshore concession in the fourth quarter of 2007.

In Pakistan, BP doubled its equity in the onshore Badin asset (BP 84%) as part of an international asset exchange with Occidental. As a result of this transaction, BP net oil production in 2007 was 6.3mboe/d, an increase of 24% from 2006, and BP net gas production was 122mmcf/d, an increase of 39.4% from 2006.

In the third quarter of 2007, BP signed a farm-in agreement with Petroleum Exploration (Private) Limited to obtain a 33% participating

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interest in Blocks P, J and O in the deepwater Indus basin offshore Pakistan.

In January 2007, BP signed a major PSA with the Sultanate of Oman to appraise sour tight gas reservoirs in Block 61. Major contracts were awarded in November with 3D seismic planned to commence in the first quarter of 2008 and drilling in the fourth quarter of 2008. The full appraisal programme is expected to take up to six years.

In September, BP signed a memorandum of understanding with Oil and Natural Gas Corporation Ltd of India regarding co-operation in coalbed methane and deepwater offshore exploration.

**Midstream activities**

Oil and natural gas transportation

The group has direct or indirect interests in certain crude oil transportation systems, the principal ones being the Trans Alaska Pipeline System (TAPS) in the US and the Forties Pipelines System (FPS) in the UK sector of the North Sea. We also operate the Central Area Transmission System (CATS) for natural gas in the UK sector of the North Sea.

BP, as operator, manages and holds a 30.1% interest in the Baku-Tbilisi-Ceyhan (BTC) oil pipeline. BP, as operator of AIOC, also operates the Western Export Route Pipeline between Azerbaijan and the Black Sea coast of Georgia and the Azeri leg of the Northern Export Route Pipeline between Azerbaijan and Russia. Revenue is earned on pipelines through charging tariffs.

BP s onshore US crude oil and product pipelines and related transportation assets are included under Refining and Marketing (see page 26).

Assets and activity during 2007 included:

*Alaska*

BP owns a 46.9% interest in TAPS, with the balance owned by four other companies. Production transported by TAPS from Alaska North Slope fields averaged 738mb/d during 2007.

Work on the strategic reconfiguration project to upgrade and automate four pump stations continued to progress during 2007. This project will install electrically-driven pumps at four critical pump stations, combined with increased automation and upgraded control systems. Two of the reconfigured pump stations came online during 2007, one in the first quarter and another in the fourth quarter. The remaining two reconfigured pump stations are expected to come online sequentially in 2009 and 2010.

There are a number of unresolved challenges lodged by instate refiners, Tesoro and Flint Hills, against BP and the other TAPS carriers, regarding intrastate tariffs charged for shipping oil through TAPS. These challenges were filed between 1986 and 2003 with the Regulatory Commission of Alaska (RCA). In 2002, the RCA determined that TAPS transportation rates charged since the beginning of 1997 have been excessive and that refunds should be paid. Proceedings relating to transportation charges covering the period between 1986 and mid-2003, including an appeal by BP and the other TAPS carriers of the RCA s 2002 determination, are progressing through the Alaska judicial system. No significant refunds have been paid pending the resolution of these matters in the courts. In the interim, the RCA has imposed intrastate rates effective from 1 July 2003 that are consistent with its 2002 order. Intrastate transport makes up roughly 7% of total TAPS throughput.

Tariffs for interstate and intrastate transportation on TAPS are calculated using the RCA and Federal Energy Regulatory Commission (FERC)-accepted TAPS Settlement Methodology (TSM) entered into with the State of Alaska in 1985. The State of Alaska, Anadarko and Tesoro have challenged BP s and the other TAPS carriers 2005, 2006 and 2007 interstate tariffs with the FERC, and the State of Alaska and Anadarko have challenged BP s and the other TAPS carriers 2008 tariffs with the FERC. The challengers assert that the interstate transportation rates charged by BP (in accordance with the TSM) and the other TAPS carriers, are excessive and discriminatory and in violation of the Interstate Commerce Act, and that costs related to the TAPS Strategic Reconfiguration project were imprudently incurred.

That portion of the challenges filed by the State, Anadarko and Tesoro relating to the TAPS Strategic Reconfiguration project costs, together with all aspects of the 2007 challenges, are being held in abeyance by the FERC until its decision on 2005 and 2006 rates is issued. There have been no proceedings in the recently filed challenges to BP s 2008 FERC tariff. The FERC s hearings on the consolidated proceedings commenced in October 2006 and concluded in January 2007. On 17 May 2007, a FERC Administrative Law Judge issued an Initial Decision as to 2005 and 2006 rates. This Initial Decision, which was adverse to BP and the other TAPS carriers, is now under consideration by the FERC Commissioners, who will issue the decision of the FERC. Pending the decision of the FERC Commissioners, BP is continuing to collect its TSM-based interstate tariffs; however, our tariffs are subject to refund depending on the decision of the FERC. Interstate transport makes up roughly 93% of total TAPS throughput.

*North Sea*

FPS (BP 100%) is 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 2007 at 653mb/d. The tie-in of the Buzzard field was completed, with first Buzzard production flowing through the system in January 2007. The Greater Kittiwake Area also joined the system in late 2007.

BP operates and has a 29.5% interest in 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 2007, throughput was 778mmcf/d (gross), 230mmcf/d (net). During September, the CATS pipeline resumed operation after divers installed a metal sleeve at the location where a large vessel had dragged its anchor causing damage to the pipeline. The pipeline was shutdown for 10 weeks resulting in a loss of production of 11mboe/d for the year.

BP operates the Dimlington/Easington gas processing terminal (BP 100%) on Humberside and the Sullom Voe oil and gas terminal in Shetland.

*Asia (including the former Soviet Union)*

BP, as operator, manages and holds a 30.1% interest in the BTC oil pipeline. The 1,768-kilometre pipeline has a capacity of 1mmboe/d from the BP-operated ACG oil field in the Caspian Sea to the eastern Mediterranean port of Ceyhan. In the first quarter of 2007, the BTC pipeline celebrated the loading of its 100-millionth barrel at the Ceyhan terminal and loaded its 250th tanker in October 2007.

Transportation of first gas to Turkey from Shah Deniz in Azerbaijan via the South Caucasus Pipeline was achieved in July 2007. BP is technical operator and holds a 25.5% interest.

Through the LukArco joint venture, BP holds a 5.75% interest (with a 25% funding obligation) in the Caspian Pipeline Consortium (CPC) pipeline. CPC is a 1,510-kilometre pipeline from Kazakhstan to the Russian port of Novorossiysk and carries crude oil from the Tengiz field (BP 2.3%). In addition to our interest in LukArco, we hold a separate 0.87% interest (3.5% funding obligation) in CPC through a 49% holding in Kazakhstan Pipeline Ventures. In 2007, CPC total throughput reached 33.03 million tonnes. During 2007, shareholders agreed to restore the profitability of CPC by increasing the CPC tariff and cutting interest rates on shareholder loans. Negotiations continued between the CPC shareholders on an expansion plan and a plan for financial restructuring. The expansion would require the construction of 10 additional pump stations, additional storage facilities and a third offshore mooring point.

**Liquefied natural gas**

Within BP, Exploration and Production is responsible for the supply of LNG. BP s Exploration and Production segment has interests in four major LNG plants: the Atlantic LNG plant in Trinidad (BP 34% in Train 1, 42.5% in each of Trains 2 and 3 and 37.8% in Train 4); in Indonesia,

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through our interests in the Sanga-Sanga PSA (BP 38%), which supplies natural gas to the Bontang LNG plant, and Tangguh PSA (BP 37.2%), which is under construction; and in Australia through our share of LNG from the NWS natural gas development (BP 16.7% infrastructure and oil reserves and 15.8% gas and condensate reserves).

Assets and activity during 2007 included:

– In Trinidad, the Atlantic LNG Train 4 (BP 37.8%) is the largest producing LNG train in the world and is designed to produce 5.2 million tonnes (253,000mmcf) per year of LNG. BP expects to continue to supply at least two-thirds of the gas to the train. The Atlantic LNG Trains 2, 3, and 4 facilities are operated under a tolling arrangement, with the equity owners retaining ownership of their respective gas. The LNG is sold in the US, Dominican Republic and other destinations. BP s net share of the capacity of Atlantic LNG Trains 1, 2, 3 and 4 is 6.5 million tonnes (310,000mmcf) of LNG per year.
– 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 14% of the total gas feed to Bontang, one of the world s largest LNG plants. The Bontang plant produced 18.4 million tonnes (831,000mmcf) of LNG in 2007, compared with 19.5 million tonnes in 2006.
– Also in Indonesia, BP has interests in the Tangguh LNG joint venture (BP 37.2% and operator) and in each of the Wiriagar (BP 38% and operator), Berau (BP 48% and operator) and Muturi (BP 1%) PSAs in north-west Papua that are expected to supply feed gas to the Tangguh LNG plant. During 2007, construction continued on two trains, with commercial delivery planned in early 2009. Tangguh will be the third LNG centre in Indonesia, with an initial capacity of 7.6 million tonnes (388,000mmcf) per year. Tangguh has signed sales contracts for delivery to China, Korea and North America s west coast.
– In Australia, we are one of seven partners in the NWS venture. Six partners (including BP) hold an equal 16.7% 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 joint venture operation covers offshore production platforms, an FPSO, trunklines, onshore gas and LNG processing plants and LNG carriers. Construction continued during 2007 on a fifth LNG train that is expected to process 4.7 million tonnes of LNG per year and is expected to increase the plant s capacity to 16.6 million tonnes per year. The train is expected to be commissioned during the second half of 2008. NWS produced 1.96 million tonnes (102,000mmcf) of LNG, equal to 2006 production.
– We have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company, which in 2007 supplied 5.6 million tonnes (272,710mmcf) of LNG, up 4.2% on 2006.
– BP has a 13.6% share in the Angola LNG project, which is expected to receive approximately one billion cubic feet of associated gas per day from offshore producing blocks and produce 5.2 million tonnes per year of LNG, as well as related gas liquids products, with first LNG expected in 2012. With the completion of the necessary agreements and the approval of the Angolan government, the project investors have authorized Angola LNG Limited to proceed with the construction and implementation of the project.

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## Refining and Marketing

Our Refining and Marketing business is responsible for the supply and trading, refining, manufacturing, marketing and transportation of crude oil, petroleum and chemicals products to wholesale and retail customers. BP markets its products in more than 100 countries. We operate primarily in Europe and North America but also manufacture and market our products across Australasia and in parts of Asia, Africa and Central and South America.

**Key statistics**

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Sales and other operating revenues for continuing operations | **250,866** | 232,855 | 213,326 |
| Profit before interest and tax from continuing operations[a] | **6,072** | 5,541 | 6,426 |
| Total assets | **95,691** | 80,964 | 77,485 |
| Capital expenditure and acquisitions | **5,586** | 3,144 | 2,860 |
| | | | $ per barrel |
| Global Indicator Refining Margin[b] | **9.94** | 8.39 | 8.60 |

[a] Profit before interest and tax from continuing operations includes profit after interest and tax of equity-accounted entities.

[b] The Global Indicator Refining Margin (GIM) is the average of regional industry indicator margins, which we weight 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 refining margins are industry-specific rather than BP-specific measures, which we believe are useful to investors in analyzing trends in the industry and their impact on our results. The margins are calculated by BP based on published crude oil and product prices and take account of fuel utilization and catalyst costs. No account is taken of BP s other cash and non-cash costs of refining, such as wages and salaries and plant depreciation. 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.

The key components of sales and other operating revenues are explained in more detail below.

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Sale of crude oil through spot and term contracts | **43,004** | 38,577 | 36,992 |
| Marketing, spot and term sales of refined products | **194,979** | 177,995 | 155,098 |
| Other sales including non-oil and to other segments | **12,883** | 16,283 | 21,236 |
| | **250,866** | 232,855 | 213,326 |
| | | | thousand barrels per day |
| Sale of crude oil through spot and term contracts | **1,885** | 2,110 | 2,464 |
| Marketing, spot and term sales of refined products | **5,624** | 5,801 | 5,888 |

The Refining and Marketing segment includes Refining, Fuels Marketing, Lubricants and Aromatics & Acetyls. Our strategy is to continue our focused investment in key assets and market positions with an increased focus on process safety, integrity and reliability following the operational issues at the Texas City and Whiting refineries. We aim to improve the quality and capability of our manufacturing portfolio. During the past five years, this has been taking place through upgrades of existing conversion units at several of our facilities and investment in new clean fuels units at most of our refineries. In 2007, we completed a major upgrade to the olefin cracker at the Gelsenkirchen refinery in Germany and an upgrade of an existing diesel hydrotreater at the Rotterdam refinery in the Netherlands. During the next five years, we expect to upgrade further our refining portfolio through the construction of a new coker at the Castellón refinery, a planned and announced investment in the Whiting refinery to increase its ability to process Canadian heavy crude, upgrades to diesel and gasoline desulphurization capability at the Rotterdam refinery in the Netherlands, the installation of modern naphtha reforming

technology at several refineries globally, the site reconfiguration and installation of a new hydrocracker at the Bayernoil refinery in Germany and the full recommissioning of the Texas City refinery in the US.

Our marketing businesses generate customer value by providing quality products and offers. Our retail network provides differentiated fuel and convenience offers to some of the most attractive markets. Our lubricants brands offer customers benefits through technology and relationships and we focus on increasing brand and product loyalty in Castrol lubricants. We continue to build deep customer relationships and strategic partnerships in the business-to-business sector. Marketing also includes the Aromatics & Acetyls business, which maintains world-class manufacturing positions globally, with an emphasis on the Asian market, particularly in China. At the end of 2007, the business increased its capacity in China by successfully commencing the commissioning of a new 900 thousand tonnes per annum (ktepa) worldscale purified terephthalic acid (PTA) plant at Zhuhai.

The segment manages a portfolio of assets that we believe are competitively advantaged across the chain of downstream activities. Such advantage may derive from several factors, including location (such as the proximity of manufacturing assets to markets), operating cost and physical asset quality.

We are one of the major refiners of gasoline and hydrocarbon products in the US, Europe and Australia. We have significant retail and business-to-business market positions in the US, UK, Germany and the rest of Europe, Australasia, Africa and Asia. We are enhancing our presence in China and exploring opportunities in India.

During 2007, significant events were:

– BP continued recommissioning the Texas City refinery in the US. By the end of 2007, we had successfully recommissioned the three desulphurization and upgrading units necessary to allow restart of the remaining crude distillation capacity. The final sour crude unit is mechanically complete and is expected to be fully operational during the first quarter of 2008. By mid-2008, we expect most of the economic capability at the Texas City refinery to have been restored.
– On 23 March 2007, a fire at the Whiting refinery in the US caused damage to the hydrogen compressors and limited the site s throughput and ability to make low-sulphur gasoline or diesel fuel from sour crude oil. By the end of 2007, the Whiting refinery had recommenced sour crude processing and available distillation capacity exceeded 300,000b/d.
– On 1 February 2007, BP announced it had selected the University of California Berkeley, and its partners the University of Illinois at Urbana-Champaign and the Lawrence Berkeley National Laboratory, to join in the previously announced $500-million research programme to explore how bioscience can be used to increase energy production and reduce the impact of energy consumption on the environment.
– On 31 March 2007, BP completed its acquisition of Chevron s Netherlands manufacturing company, Texaco Raffinaderij Pernis B.V., for $1.1 billion. The acquisition included Chevron s 31% interest in the Rotterdam (Nerefco) refinery.
– On 31 May 2007, BP completed the sale of its Coryton refinery in the UK to Petroplus Holdings AG for consideration of $1.4 billion, plus working capital.
– On 26 June 2007, BP, Associated British Foods and DuPont announced an investment of $400 million in the construction of a world-scale bioethanol plant with expected annual production capacity of some 420 million litres from wheat feedstock, expected to be commissioned in late 2009.
– On 29 June 2007, BP announced a joint venture with D1 Oils plc, a UK-based global producer of biodiesel, for the development of jatropha as a new energy crop.
– On 15 November 2007, BP announced that it would sell all of its company-owned and company-operated convenience sites in the US. The majority of sites will be sold to franchisees with the remaining sites sold to dealers and large distributors (jobbers). The sale of the sites is expected to be completed by the end of 2009. The sites will continue to market BP-branded fuels in the eastern US and ARCO- branded fuels in the western US. The franchise agreement is for 20

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years and requires sites to be supplied with BP or ARCO-branded fuels for the term of the contract.

– In December 2007, the second PTA plant at the BP Zhuhai Chemical Company Limited site in Guangdong province, China, successfully commenced commissioning.
– On 5 December 2007, BP announced it had agreed to create an integrated North American oil sands business with Husky Energy Inc., by means of two separate joint ventures. In one, BP will take a 50% interest in Husky Energy s Sunrise field in Alberta, Canada, while in the other, Husky will take a 50% interest in BP s Toledo refinery, between them forming an integrated North American oil sands business. As part of this agreement, and subject to negotiation of final agreements and obtaining the necessary approvals and permits, the Toledo refinery is intended to be expanded to process approximately 170mb/d of heavy oil and bitumen by 2015.
– BP continued to progress the planning for the previously mentioned investment in Canadian heavy crude oil processing capability at its Whiting refinery. This project is expected to reposition Whiting competitively as a top-tier refinery by increasing its Canadian heavy crude processing capability by 260mb/d and modernizing it with equipment of significant size and scale.
– In mid-January 2008, BP and Sinopec signed a memorandum of understanding to add a new 650ktepa acetic acid plant at their YARACO joint venture in Chongqing, upstream Yangtze River, south- west China. This world-scale acetic acid plant, using BP s leading Cativa™ technology, is expected to come onstream in 2011.

## Resegmentation in 2008

With effect from 1 January 2008:

– The Emerging Consumers Marketing Unit was transferred from Refining and Marketing to Alternative Energy (which is reported in Other businesses and corporate).
– The Biofuels business was transferred from Refining and Marketing to Alternative Energy (which is reported in Other businesses and corporate).
– The Shipping business was transferred from Refining and Marketing to Other businesses and corporate.

## Texas City refinery

On 23 March 2005, an explosion and fire at the Texas City refinery occurred in the isomerization unit as the unit was starting up after routine planned maintenance. The incident claimed the lives of 15 workers and injured many others.

Throughout 2007, BP continued to implement the process safety enhancement programme it initiated in response to the March 2005 incident, which included policies, practices and activities to address a number of the factors that contributed to the incident, including the siting of occupied portable buildings and the removal of blow-down stacks handling heavier-than-air light hydrocarbons. BP also implemented, across its US refining system and at other facilities worldwide, a number of additional actions relating to safety and operations, atmospheric relief valves, operating procedures and training, control of work systems, and process safety culture and leadership. In the US, BP has committed to increase spending to an average of $1.7 billion per year through 2010 to improve the integrity and reliability of its refining assets and has created an operations advisory board to assist BP America Inc. s management in monitoring and assessing BP s US operations.

### Governmental investigations

In 2007, BP continued its co-operation with the governmental entities investigating the Texas City incident, including the US Department of Justice (DOJ), the US Environmental Protection Agency (EPA), the US Occupational Safety and Health Administration (OSHA), the US Chemical Safety and Hazard Investigation Board (CSB) and the Texas Commission on Environmental Quality (TCEQ). On 25 October 2007, the DOJ announced that it had entered into a criminal plea agreement with BP Products North America Inc. (BP Products) related to the March 2005 explosion and fire. On 4 February 2008, BP Products pleaded guilty in

federal court, pursuant to the plea agreement, to one felony violation of the risk management planning regulations promulgated under the US federal Clean Air Act. At the plea hearing, the court advised that it would take the matter under review and decide whether to accept or reject the plea. If the court accepts the agreement, BP Products will pay a $50 million criminal fine and serve three years probation. Separately, BP Products reached a civil settlement in principle with the EPA and the DOJ related to issues identified in EPA inspections that followed the March 2005 incident. BP expects the settlement to be finalized in 2008.

The CSB issued its final report on the Texas City incident in March 2007. Although BP disagreed with some of the findings and conclusions in the report, BP gave full and careful consideration to the CSB s recommendations and committed to implement actions in alignment with each of the CSB s recommendations. BP has many activities under way, including activities around reporting health and safety and operational incidents, and incident investigation, in response to the recommendations of the BP US Refineries Independent Safety Review Panel (the panel) (see below) to improve process safety, both at Texas City (as recommended by the CSB) and across the group. BP and the CSB continue to discuss BP s responses with the objective of the

CSB agreeing to close out its recommendations.

### Civil tort actions

A large number of civil claims have arisen from the Texas City incident, for which BP has set aside $2,125 million in aggregate. Thus far, BP has reached more than 2,000 settlements in respect of all the fatalities and many of the personal injury claims arising from the incident. A number of claims remain to be resolved.

See Legal proceedings on page 82 for further information.

### Report of the BP US Refineries Independent Safety Review Panel

The panel was established by BP in 2005 at the recommendation of the CSB to assess the effectiveness of safety management systems at BP s five US refineries and the corporate safety culture. The panel, which was chaired by the former US Secretary of State, James A Baker, III, issued its report in January 2007. Although the panel did not specifically investigate the Texas City incident or seek to determine its causes, the report contained observations applicable to all of BP s US refineries, including Texas City. The panel s report acknowledged the measures taken by BP since the Texas City incident, including dedicating significant resources and personnel in an effort to improve the process safety performance of BP s US refineries. The panel s report can be found at *www.bp.com/bakerpanelreport*. BP accepted the 10 recommendations of the panel and began (or, in some cases, continued) improvement activities addressing a number of the recommendations, including consistent implementation of risk identification tools, improvements in incident reporting and investigation systems, and enhancements to the group s reporting and monitoring programmes. At the panel s recommendation, in May 2007, the BP board also appointed an independent expert to monitor progress in implementing the panel s recommendations to improve safety performance at BP s US refineries. The independent expert, L. Duane Wilson, who was a member of the panel, reports directly to the BP board s safety, ethics and environment assurance committee.

In addition to these direct responses to the panel s recommendations, BP has also taken a number of additional steps that are in line with the spirit of the panel s report. BP has developed a comprehensive programme to implement the panel s recommendations within its US refining system and to share learnings from the panel throughout the refining system. This programme makes use of the newly developed group-wide operating management system (OMS). Each refinery is creating an implementation plan to reduce process safety risk on a continuous improvement basis and to provide for the future implementation of OMS. In 2007, BP also reached an agreement in principle with the United Steel Workers Union to work jointly on a 10-point plan to improve process safety across the four represented US refineries.

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### Other regulatory actions

*OSHA*

In January 2007, OSHA began a new inspection at the Texas City refinery focusing on relief valves, flare capacity and other process safety issues at one of the catalytic cracking units. OSHA issued citations in July 2007 with a total penalty of $92,000. Separately, OSHA has questioned whether the process safety management expert (AcuTech), appointed in connection with the September 2005 settlement agreement with OSHA, adequately reviewed equipment pressure relief valve issues. BP has entered into negotiations to resolve the cracking unit citations and, in the interim, has agreed to the assignment of this case to a settlement judge. On 16 January 2008, BP addressed OSHA s concerns regarding the September 2005 settlement agreement by agreeing to retain an expert relief system consultant to audit individual hydrocarbon relief devices and flare systems on two units and to share the consultant s findings with OSHA.

In September 2007, BP and OSHA entered into a settlement agreement related to citations stemming from OSHA s inspection of the Toledo refinery in 2005. OSHA granted final approval of the settlement in November 2007.

BP is attempting to negotiate a settlement relating to citations, with a total penalty of $384,000, stemming from Indiana OSHA s inspection of the Whiting refinery in 2006, but the case is still pending. In August 2007, Indiana OSHA initiated a separate inspection relating to an April 2007 incident that resulted in a crude unit shutdown and the release of 40,000 pounds of hydrocarbons. On 30 January 2008, OSHA issued a safety order that alleges two violations, for a total penalty of $10,000.

OSHA conducted an inspection related to the death of a contract diver at the Cherry Point refinery in August 2007. OSHA concluded its

investigation in October 2007 and informed BP that no citations would be issued to it.

In January 2008, an employee died at Texas City refinery. This incident is currently being investigated by BP, OSHA and the CSB.

*EPA*

The EPA has asked the DOJ to file a civil lawsuit based on inspections it conducted at the Whiting, Toledo, Cherry Point and Carson refineries following the March 2005 Texas City incident. BP Products and the EPA/ DOJ have begun settlement negotiations in an effort to avoid litigation of the matter.

### **Refining**

The group s global refining strategy is to own and operate strategically advantaged refineries that benefit from vertical integration with our marketing and trading operations, as well as horizontal integration with other parts of the group s business. Refining s focus is to maintain and improve its competitive position through sustainable, safe, reliable and efficient operations of the refining system and disciplined investment for growth.

For BP, the strategic advantage of a refinery relates to its location, 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.

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The following table summarizes the BP group s interests in refineries and crude distillation capacities at 31 December 2007.

| | | | thousand barrels per day | |
|---|---|---|---|---|
| | | | Crude distillation capacities[a] | |
| | Refinery | Group interest[b] % | Total | BP share |
| Rest of Europe | | | | |
| Germany | Bayernoil | 22.5% | 272 | 61 |
| | Gelsenkirchen* | 50.0% | 268 | 134 |
| | Karlsruhe | 12.0% | 302 | 36 |
| | Lingen* | 100.0% | 91 | 91 |
| | Schwedt | 18.8% | 226 | 42 |
| Netherlands | Rotterdam* | 100.0% | 392 | 392 |
| Spain | Castellón* | 100.0% | 110 | 110 |
| Total Rest of Europe | | | 1,661 | 866 |
| US | | | | |
| California | Carson* | 100.0% | 266 | 266 |
| Washington | Cherry Point* | 100.0% | 234 | 234 |
| Indiana | Whiting* | 100.0% | 405 | 405 |
| Ohio | Toledo*[c] | 100.0% | 155 | 155 |
| Texas | Texas City* | 100.0% | 475 | 475 |
| Total US | | | 1,535 | 1,535 |
| Rest of World | | | | |
| Australia | Bulwer* | 100.0% | 101 | 101 |
| | Kwinana* | 100.0% | 137 | 137 |
| New Zealand | Whangerei | 23.7% | 102 | 24 |
| Kenya | Mombasa[d] | 17.1% | 94 | 16 |
| South Africa | Durban | 50.0% | 180 | 90 |
| Total Rest of World | | | 614 | 368 |
| Total | | | 3,810 | 2,769 |

* Indicates refineries operated by BP.

[a] Crude distillation capacity is gross rated capacity, which is defined as the maximum achievable utilization of capacity (24-hour assessment) based on standard feed.

[b] BP share of equity, which is not necessarily the same as BP share of processing entitlements.

[c] Subject to negotiation of final agreements and obtaining the necessary approval and permits, Husky Energy will take a 50% interest in BP s Toledo refinery as described on page 27.

[d] On 15 January 2008, it was announced that Essar Energy Overseas Ltd, a subsidiary of Essar Oil Limited, had entered into an agreement to acquire 50% of Kenya Petroleum Refineries Ltd. Subject to certain conditions, the acquisition, which includes all of BP s interest, is expected to

complete in early 2008.

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.

| | | | thousand barrels per day |
|---|---|---|---|
| Refinery throughputs[a] | **2007** | 2006 | 2005 |
| UK | **67** | 165 | 180 |
| Rest of Europe | **691** | 648 | 667 |
| US | **1,064** | 1,110 | 1,255 |
| Rest of World | **305** | 275 | 297 |
| Total | **2,127** | 2,198 | 2,399 |
| Refinery capacity utilization | | | |
| Crude distillation capacity at 31 December[b] | **2,769** | 2,823 | 2,832 |
| Crude distillation capacity utilization[c] | **72%** | 76% | 87% |
| US | **62%** | 70% | 82% |
| Europe | **84%** | 87% | 90% |
| Rest of World | **84%** | 78% | 88% |

[a] Refinery throughputs reflect crude and other feedstock volumes.

[b] Crude distillation capacity is gross rated capacity, which is defined as the maximum achievable utilization of capacity (24-hour assessment) based on standard feed.

[c] Crude distillation capacity utilization is defined as the percentage utilization of capacity per calendar day over the year after making allowances for average annual shutdowns at BP refineries (i.e. net rated capacity).

At the Texas City refinery, the recommissioning work in the aftermath of Hurricane Rita has involved the development of detailed plans to effect the repair, safety-upgrading and safe restart of the process units. The refinery has restarted many process units and the site is producing gasoline, diesel and chemicals products for the US market. By the end of 2007, we had successfully recommissioned the three desulphurization and upgrading units necessary to allow restart of the remaining crude distillation capacity. The final sour crude unit is mechanically complete and is expected to be fully operational during the first quarter of 2008. By mid-2008 we expect most of the economic capability at the Texas City refinery to have been restored.

Despite the partial recommissioning of the Texas City refinery, our US throughputs declined in 2007 due to several operational issues, including the March 2007 fire at the Whiting refinery as well as planned maintenance at our other refineries. By the end of 2007, the Whiting refinery had recommenced sour crude processing and available distillation capacity exceeded 300,000b/d.

The increase in Rest of Europe throughputs in 2007 is primarily related to the purchase of Chevron s 31% interest in the Rotterdam refinery. The decrease in UK throughputs is due to the sale of the Coryton refinery to Petroplus.

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## Marketing

Marketing comprises three business areas: Fuels marketing (including ground, aviation and marine fuels, bitumen and LPG), Lubricants (including automotive, marine and industrial lubricants) and Aromatics & Acetyls. We market a comprehensive range of refined products, including gasoline, gasoil, marine and aviation fuels, heating fuels, LPG, lubricants and bitumen. We also manufacture and market PTA, paraxylene (PX) and acetic acid through our Aromatics & Acetyls business.

| | | thousand barrels per day | |
|---|---|---|---|
| Sales of refined products[a] | **2007** | 2006 | 2005 |
| Marketing sales | | | |
| UK[b] | **339** | 356 | 355 |
| Rest of Europe | **1,294** | 1,340 | 1,354 |
| US | **1,533** | 1,595 | 1,634 |
| Rest of World | **640** | 581 | 599 |
| Total marketing sales[c] | **3,806** | 3,872 | 3,942 |
| Trading/supply sales[d] | **1,818** | 1,929 | 1,946 |
| Total refined products | **5,624** | 5,801 | 5,888 |
| | | | $ million |
| Proceeds from sale of refined products | **194,979** | 177,995 | 155,098 |

a Excludes sales to other BP businesses and sales of Aromatics & Acetyls products.
b UK area includes the UK-based international activities of Refining and Marketing.
c 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).
d Trading/supply sales are sales to large unbranded resellers and other oil companies.

The following table sets out marketing sales by major product group.

| | | thousand barrels per day | |
|---|---|---|---|
| Marketing sales by refined product | **2007** | 2006 | 2005 |
| Aviation fuel | **490** | 488 | 499 |
| Gasolines | **1,572** | 1,603 | 1,603 |
| Middle distillates | **1,119** | 1,170 | 1,185 |
| Fuel oil | **429** | 388 | 379 |
| Other products | **196** | 223 | 276 |
| Total marketing sales | **3,806** | 3,872 | 3,942 |

Marketing volumes were 3,806mb/d, slightly lower than last year, reflecting reduced industry demand in Europe and supply disruptions caused by the outage at Whiting refinery.

BP enjoys a strong market share and leading technologies in the Aromatics & Acetyls business. In Asia, we continue to develop a strong position in PTA and acetic acid. Our investment is biased towards this high-growth region, especially China.

BP supports its businesses through a dedicated Strategic Accounts organization. Strategic Accounts develops strategic relationships with carefully selected large multinational customers in targeted markets, where mutual strategic and financial value can be created. Its operating model manages each relationship in a disciplined manner to achieve growth and efficiency for BP and its partners through focused offer development and capability building.

## Fuels marketing

Our Fuels marketing strategy focuses on optimising the fuels value chain and delivering refined products 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, drive excellence in operating and transactional processes and deliver compelling customer offers in the various markets where we operate. The fuels business markets a comprehensive range of refined oil products focused on ground fuels, aviation, marine and bitumen sectors.

### *Ground fuels*

The ground fuels business supplies fuel 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 road and rail transport sectors.

BP s value creation in ground fuels is obtained through the integration of the value chain from the refinery gates or import hubs across retail and commercial channels to market. Convenience retail offers are managed as an autonomous business model focused on delivering appealing convenience offers across the various markets in which we operate, through the BP Connect, am/pm and Aral brands.

Our retail network is largely concentrated in Europe and the US, with established operations in Australasia and southern and eastern Africa. We are also developing networks in China with joint venture partners.

| | | | $ million |
|---|---|---|---|
| Store sales[a] | **2007** | 2006 | 2005 |
| UK | **713** | 647 | 628 |
| Rest of Europe | **2,974** | 2,821 | 3,069 |
| US | **1,712** | 1,755 | 1,776 |
| Rest of World | **670** | 591 | 610 |
| Total | **6,069** | 5,814 | 6,083 |
| Direct-managed | **2,609** | 2,528 | 2,489 |
| Franchise | **3,460** | 3,286 | 3,533 |
| Store alliances | | | 61 |
| Total | **6,069** | 5,814 | 6,083 |

[a] Store sales reported are sales through direct-managed stations, franchisees and the BP share of store alliances and joint ventures. Sales figures exclude sales taxes and lottery sales but include quick-service restaurant sales. Fuel sales are not included in these figures. Not all retail sites include a BP convenience store.

| | | | Number of retail sites |
|---|---|---|---|
| Retail sites[a] | **2007** | 2006 | 2005 |
| UK | **1,200** | 1,300 | 1,300 |
| Rest of Europe | **7,400** | 7,700 | 7,900 |
| US (excluding jobbers) | **2,500** | 2,700 | 3,100 |
| US jobbers | **9,700** | 9,600 | 9,700 |
| Rest of World | **3,300** | 3,300 | 3,200 |

| | | | |
|---|---|---|---|
| Total | **24,100** | 24,600 | 25,200 |

[a] Retail sites includes all sites operated under a BP brand. Changes in the number of retail sites over time are affected by, among other things, dealer/jobber-owned sites that move to or from the BP brand as their fuel supply agreements expire and are renegotiated in the normal course of business.

At 31 December 2007, BP s worldwide network consisted of some 24,000 locations branded BP, Amoco, ARCO and Aral, around the same as in the previous year.

At 31 December 2007, BP s retail network in the US comprised approximately 12,200 sites, of which approximately 9,700 were owned by jobbers and 500 by franchisees. Our European network amounted to approximately 8,600 sites with a further approximately 3,300 sites in Rest of World. The joint venture between BP and PetroChina (BP-PetroChina Petroleum Company Ltd) started its operation in 2004. The joint venture plans to operate and manage a total network of 500 locations in the Guangdong province and 400 sites were operational as at 31 December 2007. The joint venture with Sinopec commenced operations in 2005. The joint venture plans to build, operate and manage a network of 500 sites in Hangzhou, Ningbo and Shaoxing within Zhejiang province. As at 31 December 2007, 220 of these sites were operational.

We continue to improve the efficiency of our retail asset network and increase the consistency of our site offer through a process of regular review. In 2007, we sold 462 company-owned sites to dealers, jobbers and franchisees who continue to operate these sites under the BP brand. We also divested an additional 204 company-owned sites to third parties.

Each of our fuels brands, BP, Amoco, ARCO and Aral, carries a very strong offer and we also aim to share best practices between them. Since 2003, we have been upgrading our fuel offer with the introduction of Ultimate gasoline and diesel products. In 2007, we launched Ultimate in Switzerland and Luxembourg and now market Ultimate in 17 countries. In 2007, we launched our Helios Power campaign in the US aimed at reinforcing the BP brand s positioning in key markets.

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Our convenience retail strategy continues to focus on BP s advantaged positions in major cities and growth markets and upgrading our retail offers, while driving operational efficiencies through portfolio optimization including, where appropriate, a transition to franchising. The convenience offer comprises sales of convenience items to customers from advantaged locations in metropolitan areas, while our fuels offer is deployed at locations in all our markets, in many cases without the convenience offer. We execute our convenience offer through a quality branded store format in each of our key markets. Examples include the BP Connect offer in Europe, the UK partnership with Marks & Spencer Simply Food at selected locations, the am/pm offer in the US and the Aral offer in Germany. At 31 December 2007, our convenience store network consisted of more than 960 BP Connect stores worldwide, and around 1,000 am/pm stores in the US and 1,500 Aral stores in Germany.

In line with BP s intent to simplify the group s operations and improve performance, as well as to position the business for future growth by directly accessing the franchisees entrepreneurial experience and local knowledge, BP has announced that it will sell all of its company-owned and company-operated convenience sites in the US. The majority of sites will be sold to franchisees, with the remaining sites to dealers and large distributors (jobbers). The sale of the sites is expected to be completed by the end of 2009. The sites will continue to market BP-branded fuels in the eastern US and ARCO-branded fuels in the western US. The franchise agreement has a term of 20 years and requires sites to be supplied with BP- or ARCO-branded fuels for the term of the contract.

### *Aviation fuels*

Air BP is one of the world s largest aviation businesses, supplying aviation fuel to the airline, military and general aviation sectors. It supplies customers in approximately 80 countries, has annual marketing sales of 27.4 billion litres (more than 470mb/d) and has relationships with many of the major commercial airlines. Air BP s strategic aim is to strengthen its position in its main existing markets (Europe/US/Middle East), while creating opportunities in emerging economies such as China, where it is the largest foreign investor in the industry.

### *Marine fuels*

The marine fuels business focuses on the distribution and resale of refined fuels to the shipping industry across the world. The business has a strong presence in the marine fuels sector. It has offices in 12 countries and operates in more than 150 ports.

### *Bitumen*

The bitumen business focuses on the distribution and sale of bitumen products for road construction and maintenance. It has a strong presence in the US and in Europe and is exploring opportunities in developing economies, where new infrastructure is being built. It markets bitumen products in seven countries and product sales in 2007 were approximately 45mb/d.

### *LPG*

The LPG business sells bulk, bottled, automotive and wholesale LPG products to a wide range of customers in 14 countries. During the past few years, our LPG business has consolidated its position in established markets and pursued opportunities in new and emerging markets. BP is one of the leading importers of LPG into the Chinese market, where we continued to grow our retail LPG business. LPG product sales in 2007 were approximately 72mb/d.

## Lubricants

We manufacture and market lubricants products and also supply related products and services to business customers and end-consumers in more than 60 countries directly and to the rest of the world through local distributors. Our business is concentrated on the higher-margin sectors of automotive lubricants, especially in the consumer sector, and also has a strong presence in the marine and industrial business markets. Customer focus, distinctive brands and superior technology remain the cornerstones of our long-term strategy. BP markets primarily through its major brands, Castrol and BP, as well as Aral in specific markets. The Castrol brand is recognized worldwide and we believe it provides us with a significant competitive advantage. In the automotive lubricants segment, we supply lubricants, other products and related business services to intermediate customers such as retailers and workshops, who in turn serve end-consumers such as car, motorcycle and leisure-craft owners in the mature markets of western Europe and North America and also in the fast growing markets of the developing world such as Russia, China, India, the Middle East, South America and Africa. BP s marine lubricants business, operating under the BP and Castrol brands, is a market leader with capability to supply in about 1,200 ports. BP also supplies lubricants to the power generation, offshore oil and aviation industries. BP s industrial lubricants business supplies lubricants and value-adding services to the transportation, automotive and metal sectors.

## Aromatics & Acetyls

The Aromatics & Acetyls business manufactures and markets three main products lines: PTA, PX and acetic acid. PTA is a raw material for the manufacture of polyesters used in textiles, plastic bottles, fibres and films. PX is feedstock for the production of PTA. Acetic acid is a versatile intermediate chemical used in a variety of products such as paints, adhesives and solvents. It is also used in the production of PTA. In addition to these three main products, we are involved in a number of other petrochemicals products, namely Dimethyl 2, 6 Naphthalene dicarboxylate (NDC), which is used for optical film and specialized packaging, and acetic anhydride, ethyl acetate and vinyl acetate monomer (VAM), which are used in cellulose acetate, paints, adhesives and solvents. Our Aromatics & Acetyls strategy is to invest to maintain and grow our advantaged manufacturing positions globally, with an emphasis on growth in Asia, particularly in China. We are also investing in maintaining and developing our technology leadership position to deliver both operating and capital cost advantages.

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The following table shows BP s Aromatics & Acetyls production capacity at 31 December 2007. This production capacity is based on the original design capacity of the plants plus expansions.

thousand tonnes per year

| Geographic area | PTA | PX | Acetic acid | Other | Total BP share of capacity | |
|---|---|---|---|---|---|---|
| UK | | | | | | |
| Hull | | | 549 | 616 | 1,165 | |
| Rest of Europe | | | | | | |
| Belgium | | | | | | |
| Geel | 1,075 | 597 | | | 1,672 | |
| USA | | | | | | |
| Cooper River | 1,309 | | | | 1,309 | |
| Decatur | 1,046 | 1,109 | | 29 | 2,184 | |
| Texas City | | 1,302 | 550[a] | 123 | 1,975 | |
| Rest of World | | | | | | |
| China | | | | | | |
| Chongqing | | | 211[b] | 52 | 263 | (51% of YARACO)[b] |
| Zhuhai | 1,496[c] | | | | 1,496[c] | |
| Indonesia | | | | | | |
| Merak | 255 | | | | 255 | (50% of PT Ami) |
| Korea | | | | | | |
| Ulsan | | | 245[d] | 59[e] | 304 | (51% of SS-BP)[d] (34% of ASACCO)[e] |
| Malaysia | | | | | | |
| Kertih | | | 549 | | 549 | |
| Kuantan | 697 | | | | 697 | |
| Taiwan | | | | | | |
| Kaohsiung | 832[f] | | | | 832 | (61% of CAPCO)[f] |
| Taichung | 469[f] | | | | 469 | (61% of CAPCO)[f] |
| Mai Liao | | | 167[g] | | 167 | (50% of FBPC)[g] |
| | 7,179 | 3,008 | 2,271 | 879 | 13,337 | |

[a] Sterling Chemicals plant, the output of which is marketed by BP.
[b] Yangtze River Acetyls Company.
[c] Inclusive of 900ktepa capacity from the second BP Zhuhai PTA plant, which commenced commissioning at end of 2007.
[d] Samsung-BP Chemicals Ltd.
[e] Asian Acetyls Company Ltd.
[f] China American Petrochemical Company Ltd.
[g] Formosa BP Chemicals Corporation.

During 2007, the following significant activities took place in the Aromatics & Acetyls business:

Construction commenced on the new 500ktepa plant, in Jiangsu province, China, by BP YPC Acetyls Company (Nanjing) Limited (BYACO), BP s 50% equity-share acetic acid joint venture with Yangzi Petrochemical Co. Ltd (a subsidiary of Sinopec Corporation in China), and is scheduled to complete by mid-2009.

The second PTA plant at the BP Zhuhai Chemical Company Limited site in Guangdong province, China, successfully commenced commissioning at the end of 2007. The 900ktepa plant is the single largest PTA train in the world, employing the latest BP proprietary technology.

In the first quarter of 2007, BP announced its intention to sell its European VAM and ethyl acetate businesses. In January 2008, INEOS announced that it had reached an agreement to acquire these businesses. The transaction, which is subject to the approval of the EU competition authorities, is expected to complete in the first quarter of 2008.

In the fourth quarter of 2007, BP completed the disposal of its 47.41% equity interest in Samsung Petrochemical Co. Ltd (SPC) to our PTA joint venture partner, Samsung Group, in South Korea.

The development of a 350ktepa PTA expansion at Geel, Belgium, is expected to be operational in mid-2008 and to increase the site s PTA capacity to 1,425ktepa.

In January 2008, BP and Sinopec signed a memorandum of understanding to add a new acetic acid plant at their Yangtze River Acetyls Co. (YARACO) joint venture in Chongqing, upstream Yangtze River, south-west China. This world-scale acetic acid plant, using BP s leading Cativa™ technology, is expected to have an annual capacity of 650ktepa. The plant is expected to be onstream in 2011, when the
total production at the YARACO site is expected to be well over one million tonnes per annum, which would make it one of the largest acetic acid production locations in China.

### Supply and trading

The group has a long-established supply and trading activity responsible for delivering value across the overall crude and oil products supply chain. This activity identifies the best markets and prices for our crude oil, sources optimal feedstock for our refining assets and sources marketing activities with flexible and competitive supply. Additionally, the function creates incremental trading opportunities through holding commodity derivative contracts and trading inventory. To achieve these objectives in a liquid and volatile international market, the group enters into a range of commodity derivative contracts, including exchange-traded futures and options, over-the-counter (OTC) options, swaps and forward contracts as well as physical term and spot contracts.

Exchange-traded contracts are traded on liquid regulated markets that transact in key crude grades, such as Brent and West Texas Intermediate, and the main product grades, such as gasoline and gasoil. These exchanges exist in each of the key markets in the US, western Europe and Asia. OTC contracts include a variety of options, forwards and swaps. These swaps price in relation to a wider set of grades than those traded through the exchanges, where counterparties contract for differences between, for example, fixed and floating prices. The contracts we use are described in more detail below. Additionally, physical crude can be traded forward by using specific OTC contracts pricing in reference to Brent and West Texas Intermediate grades. OTC crude forward sales contracts are used by BP to buy and sell the underlying physical commodity, as well as to act as a risk management and trading instrument.

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Risk management is undertaken when the group is exposed to market risk, primarily due to the timing of sales and purchases, which may occur for both commercial and operational reasons. For example, if the group has delayed a purchase and has a lower-than-normal inventory level, the associated price exposure may be limited by taking an offsetting position in the most suitable commodity derivative contract described above. Where trading is undertaken, the group actively combines a range of derivative contracts and physical positions to create incremental trading gains by arbitraging prices, typically between locations and time periods. This range of contract types includes futures, swaps, options and forward sale and purchase contracts, which are described further below.

Through these transactions, the group sells crude production into the market, allowing more suitable higher-margin crude to be supplied to our refineries. The group may also actively buy and sell crude on a spot and term basis to further improve selections of crude for refineries. In addition, where refinery production is surplus to marketing requirements or can be sourced more competitively, it is sold into the market. This latter activity also encompasses opportunities to maximize the value of the whole supply chain through the optimization of storage and pipeline assets, including the purchase of product components that are blended into finished products. The group also owns and contracts for storage and transport capacity to facilitate this activity.

The range of transactions that the group enters into is described below in more detail:

Exchange-traded commodity derivatives

These contracts are typically in the form of futures and options traded on a recognized exchange, such as Nymex, Simex, ICE and Chicago Board of Trade. Such contracts are traded in standard specifications for the main marker crude oils, such as Brent and West Texas Intermediate, and the main product grades, such as gasoline and gasoil. Though potentially settled physically, these contracts are typically settled financially. 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 both crude and products. 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. OTC contracts are negotiated between two parties and are not traded on an exchange. These contracts can be used both as part of 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 Osberg or BFO). Although the contracts specify physical delivery terms for each crude blend, a significant volume are not settled physically. The contracts 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.

Swaps are contractual obligations to exchange cash flows between two parties: one usually references a floating price and the other 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 or oil products at a specified price on or before a specific future date. Amounts under these derivative financial instruments are settled at expiry, typically through netting agreements, to limit credit exposure and support liquidity.

Spot and term contracts

Spot contracts are contracts to purchase or sell crude and oil products at the market price prevailing on and 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 relate typically to purchases of crude for a refinery, sales of the group s oil production and sales of the group s oil products. 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.

## Trading investigations

See Legal proceedings on page 82 for details regarding investigations into various aspects of BP s trading activities.

During 2007, the group has taken a series of measures in relation to its trading compliance processes, systems and controls. These measures include increasing its compliance resources in the US and elsewhere, continuing to implement an enhanced compliance framework and programme that includes compliance monitoring of trading operations, and the ongoing development and implementation of operating standards and processes. In the US, the deferred prosecution agreement (DPA) between BP America Inc. (BP America) and the US Department of Justice has resulted in the appointment of an independent monitor to oversee compliance with the DPA. The independent monitor has authority to investigate and report alleged violations of the US Commodity Exchange Act or US Commodity Futures Trading Commission regulations and to recommend corrective action.

## Transportation

Our Refining and Marketing segment owns, operates or has an interest in extensive transportation facilities for crude oil, refined products and petrochemicals feedstock. We transport crude oil to our refineries principally by ship and through pipelines from our import terminals. We have interests in crude oil pipelines in Europe and the US. Bulk products are transported between refineries and storage terminals by pipeline, ship, barge and rail. Onward delivery to customers is primarily by road. We have interests in major product pipelines in the UK, Rest of Europe and the US.

## 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.

### International fleet

In 2006, we managed an international fleet of 57 vessels (42 medium-size crude and product carriers, four very large crude carriers, one North Sea shuttle tanker, seven LNG carriers and three new LPG carriers). At the end of 2007, we had 53 international vessels (39 medium-size crude and product carriers, four very large crude carriers, one North Sea shuttle tanker, five LNG carriers and four LPG carriers). All these ships are double-hulled. Of the five LNG carriers, BP manages one on behalf of a joint venture in which it is a participant and operates four LNG carriers. Three further LNG carriers are on order for delivery in 2008.

### Regional and specialist vessels

In Alaska, we redelivered one of our time-chartered vessels back to the owner, leaving a fleet of five double-hulled vessels. In the Lower 48, two of the four heritage Amoco barges remain in service, both of which are due to be phased out of BP s service in 2008. Outside the US, the specialist fleet has been reduced from 16 ships in 2006 to 14 in 2007 (two double-hulled lubricants oil barges and 12 offshore support vessels).

### Time-charter vessels

BP has 111 hydrocarbon-carrying vessels above 600 deadweight tonnes on time-charter, of which 97 are double-hulled and two are double-bottomed. All these vessels participate in BP s Time Charter Assurance Programme.

### Spot-charter vessels

To transport the remainder of the group s products, BP spot-charters vessels, typically for single voyages. These vessels are always vetted for safety assurance prior to use.

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### 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.

## Gas, Power and Renewables

In 2007, the Gas, Power and Renewables segment included four main activities: marketing and trading of gas and power; marketing and trading of liquefied natural gas (LNG); production, marketing and trading of natural gas liquids (NGLs); and low-carbon power generation through our Alternative Energy business.

**Resegmentation in 2008**

With effect from 1 January 2008:

- The Gas, Power and Renewables segment ceased to report separately.
- The NGLs, LNG and the gas and power marketing and trading businesses were transferred from the Gas, Power and Renewables segment to the Exploration and Production segment.
- The Alternative Energy business was transferred from the Gas, Power and Renewables segment to Other businesses and corporate.

**Key statistics**

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Sales and other operating revenues from continuing operations | **21,369** | 23,708 | 25,696 |
| Profit before interest and tax from continuing operations[a] | **674** | 1,321 | 1,172 |
| Total assets | **19,889** | 27,398 | 28,952 |
| Capital expenditure and acquisitions | **874** | 688 | 235 |

a Profit before interest and tax from continuing operations includes profit after tax of equity-accounted entities.

The changes in sales and other operating revenues are explained in more detail below:

| | | | $ million |
|---|---|---|---|
| | **2007** | **2006** | 2005 |
| Gas marketing sales | **8,639** | 11,428 | 15,222 |
| Other sales (including NGL marketing) | **12,730** | 12,280 | 10,474 |
| | **21,369** | 23,708 | 25,696 |

| | | | million cubic feet per day |
|---|---|---|---|
| Gas marketing sales volumes | **3,382** | 3,685 | 5,096 |
| Natural gas sales by Exploration and Production | **4,414** | 5,152 | 4,747 |

BP seeks to maximize the value of its gas by targeting high-value customer segments in selected markets and to optimize supply around our physical and contractual rights to assets. Marketing and trading activities are focused on the relatively open and deregulated natural gas and power markets of North America, the UK and the most liquid trading locations in Rest of Europe. Some long-term natural gas contracting activity is included within the Exploration and Production segment because of the nature of the gas markets when the long-term sales contracts were agreed.

Our LNG business develops opportunities to capture sales for our upstream natural gas resources, working in close collaboration with the Exploration and Production segment. For sales into non-liquid markets such as Japan and Korea, we aim to secure contracts with high-value customers. For the majority of sales into liquid wholesale markets such as the US and the UK, we are building integrated supply chains covering production, liquefaction, shipping, re-gasification and access to the wholesale transmission grid. Our strategy is to capture a growing share of the internationally-traded gas market. We are focusing on markets that offer significant prospects for growth. Our LNG activities involve the marketing of third-party LNG as well as BP equity volumes, where this allows us to optimize our existing asset and contractual positions.

Our NGLs business is engaged in the processing, fractionation and marketing of ethane, propane, butanes and pentanes extracted from natural gas. We have a significant NGLs processing and marketing

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business in North America. Our NGLs activity is underpinned by our upstream resources and serves third-party markets for chemicals and clean fuels as well as supplying BP s refining activities.

Globally, the power sector is the largest source of greenhouse gas (GHG) emissions, responsible for around twice the emissions of transport, so creating low-carbon power is critical in the effort to stabilize global GHG levels. BP is focused on power generation activities with low-carbon emissions through its Alternative Energy business, extending significantly our capabilities in solar, wind power, hydrogen power and gas-fired power generation.

Capital expenditure and acquisitions in 2007 was $874 million, compared with $688 million in 2006 and $235 million in 2005. In 2007, we acquired Wasatch Energy L.L.C. in the US and in 2006 our acquisitions included Orion Energy, LLC and Greenlight Energy, Inc. In 2005 there were no acquisitions.

### Marketing and trading activities

Gas and power marketing and trading activity is undertaken primarily in the US, Canada, the UK and Europe to market BP s gas and power production 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 enhanced margins from sources such as the management of price risk on behalf of third-party customers. These markets are large, liquid and volatile and the group enters into these transactions on a large scale to meet these objectives.

The group also has an NGLs trading activity in the US for delivering value across the overall NGLs supply chain, sourcing optimal feedstock for our processing assets and securing access to markets with flexible and competitive supply.

In connection with the above 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. 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 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. Capacity contracts allow the group to store, transport gas and transmit power between these locations. Additionally, activity is undertaken to risk-manage power generation margins related to the Texas City co-generation plant using a range of gas and power commodity derivatives.

The range of contracts that the group enters into is described below in more detail:

– Exchange-traded commodity derivatives

  Exchange-traded commodity derivatives include gas and power futures contracts. Though potentially settled physically, these contracts are typically settled financially. Gains and losses, otherwise referred to as variation margins, are settled on a daily basis with the relevant exchange. 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. OTC contracts are negotiated between two parties and are not traded on an exchange. These contracts can be used both as part of 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. Highly-developed markets exist in North America and the UK where gas and power 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. Although these contracts specify delivery terms for the underlying commodity, in practice a significant volume of these transactions are not settled physically. This 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 contractual obligations to exchange cash flows between two parties. One usually references a floating price and the other 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 natural gas products or power at a specified price on or before a specific future date. Amounts under these derivative financial instruments are settled at expiry, typically through netting agreements 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 the delivery date when title to the inventory passes. 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 relate typically to purchases of third-party gas and sales of the group s gas production to third parties. 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.

  See Financial and operating performance Gas, Power and Renewables on page 49.

## Trading investigations

See Legal proceedings on page 82 for details regarding investigations into various aspects of BP s trading activities.

During 2007, the group has taken a series of measures in relation to its trading compliance processes, systems and controls. These measures include increasing its compliance resources in the US and elsewhere, continuing to implement an enhanced compliance framework and programme that includes compliance monitoring of trading operations, and the ongoing development and implementation of operating standards and processes. In the US, the deferred prosecution agreement (DPA) between BP America Inc. (BP America) and the US Department of Justice has resulted in the appointment of an independent monitor to oversee compliance with the DPA. The independent monitor has authority to investigate and report alleged violations of the US Commodity Exchange Act or US Commodity Futures Trading Commission regulations and to recommend corrective action.

## North America

BP has a significant wholesale gas and power marketing and trading business in North America. Our business has been built on the foundation of our position as one of the continent s leading producers of gas based on volumes. Our gas activity in the US and Canada has grown during the past few years as the group increased its scale through both organic growth of operations and the acquisition of smaller marketing and trading companies, increasing reach into additional markets. At the same time, the overall volumes in these markets have also increased. The group also trades power, in addition to selling and risk managing production from the Texas City co-generation facility in the US.

Our North American natural gas marketing and trading strategy seeks to provide unconstrained market access for BP s equity gas. Our marketing strategy targets high-value customer segments through fully utilizing our rights to store and transport gas. These assets include those owned by BP and those contractually accessed through agreements with third parties such as pipelines and terminals.

### Europe

The natural gas market in the UK is significant in size and is one of the most progressive in terms of deregulation when compared with other European markets. BP is one of the largest producers of natural gas in the UK, based on volumes, with the majority of BP s volumes being sold to power generation companies and to other gas wholesalers via long-term supply deals.

In addition to the marketing of BP gas, commodity derivative contracts are used in combination with access to storage, transport flow and assets to generate trading opportunities. This may include storing physical gas to sell in future periods or moving gas between markets to access higher prices. Commodity contracts such as OTC forward contracts can be used to achieve this, while other commodity contracts such as futures and options can be used to manage the market risk relating to changes in prices.

In Europe, we maintain a marketing presence in Spain, but are increasingly focused on wholesale transactions at the existing and new gas trading hubs and exchanges in Belgium, The Netherlands, Germany and France.

## Liquefied natural gas

Our LNG and new market development activities are focused on establishing international market positions to create maximum value from our upstream natural gas resources and on capturing third-party LNG supply to complement our equity flows.

BP Exploration and Production has interests in a number of major existing LNG supply projects: Atlantic LNG in Trinidad & Tobago, Bontang in Indonesia and the North West Shelf (NWS) project in Australia. Additional LNG supplies are being pursued through an expansion of the existing LNG facilities at the NWS project in Australia and green-field developments in Indonesia (Tangguh) and Angola.

We continue to access major growth markets for the group s equity gas in the Pacific region. During 2007, development continued on the Tangguh LNG project (BP 37.2% and operator) from which the first commercial delivery is expected in early 2009. Tangguh will be the third LNG centre in Indonesia and has signed sales contracts for delivery to customers in China, South Korea and the west coast of Mexico. During 2007, further progress was made in securing contracts for LNG to be derived from the remaining uncontracted reserves at the NWS project. Agreements for the supply of LNG to Japan have been signed with Chugoku Electric, Kyushu Electric, Tohuku Electric and Toho Gas and for the supply of LNG to South Korea with the Korean Gas Corporation (KOGAS). The Guangdong LNG re-gasification and pipeline project in south-east China, in which BP is the only foreign partner, completed installation of its third storage tank in the third quarter of 2007, increasing its throughput to 7 million tonnes per annum. In addition to LNG supplied under a long-term contract with the NWS project, the terminal took delivery of an additional seven spot cargoes during the year, to meet rapidly growing local demand for gas.

In the Atlantic and Mediterranean regions, BP is creating opportunities to supply LNG to North American and European gas markets. The fourth LNG train at Atlantic LNG in Trinidad, with a capacity of 5.2 million tonnes per annum (253,000mmcf), began operations in late 2005. These BP-marketed volumes supplement a 2005 long-term agreement with EGAS of Egypt to purchase 1.45 billion cubic metres per year of LNG from the Spanish Egyptian Gas Company (SEGAS) plant at Damietta, and a short-term contract to purchase LNG from Oman and periodic spot purchases of LNG. BP is marketing its LNG entitlement directly, utilizing BP-controlled LNG shipping and contractual rights to access import terminal capacity in the liquid markets of the US (via Cove Point and Elba Island) and the UK (via the Isle of Grain). In Spain, environmental permits have been issued to allow an expansion of the Bilbao re-gasification terminal in which BP has a 25% equity stake.

In Nigeria, discussions are ongoing following the 2006 signing of a memorandum of understanding for the purchase of LNG from Brass

River LNG. A final investment decision is expected in 2008 and could lead to first LNG in 2012.

BP continues to seek approvals for a new terminal development in the US. The proposed 1.2 billion cubic feet per day (bcf/d) Crown Landing terminal is to be located on the Delaware River in New Jersey. The Federal Energy Regulatory Commission (FERC) granted its approval for the siting, construction and operation of this project during 2006. BP continues to work with state agencies in New Jersey to complete state permitting requirements and with the relevant federal, state and local authorities to put in place security plans for the facility and associated shipping activities. BP is also monitoring the progress of a proceeding filed by the State of New Jersey against the State of Delaware in the US Supreme Court concerning New Jersey s jurisdiction over developments on its shores, including the project s loading jetty that extends into the Delaware River. The US Supreme Court heard the New Jersey versus Delaware case on 27 November 2007 and a decision from the court is expected in 2008.

## Natural gas liquids

Based on sales volumes, we are one of the largest producers and marketers of NGLs in North America and hold interests for NGL volumes in the UK and Egypt.

NGLs produced in North America from gas chiefly sourced out of Alberta, Canada and the US onshore and Gulf Coast, are used as a heating fuel and as a feedstock for refineries and chemicals plants. In addition, a significant amount of NGLs are marketed on a wholesale basis under annual supply contracts that provide for price re-determination based on prevailing market prices.

In North America, BP operates or has interests in NGL extraction plants with a processing capacity of 6.4bcf/d. These facilities are located in major production areas across North America, including Alberta, Canada, the US Rockies, the San Juan basin and the Gulf of Mexico. We also own or have an interest in fractionation plants (that separate the NGL into its component products) in Canada and the US, and own or lease storage capacity in Alberta, eastern Canada, and the US Gulf Coast, as well as the US west coast and mid-continent regions. Our North American NGLs processing capacity utilization in 2007 was 72%. In 2006, we entered into a long-term supply contract with Aux Sable Liquid Products to secure additional NGLs to supply our customers in the US Midwest. A major three-year programme to inspect, assess and repair or replace equipment is under way in BP s North American NGLs business. On 20 March 2007, we completed the sale of BP s 50% equity and operating interest in the Cochin pipeline system to Kinder Morgan Energy Partners.

BP operates one NGLs plant (Central Area Transmission System, 30% owner and operator with a capacity of 1.2bcf/d) in the UK and we are a partner (33.33%) in a gas processing plant in Egypt with 1.1bcf/d of gas processing capacity. We have also secured access to the Abibes LPG terminal in Cremona, northern Italy.

## Alternative energy

BP Alternative Energy, launched in November 2005, combines all of BP s interests in businesses that provide low-carbon energy solutions for power generation: solar, wind, gas-fired power generation and hydrogen power with carbon capture and storage (CCS).

### Solar

BP Solar s main production facilities are located in Maryland (US), Madrid (Spain), Sydney (Australia), Xi an (China) and Bangalore (India). During 2007, expansion of cell capacity continued at our Madrid and Bangalore facilities, alongside a $100-million project to expand casting capacity at Maryland, increasing our annual manufacturing capacity to 228MW. BP Solar achieved sales of 115MW in 2007 (93MW in 2006 and 105MW in 2005).

In 2007, BP Solar and Banco Santander installed 14 Megawatts peak (MWp) of the planned 20MWp installations in Spain, while in the US, BP Solar won a bid to develop 4.3MW of solar energy systems for seven Wal-Mart Stores in California, with the first three installations completed by the end of December.

We are developing a new silicon growth process named Mono[2™], which significantly increases cell efficiency over traditional multicrystalline-based solar cells, making our first pilot shipment in 2007. Solar cells made with these wafers, in combination with other BP Solar advances in cell process technology, are expected to be able to produce between 5% and 8% more power than solar cells made with conventional processes. We are working with a number of research universities and institutes including the California Institute of Technology in the US where we are pursuing nanotube solar installations. This represents another step improvement in cost and efficiency. In Germany, we signed a co-operation agreement with the Institute of Crystal Growth (IKZ) in September 2006 to develop a technique to deposit silicon in very thin layers directly on glass instead of growing crystals. The programme has demonstrated this ability and work continues to improve the growth process and crystal structure. We are participating in a $40-million research and development programme (of which $20 million is provided by BP Solar) aimed at decreasing the cost of solar cells and increasing their efficiency. The programme is sponsored by the US Department of Energy.

### Wind

Since 2005, we have increased our wind capacity from 32MW to more than 370MW, with an aim to grow that to more than 1,000MW by the end of 2008. We operate wind farms in the Netherlands, Maharashtra in India and Colorado in the US.

In the US, we have a long-term supply agreement with Clipper Windpower plc, with options to purchase Clipper turbines with a total capacity of 2,250MW. During 2006, we also acquired Orion Energy, LLC, and Greenlight Energy, Inc. With the acquisition of these large-scale wind energy developers, our North American wind portfolio includes projects with potential total generating capacity of some 15,000MW. During 2007, we commenced construction on the Silver Star I project (60MW) in Texas and commenced full commercial operation of our 300MW Cedar Creek project in Colorado.

In India, we commenced full commercial operations at our 40MW wind farm in Dhule, Maharashtra, India using 32 turbines supplied and installed by Suzlon, each with the capacity to generate 1.25MW of electricity.

### Gas-fired power

Gas-fired power stations typically emit around half as much $CO_2$ as conventional coal-fired plants. We have interests in a 785MW gas-fired power generation facility and an associated LNG re-gasification facility at Bilbao, Spain (BP 25% share in each), a 1,074MW gas-fired combined cycle power (CCGT) plant at Kwangyang, South Korea (BP 35%), a 724MW CCGT facility at Phu My, Vietnam (BP 33.3%), a 1,378MW gas turbine (BP 10%) in Trinidad & Tobago, a 392MW co-generation plant (BP 51%) in California, US and a 744MW co-generation plant at Texas City, US (BP 50%), which supplies power and steam to BP s largest refining and petrochemicals complex. Also, a 50MW combined heat and power plant near Southampton, UK (BP 100%) has been in operation since the first half of 2005. Construction continues on the 250MW steam turbine power generating plant at the Texas City refinery site, which is expected to bring the total capacity of the site to around 1,000MW when completed in 2008.

### Hydrogen power

In May 2007, BP and Rio Tinto announced the formation of a new jointly owned company, Hydrogen Energy, which will develop decarbonized energy projects around the world. The venture will initially focus on hydrogen-fuelled power generation, using fossil fuels and CCS technology to produce new large-scale supplies of clean electricity.

We are developing industrial-scale hydrogen power projects with CCS technology.

General Electric and BP have formed a global alliance to jointly develop and deploy technology for hydrogen power plants that could significantly reduce emissions of the greenhouse gas $CO_2$ from electricity generation.

## Other businesses and corporate

Other businesses and corporate comprises Treasury (which includes all the group s cash, cash equivalents and associated interest income), the group s aluminium asset and corporate activities worldwide.

**Key statistics**

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Sales and other operating revenues for continuing operations | **843** | 1,009 | 668 |

| | | | |
|---|---|---|---|
| Profit (loss) before interest and tax from continuing operations[a] | **(1,128)** | (885) | (1,237) |
| Total assets | **17,188** | 14,184 | 12,144 |
| Capital expenditure and acquisitions | **275** | 281 | 817 |

[a] Includes profit after interest and tax of equity-accounted entities.

### Resegmentation in 2008

With effect from 1 January 2008:

The Alternative Energy business was transferred from the Gas, Power and Renewables segment to Other businesses and corporate.

The Emerging Consumers Marketing Unit was transferred from Refining and Marketing to Alternative Energy (which is reported in Other businesses and corporate).

The Biofuels business was transferred from Refining and Marketing to Alternative Energy (which is reported in Other businesses and corporate).

The Shipping business was transferred from Refining and Marketing to Other businesses and corporate.

### Treasury

Treasury co-ordinates the management of the group s major financial assets and liabilities. From locations in the UK, the US and the Asia Pacific region, it provides the link between BP and the international financial markets and makes available a range of financial services to the group, including supporting the financing of BP s projects around the world.

### 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.

### Research, technology and engineering

Research, technology and engineering activities are carried out by each of the major business segments on the basis of a distributed programme co-ordinated by a technology co-ordination group. This body provides leadership for scientific, technical and engineering activities throughout the group and in particular promotes cross-business initiatives and the transfer of best practice between businesses. In addition, a group of eminent industrialists and academics forms the Technology Advisory Council, which advises senior management on the state of technology within the group and helps to identify current trends and future developments in technology.

Research and development is carried out using a balance of internal and external resources. Involving third parties in the various steps of technology development and application enables a wider range of technology solutions to be considered and implemented, improving the productivity of research and development activities. External resources includes investing in technology ventures as a platform for promoting collaborative research. These ventures are not subsidiaries and, as a result, their expenditure on research and development is not included directly in the research and development expenditure stated below.

Across the group, expenditure on research and development for 2007 was $566 million, compared with $395 million in 2006 and $502 million in

2005 (2005 includes $374 million in respect of continuing operations). See Financial statements note 14 on page 125. The 43% increase in 2007 compared with 2006 reflects increased investment in enhanced oil recovery, heavy oil, advanced refining, conversion, biosciences and renewables technology.

### Insurance

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. This position is reviewed periodically.

## Technology

The realization of technological advancements is pivotal to our strategic progress and business performance. It is also the key to finding and developing solutions that meet the energy and climate challenges of the 21st century.

Our three-year technology plan provides sustained investment in our core technologies and increasing investment in long-term technologies. As we have deepened our current areas of leadership, extended their application in the field and broadened our long-term technology portfolio, our technology investment has grown at an average of 15% per annum during the period 2003-2007. In 2007, total technology investment was around $1.1 billion.

The sheer range and complexity of technologies that can impact our businesses, and the wide variety of sources for these technologies proprietary, energy service sector, universities and research institutions and other industries means that no single approach can meet all our needs.

The following guiding principles underpin our approach to technology:

- Deliver technology leadership in a select few areas.
- Develop sustainable technology-based solutions for corporate renewal.
- Drive rapid take-up of proprietary and commercially available technologies.
- Innovate and test technology at material scale.
- Develop and access world-class skills; collaborate internally and externally.

These principles are reflected in how we define technology investment. Whereas research and development is an externally reported number, internally we use a broader but very specific definition for technology investment. This consists of four elements: technology development for incremental improvement of our base businesses; technology leadership areas to create and sustain material, advantaged business positions; long-term technology investments to secure our future; and application and propagation of technology through formalized technology networks and knowledge management processes.

During 2007, we continued to advance and employ new technologies in drilling and well construction, unconventional gas development, enhanced oil recovery and seismic imaging. These technologies and know-how have enabled a new agreement with the Sultanate of Oman to develop gas resources, discoveries in Azerbaijan, Angola, Egypt and the Gulf of Mexico, increased production from tight gas fields in the continental US and increased recoveries from our fields in maturing basins such as Alaska and the North Sea.

Technology advancements are also broadening our refining capability to understand and process feedstocks of varying quality and optimize our assets in real time, enhancing the flexibility and reliability of our refineries and, in turn, improving the margins of our existing asset base. Our proprietary technologies in PTA have continued to reduce manufacturing costs and environmental impact: the new Zhuhai 2 unit in China, which started in 2007, has a lower energy consumption and environmental footprint than any other PTA unit in the world.

We also continue to progress our strategic longer-term technologies. In the field of bioscience, we selected the University of California
Berkeley and its partners the University of Illinois, Urbana-Champaign and the Lawrence Berkeley National Laboratory to join us in the previously-announced $500-million research programme to explore how bioscience can be used to increase energy production

and reduce the impact of energy consumption on the environment. This energy research laboratory is now operational. We also entered into research agreements with two biotechnology companies in the US to focus on next generation energy crops for biofuels and to research microbial processes in subsurface hydrocarbons. We have formed a research partnership with the Massachusetts Institute of Technology to complement our internal technology capabilities in converting low-value carbon feedstocks such as petcoke and coal to high-value products such as electricity, liquid fuels and chemicals while minimizing $CO_2$ emissions.

Carbon capture and storage (CCS) technologies are a key enabler to the success of low-carbon power generation and product manufacturing. Having integrated the learning from our $CO_2$ storage project in Algeria with our extensive Exploration and Production capabilities, our CCS technologies are ready for deployment at scale.

## Regulation of the group s business

BP s exploration and production activities are conducted in many different countries and are therefore subject to a broad range of legislation and regulations. These cover virtually all aspects of exploration and production activities, including matters such as licence acquisition, production rates, royalties, pricing, environmental protection, export, taxes and foreign exchange. The terms and conditions of the leases, licences and contracts under which these 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. 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.

Production-sharing agreements 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 venture with other international oil companies, state companies or private companies.

In general, BP is required to pay income tax on income generated from production activities (whether under a licence or production-sharing agreement). 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 Angola, Norway, the UK, Russia, South America and Trinidad & Tobago.

BP s other activities, including its interests in pipelines and its commodities and trading activities, are also subject to a broad range of legislation and regulations in various countries in which it operates.

Health, safety and environmental regulations are discussed in more detail in Environment on page 40.

For certain information regarding environmental proceedings, see Environment US regional review on page 42.

## Safety

This section reviews BP s 2007 performance with respect to safety and the environment. An overview of our non-financial performance will appear in *BP Sustainability Report 2007*, expected to be published in May 2008.

In total, there were seven workforce fatalities relating to BP operations in 2007, compared with the same number in 2006. Two were the result of shootings relating to our retail operations in South Africa, two occurred in operations at our US refineries in Cherry Point and Texas City, one was on board a BP marine vessel, one was road-related and one an accident involving a defective fire extinguisher in Indonesia. We deeply regret the loss of any lives. These incidents re-emphasize the need for constant vigilance in seeking to secure the safety of all members of our workforce.

Our employee and contractor reported recordable injury frequency in 2007 was 0.48 per 200,000 hours worked, the same as that for 2006 (2006 data was corrected from 0.47 to 0.48), and below the industry average for 2006.

### Implementing Baker Panel recommendations

Throughout 2007, BP continued to progress the process safety enhancement programme initiated in response to the March 2005 incident at the Texas City refinery. We worked to implement the recommendations of the BP US Refineries Independent Safety Review Panel (the panel), which issued its report on the incident in January 2007 (see *www.bp.com/bakerpanelreport*).

We have made material progress throughout the group across all of the panel s 10 recommendations. Action can be grouped under the following headings:

#### Leadership

Our executive team carried out site visits, which included BP s five US refineries. Board members also undertook site visits, including one to the Texas City refinery. We have consistently communicated that safe and reliable operations are our highest priority. Our safety and operations audit group was strengthened and completed 28 audits in 2007.

#### Management systems

Implementation of our operating management system (OMS) began at a first group of sites that included all five US refineries *(see page 40)*. We continued implementing the group s six-point plan , which focuses on key priorities for investment and action associated with safe operations *(see below)*.

#### Knowledge and expertise

We established an executive-level training programme, ran process safety workshops and launched an operations academy for site-based staff to enhance process safety capability. Specialists have been deployed at our US refineries to accelerate priority improvement programmes.

#### Culture

To reinforce the need for a stronger safety culture, our in-house team undertook assessments of BP s safety culture, supported by communication from leadership.

#### Indicators

Progress has been made in developing leading and lagging indicators, building on metrics already reported to executive management. These

include measures on the competency of employees in roles critical to safety and on the development of appropriate operating procedures. We are working with the industry to develop indicators and this already includes progress to agree a metric covering loss of primary containment.

### Progress at Texas City and our other US refineries

Across the US refining system, we have worked to address factors that contributed to the Texas City refinery incident of 2005, including facility siting, atmospheric relief systems, operating procedures and operator training, as well as control of work systems and process safety culture and leadership.

The refineries have engaged with employees on how to improve process safety. Each refinery is creating a strategic implementation plan to reduce process safety risk on a continuous improvement basis and to implement the OMS. With the United Steel Workers Union, we have reached agreement in principle to work jointly to improve safety across four represented refineries. At Texas City, face-to-face communication with staff has been supplemented by *The Future is Now*, a monthly magazine widely circulated across the group.

Approximately 640 new staff were hired across our US refineries, strengthening our support of engineering, inspection and process safety.

Further information on Texas City and other refineries can be found in the Refining and Marketing section on page 27.

### Implementing the six-point plan

We set out our immediate priorities for improving process safety management and reducing risk at our operations worldwide through a six-point plan. This plan, launched in 2006, pre-dated the panel s recommendations and creates a foundation for our approach.

Progress on the plan s elements is reviewed each quarter by the executive-level group operations risk committee (GORC).

We have taken the following actions in relation to the six-point plan:

– In 2007, we implemented a group practice on occupied portable buildings and removed all temporary buildings out of high-risk zones in refineries and major onshore plants. We continue to apply the practice and report progress on identification and removal of relevant buildings to the GORC. A total of 17 blow-down stacks all of those on heavier- than-air light hydrocarbon streams in refineries have been removed from service. The one remaining blow-down stack, at a chemical plant in Malaysia, is scheduled to be removed from service during 2008.
– We have completed 50 major accident risk assessments (MARs). The assessments identify high-level risks that, if they occur, would have a major effect on people or the environment. Many of these risks, such as a loss of containment from our operations, are common across the industry. Mitigation plans to manage and respond to identified risks form part of the MAR analysis.
– We are implementing group standards for integrity management and control of work on a locally risk-assessed and prioritized basis. Progress on implementing the standards is tracked quarterly. We have spent $6 billion on integrity management in the course of 2007, principally related to operating costs for maintenance and capital costs for plant improvement.
– We have continued to improve the way in which we seek to ensure our operations maintain compliance with health and safety laws and regulations. A project to establish a consistent compliance management framework has been under way in the US during the past two years and is expected to be completed globally by the end of 2008.
– Reviews have been undertaken resulting in many actions being closed out from past audits. Other actions requiring closure have been identified.
– Senior HSE advisors have carried out a preliminary assessment of the operational experience of BP management teams responsible for major production or manufacturing plant and any significant assessment findings have been addressed.

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### Operational integrity

As part of monitoring operational integrity, we track the number of major incidents during the year: oil spills of more than 100 barrels, significant property damage or fatal accidents related to integrity management failures. We also investigate any near-misses that could have resulted in a major incident. Overall in 2007, the total number of high potentials went down; however, more integrity management-related high potentials were reported in 2007 than in previous years as a result of improved knowledge-sharing.

The number of oil spills of one barrel or more in 2007 decreased to 340 from 417 in 2006. The volume of oil spilled was 1.05 million litres, of which 0.33 million litres were unrecovered.

### Continuing to focus on personal health and safety

In combination with our efforts to improve process safety, we have continued to strive for excellence in occupational health and safety. This is in line with our aspiration of no accidents, no harm to people and no damage to the environment.

Continued focus on driving risks has resulted in a significant reduction in major driving incidents, (those that cause a fatality or result in a vehicle rollover) since 2005.

Health is an integral part of the OMS. In 2007, work continued on developing practices in health management, covering industrial hygiene, asbestos, fitness to work, health impact assessment, medical emergency management, health promotion and wellness. These practices set minimum standards of health performance in BP *(see below)*.

We recognize that the health and safety of our workforce and communities is affected by our operations and that meeting our aspiration of no harm to people requires continuous effort, every day.

### Implementation of the OMS

We began implementation of the OMS at 12 representative pilot sites. Learnings from these pilots will be used to assess and improve the OMS before widening its introduction. We intend for the whole of BP to have commmenced use of the OMS by the end of 2010.

The OMS incorporates BP s principles for operating and provides a framework to help deliver competence, then excellence, in operations and safety. Standards for control of work and integrity management and detailed practices in matters such as risk assessment provide further underpinning. Training and development programmes have been strengthened to develop the right capability and culture across the organization.

As described by BP s group chief executive, the OMS is the foundation for a safe, effective, and high-performing BP. It has two purposes: to further reduce HSE risks in our operations and to continuously improve the quality of those operations . The system s elements of operating describe eight dimensions of how people, processes, plant and performance operate within BP. A continuous improvement process drives and sustains improvement of these elements at a local level.

### Capability development

We have initiated development programmes designed to ensure that BP has the capability among its people to achieve operational excellence and identify and manage risks.

The programmes support implementation of the OMS by developing technical knowledge and skills. They seek to improve management, behavioural, cultural and leadership skills to drive and sustain multi-year change in operations across multiple geographies.

For instance, the operating essentials programme is tailored to staff in maintenance, operations and safety who have responsibility for managing front-line employees and contractors. We completed operating essentials pilots in Anadarko (North America gas), Angola and Kwinana and started the first phase of the implementation at 11 other sites.

The Operations Academy, provided in partnership with the Massachusetts Institute of Technology, is directed towards senior operations and safety leaders of sites or large units.

The executive operations programme targets group vice presidents and senior business leaders with accountability for multiple operations or sites. Its purpose is to deepen insight into manufacturing and operations activities and the consequences of leadership decisions.

In 2007, we began the development of programmes for the wider workforce such as technicians and operators, graduate new hires and managers in roles between supervisory and senior leadership levels.

## Environment

### Health, safety and environmental regulation

The group is subject to numerous international, national and local environmental laws and regulations concerning its products, operations and activities. Current and proposed fuel and product specifications and climate change programmes under a number of environmental laws will have a significant effect on the production, sale and profitability of many of our products. Environmental laws and regulations also require the group to remediate or otherwise redress 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, chemicals plants, natural gas processing plants, oil and natural gas fields, service stations, terminals and waste disposal sites. In addition, the group may have obligations relating to prior asset sales or closed facilities. Provisions for environmental restoration and remediation are made when a clean-up is probable and the amount is reasonably determinable. Generally, their timing coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites. The provisions made are considered by management to be sufficient for known requirements.

The extent and cost of future environmental restoration, remediation and abatement programmes are often inherently difficult to estimate. They depend on the magnitude of any possible contamination, the timing and extent of the corrective actions required, technological feasibility and BP s share of liability relative to that of other solvent responsible parties. Though the costs of future restoration and remediation 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. See Financial statements Note 37 on page 151 for the amounts provided in respect of environmental remediation and decommissioning.

The group s operations are also subject to environmental and common law claims for personal injury and property damage caused by the release of chemicals, hazardous materials or petroleum substances by the group or others. Fifteen proceedings involving governmental authorities are pending or known to be contemplated against BP and certain of its subsidiaries under federal, state or local environmental laws, each of which could result in monetary sanctions of $100,000 or more. No individual proceeding is, nor are the proceedings in aggregate, expected to be material to the group s results of operations or financial position.

For information regarding Texas City and other refineries see Texas City refinery on page 27, Other regulatory actions on page 28 and Legal proceedings on page 82.

For further information regarding spills in Alaska in 2006 see Legal proceedings on page 82.

Management cannot predict future developments, such as increasingly strict requirements of environmental laws and resulting enforcement policies that might affect the group s operations or affect the exploration for new reserves or the products sold by the group. A risk of increased environmental costs and impacts is inherent in particular operations and products of the group and there can be no assurance that material liabilities and costs will not be incurred in the future. In general, the group does not expect that it will be affected differently from other companies with comparable assets engaged in similar businesses. Management believes that the group s activities are in compliance in all material respects with applicable environmental laws and regulations.

For a discussion of the group s environmental expenditure see page 52.

BP operates in more than 100 countries worldwide. In all regions of the world, BP has, or is developing, processes designed to ensure

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compliance with applicable regulations. In addition, each individual in the group is required to comply with BP health, safety and environmental policies as embedded in the BP code of conduct. Our partners, suppliers and contractors are also encouraged to adopt them.

This Environment section focuses primarily on the US and the EU, where around 65% of our fixed assets are located, and on issues of a global nature such as our operations and the environment, climate change programmes and maritime oil spills regulations.

## Our operations and the environment

During 2007, we continued to use environmental management systems to seek improvements on a wide range of environmental issues. All our major sites, except one, are certified to the ISO 14001 international environmental management system standard. The Texas City refinery, after completing planned work to strengthen its environmental management systems, is planning to seek recertification in early 2009.

Following its approval in November 2006, we began the implementation of the group practice called the Environmental Requirements for New Projects (ERNP). This practice is a full life-cycle environmental assessment process. It requires all new projects to undertake screening to determine the potential environmental sensitivities associated with the proposed projects. The highest level of environmental sensitivity in a new project requires more rigorous specific environmental management activities. By the end of 2007, more than 100 projects had begun implementation of ERNP including those in our alternative energy, upstream and downstream businesses.

Since 2001, we have been focusing on measuring and improving the carbon intensity of our operations. After six years, we estimate that our operations have delivered some 7 million tones (Mte) of GHG reductions. Our 2007 operational GHG emissions were 63.5Mte of $CO_2$ equivalent on a direct equity basis, nearly 1Mte lower than the reported figure of 64.4Mte in 2006.

Many of our EU assets have been subject to the EU Emissions Trading Scheme (ETS) since its launch in January 2005. The number of installations actively participating in the scheme increased at the end of 2007 when a temporary exclusion of exploration and production assets expired. After inclusion of these assets, around one-fifth of our reported 2007 global GHG emissions are now covered by the scheme.

In 2007, no new decisions were taken by BP to explore or develop in World Conservation Union (IUCN) category I-IV areas. We constantly try to limit the environmental impact of our operations by seeking to use natural resources responsibly and reducing waste and emissions.

## Climate change programmes

In response to rising concerns about climate change, governments continue to identify fiscal and regulatory measures at local, national and international levels.

In December 1997, at the Third Conference of the Parties to the United Nations Framework Convention on Climate Change (UNFCCC) in Kyoto, Japan, the participants agreed on a system of differentiated international legally-binding targets for the first commitment period of 2008-2012. In 2005, the Kyoto protocol came into force, committing the 176 participating countries to emissions targets. However, Kyoto was only designed as a first step and policymakers continue to discuss what new agreement might follow it after 2012, most recently at the UNFCCC conference in Bali in December 2007.

In the EU, the first phase of the EU ETS was completed at the end of 2007, with EU ETS phase II running from 2008-2012. The European Commission has approved all member-state Phase-II national allocation plans. The European Commission also announced an intention to propose a legislative framework by mid-2008, to achieve the EU objective of 120 grams per kilometre $CO_2$ for passenger cars and light commercial vehicles.

The US congress continues to develop and review proposed climate change legislation and regulation. President Bush signed an Energy bill into law in December 2007, which included stricter corporate average fuel emissions standards for automobiles sold in the US and biofuel mandates. A number of other bills currently under consideration propose

stricter emissions limits on large GHG sources and/or the introduction of a cap-and-trade programme on $CO_2$ and other GHG emissions.

In an April 2007 decision, the US Supreme Court overruled a lower court that had upheld a decision by the US Environmental Protection Agency (EPA) not to regulate GHGs from motor vehicles under the Clean Air Act for climate change purposes. The Supreme Court s ruling will require the EPA to reconsider its prior decision on motor vehicle $CO_2$ regulation and render a new decision in keeping with the Supreme Court s holding. The court opinion is expected to make it difficult for the EPA not to regulate motor vehicle GHG emissions in the future. It is also expected to increase pressure on the EPA to regulate stationary sources of

GHGs (e.g. refineries and chemical plants) under other provisions of the Clean Air Act.

In September 2006, California governor Arnold Schwarzenegger signed the California Global Warming Solutions Act of 2006 (AB 32) into law. In 2007, the California Air Resources Board (CARB) began the development of regulations that will ultimately reduce California s GHG emissions to 1990 levels by 2020 (an approximately 25% reduction from current levels). CARB has initiated work on the Scoping Plan, which will identify reduction programme mechanisms and timelines for achieving the 2020 target. In advance of the Scoping Plan, CARB has taken early actions with the development of mandatory GHG reporting and a Low Carbon Fuel Standard (LCFS). The LCFS will require all refiners, producers, blenders and importers to reduce the carbon intensity of transport fuel sold in California by 10% by 2020.

Since 1997, BP has been actively involved in policy debate. We also ran a global programme that reduced our operational GHG emissions by 10% between 1998 and 2001. We continue to look at two principal kinds of emissions: operational emissions, which are generated from our operations such as refineries, chemicals plants and production facilities; and product emissions, generated by our customers when they use the fuels and products that we sell. Since 2001, we have been focusing on measuring and improving the carbon intensity of our operations as well as developing sustainable low-carbon technologies and businesses for the future.

In 2007, as part of our engagement with technology development, two major BP-backed research institutes came into full operation: the Energy Biosciences Institute (EBI) in the US, and the Energy Technologies Institute (ETI) in the UK. The EBI is a strategic partnership between BP, the University of California, Berkeley, the Lawrence Berkeley National Laboratory and the University of Illinois, that will perform research into the production of new and cleaner energy, initially focusing on advanced biofuels for road transport. The EBI will also pursue bioscience-based research in three other key areas: the conversion of heavy hydrocarbons to clean fuels, improved recovery from existing oil and gas reservoirs and carbon sequestration. In the UK, the ETI has been established as a 50:50 public private partnership, funded equally by member companies, including BP, and the government. The ETI aims to accelerate the development, demonstration and eventual commercial deployment of a focused portfolio of energy technologies, which will increase energy efficiency, reduce GHG emissions and help achieve energy security and climate change goals. The ETI has issued its first Invitation for expressions of interest to participate in programmes to develop new technologies for offshore wind and for marine, tidal and wave energy.

### Maritime oil spill regulations

Within the US, the Oil Pollution Act of 1990 (OPA 90) imposes oil spill prevention requirements, spill response planning obligations and spill liability for tankers and barges transporting oil and for offshore facilities such as platforms and onshore terminals. To ensure adequate funding for response to oil spills and compensation for damages, when not fully covered by a responsible party, OPA 90 created a $1-billion fund that is financed by a tax on imported and domestic oil. This has recently been amended by the Coast Guard and Maritime Transportation Act 2006 to increase the size of the fund from $1 billion to $2.7 billion, through the previously-mentioned tax, together with an increase in the liability of double-hulled tankers from $1,200 per gross ton to $1,900 per gross ton. In addition to OPA 90, which imposes liability for oil spills on the owners

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and operators of the carrying vessel, some states implemented statutes also imposing liability on the shippers or owners of oil spilled from such vessels. Alaska, Washington, Oregon and California are among these states. The exposure of BP to such liability is mitigated by the vessels marine liability insurance, which has a maximum limit of $1 billion for each accident or occurrence. OPA 90 also provides that all new tank vessels operating in US waters must have double hulls and existing tank vessels without double hulls must be phased out by 2015. BP contracted with National Steel and Ship Building Company (NASSCO) for the construction of four double-hulled tankers in San Diego, California. The first of these new vessels began service in 2004, demise-chartered to and operated by Alaska Tanker Company (ATC), which transports BP Alaskan crude oil from Valdez. NASSCO delivered two more in 2005 and the fourth was delivered in 2006. At the end of 2007, the ATC fleet consisted of five tankers, all double-hulled.

Outside the US, the BP-operated fleet of tankers is subject to international spill response and preparedness regulations that are typically promulgated through the International Maritime Organization (IMO) and implemented by the relevant flag state authorities. The International Convention for the Prevention of Pollution from Ships (Marpol 73/78) requires vessels to have detailed ship-board emergency and spill prevention plans. The International Convention on Oil Pollution, Preparedness, Response and Co-operation requires vessels to have adequate spill response plans and resources for response anywhere the vessel travels. These conventions and separate Marine Environmental Protection Circulars also stipulate the relevant state authorities around the globe that require engagement in the event of a spill. All these requirements together are addressed by the vessel owners in Shipboard Oil Pollution Emergency Plans. BP Shipping s liabilities for oil pollution damage under the OPA 90 and outside the US under the 1969/1992 International Convention on Civil Liability for Oil Pollution Damage (CLC) are covered by marine liability insurance, having a maximum limit of $1 billion for each accident or occurrence. This insurance cover is provided by three mutual insurance associations (P&I Clubs): The United Kingdom Steam Ship Assurance Association (Bermuda) Limited; The Britannia Steam Ship Insurance Association Limited; and The Standard Steamship Owners Protection and Indemnity Association (Bermuda) Limited. With effect from 20 February 2006, two new complementary voluntary oil pollution compensation schemes were introduced by tanker owners, supported by their P&I Clubs, with the agreement of the International Oil Pollution Compensation Fund at the IMO. Pursuant to both these schemes, tanker owners will voluntarily assume a greater liability for oil pollution compensation in the event of a spill of persistent oil than is provided for in CLC. The first scheme, the Small Tanker Owners Pollution Indemnification Agreement (STOPIA), provides for a minimum liability of 20 million Special Drawing Rights (around $30 million) for a ship at or below 29,548 gross tons, while the second scheme, the Tanker Owners Pollution Indemnification Agreement (TOPIA), provides for the tanker owner to take a 50% stake in the 2003 Supplementary Fund, that is, an additional liability of up to 273.5 million Special Drawing Rights (around $430 million). Both STOPIA and TOPIA will only apply to tankers whose owners are party to these agreements and who have entered their ships with P&I Clubs in the International Group of P&I Clubs, so benefiting from those clubs pooling and reinsurance arrangements. All BP Shipping s managed and time-chartered vessels participate in STOPIA and TOPIA.

At the end of 2007, we had 53 international vessels (39 medium-size crude and product carriers, four very large crude carriers, one North Sea shuttle tanker, five LNG carriers and four LPG carriers). All these ships are double-hulled. Of the five LNG carriers, BP manages one on behalf of a joint venture in which it is a participant and operates four LNG carriers. Three further LNG carriers are on order for delivery in 2008. In addition to its own fleet, BP will continue to charter quality ships; all vessels will continue to be vetted prior to each use in accordance with the BP group ship vetting policy.

### US regional review

The following is a summary of significant US environmental issues and legislation or regulations affecting the group.

The Clean Air Act and its regulations require, among other things, stringent air emission limits and operating permits for chemicals plants, refineries, marine and distribution terminals; stricter fuel specifications and sulphur reductions; enhanced monitoring of major sources of specified pollutants; and risk management plans for storage of hazardous substances. This law affects BP facilities producing, storing, refining, manufacturing and distributing oil and products as well as the fuels themselves. Federal and state controls on ozone, particulate matter, carbon monoxide, benzene, sulphur, MTBE, nitrogen dioxide, oxygenates and Reid Vapor Pressure affect BP s activities and products in the US. BP is continually adapting its business to these rules, which are subject to recent change. Beginning January 2006, all gasoline produced by BP was subject to the EPA s stringent low-sulphur standards. Furthermore, by June 2006, at least 80% of the highway diesel fuel produced each year by BP was required to meet a sulphur cap of 15 parts per million (ppm) and 100% with effect from January 2010. By June 2007, all non-road diesel fuel production had to meet a sulphur cap of 500ppm and 15ppm by June 2012. With effect from January 2011, EPA s Mobile Source Air Toxics regulations will require a refinery annual average benzene level of 0.62 volume percentage on all gasoline.

The Energy Policy Act of 2005 also required several changes to the US fuels market with the following fuel provisions: elimination of the Federal Reformulated Gasoline (RFG) oxygen requirement in May 2006; establishment of a renewable fuels mandate (4 billion gallons in 2006, increasing to 7.5 billion in 2012); consolidation of the summertime RFG Volatile organic compound (VOC) standards for Regions 1 and 2; provision to allow the Ozone Transport Commission states on the east coast to opt any area into RFG; and a provision to allow states to repeal the 1psi Reid Vapor Pressure waiver for 10% ethanol blends.

In 2001, BP entered into a consent decree with the EPA and several states that settled alleged violations of various Clean Air Act requirements related largely to emissions of sulphur dioxide and nitrogen oxides at BP s refineries. Implementation of the decree s requirements continues.

The Clean Water Act is designed to protect and enhance the quality of US surface waters by regulating the discharge of wastewater and other discharges from both onshore and offshore operations. Facilities are required to obtain permits for most surface water discharges, install control equipment and implement operational controls and preventative measures, including spill prevention and control plans. Requirements under the Clean Water Act have become more stringent in recent years, including coverage of storm and surface water discharges at many more facilities and increased control of toxic discharges. New regulations are expected during the next several years that could require, for example, additional wastewater treatment systems at some facilities.

The Resource Conservation and Recovery Act (RCRA) regulates the storage, handling, treatment, transportation and disposal of hazardous and non-hazardous wastes. It also requires the investigation and remediation of locations at a facility where such wastes have been handled, released or disposed of. BP facilities generate and handle a number of wastes regulated by RCRA and have units that have been used for the storage, handling or disposal of RCRA wastes that are subject to investigation and corrective action.

Under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA or Superfund), waste generators, site owners, facility operators and certain other parties are strictly liable for part or all of the cost of addressing sites contaminated by spills or waste disposal regardless of fault or the amount of waste sent to a site. Additionally, each state has separate laws similar to CERCLA.

BP has been identified as a Potentially Responsible Party (PRP) under CERCLA or otherwise named under similar state statutes at approximately 805 sites. A PRP or named party can incur joint and several liability for site remediation costs under some of these statutes and so BP may be required to assume, among other costs, the share attributed to insolvent, unidentified or other parties. BP has the most significant exposure for remediation costs at 52 of these sites. For the remaining sites, the number of parties can range up to 200 or more. BP expects its share of remediation costs at these sites to be small in comparison with the major sites. BP has estimated its potential exposure at all sites where it has been identified as a PRP or is otherwise named and has established provisions accordingly. BP does not anticipate that its ultimate exposure at these sites individually, or in aggregate, will be significant, except as reported for Atlantic Richfield Company in the matters below.

The US and the State of Montana seek to hold Atlantic Richfield Company liable for environmental remediation, related costs and natural resource damages arising out of mining-related activities by Atlantic Richfield s predecessors in the upper Clark Fork River Basin (basin). Federal and state trustees also seek to recover damages for alleged injuries to natural resources in the basin. Past settlements resolved Atlantic Richfield s alleged liability for portions of these claims. In 2007, the parties reached an agreement in principle in which Atlantic Richfield agreed to pay approximately $169 million, plus interest, to settle all remaining claims for natural resource damages in the basin, and federal and state claims for environmental remediation and related costs in the Clark Fork River operable unit and in portions of the Anaconda operable unit owned by the State of Montana. Under the agreement, the State of Montana agreed to use most of the settlement funds to remediate and restore the identified areas. The settlement must be lodged in federal court and is contingent on government review of public comments on the settlement, and court approval of the settlement. It includes limited reservations of rights against Atlantic Richfield. Other portions of the basin, principally in Anaconda and Butte, still require remediation. The estimated future cost of completing remedies that the EPA has selected or proposed in the other remaining operable units in the basin is approximately $290 million. Past settlements between Atlantic Richfield, the US and the State of Montana, including consent decree settlements in other portions of the basin, may provide a framework for future settlement of the remaining claims.

The group is also subject to other claims for natural resource damages (NRD) under CERCLA, OPA 90 and other federal and state laws. NRD claims have been asserted by government trustees against a number of group operations. This is a developing area of the law that could affect the cost of addressing environmental conditions at some sites in the future.

In the US, many environmental clean-ups are the result of strict groundwater protection standards at both the state and federal level. Contamination or the threat of contamination of current or potential drinking water resources can result in stringent clean-up requirements even if the water is not being used for drinking water. Some states have even addressed contamination of non-potable water resources using similarly strict standards. BP has encouraged risk-based approaches to these issues and seeks to tailor remedies at its facilities to match the level of risk presented by the contamination.

Other significant legislation includes the Toxic Substances Control Act, which regulates the development, testing, import, export and introduction of new chemical products into commerce; the Occupational Safety and Health Act, which imposes workplace safety and health, training and process safety requirements to reduce the risks of physical and chemical hazards and injury to employees; and the Emergency Planning and Community Right-to-Know Act, which requires emergency planning and spill notification as well as public disclosure of chemical usage and emissions. In addition, the US Department of Transport (DOT), through the Pipeline and Hazardous Materials Safety Administration, comprehensively regulates the transportation of the group s petroleum products such as crude oil, gasoline and chemicals to protect the health and safety of the public.

BP is subject to the Marine Transportation Security Act (MTSA) and the DOT Hazardous Materials (HAZMAT) security compliance regulations in the US. These regulations require many of our US businesses to conduct security vulnerability assessments and prepare security mitigation plans that require the implementation of upgrades to security measures, the appointment and training of designated security personnel and the submission of plans for approval and inspection by government agencies.

The US government, in an effort to further mitigate the threat of terrorism to critical US infrastructure, is additionally mandating two new

security legislation initiatives, which began in the fourth quarter of 2007 and will continue through 2008:

- Chemical Facility Anti-Terrorism Standard (CFATS) rollout starting in 2007/2008.
- Transportation Workers Identification Credential (TWIC) rollout starting in 2007/2008.

CFATS is new legislation that began implementation in the fourth quarter of 2007 and will continue through 2008. It is intended to provide an enhanced security posture for US facilities that manufacture or store fuels. Additionally, it will cover facilities that have national economic impact to the US, should these facilities be a target for terrorism. A number of BP facilities will be impacted by this legislation. Compliance will require them to complete a screening review, and if not found to be exempt, they will be required to conduct a detailed security vulnerability assessment and a detailed security plan for each facility impacted.

TWIC is a new government employee background screening programme that is linked to the MTSA facilities. The programme requires all designated personnel with unescorted access to restricted areas of the MTSA designated facilities to submit to a detailed background screening programme and to be issued a bio-metric identification card. All of BP s MTSA-regulated facilities will be impacted and will be required to comply by the end of 2008 in a phased in approach.

BP has a national spill response team, the BP Americas Response Team (BART), consisting of approximately 250 trained emergency responders at group locations throughout North America. In addition to the BART, there are five Regional Response Incident Management Teams, a number of HAZMAT Teams and emergency response teams at our major facilities. Collectively, these teams are ready to assist in a response to a major incident.

See also Legal proceedings on page 82.

**European Union regional review**

Within the EU, European Community legislation is proposed by the European Commission (EC) and usually adopted jointly by the European Parliament and the Council of Ministers. It must then be implemented by each EU member state. When implementing EU legislation, member states must ensure that penalties for non-compliance are effective, proportionate and dissuasive, and must usually designate a competent authority (regulatory body) for implementation. Where the EC believes that a member state has failed fully and correctly to transpose and implement EU legislation, it can take the member state to the European Court of Justice, which can order the member state to comply and in certain cases can impose monetary penalties on the member state. A few non-EU states may also agree to apply EU environmental legislation, in particular under the framework of the European Economic Area agreement.

An EC directive for a system of integrated pollution prevention and control (IPPC) was adopted in 1996. This system requires certain listed industrial installations, including most activities and processes undertaken by the oil and petrochemicals industry within the EU, to obtain an IPPC permit, which is designed to address an installation s environmental impacts, air emissions, water discharges and waste in a comprehensive fashion. The permit requires, among other things, the application of Best Available Techniques (BAT), taking into account the costs and benefits, unless an applicable environmental quality standard requires more stringent restrictions, and an assessment of existing environmental impacts and future site closure obligations. All such plants had to obtain such a permit by 30 October 2007 and permits may include an environmental improvement programme. The EC is currently reviewing the IPPC directive with the primary aim of merging several separate directives related to industrial emissions into a single directive. Initial indications suggest there is a strong desire by the EC to propose a more prescriptive piece of legislation with a greater emphasis on mandating emission limits contained in guidance documents. In particular, the review is likely to propose more stringent regulations of combustion plant (with scope increased to include plants down to 20MW thermal input), extend IPPC to cover organic chemical manufacture by biological treatment (biofuels) and may open the way for NOx and SOx trading by member states.

In 2005, the EC published its Thematic Strategy on Air Pollution, which outlines EU-wide targets for health and environmental benefits from improved air quality to be achieved through further controls on emissions of fine particulates (PM 2.5 particulate matter less than 2.5 microns diameter), sulphur dioxide, oxides of nitrogen, volatile organic compounds and ammonia. Associated with this are two important directives.

The first is the Ambient Air Quality and Cleaner Air for Europe Directive (AAQD). This consolidates existing ambient air quality legislation (which prescribes ambient air quality limit values for sulphur dioxide, oxides of nitrogen, particulate matter, lead, carbon monoxide, ozone, cadmium, arsenic, nickel, mercury and polyaromatic hydrocarbons) and introduces new controls on the concentration of fine particles in ambient air. If the concentration of a pollutant exceeds air quality limit values plus a margin of tolerance, or there is a risk of exceeding the limit, a member state is required to take action to reduce emissions. This may affect any BP operations whose emissions contribute to such exceedances.

The second is a revision to the National Emissions Ceiling Directive (NECD). This will introduce new emissions ceilings for each member state for fine particles and will tighten existing ceilings for sulphur dioxide, oxides of nitrogen, volatile organic compounds and ammonia, in order to achieve the health and environmental benefits set in the Thematic Strategy referenced above. The ceilings set for a member state will trigger a range of abatement measures across industrial sectors that are assessed as being a cost effective means of achieving the ceiling. Recent climate change targets announced by the European Council in March 2007, together with developments in the atmospheric modeling that underpins the Thematic Strategy and NECD, mean that the proposal for the revision has been delayed until early summer 2008 and may be more stringent and therefore more costly for industry than anticipated.

In early 2007, the EC published its proposal to amend the current EU Fuel Quality Directive. This directive seeks to set environment limits on gasoline and diesel road transport fuels, and as such is linked historically to the EU legislation on vehicle (passenger car and heavy duty) regulated emissions (the Euro standards ) and has previously set the legislative timetable for the introduction of ultra-low sulphur (50ppm) and sulphur-free (<10ppm) fuels. However, a major theme of the EC s new proposal concerns biofuel policy, both directly in terms of a proposal to set life cycle GHG emission reductions and indirectly in terms of attempting facilitating the introduction of biofuels into gasoline and diesel.

Specifically the key elements of the EC s current proposal are:

- Confirmation of the 1 January 2009 sulphur-free (<10ppm) deadline date for road diesel (alignment with the gasoline deadline).
- The reduction of non-road gasoil sulphur and inland waterway gasoil sulphur to 10ppm by 31 December 2009 and 31 December 2011 respectively.
- The reduction of the Poly-cyclic Aromatic Hydrocarbon (PAH) specification in diesel from 11% by weight to 8% by weight.
- The creation of a separate grade of gasoline allowing the blending to up to 10% by volume ethanol or its equivalent.
- The provision of a summer-time gasoline vapour pressure waiver for blends containing ethanol.
- Article 7a, requiring fuel suppliers to reduce the life-cycle GHG emissions from road transport fuels by 10% by 2020.

The key items of impact to BP are the attempt to create an additional gasoline grade, and Article 7a and its potential impact on conventional gasoline and diesel.

Registration, Evaluation and Authorization of Chemicals (REACH) legislation became effective 1 June 2007 across all member states of the EU. All chemical substances manufactured in, or imported into, the EU in quantities above 1 tonne per annum must be registered by each manufacturer/importer with the new European Chemical Agency (ECHA) based in Helsinki, Finland. Registration will occur during the period 2008-2018, with the exact timing being determined by the volumes of chemicals manufactured/imported, and by the hazard the chemical may pose to human health and the environment. Time limited authorizations may be granted for substances of high concern . Crude oil and natural gas are exempt, while fuels will be exempted from authorization but not registration. In BP, REACH will affect our refining, petrochemicals and other chemical manufacturing operations, with many other businesses, such as lubricants, also being impacted in their roles as an importer or downstream user of chemicals. BP s updated broad estimate (there are still many unknowns) indicates that the cost impacts of REACH for BP, covering hundreds of registrations, are expected to be in the region of $60 million over the period 2008-2018, with about two-thirds in the period 2008-2010. Additional costs, for example submissions for authorization for relevant substances and the modification of safety data sheets, will have to be assessed further as the regulation is implemented.

The EC adopted a Directive on Environmental Liability on 21 April 2004. From 30 April 2007, member states must usually require the operators of activities that cause significant damage to water, ecological resources or land after that date to undertake restoration of that damage. Provision is also made for reporting and tackling imminent threats of such damage.

During the past two years, BP has contributed actively to the High Level Group on Competitiveness, Energy and the

Environment chaired by the EC and involving a range of stakeholders from EU member states, industry, regulators, NGOs and trade unions. This group worked successfully on a consensus basis, to offer a range of recommendations to the EC intended to support energy and environmental policy objectives while advancing the competitiveness of the European economy.

In early 2008, the EC is expected to release a directive on thegeological storage of $CO_2$ and an accompanying communication regarding incentives for carbon capture and storage (CCS). The intention of the regulation is in part to identify regulatory barriers that may restrict CCS technologies, so that those barriers can be appropriately addressed, and to identify common methodologies to be implemented across EU member states.

In 2005, the EC published a proposed EC Marine Strategy Directive, which would adopt an approach similar to that in the Water Framework Directive by requiring achievement of good environmental status for marine waters by 2021 through the implementation of programmes of measures. The legislation may have some impact on BP s upstream operations in the North Sea.

Another environment-related regulation that may have an impact on BP s operations is the Major Hazards Directive, which, for the sites to which it applies, requires emergency planning, public disclosure of emergency plans and ensuring that hazards are assessed and effective emergency management systems are in place.

## 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 13 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.

## Organizational structure

The significant subsidiaries of the group at 31 December 2007 and to the group percentage of ordinary share capital (to the nearest whole number) are set out in Financial statements Note 46 on page 167. See Financial statements Notes 26 and 27 on pages 134 and 135 respectively for information on significant jointly controlled entities and associates of the group.

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## Financial and operating performance

### Group operating results

The following summarizes the group s operating results.

| | $ million except per share amounts | | |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Sales and other operating revenues from continuing operations[a] | **284,365** | 265,906 | 239,792 |
| Profit from continuing operations[a] | **21,169** | 22,626 | 22,133 |
| Profit for the year | **21,169** | 22,601 | 22,317 |
| Profit for the year attributable to BP shareholders | **20,845** | 22,315 | 22,026 |
| Profit attributable to BP shareholders per ordinary share cents | **108.76** | 111.41 | 104.25 |
| Dividends paid per ordinary share cents | **42.30** | 38.40 | 34.85 |

[a] Excludes Innovene, which was treated as a discontinued operation in accordance with IFRS 5 Non-current Assets Held for Sale and Discontinued Operations . See Financial statements Note 3 on page 110.

#### Business environment

Crude oil prices reached new record highs in 2007 in nominal terms. The average dated Brent price rose to $72.39 per barrel, an increase of 11% over the $65.14 per barrel average seen in 2006. Daily prices began the year at $58.62 per barrel and rose to $96.02 per barrel at year-end due to OPEC production cuts in early 2007, sustained consumption growth and the resulting drop in commercial inventories after the summer.

Natural gas prices in the US and the UK declined in 2007. The Henry Hub First of Month Index averaged $6.86 per mmBtu, 5% lower than the 2006 average of $7.24 per mmBtu. Prices were pressured by record LNG imports in summer, continued domestic production growth and inventories that set a new record at the end of the storage injection season. Average UK gas prices fell to 29.95 pence per therm at the National Balancing Point in 2007, 29% below the 2006 average of 42.19 pence per therm.

Refining margins reached a new record high in 2007, with the BP Global Indicator Margin (GIM) averaging $9.94 per barrel. The premium for light products above fuel oils remained exceptionally high, reflecting a continuing shortage of upgrading capacity and favouring fully upgraded refineries over less complex sites.

The retail environment continued to be extremely competitive in 2007 with market volatility, high absolute prices, as well as a rising crude market.

The business environment in 2006 was mixed compared with 2005, but still robust in comparison with historical averages. Crude oil and UK natural gas prices increased, while US natural gas prices and global refining margins fell.

The dated Brent price averaged $65.14 per barrel, an increase of more than $10 per barrel over the $54.48 per barrel average seen in 2005, and varied between $78.69 and $55.89 per barrel. Prices peaked in early August before retreating in the face of a mild hurricane season and rising inventories. OPEC action late in the year helped support prices.

Natural gas prices in the US declined in 2006 compared with 2005, but remained well above historical averages. The Henry Hub First of Month Index averaged $7.24 per mmBtu, $1.41 per mmBtu below the 2005 average of $8.65 per mmBtu. Rising production and weak consumption resulted in above average inventories, depressing gas prices relative to crude oil. UK gas prices rose slightly in 2006, averaging 42.19 pence per therm at the National Balancing Point, compared with a 2005 average of 40.71 pence per therm.

Refining margins were only slightly lower in 2006, with the BP GIM averaging $8.39 per barrel. This reflected further oil demand growth, lingering effects on US refinery production from the 2005 hurricanes and gasoline formulation changes in several US states. The premium for light products over fuel oils remained exceptionally high, favouring upgraded refineries over less complex sites.

Retail margins improved slightly in 2006, benefiting from a decline in the cost of product during the second half of the year, despite intense competition.

### Hydrocarbon production

Our total hydrocarbon production during 2007 averaged 2,549mboe/d for subsidiaries and 1,269mboe/d for equity-accounted entities, a decrease of 3% (3.5% for liquids and 2.6% for gas) and 2% (1.3% for liquids and 8.4% for gas) respectively compared with 2006. In aggregate, the decrease primarily reflected the effect of disposals and net entitlement reductions in our PSAs. Compared with 2005, 2006 hydrocarbon production for subsidiaries decreased by 3.3% in 2006 reflecting a decrease of 5.1% for liquids and a decrease of 1.3% for natural gas. Increases in production in our new profit centres were offset by anticipated decline in our existing profit centres and the effect of disposals. Hydrocarbon production for equity-accounted entities increased by 0.1%, reflecting a decrease of 1.3% for liquids and an increase of 10.2% for natural gas.

### Profit attributable to BP shareholders

Profit attributable to BP shareholders for the year ended 31 December 2007 was $20,845 million, including inventory holding gains of $3,558 million. Inventory holding gains or losses are described in footnote a below. Profit attributable to BP shareholders for the year ended 31 December 2006 was $22,315 million, after inventory holding losses of $253 million. Profit attributable to BP shareholders for the year ended 31 December 2005 was $22,026 million, including inventory holding gains of $3,027 million. The profit attributable to BP shareholders for the year ended 31 December 2006 included a loss from Innovene operations of $25 million, compared with a profit of $184 million in the year ended 31 December 2005. The loss/profit from Innovene for the years 2006 and 2005 included losses on remeasurement to fair value of $184 million and $591 million respectively. Financial statements Note 3 on page 110 provides further financial information for Innovene.

Profit attributable to BP shareholders for the year ended 31 December 2007 included net gains of $2,132 million on the disposal of assets; and was after net impairment charges of $1,324 million, a further charge of $500 million in respect of the March 2005 Texas City refinery incident, a charge of $338 million associated with restructuring (with a further charge of $1 billion expected in 2008), a charge of $185 million in relation to new, and revisions to existing, environmental and other provisions, a charge of $91 million in respect of a donation to the BP Foundation, a net fair value loss of $7 million on embedded derivatives (these embedded derivatives are fair valued at each period end with the resulting gains or losses taken to the income statement) and a charge of $410 million in respect of the reassessment of certain provisions.

Profit attributable to BP shareholders for the year ended 31 December 2006 included net gains of $3,286 million on the disposal of assets, net fair value gains of $608 million on embedded derivatives and a credit of $44 million in relation to new, and revisions to existing, environmental and other provisions; and was after a charge of $425 million in respect of the March 2005 Texas City refinery incident, a charge of $535 million relating to the reassessment of certain provisions, a charge of $155 million in respect of a donation to the BP Foundation and a net impairment charge of $121 million.

Profit attributable to BP shareholders for the year ended 31 December 2005 included net gains of $1,429 million on the disposal of assets; and was after net fair value losses of $2,047 million on embedded derivatives, a charge of $1,200 million in respect of the March 2005 Texas City refinery incident, a charge of $412 million in respect of new, and revisions to existing, environmental and other provisions, an impairment charge of $359 million and a charge of $134 million relating to the separation of the Olefins and Derivatives business.

*(See Environmental expenditure on page 52 for more information on environmental charges.)*

The primary additional factors reflected in profit for 2007, compared with 2006, were higher liquids realizations, stronger refining and marketing margins and improved NGLs performance; however, these were more than offset by lower gas realizations, lower reported production volumes, higher production taxes in Alaska, higher costs (primarily reflecting the impact of sector-specific inflation and higher integrity spend), the impact of outages and recommissioning costs at the Texas City and Whiting refineries, reduced supply optimization benefits and a lower contribution from the marketing and trading business in the Gas, Power and Renewables segment.

The primary additional factors reflected in profit attributable to BP shareholders for the year ended 31 December 2006 compared with 2005 were higher oil realizations, higher refining margins (including the benefit of supply optimization), higher retail margins (although this was partially offset by a deterioration in other marketing margins) and higher contributions from the operating businesses in the Gas, Power and Renewables segment; these were offset by the ongoing impact following the Texas City refinery shutdown, lower gas realizations, lower production volumes and higher costs.

Profits and margins for the group and for individual business segments can vary significantly from period to period as a result of changes in such factors as oil prices, natural gas prices and refining margins. Accordingly, the results for the current and prior periods do not necessarily reflect trends, nor do they provide indicators of results for future periods.

Employee numbers were approximately 97,600 at 31 December 2007, 97,000 at 31 December 2006 and 96,200 at 31 December 2005.

[a] Inventory holding gains and losses represent the difference between the cost of sales calculated using the average cost of supplies incurred during the year and the cost of sales calculated on the first-in first-out (FIFO) method. Under the FIFO method, which we use for IFRS reporting, the cost of inventory charged to the income statement is based on the historic cost of acquisition or manufacture rather than the current 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 on a FIFO basis and the charge that would arise using average cost of supplies incurred during the period. For this purpose average cost of supplies incurred during the period is calculated by dividing the total cost of inventory purchased 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.

BP s management believes this information is useful to illustrate to investors the fact that crude oil and product prices can vary significantly from period to period and that the impact on our reported result under IFRS can be significant. Inventory holding gains and losses vary from period to period due principally to changes in oil prices as well as changes to underlying inventory levels. In order for investors to understand the operating performance of the group excluding the impact of oil price changes on the replacement of inventories, and to make comparisons of operating performance between reporting periods, BP s management believes it is helpful to disclose this information.

## Capital expenditure and acquisitions

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Exploration and Production | **13,661** | 13,075 | 10,149 |
| Refining and Marketing | **4,447** | 3,122 | 2,757 |
| Gas, Power and Renewables | **811** | 432 | 235 |
| Other businesses and corporate | **275** | 281 | 797 |
| Capital expenditure | **19,194** | 16,910 | 13,938 |
| Acquisitions and asset exchanges | **1,447** | 321 | 211 |
| | **20,641** | 17,231 | 14,149 |
| Disposals | **(4,267)** | (6,254) | (11,200) |

| | | | |
|---|---|---|---|
| Net investment | **16,374** | 10,977 | 2,949 |

Capital expenditure and acquisitions in 2007, 2006 and 2005 amounted to $20,641 million, $17,231 million and $14,149 million respectively. Acquisitions in 2007 included the remaining 31% of the Rotterdam (Nerefco) refinery from Chevron s Netherlands manufacturing company. There were no significant acquisitions in 2006 or 2005.

Excluding acquisitions and asset exchanges, capital expenditure for 2007 was $19,194 million compared with $16,910 million in 2006 and $13,938 million in 2005. In 2006, this included $1 billion in respect of our investment in Rosneft.

### Finance costs and other finance income/expense

Finance costs comprises group interest less amounts capitalized. Finance costs for continuing operations in 2007 were $1,110 million compared with $718 million in 2006 and $616 million in 2005. The charge in 2007 reflected a higher average gross debt balance than in prior years, and lower capitalized interest than in 2006 as capital construction projects concluded. The increase for 2006 compared with 2005 reflected higher interest rates, partially offset by increased capitalized interest. Finance costs in 2005 included a charge of $57 million arising from early redemption of finance leases.

Other finance income/expense included net pension finance costs, the interest accretion on provisions and, for 2005 and 2006, the interest accretion on the deferred consideration for the acquisition of our investment in TNK-BP. Other finance income for continuing operations in 2007 was $369 million compared with $202 million in 2006 and a net expense of $145 million in 2005. The increase in income year on year largely reflects the higher return on pension assets as the pension asset base applicable to each year increased, reflecting rising asset market valuations.

### Taxation

The charge for corporate taxes for continuing operations in 2007 was $10,442 million, compared with $12,516 million in 2006 and $9,288 million in 2005. The effective rate was 33% in 2007, 36% in 2006 and 30% in 2005. The reduction in the effective rate in 2007 compared with 2006 primarily reflects the reduction in the UK tax rate and a higher proportion of income arising in countries bearing a lower tax rate and other factors. The increase in the effective rate in 2006 compared with 2005 reflected the impact of the increase in the North Sea tax rate enacted by the UK government in July 2006 and the absence of non-recurring benefits that were present in 2005.

## Business results

Profit before interest and taxation from continuing operations, which is before finance costs, other finance expense, taxation and minority interests, was $32,352 million in 2007, $35,658 million in 2006 and $32,182 million in 2005.

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## Exploration and Production

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Sales and other operating revenues from continuing operations | **54,550** | 52,600 | 47,210 |
| Profit before interest and tax from continuing operations[a] | **26,938** | 29,629 | 25,502 |
| Results include: | | | |
| Exploration expense | **756** | 1,045 | 684 |
| Of which: Exploration expenditure written off | **347** | 624 | 305 |

| | | | $ per barrel |
|---|---|---|---|
| Key statistics | | | |
| Average BP crude oil realizations[b] | | | |
| UK | **70.36** | 62.45 | 51.22 |
| US | **68.51** | 62.03 | 50.98 |
| Rest of World | **70.86** | 61.11 | 48.32 |
| BP average | **69.98** | 61.91 | 50.27 |
| Average BP NGL realizations[b] | | | |
| UK | **52.71** | 47.21 | 37.95 |
| US | **44.59** | 36.13 | 31.94 |
| Rest of World | **48.14** | 36.03 | 35.11 |
| BP average | **46.20** | 37.17 | 33.23 |
| Average BP liquids realizations[b c] | | | |
| UK | **69.17** | 61.67 | 50.45 |
| US | **64.18** | 57.25 | 47.83 |
| Rest of World | **69.56** | 59.54 | 47.56 |
| BP average | **67.45** | 59.23 | 48.51 |

| | | | $ per thousand cubic feet |
|---|---|---|---|
| Average BP US natural gas realizations[b] | | | |
| UK | **6.40** | 6.33 | 5.53 |
| US | **5.43** | 5.74 | 6.78 |
| Rest of World | **3.71** | 3.70 | 3.46 |
| BP average | **4.53** | 4.72 | 4.90 |

| | | | $ per barrel |
|---|---|---|---|
| Average West Texas Intermediate oil price | **72.20** | 66.02 | 56.58 |
| Alaska North Slope US West Coast | **71.68** | 63.57 | 53.55 |
| Average Brent oil price | **72.39** | 65.14 | 54.48 |

| | | | |
|---|---|---|---|
| | $ per million British thermal units | | |
| Average Henry Hub gas price[d] | **6.86** | 7.24 | 8.65 |
| | | | pence per therm |
| Average UK National Balancing Point gas price | **29.95** | 42.19 | 40.71 |
| | thousand barrels per day | | |
| Total liquids production for subsidiaries[c e] | **1,304** | 1,351 | 1,423 |
| Total liquids production for equity-accounted entities[c e] | **1,110** | 1,124 | 1,139 |
| | million cubic feet per day | | |
| Natural gas production for subsidiaries[e] | **7,222** | 7,412 | 7,512 |
| Natural gas production for equity-accounted entities[e] | **921** | 1,005 | 912 |
| | thousand barrels of oil equivalent per day | | |
| Total production for subsidiaries[e f] | **2,549** | 2,629 | 2,718 |
| Total production for equity-accounted entities[e f] | **1,269** | 1,297 | 1,296 |

[a] Includes profit after interest and tax of equity-accounted entities.
[b] The Exploration and Production segment does not undertake any hedging activity. Consequently, realizations reflect the market price achieved.
[c] Crude oil and natural gas liquids.
[d] Henry Hub First of Month Index.
[e] Net of royalties.
[f] Expressed in thousands of barrels of oil equivalent per day (mboe/d). Natural gas is converted to oil equivalent at 5.8 billion cubic feet = 1 million barrels.

Sales and other operating revenues for 2007 were $55 billion, compared with $53 billion in 2006 and $47 billion in 2005. The increase in 2007 primarily reflected an increase of around $3.5 billion related to higher realizations, partially offset by a decrease of around $1.5 billion due to lower volumes of subsidiaries. The increase in 2006 primarily reflected an increase of around $6 billion related to higher liquids and gas realizations, partially offset by a decrease of around $1 billion due to lower volumes of subsidiaries.

Profit before interest and tax for the year ended 31 December 2007 was $26,938 million, including net gains of $907 million on the sales of assets (primarily gains from the disposal of our production and gas infrastructure in the Netherlands, our interests in non-core Permian assets in the US and our interests in the Entrada field in the Gulf of Mexico), net fair value gains of $47 million on embedded derivatives (these embedded derivatives are fair valued at each period end with the resulting gains or losses taken to the income statement) and inventory

holding gains of $11 million; and was after a net impairment charge of $55 million, restructuring costs of $166 million, a charge of $168 million in respect of the reassessment of certain provisions and a charge of $12 million in respect of new, and revisions to existing, environmental and other provisions.

Profit before interest and tax for the year ended 31 December 2006 was $29,629 million, including net gains of $2,114 million on the sales of assets (primarily gains from the sales of our interest in the Shenzi discovery in the Gulf of Mexico in the US and interests in the North Sea offset by a loss on the sale of properties in the Gulf of Mexico Shelf), net fair value gains of $515 million on embedded derivatives and a net impairment credit of $203 million (comprising a $340 million credit for reversals of previously booked impairments partially offset by a charge of $109 million against intangible assets relating to properties in Alaska, and other individually insignificant impairments), and was after inventory

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holding losses of $18 million and charges for legal provisions of $335 million.

Profit before interest and tax for the year ended 31 December 2005 was $25,502 million, including inventory holding gains of $17 million and net gains of $1,159 million on the sales of assets, primarily from our interest in the Ormen Lange field in Norway, and was after net fair value losses of $1,688 million on embedded derivatives, an impairment charge of $226 million in respect of fields in the Gulf of Mexico, a charge for impairment of $40 million relating to fields in the UK North Sea and a charge of $265 million on the cancellation of an intra-group gas supply contract.

The primary additional factors reflected in profit before interest and tax for the year ended 31 December 2007 compared with the year ended 31 December 2006 were higher overall realizations contributing around $3,000 million (liquids realizations were higher and gas realizations were lower) and a favourable effect from lagged tax reference prices in TNK-BP contributing around $500 million; however, these factors were more than offset by decreases of around $1,000 million due to lower reported volumes, around $200 million due to higher production taxes in Alaska and around $2,800 million due to higher costs, reflecting the impacts of sector-specific inflation, increased integrity spend and higher depreciation charges. Additionally, the full-year result was lower by

around $1,000 million due to the absence of disposal gains in 2006 in equity-accounted entities.

The primary additional factors reflected in profit before interest and tax for the year ended 31 December 2006 compared with the year ended 31 December 2005 were higher overall realizations contributing around $5,050 million (liquids realizations were higher and gas realizations were lower), partially offset by decreases of around $1,825 million due to lower reported volumes, $350 million due to higher production taxes and $1,950 million due to higher costs, reflecting the impacts of sector-specific inflation, increased integrity spend and revenue investments. Additionally, BP s share of the TNK-BP result was higher by around $500 million, primarily reflecting higher disposal gains.

Total production for 2007 was 2,549mboe/d for subsidiaries and 1,269mboe/d for equity-accounted entities, compared with 2,629mboe/d and 1,297mboe/d respectively in 2006. In aggregate, the decrease primarily reflected the effect of disposals and net entitlement reductions in our PSAs.

Total production for 2006 was 2,629mboe/d for subsidiaries and 1,297mboe/d for equity-accounted entities, compared with 2,718mboe/d and 1,296mboe/d respectively in 2005. For subsidiaries, increases in production in our new profit centres were offset by anticipated decline in our existing profit centres and the effect of disposals.

## Refining and Marketing

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Sales and other operating revenues from continuing operations | **250,866** | 232,855 | 213,326 |
| Profit before interest and tax from continuing operations[a] | **6,072** | 5,541 | 6,426 |
| | | | $ per barrel |
| Global Indicator Refining Margin (GIM)[b] | | | |
| Northwest Europe | **4.99** | 3.92 | 5.47 |
| US Gulf Coast | **13.48** | 12.00 | 11.40 |
| Midwest | **12.81** | 9.14 | 8.19 |
| US West Coast | **15.05** | 14.84 | 13.49 |
| Singapore | **5.29** | 4.22 | 5.56 |
| BP average | **9.94** | 8.39 | 8.60 |
| | | | % |

| | | | |
|---|---|---|---|
| Refining availability[c] | **82.9** | 82.5 | 92.9 |
| | | thousand barrels per day | |
| Refinery throughputs | **2,127** | 2,198 | 2,399 |

[a] Includes profit after interest and tax of equity-accounted entities.

[b] The GIM is the average of regional industry indicator margins that we weight 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 refining margins are industry-specific rather than BP-specific measures, which we believe are useful to investors in analyzing trends in the industry and their impact on our results. The margins are calculated by BP based on published crude oil and product prices and take account of fuel utilization and catalyst costs. No account is taken of BP s other cash and non-cash costs of refining, such as wages and salaries and plant depreciation. 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.

[c] Refining availability is defined as the ratio of units that are available for processing, regardless of whether they are actually being used, to total capacity. Where there is planned maintenance, such capacity is not regarded as being available. During 2006 and 2007, there was planned maintenance of a substantial part of the Texas City refinery.

The changes in sales and other operating revenues are explained in more detail below.

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Sale of crude oil through spot and term contracts | **43,004** | 38,577 | 36,992 |
| Marketing, spot and term sales of refined products | **194,979** | 177,995 | 155,098 |
| Other sales including non-oil and to other segments | **12,883** | 16,283 | 21,236 |
| | **250,866** | 232,855 | 213,326 |
| | | thousand barrels per day | |
| Sale of crude oil through spot and term contracts | **1,885** | 2,110 | 2,464 |
| Marketing, spot and term sales of refined products | **5,624** | 5,801 | 5,888 |

Sales and other operating revenues for 2007 was $251 billion, compared with $233 billion in 2006 and $213 billion in 2005. The increase in 2007 compared with 2006 was principally due to an increase of around $17 billion in marketing, spot and term sales of refined products. This was due to higher prices of $13 billion and a positive foreign exchange

impact due to a weaker dollar of $6 billion, partially offset by lower volumes of $2 billion. Additionally, sales of crude oil, spot and term contracts increased by $4 billion, primarily reflecting higher prices, and other sales decreased by $3 billion, due to lower volumes of $4 billion partially offset by a positive foreign exchange impact of $1 billion.

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Sales and other operating revenues for 2006 was $233 billion, compared with $213 billion in 2005 and $171 billion in 2004. The increase in 2006 compared with 2005 was principally due to an increase of around $23 billion in marketing, spot and term sales of refined products. This was due to higher prices of $25 billion, partially offset by lower volumes of $2 billion. Additionally, sales of crude oil, spot and term contracts increased by $2 billion, reflecting higher prices of $6 billion and lower volumes of $4 billion, and other sales decreased by $5 billion, primarily due to lower volumes.

Profit before interest and tax for the year ended 31 December 2007 was $6,072 million, including net disposal gains of $1,151 million (primarily related to the sale of BP s Coryton refinery in the UK, its interest in the West Texas pipeline system in the US and its interest in the Samsung Petrochemical Company in South Korea) and inventory holding gains of $3,455 million; and was after impairment charges of $1,186 million (primarily related to the sale of the majority of our US Convenience Retail business, a write-down of certain assets at our Hull site and a write-down of our Mexico retail assets), a charge of $500 million related to the March 2005 Texas City refinery incident, a charge of $138 million relating to new, and revisions to existing, environmental and other provisions, a restructuring charge of $118 million, a charge of $91 million in respect of a donation to the BP Foundation and a charge of $70 million related to the reassessment of certain provisions.

Profit before interest and tax for the year ended 31 December 2006 was $5,541 million, including net disposal gains of $884 million (related primarily to the sale of BP s Czech Republic retail business, the disposal of BP s shareholding in Zhenhai Refining and Chemicals Company, the sale of BP s shareholding in Eiffage, the French-based construction company, and pipelines assets), and was after inventory holding losses of $242 million, a charge of $425 million related to the March 2005 incident at the Texas City refinery, an impairment charge of $155 million, a charge of $155 million in respect of a donation to the BP Foundation and a charge of $33 million relating to new, and revisions to existing, environmental and other provisions.

Profit before interest and tax for the year ended 31 December 2005 was $6,426 million, including inventory holding gains of $2,532 million and net gains of $177 million principally on the divestment of a number

of regional retail networks in the US, and is after a charge of $1,200 million related to the March 2005 incident at the Texas City refinery, a charge of $140 million relating to new, and revisions to existing, environmental and other provisions, an impairment charge of $93 million and a charge of $33 million for the impairment of an equity-accounted entity.

During 2007, the segment continued to focus on the restoration of operations at the Texas City refinery and on investments in integrity management throughout our refining portfolio. We have also focused on the repair and recommissioning of the Whiting refinery following the operational issues in March 2007. In many parts of the refining portfolio and the other market-facing businesses, we delivered high reliability and improved results compared with 2006. However, for the full year, compared with 2006, the impact of the outages and recommissioning costs at the Texas City and Whiting refineries, as well as investments in integrity management and scheduled turnarounds throughout our refining portfolio, reduced the result by around $1,600 million, cost inflation reduced the result by around $100 million and lower results from supply optimization decreased the result by around $1,500 million. These factors more than offset increased margins in both refining and marketing that contributed around $1,150 million.

In comparison with the year ended 31 December 2005, profit before interest and tax for the year ended 31 December 2006 reflected higher refining margins (including the benefit of supply optimization), which contributed around $900 million, higher retail margins by around $600 million (although this was partially offset by a deterioration of around $150 million in other marketing margins) and lower costs associated with rationalization programmes of around $320 million. There was a reduction of around $1.1 billion due to the impact of the progressive recommissioning of Texas City during the year. Efficiency programmes delivered lower operating costs although the savings were offset by higher turnaround and integrity management spend.

The average refining Global Indicator Margin (GIM) in 2007 was higher than in 2006.

Refining throughputs in 2007 were 2,127mb/d, 71mb/d lower than in 2006. Refining availability was 82.9%, broadly consistent with 2006. Marketing volumes at 3,806mb/d were around 2% lower than in 2006.

## Gas, Power and Renewables

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |

| | | | |
|---|---|---|---|
| Sales and other operating revenues from continuing operations | **21,369** | 23,708 | 25,696 |
| Profit before interest and tax from continuing operations[a] | **674** | 1,321 | 1,172 |

[a] Includes profit after interest and tax of equity-accounted entities.

The changes in sales and other operating revenues are explained in more detail below.

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Gas marketing sales | **8,639** | 11,428 | 15,222 |
| Other sales (including NGL marketing) | **12,730** | 12,280 | 10,474 |
| | **21,369** | 23,708 | 25,696 |

| | | | million cubic feet per day |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Gas marketing sales volumes | **3,382** | 3,685 | 5,096 |
| Natural gas sales by Exploration and Production | **4,414** | 5,152 | 4,747 |

Sales and other operating revenues for 2007 was $21 billion, compared with $24 billion in 2006. Gas marketing sales decreased by $2.8 billion reflecting a decrease of $0.9 billion related to lower volumes and a decrease of $1.9 billion related to lower prices. Other sales (including NGLs marketing) increased by $0.5 billion, reflecting an increase of $0.8 billion related to higher prices, partially offset by a decrease of $0.3 billion related to lower volumes. Sales and other operating revenues were $24 billion in 2006, compared with $26 billion in 2005. Gas

marketing sales declined by $3.8 billion, reflecting a decrease of $4.2 billion related to lower volumes, partially offset by an increase of $0.4 billion related to higher prices. Other sales (including NGLs marketing) increased by $1.8 billion due to higher prices. Gas marketing sales volumes declined in 2007 and 2006 primarily due to customer portfolio changes.

Profit before interest and tax for the year ended 31 December 2007 was $674 million, including inventory holding gains of $116 million and

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net disposal gains of $12 million; and was after a net fair value charge of $47 million on embedded derivatives, impairment charges of $40 million and restructuring charges of $22 million.

Profit before interest and tax for the year ended 31 December 2006 was $1,321 million, including net gains of $193 million, primarily on the disposal of our interest in Enagas, and net fair value gains of $88 million on embedded derivatives, and was after inventory holding losses of $55 million and a charge $100 million for the impairment of a North American NGLs asset.

Profit before interest and tax for the year ended 31 December 2005 was $1,172 million, including inventory holding gains of $95 million, compensation of $265 million received on the cancellation of an intragroup gas supply contract and net gains of $55 million primarily on the disposal of BP s interest in the Interconnector pipeline and a power plant in the UK, and was after net fair value losses of $346 million on embedded derivatives and a credit of $6 million related to new, and revisions to existing, environmental and other provisions.

The primary additional factors reflected in profit before interest and tax for the year ended 31 December 2007, compared with the equivalent period in 2006, were lower contributions from the marketing and trading businesses of around $700 million partially offset by improved NGL s performance contributing around $250 million.

The primary additional factors reflected in profit before interest and tax for the year ended 31 December 2006, compared with the equivalent period in 2005, were higher contributions from the operating businesses of around $100 million.

## Other businesses and corporate

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Sales and other operating revenues from continuing operations | **843** | 1,009 | 668 |
| Profit (loss) before interest and tax from continuing operations[a] | **(1,128)** | (885) | (1,237) |

[a] Includes profit after interest and tax of equity-accounted entities.

Other businesses and corporate comprises treasury (which includes all the group s cash, cash equivalents and finance debt balances and associated interest income and finance costs), the group s aluminium asset, and corporate activities worldwide.

The loss before interest and tax for the year ended 31 December 2007 was $1,128 million, including a net gain on disposal of $62 million; and was after inventory holding losses of $24 million, a charge of $35 million in relation to new, and revisions to existing, environmental and other provisions, a charge of $32 million in respect of restructuring costs, an impairment charge of $43 million, a net fair value loss of $7 million on embedded derivatives and a charge of $172 million relating to the reassessment of certain provisions.

The loss before interest and tax for the year ended 31 December 2006 was $885 million, including inventory holding gains of $62 million, a credit of $94 million in relation to new, and revisions to existing, environmental and other provisions, a net gain on disposal of $95 million and a net fair value gain of $5 million on embedded derivatives; and was after a charge of $200 million relating to the reassessment of certain provisions and an impairment charge of $69 million.

The loss before interest and tax for the year ended 31 December 2005 was $1,237 million, including a net gain on disposal of $38 million; and was after a net charge of $278 million relating to new, and revisions to existing, environmental and other provisions and the reversal of environmental provisions no longer required, a charge of $134 million in respect of the separation of the Olefins and Derivatives business and net fair value losses of $13 million on embedded derivatives.

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## 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.

The Gas, Power and Renewables business 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 that are fair valued under IFRS. This results in measurement differences in relation to recognition of gains and losses.

The way that BP manages the economic exposures described above, and measures performance internally, differs from the way these activities are measured under IFRS. BP calculates this difference 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, are shown in the table below.

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| **Refining and Marketing** | | | |
| Unrecognized gains (losses) brought forward from previous period | **72** | 283 | (61) |
| Unrecognized (gains) losses carried forward | **(429)** | (72) | (283) |
| Favourable (unfavourable) impact relative to management s measure of performance | **(357)** | 211 | (344) |
| **Gas, Power and Renewables** | | | |
| Unrecognized gains (losses) brought forward from previous period | **155** | 123 | 147 |
| Unrecognized (gains) losses carried forward | **(107)** | (155) | (123) |
| Favourable (unfavourable) impact relative to management s measure of performance | **48** | (32) | 24 |
| | **(309)** | 179 | (320) |
| Taxation | **105** | (96) | 103 |

| | | | |
|---|---|---|---|
| | **(204)** | 83 | (217) |
| **By region** | | | |
| **Refining and Marketing** | | | |
| UK | **(52)** | 109 | (80) |
| Rest of Europe | **(110)** | 101 | (45) |
| US | **(165)** | 13 | (220) |
| Rest of World | **(30)** | (12) | 1 |
| | **(357)** | 211 | (344) |
| **Gas, Power and Renewables** | | | |
| UK | **1** | 63 | 39 |
| Rest of Europe | | | (9) |
| US | **(77)** | (59) | (32) |
| Rest of World | **124** | (36) | 26 |
| | **48** | (32) | 24 |
| **Reconciliation of non-GAAP information** | | | |
| **Refining and Marketing** | | | |
| Profit before interest and tax adjusted for fair value accounting effects | **6,429** | 4,830 | 7,270 |
| Impact of fair value accounting effects | **(357)** | 211 | (344) |
| Profit before interest and tax | **6,072** | 5,041 | 6,926 |
| **Gas, Power and Renewables** | | | |
| Profit before interest and tax adjusted for fair value accounting effects | **626** | 1,238 | 1,389 |
| Impact of fair value accounting effects | **48** | 83 | (217) |
| Profit before interest and tax | **674** | 1,321 | 1,172 |

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## Environmental expenditure

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Operating expenditure | **662** | 596 | 494 |
| Clean-ups | **62** | 59 | 43 |
| Capital expenditure | **1,033** | 806 | 789 |
| Additions to environmental remediation provision | **373** | 423 | 565 |
| Additions to decommissioning provision | **1,163** | 2,142 | 1,023 |

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.

The increase in environmental operating expenditure in 2007 compared with 2006 is primarily due to increased integrity management activity and activity associated with the implementation of the Baker Panel recommendations. The increase in environmental operating expenditure in 2006 compared with 2005 is largely related to expenditure incurred on reducing air emissions at US refineries. 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 is normally in subsequent periods and is not included in environmental operating expenditure reported for such periods. The charge for environmental remediation provisions in 2007 includes $339 million resulting from a reassessment of existing site obligations and $34 million in respect of provisions for new sites.

Provisions for environmental remediation are made when a clean-up is probable and the amount reasonably determinable. Generally, their timing coincides with commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

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 liability. Although the cost of any future remediation could be significant and may be material to the result of operations in the period in which it is recognized, we do not expect that such costs will have a material effect on the group s financial position or liquidity. We believe our provisions are sufficient for known requirements; we do not believe that our costs will differ significantly from those of other companies engaged in similar industries, or that our competitive position will be adversely affected as a result.

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. Additionally, we undertake periodic reviews of existing provisions. These reviews take account of revised cost assumptions, changes in decommissioning requirements and any technological developments. 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.

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 151. See also Environment on page 40.

### 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 BPs commitments to compliance and ethics, as outlined in the 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 1985 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.

## Contributing to communities

We make direct contributions to communities through community programmes. Our total contribution in 2007 was $135.8 million. This includes $0.7 million contributed by BP to UK charities. The growing focus of this is on education, the development of local enterprise and providing access to energy in remote locations.

In 2007, we spent $77.7 million promoting education, with investment in three broad areas: energy and the environment; business leadership skills; and basic education in developing countries where we operate large projects.

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## Liquidity and capital resources

### Cash flow

The following table summarizes the group s cash flows.

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Net cash provided by operating activities of continuing operations | **24,709** | 28,172 | 25,751 |
| Net cash provided by operating activities of Innovene operations | | | 970 |
| Net cash provided by operating activities | **24,709** | 28,172 | 26,721 |
| Net cash used in investing activities | **(14,837)** | (9,518) | (1,729) |
| Net cash used in financing activities | **(9,035)** | (19,071) | (23,303) |
| Currency translation differences relating to cash and cash equivalents | **135** | 47 | (88) |
| Increase (decrease) in cash and cash equivalents | **972** | (370) | 1,601 |
| Cash and cash equivalents at beginning of year | **2,590** | 2,960 | 1,359 |
| Cash and cash equivalents at end of year | **3,562** | 2,590 | 2,960 |

Net cash provided by operating activities for the year ended 31 December 2007 was $24,709 million, compared with $28,172 million for the equivalent period of 2006 reflecting an increase in working capital requirements of $6,282 million, a decrease in profit before taxation from continuing operations of $3,531 million, a decrease in dividends from jointly controlled entities and associates of $2,022 million; these were partially offset by a decrease in income taxes paid of $4,661 million, a lower net credit for impairment and gain/loss on sale of businesses and fixed assets of $2,357 million and higher depreciation, depletion and amortization of $1,451 million.

Net cash provided by operating activities for the year ended 31 December 2006 was $28,172 million, compared with $26,721 million for the equivalent period of 2005, reflecting a decrease in working capital requirements of $4,817 million, an increase in profit before taxation from continuing operations of $3,721 million and an increase in dividends from jointly controlled entities and associates of $1,662 million; these were partially offset by an increase in income taxes paid of $4,705 million and a higher net credit for impairment and gain/loss on sale of businesses and fixed assets of $2,095 million.

Net cash used in investing activities was $14,837 million in 2007, compared with $9,518 million and $1,729 million in 2006 and 2005. The increase in 2007 reflected a reduction in disposal proceeds of $1,987 million and an increase in capital expenditure of $2,713 million. The increase in 2006 compared with 2005 reflected a reduction in disposal proceeds of $4,946 million and an increase in capital expenditure of $2,844 million.

| | $ billion |
|---|---|
| Sources | |
| Net cash provided by operating activities | 79 |
| Divestments | 22 |
| Movement in net debt | 6 |

| | 107 |
|---|---|
| | $ billion |
| **Uses** | |
| Capital expenditure | 47 |
| Acquisitions | 2 |
| Net repurchase of shares | 34 |
| Dividends to BP shareholders | 23 |
| Dividends to minority interest | 1 |
| | 107 |

Acquisitions made for cash were more than offset by divestments. Net investment during the same period has averaged $9.0 billion per year. Dividends to BP shareholders, which grew on average by 15.4% per year in dollar terms, used $23 billion. Net repurchase of shares was $34 billion, which includes $35 billion in respect of our share buyback programme less proceeds from share issues. Finally, cash was used to strengthen the financial condition of certain of our pension funds. In the past three years, $2.3 billion has been contributed to funded pension plans.

Net cash used in financing activities was $9,035 million in 2007 compared with $19,071 million in 2006 and $23,303 million in 2005. The reduction in 2007 compared with 2006 reflects a reduction in net repurchases of shares of $8,038 million and an increase in proceeds from long-term financing of $4,278 million; these were partially offset by a net decrease in short-term debt of $2,379 million. The lower outflow in 2006 compared with 2005 reflects a net increase in short-term debt of $5,330 million, a decrease in repayments of long-term financing of $1,165 million and higher proceeds from long-term financing of $1,356 million, partially offset by an increase in the net repurchase of shares of $3,836 million.

The group has had significant levels of capital investment for many years. Cashflow in respect of capital investment, excluding acquisitions, was $18.4 billion in 2007, $15.7 billion in 2006 and $13.1 billion in 2005. Sources of funding are completely fungible, but the majority of the group s funding requirements for new investment come from cash generated by existing operations. The group s level of net debt, that is debt less cash and cash equivalents, was $27.5 billion at the end of 2007, $21.4 billion at the end of 2006 and was $16.2 billion at the end of 2005. The lower level of debt at the end of 2005 reflects the receipt of the Innovene disposal proceeds in December 2005.

During the period 2005 to 2007 our cash inflows and outflows were balanced, with sources and uses both totalling $107 billion. During that period, the price of Brent has averaged $64.00/bbl. The following table summarizes the three-year sources and uses of cash.

## Trend information

Total production for 2008 is expected to be higher than in 2007. This is based on the group's asset portfolio at 1 January 2008, expected startups in 2008 and Brent at $60/bbl, before any 2008 disposal effects and before any effects of prices above $60/bbl on volumes in PSAs.

We expect capital expenditure, excluding acquisitions and asset exchanges and excluding the accounting related to our entry into the Canadian oil sands via two joint ventures with Husky Energy Inc., to be between $21 billion and $22 billion in 2008. This amount includes other investments in equity-accounted entities. The exact level will depend on a number of things including: the actual level of sector inflation that we will experience in the year; time-critical and material one-off investment opportunities that further our strategy; and any acquisition opportunities that may arise.

We expect to restore revenues by ramping up production following our recent start-ups in the Gulf of Mexico, Angola and Trinidad and to bring refinery production at the Texas City and Whiting refineries back online.

## Dividends and other distributions to shareholders and gearing

The total dividend paid in 2007 was $8,106 million, compared with $7,686 million for 2006. The dividend paid per share was 42.30 cents, an increase of 10% compared with 2006. In sterling terms, the dividend remained flat due to the weakness of the dollar. We determine the dividend in US dollars, the economic currency of BP.

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During 2007, the company repurchased 663 million of its own shares for cancellation at a cost of $7.5 billion. The repurchased shares had a nominal value of $166 million and represented 3.4% of ordinary shares in issue, net of treasury shares, at the end of 2006. Since the inception of the share repurchase programme in 2000, we have repurchased 4,659 million shares at a cost of $48.2 billion.

Our dividend policy has been to grow the dividend per share progressively, guided by several considerations including the prevailing circumstances of the group, the future investment patterns and sustainability of the group and the trading environment. We have also been committed to returning all free cash flows in excess of dividend needs to our shareholders. These broad principles remain, but changes in our business and the trading environment have given us greater confidence in our future cash flows and have led us to rebalance the uses of this cash.

We now hold a more positive view of the pricing environment, especially for oil, and we expect our financial performance will be boosted by growing revenues, increased production and improved refining availability. We also see significant potential for cost efficiencies and improved performance across all our businesses. Our reduced equity base, resulting from our share buyback programme, has made per-share dividend increases more affordable. In light of these factors, we have decided to increase organic capital expenditure (that is capital expenditure excluding acquisitions and assets exchanges) to support growth, and to rebalance our distributions between dividends and share buybacks. We continue to believe that a gearing band of 20-30% provides an efficient capital structure and the appropriate level of financial flexibility. Taken together, these factors led us to increase the dividend by 25% for the fourth quarter, compared with the third quarter. As a result, the level of free cash flow allocated to share buybacks is likely to be lower. We will, however, continue to use share buybacks as a mechanism to return excess cash to shareholders when appropriate and subject to renewed authority at the April 2008 annual general meeting. At 31 December 2007, gearing was 23%, towards the bottom of the targeted band.

BP intends to continue the operation of the Dividend Reinvestment Plan (DRIP) for shareholders who wish to receive their dividend in the form of shares rather than cash. The BP Direct Access Plan for US and Canadian shareholders also includes a dividend reinvestment feature.

The discussion above and following contains forward-looking statements with regard to future production, future refining availability, future capital expenditure, sources of funding, future revenues and financial performance, potential for cost efficiencies, level of free cash flow allocated to share buybacks, shareholder distributions and share buybacks, gearing, working capital and expected payments under contractual and commercial commitments. 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 under

Forward-looking statements on page 10 and Risk factors on pages 8-9, 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.

**Financing the group s activities**

The group s principal commodity, oil, is priced internationally in US dollars. Group policy has been to minimize economic exposure to currency movements by financing operations with US dollar debt wherever possible, otherwise by using currency swaps when funds have been raised in currencies other than US dollars.

The group s finance debt is almost entirely in US dollars and at 31 December 2007 amounted to $31,045 million (2006 $24,010 million) of which $15,394 million (2006 $12,924 million) was short term.

Net debt was $27,483 million at the end of 2007, an increase of $6,063 million compared with 2006. The ratio of net debt to net debt plus equity was 23% at the end of 2007 and 20% at the end of 2006.

The maturity profile and fixed/floating rate characteristics of the group s debt are described in Financial statements  Note 28 on page 136 and Note 35 on page 148.

We have in place a European Debt Issuance Programme (DIP) under which the group may raise $15 billion of debt for maturities of one month or longer. At 31 December 2007, the amount drawn down against the DIP was $10,438 million.

In addition, the group has in place a US Shelf Registration under which it may raise $10 billion of debt with maturities of one month or longer. At 31 December 2007 the amount raised under the US Shelf Registration was $2,500 million.

Commercial paper markets in the US and Europe are a primary source of liquidity for the group. At 31 December 2007, the outstanding commercial paper amounted to $5,881 million.

The group also has access to significant sources of liquidity in the form of committed facilities and other funding through the capital markets. At 31 December 2007, the group had available undrawn committed borrowing facilities of $4,950 million ($4,700 million at 31 December 2006).

BP believes that, taking into account the substantial amounts of undrawn borrowing facilities available, the group has sufficient working capital for foreseeable requirements.

## Off-balance sheet arrangements

In addition to reported debt, BP uses conventional off-balance sheet arrangements such as operating leases and borrowings in jointly controlled entities and associates. At 31 December 2007, the group s share of third-party finance debt of jointly controlled entities and associates was $5,894 million (2006 $4,942 million) and $870 million (2006 $1,143 million) respectively. 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 2007 are summarized below. Some guarantees outstanding are in respect of borrowings of jointly controlled entities and associates noted above. The analysis by time period indicates the ultimate expiry of the guarantees.

| | | | | | | | $ million |
|---|---|---|---|---|---|---|---|
| | | | | | | | Guarantees expiring by period |
| | Total | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 and thereafter |
| Guarantees issued in respect of[a] | | | | | | | |
| Liabilities and borrowings of jointly controlled entities and associates | 443 | 180 | 19 | 6 | 3 | 56 | 179 |
| Liabilities and borrowings of other third parties | 601 | 83 | 27 | 10 | 7 | 7 | 467 |

[a] Of the amounts shown in the table, $284 million of the jointly controlled entities and associates guarantees relate to guarantees of borrowings and for other third parties guarantees $574 million relates to guarantees of borrowings.

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## Contractual commitments

The following table summarizes the group s principal contractual obligations at 31 December 2007. Further information on borrowings and finance leases is given in Financial statements Note 35 on page 148 and further information on operating leases is given in Financial statements Note 15 on page 126.

$ million

| | | | | | | | Payments due by period |
|---|---|---|---|---|---|---|---|
| Expected payments by period under contractual obligations and commercial commitments | Total | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 and thereafter |
| Borrowings[a] | 33,142 | 16,293 | 7,910 | 3,410 | 1,339 | 2,273 | 1,917 |
| Finance lease future minimum lease payments | 1,291 | 268 | 101 | 105 | 108 | 79 | 630 |
| Operating leases[b] | 16,938 | 3,780 | 3,016 | 1,975 | 1,445 | 1,224 | 5,498 |
| Decommissioning liabilities | 13,416 | 455 | 342 | 438 | 195 | 244 | 11,742 |
| Environmental liabilities | 2,260 | 448 | 424 | 326 | 245 | 202 | 615 |
| Pensions and other post-retirement benefits[c] | 23,743 | 1,134 | 1,127 | 883 | 717 | 718 | 19,164 |
| Purchase obligations[d] | 164,943 | 105,922 | 16,739 | 9,446 | 5,986 | 4,711 | 22,139 |

[a] Expected payments include interest payments on borrowings totalling $2,990 million ($1,145 million in 2008, $767 million in 2009, $401 million in 2010, $247 million in 2011, $191 million in 2012 and $239 million thereafter).

[b] The future minimum lease payments are before deducting related rental income from operating sub-leases. Where an operating lease is entered into solely by the group as the operator of a jointly controlled asset, the total cost is included irrespective of any amounts that will be reimbursed by joint venture partners. 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.

[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] 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 2008 include purchase commitments existing at 31 December 2007 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 28 on page 136.

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

$ million

| | | | | | | | Payments due by period |
|---|---|---|---|---|---|---|---|
| Purchase obligations | Total | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 and thereafter |
| Crude oil and oil products | 82,830 | 66,391 | 4,333 | 3,156 | 2,012 | 1,477 | 5,461 |
| Natural gas | 41,064 | 21,314 | 5,757 | 2,893 | 1,926 | 1,520 | 7,654 |
| Chemicals and other refinery feedstocks | 13,564 | 4,694 | 2,078 | 1,490 | 900 | 643 | 3,759 |
| Power | 14,662 | 10,929 | 3,079 | 648 | 1 | 5 | |
| Utilities | 1,545 | 182 | 135 | 119 | 118 | 116 | 875 |
| Transportation | 3,921 | 1,116 | 615 | 452 | 330 | 266 | 1,142 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Use of facilities and services | 7,357 | 1,296 | 742 | 688 | 699 | 684 | 3,248 |
| Total | 164,943 | 105,922 | 16,739 | 9,446 | 5,986 | 4,711 | 22,139 |

The group expects its total capital expenditure, excluding acquisitions and asset exchanges and excluding the accounting related to our entry into the Canadian oil sands via two joint ventures with Husky Energy Inc., to be around $21-22 billion in 2008. This amount includes other investments in equity-accounted entities. The following table summarizes the group s capital expenditure commitments for property, plant and equipment at 31 December 2007 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 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 and thereafter |
|---|---|---|---|---|---|---|---|
| Committed on major projects | 24,013 | 5,329 | 3,799 | 1,646 | 742 | 1,403 | 11,094 |
| Amounts for which contracts have been placed | 8,263 | 5,200 | 1,999 | 747 | 187 | 57 | 73 |

In addition, at 31 December 2007, the group had committed to capital expenditure relating to investments in equity-accounted entities amounting to $4.5 billion. Contracts were in place for $1.1 billion of this total. The transaction with Husky Energy Inc., whereby BP will contribute $2.5 billion in return for an interest in an equity-accounted joint venture, is included in the committed capital expenditure. For further information, see Financial statements Note 3 on page 110.

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## Critical accounting policies

The significant accounting policies of the group are summarized in Financial statements Note 1 on page 100.

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 further 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, deferred taxation, provisions and contingencies, and pensions and other post-retirement benefits.

### Oil and natural gas accounting

The group follows 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.

Licence and property acquisition costs are initially capitalized within intangible assets. These costs are amortized on a straight-line basis until such time that a determination is made on whether exploratory drilling activity is successful. Where a determination is made that the exploratory drilling is unsuccessful all costs are written off. Each property is reviewed on an annual basis to confirm that drilling activity is planned and that it is not impaired. If no future activity is planned, the remaining balance of the licence and property acquisition costs is written off.

For exploration wells and exploratory-type stratigraphic test wells, costs directly associated with the drilling of wells are temporarily capitalized within non-current 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 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 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 licence and property acquisition costs and exploration and appraisal costs are transferred to production assets within property, plant and equipment. Field development costs subject to depreciation are expenditures incurred to date, together with approved future development expenditure required to develop reserves.

The capitalized exploration and development costs for proved oil and gas properties (which include the costs of drilling unsuccessful wells) are amortized on the basis of oil-equivalent barrels that are produced in a period as a percentage of the estimated proved reserves.

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:

- Producing wells proved developed reserves.
- Licence and property acquisition, field development 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*).

Given the large number of producing fields in the group s portfolio, it is unlikely that any changes in reserves estimates for individual fields, either individually or in aggregate, year on year, will have a significant effect on the group s prospective charges for depreciation.

At the end of 2006, BP adopted the SEC rules for estimating reserves instead of the UK accounting rules contained in the UK Statement of Recommended Practice. These changes are explained in Financial statements Note 9 on page 120.

The estimation of oil and natural gas reserves and BP s process to manage reserves bookings is described in Exploration and Production Reserves and production on page 14. 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 2007 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 on pages 181 to 189.

**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 unprofitable performance, low plant utilization and, for oil and 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 cash-generating unit and associated goodwill with the recoverable amount of the asset, 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 based on the group s plans to continue to develop and produce proved reserves and associated risk-adjusted probable and possible volumes. Expected future cash flows from the sale or production of these volumes are calculated based on the group s best estimate of future oil and gas prices. 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 2007, the group s long-term planning assumptions were $60 per barrel for Brent and $7.50 per mmBtu for Henry Hub (2006 $40 per barrel and $5.50 per 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, lifting and development costs, field decline rates, market demand and supply, economic regulatory climates and other factors.

The future cash flows are adjusted for risks specific to the asset where appropriate and are discounted using a pre-tax discount rate of 11% (2006 10%). 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 country-specific risk.

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 $11.0 billion on its balance sheet, 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. The cash-generating units for impairment testing in this case are one level below business segments. As noted above, 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.

## Deferred taxation

The group has carry-forward tax losses in certain taxing jurisdictions that are available to offset against future taxable income. However, deferred tax assets are recognized only to the extent that it is considered more likely than not that suitable taxable income will arise. Management judgement is exercised in assessing whether this is the case. For further information see Financial statements Note 20 on page 128 and Note 44 on page 165.

## 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 asset removal obligations facing BP relate to the removal and disposal of oil and natural gas platforms and pipelines around the world. The estimated discounted costs of dismantling and removing these facilities are accrued on the installation of those 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 removal 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. Asset removal 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 provided for, 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 2007 was 2%, unchanged from the end of 2006. The interest rate represents the real rate (i.e. adjusted for 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 requires 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 clean-up and remediation costs are 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 2007 was 2%, the same rate as at the previous balance sheet date.

As further described in Financial statements Note 44 on page 165, 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.

### 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, healthcare cost trend rates and rates of utilization of healthcare services by 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 in December 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 post-retirement benefit expense for the following year.

The pension and other post-retirement benefit assumptions at 31 December 2007, 2006 and 2005 are provided in Financial statements Note 38 on page 152.

The assumed rate of investment return, discount 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 152.

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. BP s most substantial pension liabilities are in the UK, US and Germany and the mortality assumptions for these countries are detailed in Financial statements Note 38 on page 152.

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# Directors, senior management and employees

The following lists the company s directors and senior management as at 19 February 2008.

| Name | | Initially elected or appointed |
|---|---|---|
| P D Sutherland | Chairman | Chairman since May 1997<br>Director since July 1995 |
| Sir Ian Prosser | Non-Executive Deputy Chairman | Deputy chairman since February 1999<br>Director since May 1997 |
| A Burgmans | Non-Executive Director | February 2004 |
| C B Carroll | Non-Executive Director | June 2007 |
| Sir William Castell | Non-Executive Director | July 2006 |
| G David | Non-Executive Director | February 2008 |
| E B Davis, Jr | Non-Executive Director | December 1998 |
| D J Flint | Non-Executive Director | January 2005 |
| Dr D S Julius | Non-Executive Director | November 2001 |
| Sir Tom McKillop | Non-Executive Director | July 2004 |
| Dr W E Massey | Non-Executive Director | December 1998 |
| Dr A B Hayward | Executive Director (Group Chief Executive) | Group Chief Executive since May 2007<br>Director since February 2003 |
| Dr D C Allen | Executive Director, Special Adviser (formerly Group Chief of Staff) | February 2003 |
| I C Conn | Executive Director (Chief Executive, Refining and Marketing) | July 2004 |
| Dr B E Grote | Executive Director (Chief Financial Officer) | August 2000 |
| A G Inglis | Executive Director (Chief Executive, Exploration and Production) | February 2007 |
| P B P Bevan | Group General Counsel | September 1992 |
| S Bott | Executive Vice President, Human Resources | March 2005 |
| V Cox | Executive Vice President, Alternative Energy | July 2004 |
| R A Malone | Executive Vice President (Chairman and President of BP America Inc.) | July 2006 |
| J Mogford | Executive Vice President, Safety and Operations | October 2007 |
| S Westwell | Executive Vice President (Group Chief of Staff) | January 2008 |

At the company s 2007 annual general meeting (AGM), the following directors retired, offered themselves for re-election and were duly re-elected: Dr D C Allen, The Lord Browne of Madingley, Mr A Burgmans, Mr I C Conn, Mr E B Davis, Jr, Mr D J Flint, Dr B E Grote, Dr A B Hayward, Dr D S Julius, Sir Tom McKillop, Mr J A Manzoni, Dr W E Massey, Sir Ian Prosser and Mr P D Sutherland.

David Jackson (55) was appointed company secretary in 2003. A solicitor, he is a director of BP Pension Trustees Limited and a member of the Listing Authorities Advisory Committee.

## Directors

### Changes to the board

Set out below is a statement by the chairman describing various changes to the composition of the board that occurred during 2007.

In addition to John Browne s resignation and Tony Hayward s appointment as group chief executive, on which I have already commented in my letter to shareholders, there have been some important changes to the board.

John Manzoni agreed with the board that he would step down as a director on 31 August 2007. He has taken up a senior position in the industry in Canada. John has shown the most immense commitment and dedication to BP through a period of long and loyal service.

David Allen will retire as a director on 31 March 2008. David has served on the board since 2003 and was group chief of staff until 1 January 2008. He has made a significant contribution to the group in many key areas, most particularly in shaping and applying corporate strategy.

I would like to thank John Browne, John Manzoni and David Allen for their contributions.

Walter Massey will stand down at the forthcoming AGM. Walter joined the BP board at the time of the Amoco merger in 1998 and has made a significant contribution in his tireless work as chairman of the safety, ethics and environment assurance committee. His strong scientific background, coupled with his broad experience of the US gained through his academic work and his role on a number of high-profile boards, has resulted in a very broad and significant contribution to the work of the board and its committees. He will be sorely missed and, on behalf of the board, I would like to thank him for all he has done.

I am very pleased to welcome Cynthia Carroll and George David as new non-executive directors. Cynthia, who joined the board in June 2007, is the chief executive of Anglo American plc and has broad experience of the global extractive industries, having previously worked at Alcan and Amoco. Cynthia is a member of the chairman s committee and will join the safety, ethics and environment assurance committee in due course. George was appointed in February 2008. He is the chairman and chief executive of United Technologies Corporation and so has substantial experience of global industry. George is a member of the chairman s committee.

I would also like to welcome Andy Inglis to the board. He was appointed as a director on 1 February 2007 as chief executive of the Exploration and Production segment. On 1 June 2007, Iain Conn became chief executive of the Refining and Marketing segment.

During the year, we have kept under review the mix of skills on the board, particularly in light of the strategic and operational challenges that face the group both now and in the coming years. We have reviewed and refreshed our succession policy for non-executive directors and expect to make further appointments to the board shortly.

Peter Sutherland
Chairman

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P D Sutherland, SC, KCMG

Peter Sutherland (61) rejoined BP s board in 1995, having been a non-executive director from 1990 to 1993, and was appointed chairman in 1997. He is non-executive chairman of Goldman Sachs International and a non-executive director of The Royal Bank of Scotland Group.

*Chairman of the chairman s and the nomination committees*

Sir Ian Prosser

Sir Ian (64) joined BP s board in 1997 and was appointed non-executive deputy chairman in 1999. He is the senior non-executive director. He retired as chairman of InterContinental Hotels Group PLC, a spin-off from Bass PLC where he was chief executive, in 2003. He is the senior independent non-executive director of GlaxoSmithKline plc and a non-executive director of the Sara Lee Corporation. He was previously on the boards of The Boots Company PLC and Lloyds TSB PLC.

*Member of the chairman s, the nomination and the remuneration committees and chairman of the audit committee*

A Burgmans

Antony Burgmans (61) 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 May 2007. He is also a member of the supervisory boards of Akzo Nobel NV and Aegon NV.

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

C B Carroll

Cynthia Carroll (51) joined BP s board on 6 June 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 March 2007. She is also a director of De Beers s.a. and Anglo Platinum Ltd.

*Member of the chairman s committee*

Sir William Castell, LVO

Sir William (60) joined BP s board in July 2006. 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.

*Member of the chairman s, the audit and the safety, ethics and environment assurance committees*

G David

George David (65) joined BP s board on 11 February 2008. He has spent his career with United Technologies Corporation (UTC), becoming its chief executive officer in 1994 and chairman in 1997. He joined UTC s Otis elevator subsidiary in 1975. He is also a director of Citigroup Inc.

*Member of the chairman s committee*

E B Davis, Jr

Erroll B Davis, Jr (63) joined BP s board in 1998, having previously been a director of Amoco. He was chairman and chief executive officer of Alliant Energy, relinquishing this dual appointment in 2005. He continued as chairman of Alliant Energy until February 2006, leaving to become chancellor of the University System of Georgia. He is a member of the board of General Motors Corporation, Union Pacific Corporation and the US Olympic Committee.

*Member of the chairman s, the audit and the remuneration committees*

D J Flint, CBE

Douglas Flint (52) joined BP s board in 2005. He trained as a chartered accountant and became a partner at KPMG in 1988. In 1995, he was appointed group finance director of HSBC Holdings plc. 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.

*Member of the chairman s and the audit committees*

### Dr D S Julius, CBE

DeAnne Julius (58) 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.

*Member of the chairman s and the nomination committees and chairman of the remuneration committee*

### Sir Tom McKillop

Sir Tom (64) joined BP s board in 2004. Sir Tom was chief executive of AstraZeneca PLC from the merger of Astra AB and Zeneca Group PLC in 1999 until December 2005. He was a non-executive director of Lloyds TSB Group PLC until 2004 and is chairman of The Royal Bank of Scotland Group.

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

### Dr W E Massey

Walter Massey (69) joined BP s board in 1998, having previously been a director of Amoco. He is a non-executive director of Bank of America, McDonald s Corporation and Delta Airlines and a member of President Bush s Council of Advisors on Science and Technology. He was president of Morehouse College from 1995 until his retirement in June 2007.

*Member of the chairman s and the nomination committees and chairman of the safety, ethics and environment assurance committee*

### Dr A B Hayward

Tony Hayward (50) joined BP in 1982. He held a series of roles in exploration and production, becoming a director of exploration and production in 1997. In 2000, he was made group treasurer, and an executive vice president in 2002. He was chief executive officer of exploration and production between 2002 and February 2007. He became an executive director of BP in 2003 and was appointed as group chief executive on 1 May 2007. Dr Hayward is a non-executive director of Corus Group plc.

### Dr D C Allen

David Allen (53) joined BP in 1978 and subsequently undertook a number of corporate and exploration and production roles in London and New York. He moved to BP s corporate planning function in 1986, becoming group vice president in 1999. He was appointed executive vice president and group chief of staff in 2000 and an executive director of BP in 2003. Dr Allen relinquished the role of group chief of staff on 1 January 2008, becoming a special adviser to the group chief executive. He will retire from the board on 31 March 2008. He is a director of BP Pension Trustees Limited.

### I C Conn

Iain Conn (45) 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 June 2007. He is a non-executive director of Rolls-Royce Group plc.

### Dr B E Grote

Byron Grote (59) 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.

### A G Inglis

Andy Inglis (48) joined BP in 1980, working on various North Sea projects. Following a series of commercial roles in exploration, in 1996 he became chief of staff, exploration and production. From 1997 until 1999, he was responsible for leading BP s activities in the deepwater Gulf of Mexico. In 1999, he was appointed vice president of BP s US western gas business unit. In 2004, he became executive vice president and deputy chief executive of exploration and production. He was appointed chief executive of BP s exploration and production business and an executive director on 1 February 2007.

## Senior management

### P B P Bevan

Peter Bevan (63) joined BP in 1970 after qualifying as a solicitor with a City of London firm. He worked initially in the law department of BP s chemicals business. He became group general counsel in 1992 following roles as manager of the legal function of BP Exploration, assistant company secretary and deputy group legal adviser. He was appointed an executive vice president of BP in 1998.

### S Bott

Sally Bott (58) joined BP in 2005 as an executive vice president responsible for global human resources management. She joined Citibank in 1970 and, following a variety of roles, was appointed a vice president in human resources in 1979 and subsequently held a series of positions as a human resources director to sectors of Citibank. In 1994, she joined BZW, an investment bank, as head of human resources and in 1996 became group human resources director of Barclays Group. From 2000 to early 2005, she was managing director and head of global human resources at insurance brokers Marsh Inc.

### V Cox

Vivienne Cox (48) joined BP in 1981. Following a series of commercial roles, she was appointed chief executive of Air BP in 1998. From 1999 until 2001, she was group vice president of BP Oil, responsible for business-to-business marketing and oil supply and trading. From 2001 to 2004, she was group vice president for integrated supply and trading. In 2004, she was appointed an executive vice president, responsible for gas, power and renewables in addition to the supply and trading businesses and, in late 2005, also became responsible for alternative energy. She is a non-executive director of Rio Tinto plc.

### R A Malone

Bob Malone (55) was appointed chairman and president of BP America Inc. and an executive vice president in mid-2006. He started his career in 1974 at Kennecott Copper Corporation, holding various roles in environmental engineering, operations and safety. From 1981 until 1988, he was director of health, safety and environment for Kennecott and later held various other roles for BP in America. In 1993, he became president of BP Pipelines Alaska and, in 1996, president and chief operating officer of Alyeska Pipeline Service Company. In 2000, he became western regional president for BP America and from 2002 until 2006 he was chief executive of BP Shipping Limited.

### J Mogford

John Mogford (54) joined BP in 1977, spending the early part of his career in a variety of drilling and production roles. In 1999, he became group vice president for health, safety and the environment before being appointed as group vice president for gas, power and renewables in 2002. In 2004, he returned to exploration and production as group vice president (technology and functions). In 2005, he was appointed as senior group vice president of safety and operations before becoming executive vice president, safety and operations in October 2007. He will become chief operating officer of refining from 1 March 2008.

### S Westwell

Steve Westwell (49) 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 was appointed executive vice president and group chief of staff on 1 January 2008.

## Employees

| Number of employees at 31 December | UK | Rest of Europe | US | Rest of World | Total |
|---|---|---|---|---|---|
| 2007 | | | | | |
| Exploration and Production | 3,700 | 700 | 6,600 | 8,800 | 19,800 |
| Refining and Marketing | 10,700 | 18,400 | 22,700 | 17,200 | 69,000 |
| Gas, Power and Renewables | 300 | 800 | 1,900 | 1,500 | 4,500 |
| Other businesses and corporate | 2,300 | | 1,800 | 200 | 4,300 |
| | 17,000 | 19,900 | 33,000 | 27,700 | 97,600 |
| 2006 | | | | | |
| Exploration and Production | 3,500 | 700 | 6,200 | 8,600 | 19,000 |
| Refining and Marketing | 11,300 | 18,600 | 23,900 | 15,700 | 69,500 |
| Gas, Power and Renewables | 300 | 700 | 1,800 | 1,700 | 4,500 |
| Other businesses and corporate | 1,800 | 200 | 1,800 | 200 | 4,000 |
| | 16,900 | 20,200 | 33,700 | 26,200 | 97,000 |
| 2005 | | | | | |
| Exploration and Production | 3,100 | 700 | 5,600 | 7,600 | 17,000 |
| Refining and Marketing | 11,300 | 19,700 | 25,200 | 14,600 | 70,800 |
| Gas, Power and Renewables | 200 | 700 | 1,500 | 1,700 | 4,100 |
| Other businesses and corporate | 1,900 | 200 | 2,100 | 100 | 4,300 |
| | 16,500 | 21,300 | 34,400 | 24,000 | 96,200 |

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## People

We had approximately 97,600 employees as at 31 December 2007, compared with approximately 97,000 at 31 December 2006.

In managing our people, we seek to attract, develop and retain highly talented individuals in order to maintain BP s capability to deliver our strategy and plans.

During 2007, the group people committee was formed, consisting of the group chief executive and the executive team. This committee takes overall responsibility for policy decisions relating to employees. In 2007, these ranged from a new performance and reward approach through to a new leadership model for the organization.

The energy industry faces a shortage of professionals such as petroleum engineers as the number of experienced workers retiring is expected to exceed that of new graduate entrants. To help address this issue in 2007, we took new steps to attract talented graduates, including a new marketing campaign, a new selection process and stronger relationships with a series of selected universities worldwide.

Our policy is 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.

We run programmes designed 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, we achieved our 2007 target of 75% of professional positions to be filled by national specialists.

At the end of 2007, 16% of our top 624 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 have a number of programmes in place to help raise our senior level leaders awareness of diversity and inclusion (D&I), such as our Managing Inclusion programme in the US. D&I principles are also being incorporated into the Managing Essentials programme *(see below)*.

We aim to develop 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 2007, we appointed 72 people to positions in the 624-strong group leadership. Of these, 49 were internal candidates.

We provide development opportunities for our employees, including training courses, international assignments, mentoring, team development days, workshops, seminars and online learning. We encourage everyone to take five training days per year.

During 2007, we launched a top priority programme for BP managers called Managing Essentials, designed to enhance our leadership development and drive continuous improvement in performance. In 2007, we launched the programme s first module on effective performance conversations, which helps managers to have clear and constructive discussions with staff about their performance. By the end of the year, 36 programmes had been run, with more than 700 managers attending. In 2008, we expect to run around 200 programmes for around 4,000 managers.

Through our award-winning ShareMatch plan, run in more than 70 countries, we match BP shares purchased by employees.

Communications with employees include magazines, intranet sites, DVDs, targeted e-mails and face-to-face communication. Team meetings are the core of our employee consultation, 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, social and environmental factors affecting our performance.

The group seeks to maintain constructive relationships with labour unions.

## The code of conduct

We have a code of conduct, launched in 2005, 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 seek guidance on the code of conduct as well as to report suspected breaches of compliance or other concerns. The number of cases raised through OpenTalk in 2007 was 975, compared with 1,064 in 2006. In the US, former US district court judge Stanley Sporkin acts as an ombudsperson whom employees and contractors can contact 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 2007, 944 dismissals were reported by BP s businesses for non-compliance or unethical behaviour. This number excludes some dismissals from the retail business, mainly at service station sites, for incidents such as thefts of small amounts of money.

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. BP specifically made no donations to UK or other EU political parties or organizations in 2007.

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# Directors remuneration report

This is the board s report to shareholders on directors remuneration. It covers both executive directors and non-executive directors. The first and second parts were prepared by the remuneration committee. The third part was prepared by the company secretary on behalf of the board. The report has been approved by the board and signed on its behalf by the company secretary. The report is subject to the approval of shareholders at the annual general meeting (AGM).

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## Part 1: Summary

**Dear Shareholder**

This year has been a period of transition for the group and so the long-standing principles that guide the remuneration committee have been particularly in evidence. These centre on a demanding performance link, for the majority of executive directors remuneration, to support the creation of long-term shareholder value; and the application of informed judgement by the committee, using both quantitative and qualitative assessments, to ensure a fair and appropriate reward for the executive directors.

### Executive changes

Key among the transitions was the appointment of Dr Hayward as group chief executive. Mr Inglis was appointed chief executive of our exploration and production business and Mr Conn assumed the role of chief executive of our refining and marketing business. They, along with Dr Grote in his continuing role as chief financial officer, make up the new top team for the company. The committee considered both the scale and importance of their roles as well as the operating style of the new team in reviewing their remuneration during the year. Dr Hayward s salary was increased to £950,000 per annum and the salary of both Mr Inglis and Mr Conn was set at £650,000 per annum. Dr Grote s salary was increased to $1,300,000 per annum. All will have a target bonus opportunity of 120% of salary and long-term performance share awards of 5.5 times salary. These performance shares only vest to the extent that demanding performance conditions are met. In addition to these ongoing plans, Mr Inglis and Mr Conn were each recently granted one-off retention awards in the form of restricted shares to a value of £1,500,000. These will vest in equal tranches after three and five years, subject to their continued service and satisfactory performance.

Both Lord Browne and Mr Manzoni left the company during the year. Lord Browne remained eligible for a lump sum ex gratia superannuation payment equal to one year s salary but, in light of his resignation, received no other compensation on his retirement. Mr Manzoni received one year s salary in line with his contractual entitlement. Both were eligible for a pro-rata bonus for 2007, reflecting the results achieved as well as their time employed during the year. Both retain full participation in the 2005-2007 and 2006-2008 share element but forfeit any participation in the 2007-2009 plan. They both retain outstanding share options granted in earlier years.

### 2007 performance

Overall performance for the year was constrained by the continuing impact of past operating challenges. Bonuses awarded reflect the balance of somewhat disappointing financial results coupled with good progress on non-financial measures, including health, safety and environment (HSE), and very committed efforts by the executive directors to resolve past issues, advance the forward agenda and deliver results. These are set out in the summary table opposite, along with all remuneration paid to executive directors in 2007.

The impact of past operating problems affected the Executive Directors Incentive Plan (EDIP) share element. Shares vest in this element based principally on the total shareholder return (TSR) relative to the oil majors over the three-year performance period. Performance failed to meet satisfactory levels and consequently no shares will vest in the 2005-2007 plan. Although Lord Browne similarly did not receive shares under the main 2005-2007 plan, around 15% of the shares of the separate leadership portion vested.

### Review of policy

With a new top team in place and having come through a testing time in terms of company performance, the committee decided to review remuneration policy during the year. The key area of review was the performance conditions applied to the EDIP share element. In particular, the committee considered whether additional performance measures or non-financial measures, such as health and safety indicators, should be included. The review included consultation with major shareholders and a comparison with other companies remuneration policies. The review reinforced our confidence in the current plan, approved by shareholders in 2005, in particular in the flexibility it gives us to exercise our judgement with regard to underlying performance and non-financial indicators without being formulaic. No changes to the policy are planned.

For 2008, therefore, our policy is as follows:

– Salary Salaries are reviewed annually, based on independent advice, with regard to comparator companies and market conditions.
–

Annual bonus  On-target  bonus is set at 120% of salary. The normal maximum bonus, also unchanged, is 150% of salary but, as in past years, the committee may in exceptional circumstances award bonus above that level if deemed justified by performance. Bonus for 2008 will reflect the business priorities of safety, people and performance as articulated by Dr Hayward. Of the 120%  on-target  bonus, 50 will be measured on financial results, principally earnings before interest, taxes, depreciation and amortization (EBITDA), return on average capital employed and cash flow; 25 will be based on safety as assessed by the safety, ethics and environment assurance committee (SEEAC); 25 on people, behaviour and values; and 20 on individual performance, which will primarily reflect relevant operating results and leadership.

– EDIP The share element will provide the primary long-term remuneration vehicle. Shares will be awarded to a level of 5.5 times salary for each executive director. These will vest after three years to the extent that performance relative to the other oil majors merits it.

  Performance is measured principally on TSR versus ExxonMobil, Shell, Total and Chevron. 100% of shares vest if first, 70% if second, 35% if third and nothing if fourth or fifth. The committee will also apply informed judgement, looking at overall performance in determining the final vesting level. Shares that vest must be retained for a further three years before being released to the executive director. In addition, each executive director is expected to build a significant personal shareholding in BP.

– Pensions Executive directors are eligible to participate in the appropriate pension schemes applying to their home countries.

  With this policy, the majority of executive directors  target remuneration is performance-based.

Recognizing that unforeseen developments mean no remuneration structure is perfect, the committee will continue to apply its judgement in the implementation of the policy so as to reflect shareholders  interests and also engage and retain our talented team of executives.

Dr D S Julius

Chairman, Remuneration Committee
22 February 2008

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**Summary of remuneration of executive directors in 2007[a]**

| | Annual remuneration | | | | | | | | Long-term remuneration: Share element of EDIP[b] | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | 2004-2006 plan (vested in Feb 2007) | | **2005-2007 plan (vested in Feb 2008)** | | 2007-2009 plan |
| | Salary (thousand) | | Annual performance bonus (thousand) | | Non-cash benefits and other emoluments (thousand) | | Total (thousand) | | Actual shares vested | Value[c] (thousand) | Actual shares vested | Value[d] (thousand) | Potential maximum performance shares[e] |
| | 2006 | 2007 | 2006 | 2007 | 2006 | 2007 | 2006 | **2007** | | | | | |
| Dr A B Hayward | £463 | £877 | £250 | £1,262 | £20 | £14 | £733 | **£2,153** | 112,941 | £606 | 0 | 0 | 706,311 |
| Dr D C Allen | £463 | £500 | £250 | £539 | £13 | £13 | £726 | **£1,052** | 112,941 | £606 | 0 | 0 | 456,748 |
| I C Conn | £463 | £581 | £250 | £698 | £42 | £45 | £755 | **£1,324** | 54,600 | £293 | 0 | 0 | 456,748 |
| Dr B E Grote | $973 | $1,175 | $525 | $1,551 | $1 | $10 | $1,499 | **$2,736** | 127,601 | $1,338 | 0 | 0 | 491,640 |
| A G Inglis[f] | n/a | £556 | n/a | £800 | n/a | £188 | n/a | **£1,544** | 30,090 | £162 | 0 | 0 | 400,243 |
| Directors leaving the board in 2007 | | | | | | | | | | | | | |
| Lord Browne[g] | £1,531 | £531 | £900 | £621 | £95 | £85 | £2,526 | **£1,237** | 380,668 | £2,044 | 80,000 | £436 | 0 |
| J A Manzoni[h] | £463 | £323 | £250 | £311 | £45 | £33 | £758 | **£667** | 112,941 | £606 | 0 | 0 | 0 |

Amounts shown are in the currency received by executive directors. Annual bonuses are shown in the year they were earned.

a This information has been subject to audit.
b Or equivalent plans in which the individual participated prior to joining the board.
c Based on market price on vesting date (£5.37 per share/$62.91 per ADS).
d Based on market price on vesting date (£5.45 per share).
e Maximum potential shares that could vest at the end of the three-year period depending on performance.
f Appointed to the board on 1 February 2007.
g Lord Browne resigned from the board on 1 May 2007. In addition to the above, he was awarded a lump sum ex gratia superannuation payment of one year s salary (£1,575,000).
h Mr Manzoni resigned from the board on 31 August 2007. In addition to the above, he was awarded compensation for loss of office equal to one year s salary (£485,000). He also received £30,000 in respect of statutory rights and retained his company car.

## Pensions

All executive directors are part of a final salary pension scheme. Accrued annual pension earned as at 31 December 2007 is £488,000 for Dr Hayward, £248,000 for Dr Allen, £238,000 for Mr Conn, $778,000 for Dr Grote and £296,000 for Mr Inglis.

## 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 £172.09 and £188.23 respectively.

**Remuneration of non-executive directors in 2007[a]**

| | | £ thousand |
|---|---|---|
| | 2006 | 2007 |
| A Burgmans | 85 | 86 |
| Sir William Castell | 39 | 87 |
| C B Carroll[b] | n/a | 43 |
| E B Davis, Jr | 100 | 107 |
| D J Flint | 100 | 86 |
| Dr D S Julius | 105 | 106 |
| Sir Tom McKillop | 85 | 87 |
| Dr W E Massey | 130 | 133 |
| Sir Ian Prosser | 130 | 137 |
| P D Sutherland | 500 | 517 |
| **Directors leaving the board in 2007** | | |
| J H Bryan[c] | 110 | 45 |

a This information has been subject to audit.

b Appointed on 6 June 2007.

c Also received a superannuation gratuity of £21,000.

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## Part 2: Executive directors remuneration

### 2007 remuneration

#### Salary increases

During the year, salary increases were awarded reflecting promotions and changed job responsibilities as well as regular market movement. The remuneration committee seeks to position salaries competitively relative to appropriate comparators in Europe and the US oil and gas sectors, as well as to reflect the operating style of the team at the top . At the end of 2007, annual salaries were as follows: Dr Hayward £950,000, Dr Allen £510,000, Mr Conn £650,000, Dr Grote $1,300,000 and Mr Inglis £650,000.

#### Annual bonus result

Performance measures and targets were set at the beginning of the year and formed the main basis for determining the 2007 bonus. Financial measures accounted for 50% weighting and focused on EBITDA, cash costs and capital expenditure. Non-financial measures carried 30% weight and centred on HSE performance, growth and reputation. Individual performance, including segment deliverables and living the values of the group, made up the final 20%.

Financially, underlying EBITDA results reflected a favourable price environment but also some performance shortfall, related largely to reduced refining availability at Whiting and Texas City, as well as delays in start-up of some major exploration and production projects. Overall it was below expectation. Cash costs were marginally above plan, largely due to higher expenditures in refining, especially Texas City. Capital expenditure was near plan, despite higher than expected sector inflation.

On the non-financial side, safety was maintained as the highest priority of the executive top team. Significant progress was made on many aspects of process safety, ranging from development and testing of a process safety index, addressing specific recommendations of the Baker Panel, implementing a holistic operating management system (OMS) and ensuring clear accountability. Personal safety metrics and greenhouse gas emissions were also good.

Growth was led by upstream, which had the strongest year of resource access since the early 1990s and reserves replacement in excess of 100%. Refinery throughput was below target, due to reduced availability at Texas City and Whiting. BP Alternative Energy met plan targets, achieving some 40% growth compared with 2006.

External assessments indicate that significant progress has been made to rebuild the company s reputation.

In terms of individual performance during a transition year, the committee recognized very high levels of personal and team effort to produce results, resolve past issues and position the company for future success.

The strong individual performances, combined with above-target non-financial and near-target financial performance, led the committee to award bonuses generally around or just above target, as set out in the summary table on page 64.

#### 2005-2007 share element result

Performance for the 2005-2007 share element was assessed relative to the TSR of the company compared with the other oil majors ExxonMobil, Shell, Total and Chevron. BP s TSR result, reflecting past operating problems, was last relative to the other majors. The committee also reviewed the underlying business performance relative to competitors, including financial (ROACE, EPS, cash flow etc.) and non-financial (HSE etc.) indicators. While this showed some areas of strong performance, the committee s overall assessment, considering both the TSR result and the underlying performance, was that performance failed to meet satisfactory levels and consequently no shares will vest in the Plan for 2005-2007.

Lord Browne also held an award under the 2005-2007 share element related to long-term leadership measures. These focused on sustaining BP s financial, strategic and organizational health. Performance relative to the award was assessed by the chairman s committee and, based

on this assessment, 80,000 shares vested, representing about 15% of the award.

#### Remuneration policy

Our remuneration policy for executive directors aims to ensure there is a clear link between the company s purpose, its business plans and executive reward, with pay varying with performance. In order to achieve this, the policy is based on these key principles:

– The majority of executive remuneration will be linked to the achievement of demanding performance targets, independently set to support the creation of long-term shareholder value.
– The structure will reflect a fair system of reward for all the participants.

- The remuneration committee will determine the overall amount of each component of remuneration, taking into account the success of BP and the competitive environment.
- There will be a quantitative and qualitative assessment of performance, with the remuneration committee making an informed judgement within a framework approved by shareholders.
- Remuneration policy and practice will be as transparent as possible.
- Executives will develop a significant personal shareholding in order to align their interests with those of shareholders.
- Pay and employment conditions elsewhere in the group will be taken into account, especially in setting annual salary increases.
- The remuneration policy for executive directors will be reviewed regularly, independently of executive management, and will set the tone for the remuneration of other senior executives.
- The remuneration committee will actively seek to understand shareholder preferences.

Executive directors total remuneration consists of salary, annual bonus, long-term incentives, pensions and other benefits. The remuneration committee reviews this structure regularly to ensure it is achieving its aims and did so in 2007.

The main part of the review centred on the share element of the EDIP. The committee investigated alternative and additional measures to TSR, in particular those representing underlying operational performance, and also considered the inclusion of non-financial measures, most notably those relating to HSE.

In the process of the review, input was sought from key institutional investors and their representative bodies.

After thorough review, the committee concluded that, for the long-term metrics, there was no perfect measure and, on balance, no strong reason for change. TSR remains an appropriate measure to reflect long-term shareholder value. The detailed rationale behind the current scoring system, as set out in the notes to the resolution in 2005 that was approved by shareholders, still remained relevant and valid. The committee felt that this system gives an optimal balance of quantitative assessment relative to oil major performance as well as the ability of the committee to make qualitative evaluation of underlying business performance, including non-financial factors (such as HSE). Finally, the committee felt that, in BP s current circumstances, there is merit in maintaining the stability of the plan.

### Salary

The remuneration committee reviews salaries annually, taking into account other large Europe-based global companies and companies in the US oil and gas sector. These groups are each defined and analysed by the committee s independent remuneration advisers. The committee makes a judgement on salary levels based on its assessment of market conditions and the external advice.

### Annual bonus

All executive directors are eligible to take part in an annual performance-based bonus scheme. The remuneration committee sets bonus targets and levels of eligibility each year.

The target level for 2008 is 120% of base salary. In normal circumstances, the maximum payment for substantially exceeding performance targets will continue to be 150% of base salary.

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Annual bonus awards for 2008 will be based on a mix of demanding financial targets, based on the annual plan and the leadership objectives set at the beginning of the year. The target-level bonus of 120% of base salary is split as follows:

50% financial metrics from the annual plan, principally EBITDA, cash costs and capital expenditure.

25% safety performance, including satisfactory and improving key metrics as well as progress on OMS implementation.

25% people, including behaviour, values and culture.

20% individual performance, principally on relevant operating results and personal leadership.

The remuneration committee will also review carefully the underlying performance of the group in light of company business plans and will look at competitors results, analysts reports and the views of the chairmen of other BP board committees when assessing results.

In exceptional circumstances, the remuneration committee can decide to award bonuses moderately above the maximum level. The committee can also decide to reduce bonuses where this is warranted and, in exceptional circumstances, bonuses could be reduced to zero. We have a duty to shareholders to use our discretion in a reasonable and informed manner, acting to promote the success of the company, and also to be accountable and transparent in our decisions. Any significant exercise of discretion will be explained in the subsequent directors remuneration report.

## Long-term incentives

Each executive director participates in the EDIP. It has three elements: shares, share options and cash. The remuneration committee did not use either share option or cash elements in 2007 and does not intend to do so in 2008. We intend that executive directors will continue to receive performance shares under the EDIP, barring unforeseen circumstances, until it expires or is renewed in 2010.

### Policy for performance share awards

The remuneration committee can award shares to executive directors that will only vest to the extent that demanding performance conditions are satisfied at the end of a three-year period. The maximum number of these performance shares that can be awarded to an executive director in any year is at the discretion of the remuneration committee, but will not normally exceed 5.5 times base salary.

In exceptional circumstances, the committee also has an overriding discretion to reduce the number of shares that vest or to decide 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, as shown in the timeline below, which is designed to ensure their interests are aligned with those of shareholders.

**TIMELINE FOR 2008-2010 EDIP SHARE ELEMENT**

Where shares vest, the executive director will receive additional shares representing the value of the reinvested dividends.

The committee s policy continues to be that each executive director build a significant personal shareholding, with a target of shares equivalent in value to five times his or her base salary within a reasonable timeframe from appointment as an executive director. This policy is reflected in the terms of the EDIP, as shares awarded will normally only be released at the end of the three-year retention period, described above, if these minimum shareholding guidelines are met.

### Performance conditions

For performance share awards in 2008, the performance conditions will continue to relate to BP s TSR compared with the other oil majors ExxonMobil, Shell, Total and Chevron over three years. We have the discretion to alter this comparison group if circumstances change for example, if there are significant consolidations in the industry.

We consider this relative TSR to be the most appropriate measure of performance for the purpose of long-term incentives for executive directors. It best reflects the creation of shareholder value while minimizing the impact of sector-specific effects such as the oil price.

TSR is calculated as share price performance over the relevant period, assuming dividends are reinvested. All share prices are averaged over the three months before the beginning and end of the performance period. They are measured in US dollars. At the end of the performance period, the companies TSRs will be ranked. Executive directors performance shares will vest at 100%, 70%

and 35% if BP is ranked first, second or third respectively; none will vest if BP is in fourth or fifth place.

As the comparator group is small and as the oil majors underlying businesses are broadly similar, a simple ranking could sometimes distort BP s underlying business performance relative to the comparators. The committee is therefore able to exercise discretion in a reasonable and informed manner to adjust the vesting level upwards or downwards to reflect better the underlying health of BP s business. This would be judged by reference to a range of measures including ROACE, growth in EPS, reserves replacement and cash flow, as well as non-financial reasons such as safety. The need to exercise discretion is most likely to arise when the TSR of some companies is clustered, so that a relatively small difference in TSR performance would produce a major difference in vesting levels.

The remuneration committee will explain any adjustments in the next directors remuneration report following the vesting, in line with its commitment to transparency.

### Special retention awards

The committee reviews on an ongoing basis the overall approriateness of the long-term incentive arrangements in ensuring the retention of key executives. After careful review, the committee considered that it was appropriate to strengthen the retention element of remuneration for Mr Inglis and Mr Conn. Accordingly, the committee in February 2008 granted, on a one-off basis, a restricted stock award to both Mr Inglis and Mr Conn of shares worth £1,500,000 each. These awards recognize the importance of these individuals leadership in re-establishing the company s competitive performance as well as their personal attractiveness for top jobs externally. The shares will vest, subject to continued service, in equal tranches after three and five years. Vesting of each tranche is dependent on the committee being satisfied, at each vesting date, with the performance of the individual.

These retention awards have been granted under the EDIP, which permits awards to be made, on an exceptional basis, subject to a requirement of continued service over a specified period.

## Pensions

Executive directors are eligible to participate in the appropriate pension schemes applying in their home countries. Additional details are given on page 67.

### 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.

## US directors

Dr Grote participates in the US BP Retirement Accumulation Plan (US 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.

The Supplemental Executive Retirement Benefit (supplemental plan) is a non-qualified top-up arrangement that became effective on 1 January 2002 for US employees above a specified salary level. The benefit formula is 1.3% of final average earnings, which comprise base salary and bonus in accordance with standard US practice (and as specified under the qualified arrangement), multiplied by years of service.

There is an offset for benefits payable under all other BP qualified and non-qualified pension arrangements. This benefit is unfunded and therefore paid from corporate assets.

Dr Grote is eligible to participate under the supplemental plan. His pension accrual for 2007, shown in the table below, includes the total amount that could become payable under all plans.

## Other benefits

Executive directors are eligible to participate in regular employee benefit plans and in all-employee share saving schemes and savings plans applying in their home countries. Benefits in kind are not pensionable. Expatriates may receive a resettlement allowance for a limited period.

Mr Inglis is currently based in Houston, US, and the company provides accommodation in London.

## Pensions[a]

thousand

| | Service at 31 Dec 2007 | Accrued pension entitlement at 31 Dec 2007 | Additional pension earned during the year ended 31 Dec 2007[b] | Transfer value of accrued benefit[c] at 31 Dec 2006 (A) | Transfer value of accrued benefit[c] at 31 Dec 2007 (B) | Amount of B-A less contributions made by the director in 2007 |
|---|---|---|---|---|---|---|
| Dr A B Hayward (UK) | 26 years | £488 | £250 | £4,017 | £7,986 | £3,925 |
| Dr D C Allen (UK)[d] | 29 years | £248 | £20 | £4,006 | £4,256 | £250 |
| I C Conn (UK) | 22 years | £238 | £69 | £2,510 | £3,375 | £865 |
| Dr B E Grote (US) | 28 years | $778 | $102 | $7,591 | $7,902 | $311 |
| A G Inglis (UK) | 27 years | £296 | £114 | £2,936 | £4,613 | £1,677 |
| Directors leaving the board in 2007 | | | | | | |
| Lord Browne (UK) | n/a | £1,050 | £0 | £21,700 | £21,552 | (£148) |

| | | | | | | |
|---|---|---|---|---|---|---|
| J A Manzoni (UK) | n/a | £193 | £5 | £2,961 | £4,195 | £1,234 |

[a] This information has been subject to audit.
[b] Additional pension earned during the year includes an inflation increase of 4.4% for UK directors and 2.3% for US directors.
[c] Transfer values have been calculated in accordance with version 8.1 of guidance note GN11 issued by the actuarial profession.
[d] Dr Allen is due to retire on 31 March 2008 and will be entitled to take an immediate unreduced pension. The figures in the table relate to 2007 and so do not include anticipated incremental cost of the unreduced pension (£1.36 million).

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## Share element of EDIP[a]

| | | | | Share element interests Potential maximum performance shares[b] | | | Interests vested in 2007 and 2008 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Performance period | Date of award of performance shares | Market price of each share at date of award of performance shares £ | At 1 Jan 2007 | Awarded 2007 | At 31 Dec 2007 | Number of ordinary shares vested[c] | Vesting date | Market price of each share at vesting date £ |
| Dr A B Hayward | 2004-2006 | 25 Feb 2004 | 4.25 | 376,470 | | | 112,941 | 15 Feb 2007 | 5.37 |
| | **2005-2007** | **28 Apr 2005** | **5.33** | **436,623** | | **436,623** | **0** | **n/a** | **n/a** |
| | 2006-2008 | 16 Feb 2006 | 6.54 | 383,200 | | 383,200 | | | |
| | 2007-2009 | 06 Mar 2007 | 5.12 | | 706,311 | 706,311 | | | |
| Dr D C Allen | 2004-2006 | 25 Feb 2004 | 4.25 | 376,470 | | | 112,941 | 15 Feb 2007 | 5.37 |
| | **2005-2007** | **28 Apr 2005** | **5.33** | **436,623** | | **436,623** | **0** | **n/a** | **n/a** |
| | 2006-2008 | 16 Feb 2006 | 6.54 | 383,200 | | 383,200 | | | |
| | 2007-2009 | 06 Mar 2007 | 5.12 | | 456,748 | 456,748 | | | |
| I C Conn | 2004-2006 | 25 Feb 2004 | 4.25 | 182,000 | | | 54,600 | 15 Feb 2007 | 5.37 |
| | **2005-2007** | **28 Apr 2005** | **5.33** | **415,832** | | **415,832** | **0** | **n/a** | **n/a** |
| | 2006-2008 | 16 Feb 2006 | 6.54 | 383,200 | | 383,200 | | | |
| | 2007-2009 | 06 Mar 2007 | 5.12 | | 456,748 | 456,748 | | | |
| Dr B E Grote | 2004-2006 | 25 Feb 2004 | 4.25 | 425,338 | | | 127,601 | 15 Feb 2007 | 5.37 |
| | **2005-2007** | **28 Apr 2005** | **5.33** | **501,782** | | **501,782** | **0** | **n/a** | **n/a** |
| | 2006-2008 | 16 Feb 2006 | 6.54 | 470,432 | | 470,432 | | | |
| | 2007-2009 | 06 Mar 2007 | 5.12 | | 491,640 | 491,640 | | | |
| A G Inglis | 2004-2006 | 24 Feb 2004 | 4.25 | 51,000[d] | | | 30,090 | 15 Feb 2007 | 5.37 |
| | **2005-2007** | **8 Mar 2005** | **5.70** | **209,000[d]** | | **209,000** | **0** | **n/a** | **n/a** |
| | 2006-2008 | 27 Mar 2006 | 6.59 | 325,750[d] | | 325,750 | | | |
| | 2007-2009 | 06 Mar 2007 | 5.12 | | 400,243 | 400,243 | | | |
| Directors leaving the board in 2007 | | | | | | | | | |
| Lord Browne | 2004-2006 | 25 Feb 2004 | 4.25 | 1,268,894 | | | 380,668 | 15 Feb 2007 | 5.37 |
| | **2005-2007** | **28 April 2005** | **5.33** | **2,006,767** | | **2,006,767** | **80,000** | **6 Feb 2008** | **5.45** |
| | 2006-2008 | | 6.54 | 1,761,249 | | 1,761,249 | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 16 Feb 2006 | | | | | | | |
| | 2007 2009 | 06 Mar 2007 | 5.12 | | 2,022,619[e] | | | | |
| J A Manzoni | 2004-2006 | 25 Feb 2004 | 4.25 | 376,470 | | | 112,941 | 15 Feb 2007 | 5.37 |
| | **2005-2007** | **28 Apr 2005** | **5.33** | **436,623** | | **436,623** | **0** | **n/a** | **n/a** |
| | 2006-2008 | 16 Feb 2006 | 6.54 | 383,200 | | 383,200 | | | |
| | 2007-2009 | 06 Mar 2007 | 5.12 | | 456,748[e] | | | | |

[a] This information has been subject to audit. Includes equivalent plans in which the individual participated prior to joining the board.

[b] BP s performance is measured against the oil sector. For the 2005-2007 and subsequent awards, the performance condition is TSR measured against ExxonMobil, Shell, Total and Chevron other than the portion of Lord Browne s award that relates to leadership measures. Each performance period ends on 31 December of the third year.

[c] Represents awards of shares made at the end of the relevant performance period based on performance achieved under rules of the plan.

[d] On appointment to the board on 1 February 2007.

[e] Awards under 2007-2009 plan lapsed for Lord Browne and Mr Manzoni on leaving.

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**Share options**[a]

| | Option type | At 1 Jan 2007 | Granted | Exercised | At 31 Dec 2007 | Option price | Market price at date of exercise | Date from which first exercisable | Expiry date |
|---|---|---|---|---|---|---|---|---|---|
| Dr A B Hayward | SAYE | 3,302 | | 3,302 | | £5.11 | £5.35[b] | 1 Sep 2006 | 28 Feb 2007 |
| | SAYE | 3,220 | | | 3,220 | £5.00 | | 1 Sep 2011 | 29 Feb 2012 |
| | EXEC | 34,000 | | | 34,000 | £5.99 | | 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 | 220,000 | | | 220,000 | £3.88 | | 17 Feb 2004 | 17 Feb 2010 |
| | EDIP | 275,000 | | | 275,000 | £4.22 | | 25 Feb 2005 | 25 Feb 2011 |
| Dr D C Allen | EXEC | 37,000 | | | 37,000 | £5.99 | | 15 May 2003 | 15 May 2010 |
| | EXEC | 87,950 | | | 87,950 | £5.67 | | 23 Feb 2004 | 23 Feb 2011 |
| | EXEC | 175,000 | | | 175,000 | £5.72 | | 18 Feb 2005 | 18 Feb 2012 |
| | EDIP | 220,000 | | | 220,000 | £3.88 | | 17 Feb 2004 | 17 Feb 2010 |
| | EDIP | 275,000 | | | 275,000 | £4.22 | | 25 Feb 2005 | 25 Feb 2011 |
| I C Conn | SAYE | 1,456 | | | 1,456 | £3.50 | | 1 Sep 2008 | 28 Feb 2009 |
| | SAYE | 1,186 | | | 1,186 | £3.86 | | 1 Sep 2009 | 28 Feb 2010 |
| | SAYE | 1,498 | | | 1,498 | £4.41 | | 1 Sep 2010 | 28 Feb 2011 |
| | 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 |
| | EXEC | 126,000 | | 126,000 | | £4.22 | £5.68-£6.13 | 25 Feb 2007 | 25 Feb 2014 |
| Dr B E Grote[c] | SAR | 40,000 | | 40,000 | | $33.34 | $64.03 | 28 Feb 2000 | 28 Feb 2007 |
| | BPA | 10,404 | | | 10,404 | $53.90 | | 15 Mar 2000 | 14 Mar 2009 |
| | BPA | 12,600 | | | 12,600 | $48.94 | | 28 Mar 2001 | 27 Mar 2010 |
| | EDIP | 40,182 | | | 40,182 | $49.65 | | 19 Feb 2002 | 19 Feb 2008 |
| | EDIP | 58,173 | | | 58,173 | $48.82 | | 18 Feb 2003 | 18 Feb 2009 |
| | EDIP | 58,173 | | | 58,173 | $37.76 | | 17 Feb 2004 | 17 Feb 2010 |
| | EDIP | 58,333 | | | 58,333 | $48.53 | | 25 Feb 2005 | 25 Feb 2011 |
| A G Inglis | SAYE | 4,550[d] | | | 4,550 | £3.50 | | 1 Sep 2008 | 28 Feb 2009 |
| | EXEC | 72,250[d] | | | 72,250 | £5.67 | | 23 Feb 2004 | 22 Feb 2011 |
| | EXEC | 119,000[d] | | | 119,000 | £5.72 | | 18 Feb 2005 | 17 Feb 2012 |
| | EXEC | 119,000[d] | | | 119,000 | £3.88 | | 17 Feb 2006 | 16 Feb 2013 |
| | EXEC | 100,500[d] | | | 100,500 | £4.22 | | 25 Feb 2007 | 24 Feb 2014 |

Directors leaving the board in 2007

| | | | | | | |
|---|---|---|---|---|---|---|
| Lord Browne | SAYE | 4,550 | 4,550[e] | £3.50 | 1 Sep 2008 | 28 Feb 2009 |
| | EDIP | 408,522 | 408,522[e] | £5.99 | 15 May 2001 | 15 May 2007 |
| | EDIP | 1,348,032 | 1,348,032[e] | £5.72 | 18 Feb 2003 | 18 Feb 2009 |
| | EDIP | 1,500,000 | 1,500,000[e] | £4.22 | 25 Feb 2005 | 25 Feb 2011 |
| J A Manzoni | SAYE | 878 | 878[f] | £4.52 | 1 Sep 2007 | 28 Feb 2008 |
| | SAYE | 2,548 | 2,548[f] | £3.50 | 1 Sep 2008 | 28 Feb 2009 |
| | SAYE | 847 | 847[f] | £3.86 | 1 Sep 2009 | 28 Feb 2010 |
| | EXEC | 34,000 | 34,000[f] | £5.99 | 15 May 2003 | 15 May 2010 |
| | EXEC | 72,250 | 72,250[f] | £5.67 | 23 Feb 2004 | 23 Feb 2011 |
| | EXEC | 175,000 | 175,000[f] | £5.72 | 18 Feb 2005 | 18 Feb 2012 |
| | EDIP | 220,000 | 220,000[f] | £3.88 | 17 Feb 2004 | 17 Feb 2010 |
| | EDIP | 275,000 | 275,000[f] | £4.22 | 25 Feb 2005 | 25 Feb 2011 |

The closing market prices of an ordinary share and of an ADS on 31 December 2007 were £6.15 and $73.17 respectively. During 2007, the highest market prices were £6.34 and $79.70 respectively and the lowest market prices were £5.07 and $58.80 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 April 2005 as described on page 66.
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.
SAR = Stock Appreciation Rights under BP America Inc. Share Appreciation Plan.
SAYE = Save As You Earn employee share scheme.

[a] This information has been subject to audit.
[b] Closing market price for information. Shares were retained when exercised.
[c] Numbers shown are ADSs under option. One ADS is equivalent to six ordinary shares.
[d] On appointment to the board on 1 February 2007.
[e] On leaving the board on 1 May 2007.
[f] On leaving the board on 31 August 2007.

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## Service contracts

| Director | Contract date | Salary as at 31 Dec 2007 |
|---|---|---|
| Dr A B Hayward | 29 Jan 2003 | £950,000 |
| Dr D C Allen | 29 Jan 2003 | £510,000 |
| I C Conn | 22 Jul 2004 | £650,000 |
| Dr B E Grote | 7 Aug 2000 | $1,300,000 |
| A G Inglis | 1 Feb 2007 | £650,000 |

Service contracts are expressed to expire at a normal retirement age of 60 (subject to age discrimination). The contracts have a notice period of one year.

The service contracts of UK directors 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 terminated on the expiry of the remainder of the notice period.

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 on 31 March 2010. The secondment can be terminated by one month s notice by either party and terminates automatically on the termination of Dr Grote s service contract.

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.

Since January 2003, new service contracts include a provision to allow for severance payments to be phased, when appropriate. The committee will also consider mitigation to reduce compensation to a departing director, when appropriate to do so.

### Directors leaving the board

#### 2007

Both Lord Browne and Mr Manzoni, who were employed by the company under service contracts dated 11 November 1993 and 29 January 2003 respectively, left the company during the year. Lord Browne, who left on 1 May 2007, was eligible for an ex gratia lump sum superannuation payment equal to one year s salary (£1,575,000) but, in light of his resignation, did not receive the compensation for loss of office previously notified to shareholders. Mr Manzoni, who left on 31 August 2007, was entitled to one year s salary (£485,000) as compensation on termination in accordance with his contractual entitlement. Both individuals were eligible for a pro-rata bonus for 2007, reflecting achievement of bonus targets and their period of employment during the year. As regards long-term incentives, both individuals retain their performance awards under the EDIP in respect of 2005-2007 and 2006-2008 share element and these will vest at the normal time to the extent the performance targets are met. Both individuals forfeited their participation in the 2007-2009 share element. Further details of these awards are set out in the table on page 68. Both individuals retained their outstanding share options, as set out in the table on page 69.

In connection with the shareholder derivative actions brought in the US against the directors of the company, the company has agreed with the plaintiffs in the Alaska action, with the consent of Lord Browne and Mr Manzoni, to defer the release of certain amounts and preserved share awards to those individuals (other than Lord Browne s ex gratia superannuation payment) pending resolution of the action. The company has agreed to pay the individuals simple interest at the rate of 6.5% in respect of the period of deferral.

#### 2008

As has been announced, Dr Allen will leave the company at the end of March 2008. He will be entitled to one year s salary (£510,000) as compensation in accordance with his contractual entitlement, as well as a pro-rata bonus for 2008 and continued full participation in the 2006-2008 and 2007-2009 share elements, according to the normal rules of the plan.

## 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 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 | Total fees |
|---|---|---|
| Dr A B Hayward | Corus | £62,250 |
| | Tata Steel | £177 |
| I C Conn | Rolls Royce | £57,166 |
| Dr B E Grote | Unilever | Unilever PLC £31,000<br>Unilever NV €45,000 |
| A G Inglis | BAE Systems | £39,661 |

## Remuneration committee

All the members of the committee are independent non-executive directors. Throughout the year, Dr Julius (chairman), Mr Davis, Sir Tom McKillop and Sir Ian Prosser were members. Mr Bryan retired as a member in April 2007. The group chief executive at the time was consulted on matters relating to the other executive directors who report to him and on matters relating to the performance of the company; he was not present when matters affecting his own remuneration were discussed.

### Tasks

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 directorsare members.

To nominate, on behalf of the board, any trustees (or directors of corporate trustees) of the scheme.

To review the policies being applied by the group chief executive in remunerating senior executives other than executive directors to ensure alignment and proportionality.

### Constitution and operation

Each member of the remuneration committee is subject to annual reelection as a director of the company. The board considers all committee members to be independent *(see page 74).*

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. There was a full attendance record. Mr Sutherland, as chairman of the board, attended all the committee meetings.

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.

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### Advice

Advice is provided to the committee by the company secretary s office, which is independent of executive management and reports to the chairman of the board. Mr Aronson, an independent consultant, is the committee s secretary and special adviser. Advice was also received from Mr Jackson, the company secretary.

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 2007, the committee continued to engage Towers Perrin as its principal external adviser. Towers Perrin also provided limited ad-hoc remuneration and benefits advice to parts of the group, principally changes in employee share plans and some market information on pay structures.

Freshfields Bruckhaus Deringer provided legal advice on specific matters to the committee, as well as providing some legal advice to the group.

Ernst & Young reviewed the calculations on the financial-based targets that form the basis of the performance-related pay for executive directors, that is, the annual bonus and share element awards described on page 65, to ensure they met an independent, objective standard. They also provided audit, audit-related and taxation services for 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. In accordance with BP s board governance principles, the remuneration of the chairman is set by the board rather than by the remuneration committee, as the performance of the chairman is seen as a matter for the board as a whole rather than any one committee.

Key elements of BP s non-executive director remuneration policy include:

- Remuneration should be sufficient to attract and retain world-class non-executive talent.
- Remuneration of non-executive directors is set 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.

### Remuneration review

In 2007, an ad-hoc board committee was formed to review the structure and quantum of BP non-executive directors remuneration (having previously been reviewed in 2004).

The committee considered the existing BP policy on non-executive directors remuneration and concluded that it should remain unchanged. The committee evaluated non-executive director remuneration levels and trends in both the UK and internationally, using a number of external data sources. Outside the UK, particular focus was given to the remuneration practices for non-executive directors in the US. The committee also examined how the time commitment and workload for the board and its committees had changed in the three years since the previous review.

Following the review, the committee proposed a revised structure and level of remuneration for BP non-executive directors. Key changes included:

- Increases to the fees for the chairman and deputy chairman/senior independent director to reflect the market rates paid for those positions in companies of comparable size to BP.
- The introduction of a flat fee for membership of the audit, the safety, ethics and environment assurance, the remuneration and the nomination committees (but not the chairman s committee) to reflect the increased time commitment for board committees over the past three years.
- An increase in the fee for the chairmen of the audit committee and SEEAC to reflect the increase in time commitment and market rates for those committees.

Consideration was also given to abolishing the transatlantic attendance allowance, but the committee concluded that this would be to the detriment of non-executives based outside Europe, who would not otherwise be compensated for the additional travel time required for UK meetings.

Changes to the structure and an increase to the level of non-executive directors fees were approved by the board and became effective 1 November 2007.

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## Fee structure

The table below shows the revised fee structure for non-executive directors.

£ thousand

| | Fee level 2005-07 | Fee level from 1 Nov 2007 |
|---|---|---|
| Chairman[a] | 500 | 600 |
| Deputy chairman[b] | 100 | 120 |
| Board member | 75 | 75 |
| Committee chairmanship flat fee[c] | 20 | |
| Audit committee and SEEAC chairmanship fees | | 30 |
| Remuneration committee chairmanship fee | | 20 |
| Transatlantic attendance allowance | 5 | 5 |
| Committee membership fee | | 5 |

[a] The chairman remains ineligible for committee chairmanship and membership fees or transatlantic attendance allowance.
[b] The role of deputy chairman is combined with that of senior independent director. The deputy chairman is still eligible for committee chairmanship fee and transatlantic attendance allowance plus any committee membership fees.
[c] Committee chairmen will not receive an additional membership fee for the committee they chair.

### Remuneration of non-executive directors in 2007[a]

£ thousand

| | 2006 | 2007 |
|---|---|---|
| A Burgmans | 85 | 86 |
| Sir William Castell | 39 | 87 |
| C B Carroll[b] | n/a | 43 |
| E B Davis, Jr | 100 | 107 |
| D J Flint | 100 | 86 |
| Dr D S Julius | 105 | 106 |
| Sir Tom McKillop | 85 | 87 |
| Dr W E Massey | 130 | 133 |
| Sir Ian Prosser | 130 | 137 |
| P D Sutherland | 500 | 517 |
| **Directors leaving the board in 2007** | | |
| J H Bryan[c] | 110 | 45 |

[a] This information has been subject to audit.
[b] Appointed on 6 June 2007.
[c] Also received a superannuation gratuity of £21,000.

No share or share option awards were made to any non-executive director in respect of service on the board during 2007.

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, having regard to the director s period of service as a director 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.

The board made a superannuation gratuity of £21,000 during the year to Mr John Bryan, who retired in April 2007. This payment was 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, in accordance with the Directors Remuneration Report Regulations 2002.

| | Interest in BP ADSs at 1 Jan 2007 and 31 Dec 2007[a] | Date on which director reaches age 70[b] |
|---|---|---|
| E B Davis, Jr | 4,490 | 5 August 2014 |
| Dr W E Massey | 3,346 | 5 April 2008 |
| Directors leaving the board in 2007 | | |
| J H Bryan[c] | 5,546 | 5 October 2006 |

[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] Mr Bryan retired from the board on 12 April 2007. He had received awards of Amoco shares under the plan between 25 April 1989 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 on 12 April 2007 and the shares vested on that date (when the BP ADS market price was $66.79) without payment by him.

### 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 in October 2006 for a term of three years. During 2007, he received £150,000 for this role.

This directors remuneration report was approved by the board and signed on its behalf by David J Jackson, Company Secretary, on 22 February 2008.

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# BP board performance report

## Letter from the chairman

**Dear Shareholder**

During the past year, the board has carefully considered the role it plays and its method of working. Central to this is the board s review of its system of governance. This has been timely BP adopted its prior governance framework for the board more than 10 years ago. This approach has stood the board in good stead and has been robust when judged against the standards of governance that have developed over time. This framework will continue to underpin our approach.

It has, however, been important for the board to consider the position of the company in the markets in which it operates and to ensure that the manner in which the board works will meet the challenges that BP will face in the future. As part of the review, each board member discussed their evaluation of the existing policies and proposed their views on the role and challenges for the BP board going forward. The review process also involved benchmarking, identifying examples of governance best practice and a legal review of US and UK board policies.

The board clearly needs to focus on its unique tasks and these are described in the company s board governance principles , which were approved in November and can now be found on our website.

The board will keep its work and performance under regular review and will revisit the governance principles annually. Set out below is a description of the board and its committees and an account of the work that they have done during the year.

Peter Sutherland
Chairman
22 February 2008

## Board governance principles

The board governance principles describe the board s relationship with shareholders and executive management, the conduct of board affairs and the tasks and requirements for board committees. They outline the board s focus on activities that enable it to promote shareholders interests, specifically the active consideration of strategy, the monitoring of executive action and ongoing board and executive management succession.

The board believes that the governance of BP is best achieved by the delegation of its authority for executive management to the group chief executive, subject to monitoring by the board and the limitations defined in the board governance principles. These executive limitations require that any executive action taken in the course of business takes specific issues into consideration, including health, safety and the environment, risk and internal controls and financing.

BP s board governance principles can be viewed on the governance section of bp.com at *www.bp.com/corporategovernance*.

### Operating the principles

The group chief executive describes to the board in the annual business plan how the strategy is to be delivered, together with an assessment of the group s risks. During the year, the board monitors progress and keeps the strategy under regular review.

The group chief executive is obliged to review and discuss with the board all strategic projects or developments and all material matters currently or prospectively affecting the company and its performance.

The board governance principles further set out how the group chief executive s performance will be monitored during the year.

## The board s engagement with shareholders

The board is accountable to shareholders for the performance and activities of the BP group. The board takes steps to engage with shareholders and to evaluate the relevant financial, social, environmental and ethical matters that may influence or affect the business. The board recognizes that, in conducting its business, BP should be responsive to other relevant constituencies.

During the year, the chairman met with institutional shareholders to discuss issues relating to the board, governance and high-level strategy and the remuneration committee consulted with larger shareholders on elements of the executive remuneration plan.

The group chief executive, other executive directors and senior management, company secretary s office, investor relations and other teams within BP also engage with a broad range of shareholders on wider issues relating to the group, including in particular its safety, operations and financial performance. Presentations given by the company to the investment community are available to download from the investors section of *www.bp.com*, as are speeches on topics of broad interest to shareholders made by the group chief executive and other senior members of the management team.

## BP s AGM

Shareholders are encouraged to attend the AGM and use the opportunity to ask questions and hear the resulting discussion about BP s performance. However, given the size and geographical diversity of the company s shareholder base, attendance may not always be practical and shareholders are encouraged to use proxy voting on the resolutions put forward. Every vote cast, whether in person or by proxy at shareholder meetings, is counted, because votes on all matters except procedural issues are taken by a poll.

Copies of speeches and presentations given at the AGM are available to download from the BP website after the event, together with the outcome of voting on the resolutions.

Both the chairman and board committee chairmen were present during the 2007 AGM. Board members met shareholders on an informal basis after the main business of the meeting. In 2007, voting levels at the AGM showed a slight decrease to 61%, compared with 64% in 2006. It is proposed that the AGM in 2008 will also be webcast.

## Director elections

All directors stand for re-election by shareholders each year, with new directors being subject to election at the first opportunity following their appointment. All the names submitted to shareholders for election are accompanied by a biography and a description of the skills and experience that the company feels are relevant in proposing each director for election.

Voting levels at the 2007 AGM demonstrated continued support for all BP directors.

## Board composition, skills and renewal

The board governance principles require the majority of the board to be composed of independent non-executive directors and the size of the board not normally to exceed 16 directors. The board is composed of the chairman, 10 non-executive and five executive directors; in total, four nationalities are represented.

Lord Browne resigned as group chief executive on 1 May 2007 and was succeeded by Dr Anthony Hayward, who had been appointed group chief executive designate on 1 February 2007. Andy Inglis joined the board on 1 February 2007 as chief executive of the exploration and production segment succeeding Dr Hayward. John Manzoni resigned as an executive director and chief executive of refining and marketing and left the company on 31 August 2007. Dr David Allen will retire from the board and the company at the end of March 2008.

From the non-executive directors, Mr John Bryan retired in April 2007 and, at the 2008 AGM, Dr Walter Massey will retire from the board.

In June 2007, Mrs Cynthia Carroll and, in February 2008, Mr George David were appointed as a non-executive directors. External recruitment consultants were used to identify Mrs Carroll and Mr David as candidates and the board believes that their skills and experience will complement those of existing board members and enhance the efficiency and effectiveness of the board as a whole, particularly from the aspect of BP s US operations.

The board remains actively engaged in orderly succession planning for both executive and non-executive roles and manages this with the assistance of the nomination committee. The committee assesses the balance of executive and non-executive directors and the composition of the board in terms of the skills and diversity required to ensure it remains relevant and effective. Following an assessment by the nomination committee, the board will continue its policy of regularly refreshing board membership.

The board has also begun the process for the identification and selection of the board s chairman, as Peter Sutherland will step down at the 2009 AGM. This is being led by Sir Ian Prosser, deputy chairman and the board s senior independent director. The board is using an external adviser to evaluate the board s mix of skills and experience and to assist in defining the criteria to be used in identifying potential candidates. The adviser has also been engaged to assist with the selection process.

## Board independence

Part of the qualification for board membership of BP is the requirement that non-executive directors be free from any relationship with the company s executive management that could materially interfere with the exercise of their independent judgement. In the board s view, BP s non-executive directors fulfil this requirement and the board has determined that those who served during 2007 were independent. BP is involved in a long-term business of global scale and scope. Membership of the board needs to reflect that not only in terms of skills but also in terms of tenure where artificial restrictions on the duration of tenure may not be best for the company. It is for this reason that all non-executive directors have been subject to annual re-election since 2004.

Sir Ian Prosser joined the board in 1997. It is the view of the board that he remains independent. His experience and long-term perspective on

BP s business have provided and continue to provide a valuable contribution to the board and to the audit committee, which he chairs. As deputy chairman and senior independent director, Sir Ian is leading the board s search for the successor to the current chairman. He has been asked by the board to remain in post until April 2010 at the latest in order that he may conclude both the chairman s succession process and the identification and appointment by the new chairman of a senior independent director.

BP completed the merger with Amoco in December 1998. Dr Walter Massey and Erroll Davis, Jr are the two remaining former Amoco directors. Dr Massey will retire as a director at the 2008 AGM. Both directors have continued to be determined by the board to be independent during the past year, with Dr Massey chairing the safety, ethics and environment assurance committee (SEEAC). Mr Davis will remain on the board until such time as he steps down as part of the implementation of the board s succession policy. The board believes Mr Davis continues to demonstrate his independence as a director through his ongoing contribution and challenge at board and committee discussions.

The board has satisfied itself that there is no compromise to the independence of those directors who serve together as directors on the boards of outside entities (or who have other appointments in outside entities). Where necessary, the board ensures appropriate processes are in place to manage any possible conflict of interest.

## The board: terms of appointment

The chairman and non-executive directors of BP serve on the basis of letters of appointment. Executive directors of BP have service contracts with the company. Details of all payments to directors are described in the directors remuneration report.

The service contracts of executive directors are expressed to expire at a normal retirement age of 60 (subject to age discrimination), while non-executive directors ordinarily retire at the AGM following their 70th birthday.

In accordance with the company 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 2007. During the year, a review of the terms and nature of the policy was undertaken and has been renewed for 2008. 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.

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## Board and committees: meetings and attendance

The board requires all members to devote sufficient time to the work of the board to discharge the office of director and to use their best endeavours to attend meetings.

In addition to the AGM (which 17 directors attended), the board met 12 times during 2007 for meetings of varying length: nine times in the UK, twice in the US and once in Brussels. Two of these meetings focused solely on strategy, one of them of two-days duration. A number of board committee meetings were held during the year; for details of these and their attendance by board members please see the table below.

| | Board meetings | Audit committee | SEEAC | Chairman s committee | Remuneration committee | Nomination committee |
|---|---|---|---|---|---|---|
| P D Sutherland | 12/12 | | | 5/5 | 6/6 | 5/5 |
| J H Bryan | 6/6 | 7/7 | | 2/2 | 2/2 | |
| A Burgmans | 12/12 | | 8/8 | 5/5 | | |
| C B Carroll | 3/4 | | | 2/2 | | |
| Sir William Castell | 11/12 | 14/14 | 7/8 | 5/5 | | |
| E B Davis, Jr | 11/12 | 13/14 | | 5/5 | 6/6 | |
| D J Flint | 11/12 | 12/14 | | 5/5 | | |
| Dr D S Julius | 12/12 | | | 5/5 | 6/6 | 5/5 |
| Sir Tom McKillop | 10/12 | | 7/8 | 5/5 | 6/6 | |
| Dr W E Massey | 12/12 | | 8/8 | 5/5 | | 5/5 |
| Sir Ian Prosser | 12/12 | 14/14 | | 5/5 | 6/6 | 5/5 |
| Lord Browne | 6/6 | | | | | |
| Dr D C Allen | 12/12 | | | | | |
| I C Conn | 12/12 | | | | | |
| Dr B E Grote | 11/12 | | | | | |
| Dr A B Hayward | 12/12 | | | | | |
| A G Inglis | 9/9 | | | | | |
| J A Manzoni | 8/9 | | | | | |

## Serving as a director

### Induction

Following their appointment to the board, new directors undertake an induction programme, which includes matters such as the operation and activities of the group (for example, key financial, business, social and environmental risks to the group s activities), the board governance principles and the duties of directors. The operational and business element of the induction programme is tailored to the requirements of the new director and is targeted for completion within the first six to nine months of taking office.

The chairman is accountable for the induction of new board members and is assisted by the company secretary s office in this task.

### Training and site visits

Directors are kept briefed on BP s business, the environment in which it operates and other matters throughout their period in office. Non-executive directors also receive training specific to the tasks of the particular board committees on which they serve in order to complement their skills and knowledge and enhance their effectiveness during their tenure. On appointment, directors are advised of the legal and other duties and obligations they have as directors of a listed company. The board regularly considers the implications of these duties under the board governance principles.

During 2007, board members undertook visits to Thunder Horse in the Gulf of Mexico, the refineries at Texas City and Gelsenkirchen, BP s UK trading operations in Canary Wharf and BP s offices in Houston. All non-executive directors are now required to participate in at least one site visit per year.

### Outside appointments

As part of their ongoing development, executive directors are permitted to take up one external board appointment, subject to the agreement

of the chairman (which is then reported to the BP board). The board is satisfied that these appointments do not conflict with their duties and commitments to BP. Executive directors retain any fees received in respect of such external appointments and this is reported in the directors remuneration report.

Non-executive directors may serve on a number of outside boards, provided they continue to demonstrate the requisite commitment to discharge their duties to BP effectively. The nomination committee keeps under review the nature of directors other interests to ensure that the efficacy of the board is not compromised and may make recommendations to the board if it concludes that a director s other commitments are inconsistent with those required by BP.

### Evaluation

The board continued its ongoing evaluation processes to assess its performance and identify areas in which its effectiveness, policies and processes might be enhanced. The board evaluated its performance during the year through the use of a board skills evaluation completed by an external facilitator and also individual director interviews held by the company secretary. The process aimed at building on the outcome of the previous year s evaluation and assessing the way in which the board had responded to issues that occurred during 2007. A report from the external facilitator was considered by the board and recommendations adopted. The outcome from the evaluation has led the board to focus on certain areas for 2008, including a greater use of site visits and restructuring of forward board agendas.

Separate evaluations of the audit and remuneration committees and of SEEAC took place during the year and are outlined in the reports for those committees below (and in the directors remuneration report in the case of the remuneration committee).

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## The chairman and senior independent director

BP s board governance principles require that neither the chairman nor the deputy chairman is employed as an executive of the group. During 2007, the posts were held by Mr Sutherland and Sir Ian Prosser respectively. Sir Ian also acts as BP s senior independent director and is available to shareholders who have concerns that cannot be addressed through normal channels.

The chairman is responsible for leading the board and facilitating its work. He ensures that the governance principles and processes of the board are maintained and encourages debate and discussion. The chairman also leads board performance appraisals. He represents the views of the board to shareholders on key issues, not least in succession planning for both executive and non-executive appointments. Shareholders views are fed back to the board by the chairman.

The company secretary reports to the chairman and has no executive functions. His remuneration is determined by the remuneration committee.

Between board meetings, the chairman has responsibility for ensuring the integrity and effectiveness of the relationship with executive management. This requires his interaction with the group chief executive between board meetings, as well as his contact with other board members and shareholders.

The chairman and all the non-executive directors meet periodically as the chairman s committee. The performance of the chairman is evaluated each year, with the evaluation discussion taking place when the chairman is not present. The BP board governance principles require that the board develop and maintain a plan for the succession of both the chairman and the deputy chairman.

## The Board committees

The board governance principles allocate the tasks of monitoring executive actions and assessing performance to certain board committees. These tasks prescribe the authority and role of the board committees.

Reports for each of the main board committees follow. In common with the board, each committee has access to independent advice and counsel as required and each is supported by the company secretary s office, which is independent of the executive management of the group.

### Audit committee report

#### Membership

The audit committee consists solely of independent non-executive directors who have been selected to provide a wide range of financial, international and commercial expertise appropriate to fulfil the committee s duties.

Members of the audit committee throughout the year were Sir Ian Prosser (chairman), Douglas Flint, Erroll Davis, Jr and Sir William Castell. John Bryan was a member until his retirement in April 2007. Support is provided by the committee secretary, David Pearl (deputy company secretary).

The board has determined that Douglas Flint possesses the financial and audit committee experience, as defined by the Combined Code guidance and the SEC, and has nominated him as the audit committee s financial expert.

#### Meetings and attendance

The audit committee met 14 times during 2007.

At the request of the audit committee chairman, each meeting is attended by the lead partner of the external auditors (Ernst & Young). From BP, the group chief financial officer, the general auditor (head of internal audit), the chief accounting officer and the deputy chief financial officer also attend each meeting by invitation. Private sessions without executive management present are held regularly.

#### Role and authority of the audit committee

The audit committee monitors the observance of the executive limitations relating to financial matters and does this on behalf of the board.

BP s board governance principles set out the main tasks and requirements for each of the board committees. Key tasks for the audit committee include gaining assurance on the integrity of the group s reports, accounts and financial processes and reviewing the management of financial risks and the internal controls designed to address them. The audit committee believes that the tasks outlined in the board governance principles meet each of the tasks and activities outlined by the Combined Code as falling within the remit of an audit committee.

### Agendas

The audit committee uses a forward agenda at the start of each year to establish an initial work programme. This is compiled using a combination of regular items (including those required by regulation) and items that reflect a current review of the group s risks. The forward agenda also includes regular meetings during the year with both the external and internal auditors in private sessions where members of executive management are not present.

During the year, the committee chairman reviews any issues that may arise with the group chief financial officer, the external auditors and the BP general auditor and will add items to the next meeting agenda where appropriate.

### Information

Information on audit committee agenda items are received from both internal and external sources, including Ernst & Young, the general auditor and the chief financial officer. The committee receives presentations from a wide cross-section of BP s business and financial control management, with the attendance of additional Ernst & Young partners, if appropriate, to a particular business or functional review.

The audit committee is able to access independent advice and counsel when needed, on an unrestricted basis. Further support is provided to the committee by the company secretary s office and during 2007 external specialist legal and regulatory advice was provided by Sullivan & Cromwell LLP.

The board is kept informed of the activities of the committee and any issues that have arisen through the regular report given by the audit committee chairman after each meeting. Minutes of the committee are circulated to all board members.

### Training

A programme has been developed with the committee to enable committee members to update their skills and knowledge with regard to the financial issues that may impact BP, for example on developments in financial reporting and changes to financial standards.

### Committee activities in 2007

#### *Financial reports*

During the year, the committee reviewed all financial reports before recommending their publication to the board.

#### *Internal controls and risk management*

In 2007, the audit committee reviewed reports on risks, controls and assurance for the BP business segments (Exploration and Production and Refining and Marketing), together with gas, shipping, BP Alternative Energy and BP s trading function. A monitoring review was also carried out on the performance of major BP projects against their original sanctioned investment.

A joint meeting with SEEAC was held in early 2007 to review the general auditor s report on internal controls and risk management; a further joint meeting took place in early 2008 on the same theme.

The committee discussed key regulatory issues during the year as part of its standing agenda items, including a quarterly review of the company s evaluation of its internal controls systems as part of the requirement of Section 404 of the Sarbanes-Oxley Act. The effectiveness

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of BP s enterprise level controls was examined through the annual assessment undertaken by the internal audit function.

In addition to the standing items on the agenda, the committee considered a range of other topics including an update on TNK-BP, a review of the group s decommissioning provisions and the legal settlements reached in the US. The committee also received an independent report on the group s US trading operations and visited the trading operations in the UK.

### *External auditors*

The lead audit partner from Ernst & Young attends all meetings of the audit committee at the request of the committee chairman. Other audit partners are invited to attend meetings where they can utilize their areas of expertise, for example, during business segment or function reviews.

The committee held two private meetings during the year with the external auditors without the presence of BP management, in order to discuss any issues or concerns from either the committee or the auditors.

Performance of the external auditors is evaluated by the audit committee each year, with particular scrutiny of their independence, objectivity and viability. Independence is assisted through the limiting of non-audit services to tax and audit-related work that fall within defined categories. This work is pre-approved by the audit committee and all non-audit services are monitored quarterly.

Fees paid to the external auditors for the year *(see Financial statements Note 17 on page 126)* were $75 million, of which 16% was for non-audit work. Non-audit services provided by Ernst & Young have remained constant from 2006, and audit fees ($63 million in 2007 compared with $61 million in 2006) are also little changed as the impact of inflation and exchange rate movements have been offset by efficiency gains.

A new lead audit partner is appointed every five years and other senior audit partners and staff are rotated every seven years. No partners or senior staff from Ernst & Young who are currently connected with the BP audit may transfer to the group. During the year, the committee approved the appointment of a new lead partner from Ernst & Young to replace the current partner who reaches five years service in early 2008.

The audit committee has considered both the proposed fee structure and the audit engagement terms for 2008 and has recommended to the board that the reappointment of the external auditors be proposed to shareholders at the 2008 AGM.

### *Internal audit*

BP s internal audit function advises the committee on the company s identification and control of risk. The general auditor attends each committee meeting at the invitation of the committee chairman and presents a quarterly internal audit and controls report.

During the year, the audit committee evaluated the performance of the internal audit function and agreed to the proposed forward programme of work. The committee was also involved with finding a successor to the general auditor who is due to retire in 2008. An external consultant was engaged to undertake the search and the committee approved the appointment of an external candidate with deep audit experience.

In 2007, the committee met once with the general auditor in a private session without the presence of executive management.

### *Fraud reporting and employee concerns on financial matters*

The audit committee received a quarterly report from internal audit on instances of actual or potential fraud, and concerns relating to the financial accounting of the company. The committee also received reports on a quarterly basis from the group compliance and ethics function, which captured issues relating to financial matters raised through the employee concerns programme, OpenTalk, together with topics highlighted by the company s annual certification process.

### *Performance evaluation*

The committee conducts a yearly evaluation of its performance. For 2007, the review methodology included a survey of committee members and those individuals who regularly attend committee meetings. The survey results were analysed by the company secretary s office and discussed at the November audit committee meeting. Areas for future focus were identified following the evaluation, including training opportunities for committee members. These have been incorporated into the committee s agenda for 2008.

The audit committee plans to meet 12 times during 2008.

## Safety, ethics and environment assurance committee report

### Membership

The committee s members consist solely of independent non-executive directors who have been selected to provide a wide range of operational and international expertise appropriate to fulfil the committee s duties.

Members of SEEAC during 2007 were Dr Walter Massey (chairman), Antony Burgmans, Sir William Castell and Sir Tom McKillop. Support was provided by the committee secretary, David Pearl (deputy company secretary).

The committee chairman, Dr Massey, will retire as a director at the 2008 AGM. The appointment of his successor will be announced at the 2008 AGM. Mrs Cynthia Carroll will be joining the committee in due course.

### Meetings and attendance

SEEAC met eight times during 2007.

At the request of the committee chairman, each SEEAC meeting is attended by the lead partner of the external auditors (Ernst & Young) and the BP general auditor (head of internal audit).

Reports and presentations to SEEAC are led by a member of executive management. Following a change in executive responsibilities during the year, the executive liaison with SEEAC changed from Iain Conn to Dr Anthony Hayward, who attended three meetings of the committee in the second half of 2007. Private sessions without executive management in attendance are held at the end of each meeting.

### Role and authority of the committee

On behalf of the board, SEEAC monitors observance of the executive limitations policy relating to the environmental, health and safety, security and ethical performance of the company and compliance to its code of conduct.

In common with the other BP board committees, the board governance principles set out the main tasks and requirements for SEEAC. These include monitoring and obtaining assurance that the management or mitigation of material non-financial risks is appropriately addressed by the group chief executive.

### Agendas

The committee s tasks are broad as they cover all non-financial risk, and in constructing the forward agenda, the committee considers the risks identified in BP s business and annual plans and also the review of risks conducted by the general auditor.

The forward agenda includes standing items that enable the committee to monitor and assess how the executive limitations policy is being observed (for example, health, safety and environment reports) and to review the non-financial risks identified in the business plan (for example, regional risk reviews). The committee also holds a joint session with the audit committee to review the general auditor s report on internal controls and risk management.

During the year, the forward agenda is supplemented with any emerging issues or developments that may arise.

### Information

The committee receives information on agenda items from both internal and external sources, including internal audit, the safety and operations function, the group compliance and ethics function and Ernst & Young. Like other board committees, SEEAC can access independent advice and counsel if it requires, on an unrestricted basis.

The activities of the committee and any issues that have arisen are reported back to the main board by the committee chairman following each meeting.

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## Committee activities in 2007

*Baker Panel Report and appointment of independent expert*

In January 2007, the Baker Panel published its report on BP s corporate safety culture and the oversight of safety management systems at BP s five US refineries. The company agreed to adopt all the panel s recommendations, which were aimed at improving process safety performance at the five US plants, including the appointment of an independent expert for a period of at least five years to monitor and report annually on the progress of such implementation to the BP board.

In May, the board announced that L Duane Wilson, a member of the Baker Panel, was appointed as the independent expert to provide an objective assessment to the board of the company s progress towards implementation of the panel s recommendations. Mr Wilson reports to the chairman of SEEAC, has attended three of the committee s meetings since his appointment and has also accompanied the committee to its site visit of the Texas City refinery.

SEEAC received a presentation on Mr Wilson s detailed work plan in early 2008 and he will now periodically report to SEEAC on his progress. On behalf of the board, SEEAC will receive an annual report by mid-2008 in which Mr Wilson will address progress against the 10 Baker Panel recommendations.

*Group operations risk committee*

The group operations risk committee (GORC) was formed at the end of 2006 by executive management. The GORC is chaired by the group chief executive and reports regularly to SEEAC. GORC reports presented to SEEAC during the year included reviews of the progress of the six-point plan and the development of leading and lagging indicators of safety and operational performance.

*Site visits*

The committee visited BP s Gelsenkirchen refinery in Germany in March 2007 and the Texas City refinery in September. The annual committee evaluation process concluded that such site visits were valuable to the committee s work and, as a result, other site visits are planned for inclusion on the forward agenda for 2008.

*Compliance and ethics*

The committee is tasked with reviewing reports on the group s compliance with its code of conduct and on the employee concerns programme (OpenTalk) as it relates to non-financial issues. During the year, the committee received quarterly compliance and ethics reports, reviewed the 2006 certification process and the nature and resolution of cases raised through OpenTalk.

*Other topics*

Other topics reviewed during the year by SEEAC included a risk review of the Latin America and Caribbean region; health, safety and environmental progress in TNK-BP; and the BTC pipeline.

*Performance evaluation*

The committee conducts an annual review of its process and performance. The 2007 committee review involved a facilitated discussion at its November meeting. The review concluded that overall the committee was functioning as intended but that going forward more emphasis would be given to operational risk. In terms of committee processes, the review concluded that greater focus should be given to the effective use of the committee s time, as the committee s workload had increased with the frequency and duration of meetings lengthening.

SEEAC plans to meet seven times during 2008.

## **Remuneration committee report**

### Membership

The committee s members consist solely of non-executive directors who are considered by the board to be independent.

Members of the remuneration committee during the year were Dr DeAnne Julius (chairman), Erroll Davis, Jr, Sir Tom McKillop and Sir Ian Prosser. John Bryan retired from the committee in April 2007. The chairman of the board also attends meetings of the committee.

### Meetings and attendance

The remuneration committee met six times during 2007 and is independently advised.

### Role and authority of the committee

The committee s main task is 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 those to shareholders.

Further details on the committee s role, authority and activities during the year are set out in the directors remuneration report, which is the subject of a vote by shareholders at the 2008 AGM.

## Chairman s committee report

The chairman s committee completed the task that it commenced in 2006, formally concluding the process for the identification and appointment of a group chief executive to replace Lord Browne. This process involved establishing a clear definition of the role description and benchmarking internal candidates against an external population. The committee held detailed interviews with each of the candidates and undertook an evaluation of the candidates strengths and weaknesses.

During the year, the committee reviewed with Dr Hayward the short-and long-term challenges facing the group and, in particular, Dr Hayward s proposals for the forward agenda .

The committee also considered a number of management changes initiated by Dr Hayward and discussed his proposals for executive succession. The committee reviewed Lord Browne s performance at the start of the year and that of Mr Sutherland at the end.

## Nomination committee report

During the year, the nomination committee, through an external facilitator, carried out a detailed review of the board s skills aimed at identifying any perceived deficiencies such that a comprehensive succession plan could be prepared. The committee, under the chairmanship of Sir Ian Prosser, has acted as the working group for the identification of a successor to Mr Sutherland as chairman.

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## Directors interests

| Current directors | At 31 Dec 2007 | At 1 Jan 2007 | Change from 31 Dec 2007 to 19 Feb 2008 |
|---|---|---|---|
| Dr D C Allen | 597,568[a] | 530,933[a] | |
| A Burgmans | 10,000 | 10,000 | |
| C B Carroll | | | |
| Sir William Castell | 50,000 | | |
| I C Conn | 229,969[b] | 209,449[b] | 123 |
| E B Davis, Jr | 70,602[c] | 68,992[c] | |
| D J Flint | 15,000 | 15,000 | |
| Dr B E Grote | 1,193,137[d] | 1,105,825[d] | |
| Dr A B Hayward | 482,398 | 407,021 | 123 |
| A G Inglis | 758,756[e] | 727,772[f] | (209,000) |
| Dr D S Julius | 15,000 | 15,000 | |
| Sir Tom McKillop | 20,000 | 20,000 | |
| Dr W E Massey | 49,722[c] | 49,722[c] | |
| Sir Ian Prosser | 16,301 | 16,301 | |
| P D Sutherland | 30,906 | 30,079 | |

| Directors leaving the board in 2007 | At resignation/retirement | At 1 Jan 2007 |
|---|---|---|
| Lord Browne | 2,750,521[g] | 2,525,313[g] |
| J H Bryan | 158,760[c] | 158,760[c] |
| J A Manzoni | 451,806 | 376,213 |

| Directors joining the board in 2008 | On appointment 11 Feb 2008 | Change from 11 Feb 2008 to 19 Feb 2008 |
|---|---|---|
| G David | | 9,000[c] |

[a] Includes 25,368 shares held as ADSs.
[b] Includes 41,692 shares held as ADSs at 31 December 2007 and 40,155 shares held as ADSs at 1 January 2007.
[c] Held as ADSs.
[d] Held as ADSs, except for 94 that are held as ordinary shares.
[e] Includes 34,962 shares held as ADSs.
[f]

Interest as at 1 February 2007 on appointment as a director. Includes 34,962 shares held as ADSs and 534,750 MTPPs granted prior to appointment as a director, 209,000 of which lapsed on 6 February 2008.

g Includes 61,800 held as ADSs at resignation and 61,186 at 1 January 2007.

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 and Companies Acts 1985 or 2006 (as the case may be) 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.

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# Additional information for shareholders

## Share ownership

**Directors and senior management**

As at 19 February 2008, 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:

| | | | |
|---|---|---|---|
| Dr D C Allen | 597,568 | 839,948[a] | |
| I C Conn | 230,092 | 1,418,324[a] | 266,904[b] |
| Dr B E Grote | 1,193,137 | 1,543,820[a] | |
| Dr A B Hayward | 482,521 | 1,934,830[a] | |
| A G Inglis | 549,756 | 978,619[a] | 266,904[b] |
| A Burgmans | 10,000 | | |
| C B Carroll | | | |
| Sir William Castell | 50,000 | | |
| G David | 9,000 | | |
| E B Davis, Jr | 70,602 | | |
| D J Flint | 15,000 | | |
| Dr D S Julius | 15,000 | | |
| Sir Tom McKillop | 20,000 | | |
| Dr W E Massey | 49,722 | | |
| Sir Ian Prosser | 16,301 | | |
| P D Sutherland | 30,906 | | |

As at 19 February 2008, 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:

| | |
|---|---|
| Dr D C Allen | 794,950 |
| I C Conn | 206,390 |
| Dr B E Grote | 1,186,098 |
| Dr A B Hayward | 769,620 |
| A G Inglis | 415,300 |

[a] Performance shares awarded under the BP Executive Directors Incentive Plan. These 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 will vest in equal tranches after three and five years, subject to their continued service and satisfactory performance.

There are no directors or members of senior management who own more than 1% of the ordinary shares outstanding. At 19 February 2008, all directors and senior management as a group held interests in 14,132,552 ordinary shares or their calculated equivalent and 4,323,092 options for ordinary shares or their calculated equivalent under the BP group share options schemes.

Additional details regarding the options granted, including exercise price and expiry dates, are found in the directors remuneration report on page 69.

## Employee share plans

The following table shows employee share options granted.

| | | | options thousands |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Employee share options granted during the year[a] | **6,004** | 53,977 | 54,482 |

[a] For the options outstanding at 31 December 2007, the exercise price ranges and weighted average remaining contractual lives are shown in Financial statements Note 41 on page 160.

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 long-term performance plans (*see Financial statements Note 41 on page 160*) and the granting of share options 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.

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*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 70 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.

The above share plans are indicated as being equity-settled. In certain countries, however, it is not possible to award shares to employees owing to local legislation. In these instances, the award will be settled in cash, calculated as the cash equivalent of the value to the employee of an equity-settled plan.

### Cash plans

*Cash-settled share-based payments/Stock Appreciation Rights (SARs)*

These are cash-settled share-based payments available to certain employees that require the group to pay the intrinsic value of the cash option/SAR/restricted shares to the employee at the date of exercise/maturity.

### Employee share ownership plans (ESOPs)

ESOPs have been established to acquire BP shares to satisfy any awards made to participants under the Executive Directors Incentive Plan, the Medium-Term Performance Plan, the Long Term Performance Plan, the Deferred Annual Bonus Plan and the BP ShareMatch 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 which 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 158.*) Assets and liabilities of the ESOPs are recognized as assets and liabilities of the group.

At 31 December 2007, the ESOPs held 6,448,838 shares (2006 12,795,887 shares and 2005 14,560,003 shares) for potential future awards, which had a market value of $79 million (2006 $142 million and 2005 $156 million).

Pursuant to the various BP group share option schemes, the following options for ordinary shares of the company were outstanding at 19 February 2008:

| Options outstanding (shares) | Expiry dates of options | Exercise price per share |
|---|---|---|
| 352,819,401 | 2008-2016 | 5.0967-11.9210 |

Further details on share options appear in Financial statements Note 41 on page 160.

## Major shareholders and related party transactions

**Register of members holding BP ordinary shares as at 31 December 2007**

| Range of holdings | Number of ordinary shareholders | Percentage of total ordinary shareholders | Percentage of total ordinary share capital |
|---|---|---|---|

| | | | |
|---|---|---|---|
| 1-200 | 62,098 | 19.06 | 0.02 |
| 201-1,000 | 124,075 | 38.08 | 0.31 |
| 1,001-10,000 | 125,886 | 38.63 | 1.81 |
| 10,001-100,000 | 11,944 | 3.66 | 1.15 |
| 100,001-1,000,000 | 1,061 | 0.33 | 1.83 |
| Over 1,000,000[a] | 779 | 0.24 | 94.88 |
| Totals | 325,843 | 100.00 | 100.00 |

[a] Includes JP Morgan Chase Bank holding 28.51% 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 as at 31 December 2007[a]

| Range of holdings | Number of ADS holders | Percentage of total ADS holders | Percentage of total ADSs |
|---|---|---|---|
| 1-200 | 36,682 | 25.87 | 0.05 |
| 201-1,000 | 34,313 | 24.20 | 0.34 |
| 1,001-10,000 | 54,864 | 38.70 | 3.57 |
| 10,001-100,000 | 15,359 | 10.83 | 7.30 |
| 100,001-1,000,000 | 558 | 0.39 | 1.82 |
| Over 1,000,000[b] | 12 | 0.01 | 86.92 |
| Totals | 141,788 | 100.00 | 100.00 |

[a] One ADS represents six 25 cent ordinary shares.
[b] One of the holders of ADSs represents some 792,000 underlying shareholders.

As at 31 December 2007, there were also 1,597 preference shareholders. Preference shareholders represented 0.44% and ordinary shareholders represented 99.56% of the total issued nominal share capital of the company as at that date.

### Substantial shareholdings

As at the date of this report, the company had been notified that JPMorgan Chase Bank, as depositary for American depositary shares (ADSs) holds interests through its nominee, Guaranty Nominees Limited, in 5,395,627,629 ordinary shares (28.34% of the company s ordinary share capital excluding shares held in Treasury). Legal & General Group plc hold interests in 870,551,838 ordinary shares (4.57% of the company s ordinary share capital excluding shares held in treasury).

At the date of this report the company has also been notified of the following interests in preference shares. Co-operative Insurance Society Ltd. holds interests in 1,530,077 8% cumulative first preference shares (21.15% of that class) and 1,789,796 9% cumulative second preference shares (32.70% of that class). The National Farmers Union Mutual Insurance Society 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). Ruffer Limited Liability Partnership holds interests in 653,000 9% cumulative second preference shares (11.93% of that class). Lazard Asset Management Ltd. (U.K.) holds interests in 443,000 8% cumulative first preference shares (6.12% of that class).

The total preference shares in issue comprise only 0.44% of the company s total issued nominal share capital, 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 26

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on page 134 and Financial statements Note 27 on page 135. 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 2007 to 19 February 2008.

## Dividends

BP has paid dividends on its ordinary shares in each year since 1917. In 2000 and thereafter, dividends were, and are expected to continue to be, paid quarterly in March, June, September and December. Former Amoco Corporation and Atlantic Richfield Company shareholders will not be able to receive dividends, or proxy material, until they send in their Amoco Corporation or Atlantic Richfield Company common shares for exchange.

BP currently announces dividends for ordinary shares in US dollars and states 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 forward exchange rate in London over the five business days prior to the 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. In the case of dividends paid before 1 May 2004, the dividends shown are before the deemed credit allowed to shareholders resident in the US under the former income tax convention between the US and the UK and the associated withholding tax in respect thereof equal to the amount of such credit. (This deemed credit and associated withholding tax do not apply to dividends paid after 30 April 2004 to shareholders resident in the US.)

| | | March | June | September | December | Total |
|---|---|---|---|---|---|---|
| Dividends per American depositary share | | | | | | |
| 2003 | UK pence | 22.9 | 23.7 | 24.2 | 23.1 | 93.9 |
| | US cents | 37.5 | 37.5 | 39.0 | 39.0 | 153.0 |
| | Canadian cents | 57.4 | 54.3 | 54.0 | 51.1 | 216.8 |
| 2004 | UK pence | 22.0 | 22.8 | 23.2 | 23.5 | 91.5 |
| | US cents | 40.5 | 40.5 | 42.6 | 42.6 | 166.2 |
| | Canadian cents | 53.7 | 54.8 | 56.7 | 52.2 | 217.4 |
| 2005 | UK pence | 27.1 | 26.7 | 30.7 | 30.4 | 114.9 |
| | US cents | 51.0 | 51.0 | 53.55 | 53.55 | 209.1 |
| | Canadian cents | 64.0 | 63.2 | 65.3 | 63.7 | 256.2 |
| 2006 | UK pence | 31.7 | 31.5 | 31.9 | 31.4 | 126.5 |
| | US cents | 56.25 | 56.25 | 58.95 | 58.95 | 230.40 |
| | 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** | **67.80** | **63.60** | **274.2** |

A dividend reinvestment plan is in place whereby holders of BP ordinary shares can elect to reinvest the net cash dividend in shares purchased on the London Stock Exchange. This plan is not available to any person resident in the US or Canada or in any jurisdiction outside the UK where such an offer requires compliance by the company with any governmental or regulatory procedures or any similar formalities. A dividend reinvestment plan is, however, available for holders of ADSs through JPMorgan Chase Bank.

Future dividends will be dependent on future earnings, the financial condition of the group, the Risk factors set out on pages 8-9 and other matters that may affect the business of the group set out in Financial and operating performance on page 45.

## Legal proceedings

Save as disclosed in the following paragraphs, no member of the group is a party to, and no property of a member of the group is subject to, any pending legal proceedings that are significant to the group.

On 28 June 2006, the US Commodity Futures Trading Commission (CFTC) filed a civil enforcement action in the US District Court for the Northern District of Illinois against BP Products North America Inc. (BP Products), a wholly owned subsidiary of BP, alleging that BP Products manipulated the price of February 2004 TET physical propane. The CFTC also charged BP Products with attempting to manipulate the price of February 2004 and April 2003 TET physical propane. On 28 June 2006, the US Department of Justice (DOJ) filed a criminal charge against a former BP Products propane trader, who entered a guilty plea, and on 8 November 2007, four additional former BP Products traders were indicted on charges of conspiracy and market corner and commodity price manipulation. Private class action complaints have also been filed against BP Products that have been consolidated in the US District Court for the Northern District of Illinois. The complaints contain 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 seek actual and punitive damages and injunctive relief.

On 25 October 2007, BP America Inc. (BP America) entered into a deferred prosecution agreement (DPA) with the DOJ 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. The DPA requires BP America s and certain of its affiliates continued co-operation with the US government investigations of the trades in question, as well as other trading matters that may arise. Pursuant to the DPA, an independent monitor has been appointed to oversee compliance with the DPA. The independent monitor has authority to investigate and report alleged violations of the US Commodity Exchange Act or CFTC regulations and to recommend corrective action. The DPA has a term of three years and contemplates 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. BP America understands that its entry into the DPA concludes the pending criminal investigations of it and its affiliates relating to trading in various commodities, including propane, unleaded gasoline and crude oil. On 25 October 2007, BP Products also entered a companion consent order with the CFTC resolving all civil enforcement matters concerning BP Products propane trading. The remit of the independent monitor includes overseeing compliance with the Consent Order. BP Products understands that with its entry into the Consent Order, the CFTC closed its investigation of trading in unleaded gasoline without the filing of any charges against BP Products. In connection with the DPA and the Consent Order, BP America and BP Products agreed to pay fines, penalties and restitution totaling just over $303.5 million, including $53.5 million to a victim restitution fund, a criminal penalty of $100 million, a civil penalty of $125 million and a $25 million payment to the US Postal Inspection Service Consumer Fraud Fund. Investigations into BP s trading activities continue to be conducted from time to time.

On 23 March 2005, an explosion and fire occurred in the isomerization unit of BP Products 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 reached more than 2,000 settlements in respect of all the fatalities and many of the personal injury claims arising from the incident and has set aside $2,125 million, in aggregate, for the purpose. A number of claims remain to be resolved.

The US Occupational Safety and Health Administration (OSHA), the US Chemical Safety and Hazard Investigation Board (CSB), the US Environmental Protection Agency (EPA), the Texas Commission on Environmental Quality (TCEQ) and the DOJ, among other agencies, have conducted or are conducting investigations. At the conclusion of their investigation, OSHA issued citations that BP Products agreed not to contest. BP Products settled that matter with OSHA on 22 September 2005, paying a $21.4 million penalty and undertaking a number of corrective actions designed to make the refinery safer.

In June 2006, BP Products and the TCEQ entered into an agreed order resolving a number of alleged violations and, among other things, authorizing the refinery to construct certain new flares needed to replace blowdown stacks. In addition, BP Products agreed to pay a $336,556 civil penalty.

At the recommendation of the CSB, BP appointed an independent safety panel, the BP US Refineries Independent Safety Review Panel, under the chairmanship of former US Secretary of State James A Baker, III. See Report of the BP US Refineries Safety Review Panel on page 27 for a discussion of the panel s report, which was published on 16 January 2007.

In March 2007, the CSB issued its final report, which contained recommendations to the Texas City refinery and to the board of the company. In May 2007, BP responded to the CSB s recommendations.

BP and the CSB continue to discuss BP s responses with the objective of the CSB 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 in federal court, pursuant to the plea agreement, to one felony violation of the risk management planning regulations promulgated under the US federal Clean Air Act. At the plea hearing the court advised that it would take the matter under review and decide whether to accept or reject the plea. If the court accepts the agreement, BP Products will pay a $50 million criminal fine and serve three years probation. Compliance with the 2005 OSHA settlement agreement and the 2006 TCEQ Agreed Order are conditions of probation.

On 2 March 2006, a crude oil leak of approximately 4,800 barrels occurred on a low-pressure transit line on the Alaskan North Slope in the Western Operating Area of the Prudhoe Bay field operated by BP Exploration (Alaska) Inc. (BPXA). The March 2006 leak was determined to be the result of internal corrosion. On 6 August 2006, BPXA ordered a phased shutdown of the Prudhoe Bay oil field following the discovery of unexpectedly severe internal corrosion and a leak of 199 barrels of crude oil from the oil transit line in the Eastern Operating Area of Prudhoe Bay. Shortly after the March 2006 leak, the DOJ initiated an investigation of the spill through a federal grand jury in Alaska. During the course of the following 17 months, BPXA co-operated with the US government s investigation, including among other things, by producing millions of pages of documents, encouraging its employees to co-operate with the investigation and provide testimony to the grand jury, and by providing the government s investigators with samples from and sections of the segment of the failed transit line.

On 25 October 2007, BPXA entered into an agreement with the DOJ in which it agreed to plead guilty to one US Federal Water Pollution Control Act misdemeanour violation relating to the March 2006 crude oil leak. The plea agreement resolved all of the federal and State of Alaska criminal culpability of BPXA associated with the March and August leaks at Prudhoe Bay. On 29 November 2007, the US District Court for the District of Alaska accepted the plea agreement, entered a misdemeanour guilty plea against BPXA and sentenced BPXA to pay a combined $20 million in criminal fines, restitution and community service payments and serve three years of probation. BPXA has the right to petition the court for termination of the probation term after one year if it meets certain benchmarks relating to replacement of the transit lines, upgrades to its leak detection system and improvements to its integrity management programme. All criminal fines and other payments required by the plea agreement and sentence were made by BPXA on the date of sentencing following entry of the plea.

BPXA continues to co-operate with a parallel State of Alaska civil investigation into the March and August 2006 spills, including three separate subpoenas issued to BPXA by the Alaska Department of Environmental Conservation. BPXA is also engaged in discussions with the DOJ, the EPA and the US Department of Transport concerning civil regulatory claims relating to the 2006 Prudhoe Bay oil transit line incidents.

Shareholder derivative lawsuits have been filed in US federal and state courts against the directors of the company and others, nominally the company and certain US subsidiaries following the events relating to, inter alia, Prudhoe Bay, Texas City and the trading cases, alleging breach of fiduciary duty. These derivative lawsuits have been settled, subject to court approval.

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 47% interest (reduced during 2001 from 50% by a sale of 3% 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, 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, which, along with a predecessor company, 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 and it intends to defend such actions vigorously and that the incurrence of liability is remote. Consequently, BP believes that the impact of these lawsuits on the group s results of operations, financial position or liquidity will not be material.

For certain information regarding environmental proceedings, see Environmental protection US regional review on page 42.

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## The offer and listing

### 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 stock exchanges in France, Germany, Japan and Switzerland.

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 to the exchange electronically 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 reestablish 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 and Canada, the company s securities are traded in the form of ADSs, for which JPMorgan Chase Bank is the depositary (the Depositary) and transfer agent. The Depositary s principal office is 4 New York Plaza, Floor 13, New York, NY 10004, US. Each ADS represents six ordinary shares. ADSs are listed on the New York Stock Exchange and are also traded on the Chicago and Toronto Stock Exchanges. 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 for the periods shown. These are derived from the Daily Official List of the LSE and the highest and lowest sales prices of ADSs as reported on the New York Stock Exchange (NYSE) composite tape.

| | | | Pence | | Dollars |
|---|---|---|---|---|---|
| | | | Ordinary shares | | American depositary shares[a] |
| | | High | Low | High | Low |
| Year ended 31 December | | | | | |
| 2003 | | 458.00 | 348.75 | 49.59 | 34.67 |
| 2004 | | 561.00 | 407.75 | 62.10 | 46.65 |
| 2005 | | 686.00 | 499.00 | 72.75 | 56.60 |
| 2006 | | 723.00 | 558.50 | 76.85 | 63.52 |
| 2007 | | 640.00 | 504.50 | 79.77 | 58.62 |
| Year ended 31 December | | | | | |
| 2006: | First quarter | 693.00 | 623.00 | 72.88 | 65.35 |
| | Second quarter | 723.00 | 581.00 | 76.85 | 64.19 |
| | Third quarter | 653.00 | 560.00 | 73.28 | 63.81 |
| | Fourth quarter | 619.00 | 558.50 | 69.49 | 63.52 |
| 2007: | First quarter | **574.50** | **504.50** | **67.27** | **58.62** |
| | Second quarter | **606.50** | **542.50** | **72.49** | **64.42** |
| | Third quarter | **617.00** | **516.00** | **75.25** | **61.10** |
| | Fourth quarter | **640.00** | **548.00** | **79.77** | **67.24** |
| 2008: | First quarter (to 19 February) | **648.00** | **498.00** | **75.87** | **57.85** |
| Month of | | | | | |

| | | | | |
|---|---|---|---|---|
| September 2007 | **600.00** | **548.00** | **72.11** | **66.76** |
| October 2007 | **639.50** | **548.00** | **78.58** | **67.24** |
| November 2007 | **640.00** | **564.00** | **79.77** | **69.81** |
| December 2007 | **624.00** | **585.00** | **76.50** | **72.10** |
| January 2008 | **648.00** | **498.00** | **75.87** | **57.85** |
| February 2008 (to 19 February) | **576.50** | **529.50** | **67.50** | **62.38** |

[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 and other North American stock exchanges 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. Trading in ADSs began on the LSE on 3 August 1987.

On 19 February 2008, 899,270,264 ADSs (equivalent to 5,395,621,585 ordinary shares or some 28.34% of the total) were outstanding and were held by approximately 140,195 ADR holders. Of these, about 138,696

had registered addresses in the US at that date. One of the registered holders of ADSs represents some 800,000 underlying holders.

On 19 February 2008, there were approximately 328,855 holders of record of ordinary shares. Of these holders, around 1,487 had registered addresses in the US and held a total of some 4,238,685 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.

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## 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 and the company s Memorandum and Articles of Association. Information on where investors can obtain copies of the Memorandum and Articles of Association is described under the heading Documents on display on page 88.

On 24 April 2003, the shareholders of BP voted at the AGM to adopt new Articles of Association to consolidate amendments that had been necessary to implement legislative changes since the previous Articles of Association were adopted in 1983.

At the AGM held on 15 April 2004, shareholders approved an amendment to the Articles of Association such that, at each AGM held after 31 December 2004, all directors shall retire from office and may offer themselves for re-election. There have been no further amendments to the Articles of Association.

At the upcoming annual general meeting of the company, it will be proposed that the company adopts new articles of association, largely to take account of changes in UK company law brought about by the Companies Act 2006.

### Objects and purposes

BP is incorporated under the name BP p.l.c. and is registered in England and Wales with registered number 102498. Clause 4 of BP s Memorandum of Association provides that its objects include the acquisition of petroleum-bearing lands; the carrying on of refining and dealing businesses in the petroleum, manufacturing, metallurgical or chemicals businesses; the purchase and operation of ships and all other vehicles and other conveyances; and the carrying on of any other businesses calculated to benefit BP. The memorandum grants BP a range of corporate capabilities to effect these objects.

### Directors

The business and affairs of BP shall be managed by the directors.

The Articles of Association place a general prohibition on a director voting in respect of any contract or arrangement in which he has a material interest other than by virtue of his 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.
- Any proposal in which he is interested concerning the underwriting of company securities or debentures.
- Any proposal concerning any other company in which he is interested, directly or indirectly (whether as an officer or shareholder or otherwise) provided that he and persons connected with him 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 he 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 he may benefit.

The UK Companies 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 his interest at a meeting of the directors of the company. The definition of interest now includes the interests of spouses, children, companies and trusts. 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 effected 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. Any director attaining the age of 70 shall retire at the next AGM. 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 UK Companies 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.

Apart from shareholders rights to share in BP s profits by dividend (if any is declared), 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 three types: ordinary, special or extraordinary.

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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. Special and extraordinary resolutions require the affirmative vote of not less than three-fourths of the persons voting at a meeting at which there is a quorum. Any AGM at which it is proposed to put a special or ordinary resolution requires 21 days notice. An extraordinary resolution put to the AGM requires no notice period. Any extraordinary general meeting at which it is proposed to put a special resolution requires 21 days notice; otherwise, the notice period for an extraordinary general meeting is 14 days.

### 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 an extraordinary 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 in order 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 15 months after the preceding AGM. All other general meetings of shareholders shall be called extraordinary general meetings and 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 ADSs, other than limitations that would generally apply to all of the shareholders.

### Disclosure of interests in shares

The UK Companies Act permits a public company, on written notice, to require any person whom the company believes to be or, at any time during the previous 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.

## 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.

A US holder is any beneficial owner of ordinary shares or ADSs that is for US federal income tax purposes (i) a citizen or resident of the US, (ii) a US domestic corporation, (iii) an estate whose income is subject to US federal income taxation regardless of its source, or (iv) a trust if a US court can exercise primary supervision over the trust s administration and one or more US persons are authorized to control all substantial decisions of the trust.

This section is based on the Internal Revenue Code of 1986, as amended, its legislative history, existing and proposed regulations thereunder, published rulings and court decisions, and the taxation laws of the UK, all as currently in effect, as well as the income tax convention between the US and the UK that entered into force on 31 March 2003 (the Treaty). These laws are subject to change, possibly on a retroactive basis. This section is further based in part on the representations of the Depositary and assumes that each obligation in the Deposit Agreement and any related agreement will be performed in accordance with its terms.

For purposes of the Treaty and the estate and gift tax Convention (the Estate Tax Convention ), and for US federal income tax and UK taxation purposes, a holder of ADRs evidencing ADSs will be treated as the owner of the company s ordinary shares represented by those ADRs. Exchanges of ordinary shares for ADRs and ADRs for ordinary shares generally will not be subject to US federal income tax or to UK taxation other than stamp duty or stamp duty reserve tax, as described below.

Investors should consult their own tax adviser regarding the US federal, state and local, 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 generally will not be taxable on a dividend it receives from the company. A shareholder who is an individual resident for tax purposes in the UK is 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.

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### 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 2011 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 the allowable foreign tax credit.

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.

## 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 that 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 2011 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-mark 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 and certain excess distribution 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.

## Additional tax considerations

### 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 both to inheritance tax and to 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 the UK Inland Revenue under existing law.

Provided that the 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 50 pence per £100 (or part), 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

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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.

A transfer of the underlying ordinary shares to an ADR holder on cancellation of the ADSs without transfer of beneficial ownership will give rise to UK stamp duty at the rate of £5 per 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. Current UK Inland Revenue 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 s Annual Report and Accounts is also available online at *www.bp.com*. 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 e-mail request addressed to *bpdistributionservices@bp.com*, or BP s US Shareholder Services office in Warrenville, Illinois at +1 800 638 5672 or through an e-mail request addressed to *shareholderus@bp.com*.

The company is subject to the information requirements of the US Securities Exchange Act of 1934 applicable to foreign private issuers. In accordance with these requirements, the company files its Annual Report 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 web site at www.sec.gov. BP discloses on its website at *www.bp.com/NYSEcorporategovernancerules* significant ways (if any) in which its corporate governance practices differ from those mandated for US companies under NYSE listing standards.

## Material modifications to the rights of security holders and use of proceeds

Following the acquisition of the corporate trust business of JPMorgan Chase Bank, N.A., the Bank of New York Trust Company, N.A. succeeded JP Morgan Chase Bank, N.A. as the trustee under the Indenture, dated as of 8 March 2002, among BP Capital Markets p.l.c., BP p.l.c. and JPMorgan Chase Bank, the Indenture, dated as of 27 September 2002, among BP Canada Finance Company, BP p.l.c. and JPMorgan Chase Bank, N.A. and the Indenture, dated as of 4 June 2003, among BP Capital Markets America Inc., BP p.l.c. and JPMorgan Chase Bank. The address of The Bank of New York Trust Company, N.A. is 227 W. Monroe, 26th Floor, Chicago, Illinois 60606.

During 2006, the transfer agent for BP s ADRs changed to Mellon. BP s Registrar, LloydsTSB Registrars, has changed its name to Equiniti in 2007.

## 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 judgment 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, mis-statements 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 believe 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.

### Changes in internal controls over financial reporting

There were no changes in the group s internal controls over financial reporting that occurred during the period covered by the Form 20-F that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

### 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 principal 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 2007 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 2007 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 2007 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report appearing on page 94.

## Audit committee financial expert

The board determined that Douglas Flint is the audit committee member with recent and relevant financial experience as defined by the Combined Code guidance.

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The board also determined that Douglas Flint 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. Mr Flint is group finance director of HSBC Holdings plc and a former member of the Accounting Standards Board and the Standards Advisory Council of the International Accounting Standards Board.

## Code of ethics

The company has adopted a code of ethics for its group chief executive, chief financial officer, general auditor, group chief accounting officer and deputy chief financial officer (previously titled group controller) 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 amendments to, or waivers from, the code of ethics relating to any of those officers. The code of ethics has been filed as an exhibit to our Annual Report on Form 20-F.

In June 2005, BP published a code of conduct, which is applicable to all employees.

## 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; 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. It requires the auditors to rotate their lead audit partner every five years.

(See Financial statements Notes 17 and 49 on pages 127 and 175 for details of audit fees.)

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## Purchases of equity securities by the issuer and affiliated purchasers

The following table provides details of ordinary shares repurchased.

| | Total number of shares purchased[a b] | $ Average price 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[c] |
|---|---|---|---|---|
| 2007 | | | | |
| January | **73,361,264** | **10.80** | **73,361,264** | |
| February | **83,747,871** | **10.52** | **83,747,871** | |
| March | **80,807,070** | **10.21** | **80,807,070** | |
| April | **74,516,902** | **11.31** | **74,516,902** | |
| May | **52,957,411** | **11.33** | **52,957,411** | |
| June | **48,331,426** | **11.50** | **48,331,426** | |
| July | **50,630,000** | **12.29** | **50,630,000** | |
| August | **44,808,000** | **11.08** | **44,808,000** | |
| September | **32,815,000** | **11.61** | **32,815,000** | |
| October | **43,067,439** | **12.36** | **43,067,439** | |
| November | **46,775,350** | **12.34** | **46,775,350** | |
| December | **31,331,795** | **12.44** | **31,331,795** | |
| 2008 | | | | |
| January | **41,187,000** | **11.26** | **41,187,000** | |
| February (to 19 February) | **11,293,523** | **10.77** | **11,293,523** | |

[a] All share purchases were open market transactions.
[b] All shares were repurchased for cancellation.
[c] At the AGM on 12 April 2007, authorization was given to repurchase up to 1.95 billion ordinary shares in the period to the next AGM in 2008 or 11 July 2008, the latest date by which an AGM must be held. This authorization is renewed annually at the AGM.

The following table provides details of share purchases made by ESOP trusts.

| | Total number of shares purchased | $ Average price paid per share | Total number of shares purchased as part of publicly announced programmes[a] | Maximum number of shares that may yet be purchased under the programme[a] |
|---|---|---|---|---|
| 2007 | | | | |
| January | **77,553** | **11.15** | | |
| February | **326,535** | **10.75** | | |

| | | |
|---|---|---|
| March | **194** | **11.42** |
| April | **8,207** | **11.56** |
| May | **5,181,599** | **11.60** |
| June | **13,140** | **11.37** |
| July | **3,507,928** | **12.32** |
| August | | |
| September | | |
| October | | |
| November | | |
| December | **2,000,000** | **11.78** |
| 2008 | | |
| January | | |
| February (to 19 February) | **2,943,710** | **11.25** |

[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.

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## Called up share capital

Details of the allotted, called up and fully paid share capital at 31 December 2007 are set out in Financial statements Note 39 on page 157.

At the AGM on 12 April 2007, authorization was given to the directors to allot shares up to an aggregate nominal amount equal to $1,626 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 $244 million, without having to offer such shares to existing shareholders. These authorities are given for the period until the next AGM in 2008 or 11 July 2008, whichever is the earlier. These authorities are renewed annually at the AGM.

## Annual general meeting

The 2008 AGM will be held on Thursday 17 April 2008 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 2008*.

By order of the board
David J Jackson
Secretary
22 February 2008

## Exhibits

The following documents are filed as part of this annual report:

| | |
|---|---|
| Exhibit 1. | Memorandum and Articles of Association of BP p.l.c.* |
| Exhibit 4.1 | The BP Executive Directors Incentive Plan** |
| Exhibit 4.2 | Directors Service Contracts for Dr AB Hayward, Dr DC Allen, IC Conn and Dr BE Grote** |
| Exhibit 4.3 | Director Service Contract for AG Inglis |
| Exhibit 4.4 | Medium Term Performance Plan |
| Exhibit 4.5 | Deferred Annual Bonus Plan |
| Exhibit 4.6 | Performance Share Plan |
| Exhibit 7. | Computation of Ratio of Earnings to Fixed Charges (Unaudited) |
| Exhibit 8. | Subsidiaries |
| Exhibit 11. | Code of Ethics* |
| Exhibit 12. | Rule 13a 14(a) Certifications |
| Exhibit 13. | Rule 13a 14(b) Certifications# |

* Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2003.

** Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2004.

\# Furnished only.

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 Securities and Exchange Commission upon request.

## Administration

If you have any queries about the administration of shareholdings, such as change of address, change of ownership, dividend payments, the dividend reinvestment plan or the ADS direct access plan, or to change the way you receive your company documents (such as the Annual Report and Accounts, Annual Review and Notice of 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
Tel: +44 (0)121 415 7005; Freephone in UK: 0800 701107
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
PO Box 358408, Pittsburgh, PA 15252-8408
Tel: +1 201 680 6630
Toll-free in US and Canada: +1 877 638 5672

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# Financial statements contents

**Additional information for US reporting**

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# Report of Independent Registered Public Accounting Firm

**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 2007 and 2006, and the related group statements of income, cash flows, and recognized income and expense, for each of the three years in the period ended 31 December 2007. 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, 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 2007 and 2006, and the group results of operations and cash flows for each of the three years in the period ended 31 December 2007, 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.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of BP p.l.c. s internal control over financial reporting as of 31 December 2007, 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 22 February 2008 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP
Ernst & Young LLP
London, England
22 February 2008

# Report of Independent Registered Public Accounting Firm

**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 2007, 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 88. 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 2007, 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 2007 and 2006, and the related group statements of income, cash flows and recognized income and expense, for each of the three years in the period ended 31 December 2007, and our report dated 22 February 2008 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP
Ernst & Young LLP
London, England
22 February 2008

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# Consent of independent registered public accounting firm

We consent to the incorporation by reference of our reports dated 22 February 2008 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 2007 in the following registration statements:

Registration Statements on Form F-3 (File Nos. 333-9790 and 333-65996) of BP p.l.c.,

Registration Statement on Form F-3 (File Nos. 333-110203) of BP Canada Finance Company, BP Capital Markets p.l.c., BP Capital Markets America Inc, and BP p.l.c., and

Registration Statements on Form S-8 (File Nos. 333-21868, 333-9020, 333-09798, 333-79399, 333-34968, 333-67206, 333-74414, 333-102583, 333-103923, 333-103924, 333-119934, 333-123482, 333-123483, 333-132619, 333-131584, 333-131583, 333-146868, 333-146870 and 333-146873) of BP p.l.c.

/s/ERNST & YOUNG LLP
Ernst & Young LLP

London, England
4 March 2008

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# Group income statement

For the year ended 31 December $ million

| | Note | 2007 | 2006 | 2005 |
|---|---|---|---|---|
| Sales and other operating revenues | 5 | **284,365** | 265,906 | 239,792 |
| Earnings from jointly controlled entities after interest and tax | | **3,135** | 3,553 | 3,083 |
| Earnings from associates after interest and tax | | **697** | 442 | 460 |
| Interest and other revenues | 6 | **754** | 701 | 613 |
| Total revenues | | **288,951** | 270,602 | 243,948 |
| Gains on sale of businesses and fixed assets | 7 | **2,487** | 3,714 | 1,538 |
| Total revenues and other income | | **291,438** | 274,316 | 245,486 |
| Purchases | | **200,766** | 187,183 | 163,026 |
| Production and manufacturing expenses | | **25,915** | 23,293 | 21,592 |
| Production and similar taxes | 8 | **4,013** | 3,621 | 3,010 |
| Depreciation, depletion and amortization | 9 | **10,579** | 9,128 | 8,771 |
| Impairment and losses on sale of businesses and fixed assets | 10 | **1,679** | 549 | 468 |
| Exploration expense | 16 | **756** | 1,045 | 684 |
| Distribution and administration expenses | 12 | **15,371** | 14,447 | 13,706 |
| Fair value (gain) loss on embedded derivatives | 34 | **7** | (608) | 2,047 |
| Profit before interest and taxation from continuing operations | | **32,352** | 35,658 | 32,182 |
| Finance costs | 18 | **1,110** | 718 | 616 |
| Other finance (income) expense | 19 | **(369)** | (202) | 145 |
| Profit before taxation from continuing operations | | **31,611** | 35,142 | 31,421 |
| Taxation | 20 | **10,442** | 12,516 | 9,288 |
| Profit from continuing operations | | **21,169** | 22,626 | 22,133 |
| Profit (loss) from Innovene operations | 3 | | (25) | 184 |
| Profit for the year | | **21,169** | 22,601 | 22,317 |
| Attributable to | | | | |
| BP shareholders | | **20,845** | 22,315 | 22,026 |
| Minority interest | | **324** | 286 | 291 |
| | | **21,169** | 22,601 | 22,317 |

Earnings per share cents

Profit for the year attributable to BP shareholders

| | | | | |
|---|---|---|---|---|
| Basic | 22 | **108.76** | 111.41 | 104.25 |
| Diluted | 22 | **107.84** | 110.56 | 103.05 |
| Profit from continuing operations attributable to BP shareholders | | | | |
| Basic | | **108.76** | 111.54 | 103.38 |
| Diluted | | **107.84** | 110.68 | 102.19 |

The notes on pages 100-180 are an integral part of these consolidated financial statements of the BP group.

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# Group balance sheet

At 31 December — $ million

| | Note | 2007 | 2006 |
|---|---|---|---|
| **Non-current assets** | | | |
| Property, plant and equipment | 23 | **97,989** | 90,999 |
| Goodwill | 24 | **11,006** | 10,780 |
| Intangible assets | 25 | **6,652** | 5,246 |
| Investments in jointly controlled entities | 26 | **18,113** | 15,074 |
| Investments in associates | 27 | **4,579** | 5,975 |
| Other investments | 29 | **1,830** | 1,697 |
| Fixed assets | | **140,169** | 129,771 |
| Loans | | **999** | 817 |
| Other receivables | 31 | **968** | 862 |
| Derivative financial instruments | 34 | **3,741** | 3,025 |
| Prepayments | | **1,083** | 1,034 |
| Defined benefit pension plan surplus | 38 | **8,914** | 6,753 |
| | | **155,874** | 142,262 |
| **Current assets** | | | |
| Loans | | **165** | 141 |
| Inventories | 30 | **26,554** | 18,915 |
| Trade and other receivables | 31 | **38,020** | 38,692 |
| Derivative financial instruments | 34 | **6,321** | 10,373 |
| Prepayments | | **3,589** | 3,006 |
| Current tax receivable | | **705** | 544 |
| Cash and cash equivalents | 32 | **3,562** | 2,590 |
| | | **78,916** | 74,261 |
| Assets classified as held for sale | 3 | **1,286** | 1,078 |
| | | **80,202** | 75,339 |
| Total assets | | **236,076** | 217,601 |
| **Current liabilities** | | | |
| Trade and other payables | 33 | **43,152** | 42,236 |
| Derivative financial instruments | 34 | **6,405** | 9,424 |
| Accruals | | **6,640** | 6,147 |
| Finance debt | 35 | **15,394** | 12,924 |
| Current tax payable | | **3,282** | 2,635 |

| | | | |
|---|---|---|---|
| Provisions | 37 | **2,195** | 1,932 |
| | | **77,068** | 75,298 |
| Liabilities directly associated with the assets classified as held for sale | 3 | **163** | 54 |
| | | **77,231** | 75,352 |
| Non-current liabilities | | | |
| Other payables | 33 | **1,251** | 1,430 |
| Derivative financial instruments | 34 | **5,002** | 4,203 |
| Accruals | | **959** | 961 |
| Finance debt | 35 | **15,651** | 11,086 |
| Deferred tax liabilities | 20 | **19,215** | 18,116 |
| Provisions | 37 | **12,900** | 11,712 |
| Defined benefit pension plan and other post-retirement benefit plan deficits | 38 | **9,215** | 9,276 |
| | | **64,193** | 56,784 |
| Total liabilities | | **141,424** | 132,136 |
| Net assets | | **94,652** | 85,465 |
| Equity | | | |
| Share capital | 39 | **5,237** | 5,385 |
| Reserves | | **88,453** | 79,239 |
| BP shareholders equity | 40 | **93,690** | 84,624 |
| Minority interest | 40 | **962** | 841 |
| Total equity | 40 | **94,652** | 85,465 |

P D Sutherland Chairman
Dr A B Hayward Group Chief Executive

The notes on pages 100-180 are an integral part of these consolidated financial statements of the BP group.

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# Group cash flow statement

| For the year ended 31 December | | | | $ million |
|---|---|---|---|---|
| | Note | **2007** | 2006 | 2005 |
| Operating activities | | | | |
| Profit before taxation from continuing operations | | **31,611** | 35,142 | 31,421 |
| Adjustments to reconcile profit before taxation to net cash provided by operating activities | | | | |
| Exploration expenditure written off | 16 | **347** | 624 | 305 |
| Depreciation, depletion and amortization | 9 | **10,579** | 9,128 | 8,771 |
| Impairment and (gain) loss on sale of businesses and fixed assets | 7, 10 | **(808)** | (3,165) | (1,070) |
| Earnings from jointly controlled entities and associates | | **(3,832)** | (3,995) | (3,543) |
| Dividends received from jointly controlled entities and associates | | **2,473** | 4,495 | 2,833 |
| Interest receivable | | **(489)** | (473) | (479) |
| Interest received | | **500** | 500 | 401 |
| Finance costs | 18 | **1,110** | 718 | 616 |
| Interest paid | | **(1,363)** | (1,242) | (1,127) |
| Other finance (income) expense | 19 | **(369)** | (202) | 145 |
| Share-based payments | | **420** | 416 | 278 |
| Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans | | **(404)** | (261) | (435) |
| Net charge for provisions, less payments | | **(92)** | (160) | 1,100 |
| (Increase) decrease in inventories | | **(7,255)** | 995 | (6,638) |
| (Increase) decrease in other current and non-current assets | | **5,210** | 3,596 | (16,427) |
| Increase (decrease) in other current and non-current liabilities | | **(3,857)** | (4,211) | 18,628 |
| Income taxes paid | | **(9,072)** | (13,733) | (9,028) |
| Net cash provided by operating activities of continuing operations | | **24,709** | 28,172 | 25,751 |
| Net cash provided by operating activities of Innovene operations | 3 | | | 970 |
| Net cash provided by operating activities | | **24,709** | 28,172 | 26,721 |
| Investing activities | | | | |
| Capital expenditures | | **(17,830)** | (15,125) | (12,281) |
| Acquisitions, net of cash acquired | | **(1,225)** | (229) | (60) |
| Investment in jointly controlled entities | | **(428)** | (37) | (185) |
| Investment in associates | | **(187)** | (570) | (619) |
| Proceeds from disposal of fixed assets | 4 | **1,749** | 5,963 | 2,803 |
| Proceeds from disposal of businesses, net of cash disposed | 4 | **2,518** | 291 | 8,397 |
| Proceeds from loan repayments | | **192** | 189 | 123 |
| Other | | **374** | | 93 |
| Net cash used in investing activities | | **(14,837)** | (9,518) | (1,729) |

| | | | | |
|---|---|---|---|---|
| Financing activities | | | | |
| Net repurchase of shares | | **(7,113)** | (15,151) | (11,315) |
| Proceeds from long-term financing | | **8,109** | 3,831 | 2,475 |
| Repayments of long-term financing | | **(3,192)** | (3,655) | (4,820) |
| Net increase (decrease) in short-term debt | | **1,494** | 3,873 | (1,457) |
| Dividends paid | | | | |
| BP shareholders | 21 | **(8,106)** | (7,686) | (7,359) |
| Minority interest | | **(227)** | (283) | (827) |
| Net cash used in financing activities | | **(9,035)** | (19,071) | (23,303) |
| Currency translation differences relating to cash and cash equivalents | | **135** | 47 | (88) |
| Increase (decrease) in cash and cash equivalents | | **972** | (370) | 1,601 |
| Cash and cash equivalents at beginning of year | | **2,590** | 2,960 | 1,359 |
| Cash and cash equivalents at end of year | | **3,562** | 2,590 | 2,960 |

The notes on pages 100-180 are an integral part of these consolidated financial statements of the BP group.

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# Group statement of recognized income and expense

| For the year ended 31 December | | | | $ million |
| --- | --- | --- | --- | --- |
| | Note | **2007** | 2006 | 2005 |
| Currency translation differences | | **1,887** | 2,025 | (2,502) |
| Exchange gain on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets | | **(147)** | | (315) |
| Actuarial gain relating to pensions and other post-retirement benefits | | **1,717** | 2,615 | 975 |
| Available-for-sale investments marked to market | | **200** | 561 | 322 |
| Available-for-sale investments recycled to the income statement | | **(91)** | (695) | (60) |
| Cash flow hedges marked to market | | **155** | 413 | (212) |
| Cash flow hedges recycled to the income statement | | **(74)** | (93) | 36 |
| Cash flow hedges recycled to the balance sheet | | **(40)** | (6) | |
| Tax on currency translation differences | | **139** | (201) | 11 |
| Tax on exchange gain on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets | | | | 95 |
| Tax on actuarial gain relating to pensions and other post-retirement benefits | | **(427)** | (820) | (356) |
| Tax on available-for-sale investments | | **(14)** | 108 | (72) |
| Tax on cash flow hedges | | **26** | (47) | 63 |
| Tax on share-based payments | | **213** | 26 | |
| Net income (expense) recognized directly in equity | | **3,544** | 3,886 | (2,015) |
| Profit for the year | | **21,169** | 22,601 | 22,317 |

| | | | | |
|---|---|---|---|---|
| Total recognized income and expense for the year | | **24,713** | 26,487 | 20,302 |
| Attributable to | | | | |
| BP shareholders | | **24,365** | 26,152 | 20,011 |
| Minority interest | | **348** | 335 | 291 |
| | | **24,713** | 26,487 | 20,302 |
| Effect of change in accounting policy adoption of IAS 32 and IAS 39 on 1 January 2005 | | | | |
| BP shareholders | 1 | | | (243) |
| Minority interest | | | | |
| | | | | (243) |

The notes on pages 100-180 are an integral part of these consolidated financial statements of the BP group.

# 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 2007 were authorized for issue by the board of directors on 22 February 2008 and the balance sheet was signed on the board s behalf by P D Sutherland and Dr A B Hayward. 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) and IFRS as adopted by the European Union (EU). 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 International Financial Reporting Interpretations Committee (IFRIC) interpretations issued and effective for the year ended 31 December 2007, or issued and early adopted.

In preparing the consolidated financial statements for the current year, the group has adopted the following new IFRS, amendment to IFRS and IFRIC interpretations:

- IFRS 7 Financial Instruments: Disclosures .
- Amendment to IAS 1 Presentation of Financial Statements Capital Disclosures.
- IFRIC 10 Interim Financial Reporting and Impairment .
- IFRIC 11 IFRS 2 Group and Treasury Share Transactions .

Further information regarding the impact of adoption is given below.

The accounting policies that follow have been consistently applied to all years presented with the exception of those relating to financial instruments under IAS 32 Financial Instruments: Presentation (IAS 32) and IAS 39 Financial Instruments: Recognition and Measurement (IAS 39) which have been applied with effect from 1 January 2005. The standards in force at the time of BP s first time adoption of IFRS in 2005 were applied retrospectively to 1 January 2003, BP s date of transition to IFRS. However, BP elected to take advantage of the exemption allowing comparative information on financial instruments to be prepared in accordance with the group s previous accounting policies under UK generally accepted accounting practice (UK GAAP). The effect on shareholders equity of this change on 1 January 2005 is shown in the group statement of recognized income and expense and related mainly to all derivative financial instruments being brought on to the group balance sheet at fair value and available-for-sale investments being measured at fair value rather than at cost.

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 56 to 57, 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. All intercompany balances and transactions, including unrealized profits arising from intragroup transactions, have been eliminated in full. Unrealized losses are eliminated unless the transaction provides evidence of an impairment of the asset transferred. Minority interests represent the portion of profit or loss and net assets in subsidiaries that is not held by the group.

### 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 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. The group statement of recognized income and expense reflects the group s share of any income and expense recognized by the jointly controlled entity outside profit and loss.

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.

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## 1 Significant accounting policies *continued*

The group ceases to use the equity method of accounting on the date from which it no longer has joint control over, or significant influence in the joint venture, 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. The income, expenses, assets and liabilities of these jointly controlled assets are included in the consolidated financial statements in proportion to the group s interest.

### 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 that 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.

### 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 that are measured at historical cost and denominated in a foreign currency are translated into the functional currency using the rates of exchange as at the dates of the initial transactions. Non-monetary assets and liabilities measured at fair value in a foreign currency are translated into the functional currency using the rate of exchange at the date the fair value was determined.

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 recognized income and expense. 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 recognized in equity relating to that particular non-US dollar operation is recognized in the income statement.

### Business combinations and goodwill

Business combinations are accounted for using the purchase method of accounting. The cost of an acquisition is measured as the cash paid and the fair value of other assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange, plus costs directly attributable to the acquisition. The acquired identifiable assets, liabilities and contingent liabilities are measured at their fair values at the date of acquisition. Any excess of the cost of acquisition over the net fair value of the identifiable assets, liabilities and contingent liabilities acquired is recognized as goodwill. Any deficiency of the cost of acquisition below the fair values of the identifiable net assets acquired (i.e. discount on acquisition) is credited to the income statement in the period of acquisition. Where the group does not acquire 100% ownership of the acquired company, the interest of minority shareholders is stated at the minority s proportion of the fair values of the assets and liabilities recognized. Subsequently, any losses applicable to the minority shareholders in excess of the minority interest on the group balance sheet are allocated against the interests of the parent.

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.

Goodwill arising on business combinations prior to 1 January 2003 is stated at the previous carrying amount 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 goodwill is included within the earnings from jointly controlled entities and associates.

### Non-current assets held for sale

Non-current assets and disposal groups classified as held for sale are measured at the lower of carrying amount and fair value less costs to sell.

Non-current assets and disposal groups are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is regarded as met only when the sale is highly probable and the asset or disposal group is available for immediate sale in its present condition. 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.

Property, plant and equipment and intangible assets once classified as held for sale are not depreciated.

### Intangible assets

Intangible assets are stated at the amount initially recognized, less accumulated amortization and accumulated impairment losses. Intangible assets include expenditure on the exploration for and evaluation of oil and natural gas resources, computer software, patents, licences and trademarks.

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 and its fair value can be measured reliably.

**1 Significant accounting policies** *continued*

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, which can range from three to 15 years. Computer software costs 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 and development expenditure**

Oil and natural gas exploration and development expenditure is accounted for using the successful efforts method of accounting.

*Licence and property acquisition costs*

Exploration licence and leasehold property acquisition costs are capitalized within intangible fixed assets and amortized on a straight-line basis over the estimated period of exploration. Each property is reviewed on an annual basis to confirm that drilling activity is planned and it is not impaired. If no future activity is planned, the remaining balance of the licence and property acquisition costs is written off. Upon determination of economically recoverable reserves ( proved reserves or commercial reserves ), amortization ceases and the remaining costs are aggregated with exploration expenditure and held on a field-by-field basis as proved properties awaiting approval within other intangible assets. When development is approved internally, the relevant expenditure is transferred to property, plant and equipment.

*Exploration expenditure*

Geological and geophysical exploration costs are charged against income as incurred. Costs directly associated with an exploration well are 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, delay rentals and payments made to contractors. If hydrocarbons are not found, the exploration expenditure is written off as a dry hole. If hydrocarbons are found and, subject to further appraisal activity, which may include the drilling of further wells (exploration or exploratory-type stratigraphic test wells), are likely to be capable of commercial development, the costs continue to be carried as an 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 sanctioned, the relevant expenditure is transferred to property, plant and equipment.

*Development expenditure*

Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including 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 amount 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 are expensed as incurred. 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, field development and future decommissioning costs are amortized over total proved reserves. The unit-of-production rate for the amortization of field development costs takes into account expenditures incurred to date, together with approved future development expenditure required to develop reserves.

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 plants | 20 to 30 years |
| Pipelines | 10 to 50 years |
| Service stations | 15 years |
| Office equipment | 3 to 7 years |
| Fixtures and fittings | 5 to 15 years |

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**1 Significant accounting policies** *continued*

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 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. If any such indication of impairment exists, the group makes an estimate of its 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.

### 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 as a separate component of equity until the investment is derecognized or until the investment is determined to be impaired, at which time the cumulative gain or loss previously reported in equity is included in the income statement.

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 estimated, 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 are 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 profit or loss.

*Available-for-sale financial assets*

If an available-for-sale financial asset is impaired, an amount comprising the difference between its cost (net of any principal payment and amortization) and its fair value is transferred from equity to the income statement.

## 1 Significant accounting policies *continued*

If there is objective evidence that an impairment loss on an unquoted equity instrument that is not carried at fair value because its fair value cannot be reliably measured 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.

Financial assets are derecognized on sale or settlement.

### 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.

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, 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 are 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.

### 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.

### 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 the 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.

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**1 Significant accounting policies** *continued*

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 directly in equity, 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 taken to equity 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 in equity 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 transferred to profit or loss.

*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 directly in equity, 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.

*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 profit or loss.

**Provisions and contingencies**

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. Where the group expects some or all of a provision to be reimbursed, for example, under an insurance contract, the reimbursement is recognized as a separate asset, but only when the reimbursement is virtually certain. The expense relating to any provision is presented in the income statement net of any reimbursement.

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 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 as other finance expense.

A contingent liability is disclosed where the existence of an obligation will only be confirmed by future events or where the amount of the obligation cannot be measured with reasonable reliability. Contingent assets are not recognized, but are disclosed where an inflow of economic benefits is probable.

### 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 environmental assessments or clean-ups are 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.

### 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.

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## 1 Significant accounting policies *continued*

A corresponding item of property, plant and equipment of an amount equivalent to the provision is also created. 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.

### 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 policy for pensions and other post-retirement benefits is 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).

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.

Where 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.

Where 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. Any compensation paid up to the fair value of the award at the cancellation or settlement date is deducted from equity, with any excess over fair value being treated as an expense in the income statement.

*Cash-settled transactions*

The cost of cash-settled transactions is measured at fair value using an appropriate option valuation model. Fair value is established initially at the grant date and at each balance sheet date thereafter until the awards are settled. During the vesting period, a liability is recognized representing the product of the fair value of the award and the portion of the vesting period expired as at the balance sheet date. From the end of the vesting period until settlement, the liability represents the full fair value of the award as at the balance sheet date. Changes in the carrying amount of the liability are recognized in profit or loss for the period.

### 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 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 scheme 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 in the group statement of recognized income and expense in the period in which they occur.

The defined benefit pension asset or liability 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. Any liability relating to unrecognized tax benefits is included in current tax payable on the group balance sheet.

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.

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**1 Significant accounting policies** *continued*

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 assets 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 assets 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 only recognized 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 income 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 directly in equity is recognized 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 holding in its own equity instruments, including ordinary shares held by Employee Share Ownership Plans (ESOPs), are classified as treasury shares , and 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 performance statements on the purchase, sale, issue or cancellation of equity shares.

**Revenue**

Revenue arising from the sale of goods is recognized when the significant risks and rewards of ownership have passed to the buyer 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 chemicals 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.

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## 1 Significant accounting policies *continued*

### Impact of new International Financial Reporting Standards

*Adopted for 2007*

The following new IFRS, amendment to IFRS and IFRIC interpretations have been adopted by the group with effect from 1 January 2007.

IFRS 7 Financial Instruments: Disclosures was issued in August 2005 and replaced the disclosure requirements previously contained in IAS 32 Financial Instruments: Presentation and Disclosure . The group has disclosed in its annual report additional information about its financial instruments, their significance and the nature and extent of risks to which they give rise. More specifically, the group has also made specified disclosures about market risk, credit risk and liquidity risk. There was no effect on the group s reported income or net assets as a result of adoption of this new standard.

Also in August 2005, the IASB issued Amendment to IAS 1 Presentation of Financial Statements Capital Disclosures, which requires disclosures of an entity s objectives, policies and processes for managing capital, quantitative data about what the entity regards as capital, whether the entity has complied with any capital requirements, and the consequences of any non-compliance. The group has included the required disclosures in its annual report. There was no effect on the group s reported income or net assets as a result of adoption of this amendment.

In addition, in 2007 BP has adopted IFRIC 10 Interim Financial Reporting and Impairment and early adopted IFRIC 11 IFRS 2 Group and Treasury Share Transactions . There were no changes in the group s accounting policies and no restatement of financial information consequent upon adoption of these interpretations.

*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.

IFRS 8 Operating Segments was issued in October 2006 and defines operating segments as components of an entity about which separate financial information is available and is evaluated regularly by the chief operating decision maker in deciding how to allocate resources and in assessing performance. The new standard sets out the required disclosures for operating segments and is effective for annual periods beginning on or after 1 January 2009. BP has not yet completed its evaluation of the impact on its disclosures of adopting IFRS 8. There will be no effect on the group s reported income or net assets. IFRS 8 has been adopted by the EU.

In September 2007, the IASB issued Amendments to IAS 1 Presentation of Financial Statements A Revised Presentation, which requires separate presentation of owner and non-owner changes in equity by introducing the statement of comprehensive income. The statement of recognized income and expense will no longer be presented. Whenever there is a restatement or reclassification, an additional balance sheet, as at the beginning of the earliest period presented, will be required to be published. The revised standard is effective for annual periods beginning on or after 1 January 2009. There will be no effect on the group s reported income or net assets. IAS 1 revised has not yet been adopted by the EU.

An amendment to IAS 23 Borrowing Costs was issued by the IASB in March 2007 and eliminates the option of recognizing borrowing costs immediately as an expense if they are directly attributable to the acquisition, construction or production of a qualifying asset. The amended standard is effective for annual periods beginning on or after 1 January 2009. There will be no effect on the group s reported income or net assets. This amendment has not yet been adopted by the EU.

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 will introduce some changes to existing accounting treatment. For example, contingent consideration should be 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 will be expensed. The standard is applicable to business combinations occurring in accounting periods beginning on or after 1 July 2009. Assets and liabilities arising from business combinations occurring before the date of adoption by the group will not be restated and thus there will be no effect on the group s reported income or net assets on adoption. The revised standard has not yet been adopted by the EU.

Also in January 2008, the IASB issued an amended version of IAS 27 Consolidated and Separate Financial Statements . This requires the effects of all transactions with non-controlling interests to be recorded in equity if there is no change in control. Such transactions will no longer result in goodwill or gains or losses. 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. The amendments are effective for annual periods beginning on or after 1 July 2009 and are to be applied retrospectively, with certain exceptions. BP has not yet completed its evaluation of the effect of adopting this amendment. The revised standard has not yet been adopted by the EU.

An amendment to IFRS 2 Share-based Payment was issued in January 2008, clarifying that only service conditions and performance conditions are vesting conditions, and other features of a share-based payment are not vesting conditions. In addition, it specifies that all cancellations, whether by the entity or by other parties, should receive the same accounting treatment. The amendment is effective for annual periods beginning on or after 1 January 2009 and has not yet been adopted by the EU. BP has not yet completed its evaluation of the effect of adopting this amendment.

In February 2008, the IASB issued Amendments to IAS 32 Financial Instruments: Presentation and IAS 1 Presentation of Financial Statements Puttable Financial Instruments and Obligations Arising on Liquidation. The amended standards require entities to classify as equity certain financial instruments provided certain criteria are met. The instruments to be classified as equity are puttable financial instruments and those instruments that impose an obligation on the entity to deliver to another party a pro rata share of the net assets of the entity only on liquidation. The amendments are effective for annual periods beginning on or after 1 January 2009 and have not yet been adopted by the EU. BP has not yet completed its evaluation of the effect of adopting these amendments.

Three IFRIC interpretations have been issued but are not yet effective and have not yet been adopted by the EU.

IFRIC 12 Service Concession Arrangements gives guidance on the accounting by operators for public-to-private service concession arrangements. The directors do not anticipate that the adoption of this interpretation will have a material effect on the reported income or net assets of the group. We plan to adopt this interpretation with effect from 1 January 2008.

IFRIC 13 Customer Loyalty Programmes addresses the accounting by entities that grant loyalty award credits (e.g. points or travel miles) to customers who buy other goods or services. The directors do not anticipate that the adoption of this interpretation will have a material effect on the reported income or net assets of the group. We plan to adopt this interpretation with effect from 1 January 2009.

IFRIC 14 IAS 19 The Limit on a Defined Benefit Asset, Minimum Funding Requirements, and their Interaction provides clarification regarding how to determine whether a surplus may be recognized on the balance sheet in relation to a retirement benefit plan. The directors do not anticipate that the adoption of this interpretation will have a material effect on the reported income or net assets of the group. We plan to adopt this interpretation with effect from 1 January 2008.

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## 2 Acquisitions

### Acquisitions in 2007

BP made a number of acquisitions in 2007 for a total consideration of $1,200 million. These business combinations were predominantly in the Refining and Marketing segment, the most significant of which was the acquisition of Chevron s Netherlands manufacturing company, Texaco Raffiniderij Pernis B.V. The acquisition included Chevron s 31% minority shareholding in Nerefco, its 31% shareholding in the 22.5 megawatt wind farm co-located at the refinery as well as a 22.8% shareholding in the TEAM joint venture terminal and shareholdings in two local pipelines linking the TEAM terminal to the refinery. Fair value adjustments were made to the acquired assets and liabilities. Goodwill of $270 million arose on these acquisitions.

### Acquisitions in 2006

BP made a number of acquisitions in 2006 for a total consideration of $256 million. All these business combinations were in the Gas, Power and Renewables segment. Fair value adjustments were made to the acquired assets and liabilities and goodwill of $64 million arose on these acquisitions.

### Acquisitions in 2005

BP made a number of acquisitions in 2005 for a total consideration of $84 million. No significant fair value adjustments were made to the acquired assets and liabilities. Goodwill of $27 million arose on these acquisitions. Also in 2005, additional goodwill of $59 million was recognized relating to the 2004 acquisition from Solvay of the remaining interests in two equity-accounted entities. This goodwill arose due to final closing adjustments and selling costs and was written off.

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## 3 Non-current assets held for sale and discontinued operations

### Non-current assets held for sale

On 5 December 2007, BP announced it had signed a memorandum of understanding with Husky Energy Inc. to form an integrated North American oil sands business. BP will contribute its Toledo refinery to a US joint venture in return for Husky contributing its Sunrise field to a Canadian joint venture. The transaction is expected to be completed by the end of March 2008. At 31 December 2007, certain Toledo refinery assets and associated liabilities were classified as a disposal group held for sale. No impairment loss has been recognized in relation to this disposal group.

On 27 June 2006, BP announced its intention to sell the Coryton refinery in the UK, following a review of its European refinery portfolio, that concluded that the group would optimize its value by focusing on a smaller, but more advantaged, refining portfolio in Europe. In addition, given the integrated nature of the operations, the bitumen business in the UK was also included with the divestment, along with the Coryton bulk terminal (together the Coryton disposal group ).

At 31 December 2006, negotiations for the sale were in progress and the assets and associated liabilities were classified as a disposal group held for sale. No impairment loss was recognized at the time of reclassification of the Coryton disposal group as held for sale nor at 31 December 2006.

The major classes of assets and liabilities of the Toledo and Coryton disposal groups, both reported within the Refining and Marketing segment, classified as held for sale at 31 December 2007 and 2006 respectively, are set out below.

| | | $ million |
|---|---|---|
| | **2007** | 2006 |
| Assets | | |
| Property, plant and equipment | **635** | 564 |
| Goodwill | **90** | 60 |
| Inventories | **561** | 454 |
| Assets classified as held for sale | **1,286** | 1,078 |
| Liabilities | | |
| Current liabilities | **163** | 54 |
| Liabilities directly associated with assets classified as held for sale | **163** | 54 |

In addition, accumulated foreign exchange gains recognized directly in equity relating to the Coryton disposal group amounted to $122 million at 31 December 2006. On disposal such foreign exchange differences were recycled to the income statement. The disposal of the Coryton disposal group was completed in May 2007. For further information see Note 4.

### Discontinued operations

The sale of Innovene, BP s olefins, derivatives and refining group, to INEOS was completed on 16 December 2005.

The Innovene operations represented a separate major line of business for BP. As a result of the sale, these operations were treated as discontinued operations for the year ended 31 December 2005. A single amount was shown on the face of the income statement comprising the post-tax result of discontinued operations and the post-tax loss recognized on the remeasurement to fair value less costs to sell and on disposal of the discontinued operation. That is, the income and expenses of Innovene are reported separately from the continuing operations of the BP group. The table below provides further detail of the amount shown in the income statement.

In the cash flow statement, the cash provided by the operating activities of Innovene was separated from that of the rest of the group and reported as a single line item.

Gross proceeds received amounted to $8,477 million. In 2005, there were selling costs of $120 million and initial closing adjustments of $43 million. In 2006, there was a final closing adjustment of $34 million. The remeasurement to fair value less costs to sell resulted in a loss of $775 million before tax ($184 million recognized in 2006 and $591 million in 2005).
Financial information for the Innovene operations after group eliminations is presented below.

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Total revenues and other income | | | 12,441 |
| Expenses | | | 11,709 |
| Profit (loss) before interest and taxation | | | 732 |
| Other finance income (expense) | | | 3 |
| Profit (loss) before taxation and loss recognized on remeasurement to fair value less costs to sell and on disposal | | | 735 |
| | (184) | (591) | |
| Profit (loss) before taxation from Innovene operations | | (184) | 144 |
| Tax (charge) credit | | | |
| | 166 | (306) | |
| | (7) | 346 | |
| Profit (loss) from Innovene operations | | (25) | 184 |
| Earnings (loss) per share from Innovene operations cents | | | |
| Basic | | (0.13) | 0.87 |
| Diluted | | (0.12) | 0.86 |
| The cash flows of Innovene operations are presented below | | | |
| Net cash provided by operating activities | | | 970 |
| Net cash used in investing activities | | | (524) |
| Net cash used in financing activities | | | (446) |

Further information is contained in Note 4.

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## 4 Disposals

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Proceeds from the sale of Innovene operations | | (34) | 8,304 |
| Proceeds from the sale of other businesses | **2,518** | 325 | 93 |
| Proceeds from the sale of businesses | **2,518** | 291 | 8,397 |
| Proceeds from disposal of fixed assets | **1,749** | 5,963 | 2,803 |
| | **4,267** | 6,254 | 11,200 |
| By business | | | |
| Exploration and Production | **1,276** | 4,005 | 1,416 |
| Refining and Marketing | **2,953** | 1,789 | 888 |
| Gas, Power and Renewables | **31** | 297 | 540 |
| Other businesses and corporate | **7** | 163 | 8,356 |
| | **4,267** | 6,254 | 11,200 |

As part of the strategy to upgrade the quality of its asset portfolio, the group has an active programme to dispose of non-strategic assets. In the normal course of business in any particular year, the group may sell interests in exploration and production properties, service stations and pipeline interests as well as non-core businesses. The group may also dispose of other assets, such as refineries, when this meets strategic objectives.

Cash received during the year from disposals amounted to $4.3 billion (2006 $6.3 billion and 2005 $11.2 billion). The major transactions in 2007 were the disposals of our Coryton refinery, our exploration and production and gas infrastructure business in the Netherlands, our interest in non-core Permian assets in the US and our interest in the Entrada field in the Gulf of Mexico.

The major transactions in 2006 were the disposals of our interests in the Gulf of Mexico Shelf and our interest in the Shenzi discovery in the Gulf of Mexico. The divestment of Innovene contributed $8.3 billion to the total in 2005. The principal transactions generating the proceeds for each business segment are described below.

### Exploration and Production

The group divested interests in a number of oil and natural gas properties in all three years. During 2007, the major transactions were the disposal of an exploration and production and gas infrastructure business in the Netherlands and the divestments of our interests in non-core Permian assets in the US and in the Entrada field in the Gulf of Mexico. We also sold our interests in a number of fields in Egypt, Canada and the US.

During 2006, the major transactions were disposals of our interests in the Gulf of Mexico Shelf, in the Shenzi discovery in the Gulf of Mexico, in the Statfjord oil and gas field and in the Luva gas field in the North Sea. We also divested our interests in a number of onshore fields in South Louisiana, interests in fields in the North Sea, the Gulf of Suez and Venezuela, and part of an interest in Colombia.

During 2005, the major transaction was the sale of the group s interest in the Ormen Lange field in Norway. In addition, the group sold interests in oil and natural gas properties in Venezuela, Canada and the Gulf of Mexico.

### Refining and Marketing

The churn of retail assets represents a significant element of the total in all three years. In addition, in 2007, we disposed of the Coryton refinery in the UK, our interest in the West Texas Pipeline in the US, our interest in the Samsung Petrochemical Company in South Korea and other interests in France, Brazil and Africa.

During 2006, we disposed of our interests in Zhenhai Refining and Chemicals Company in China and in Eiffage, the French-based construction company. We also exited the retail market in the Czech Republic and disposed of our interests in a number of pipelines.

During 2005, the group sold a number of regional retail networks in the US and in addition its retail network in Malaysia.

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## 4 Disposals *continued*

### Gas, Power and Renewables

There were no significant disposals in 2007. During 2006, we disposed of our shareholding in Enagas, the Spanish gas transport grid operator. In 2005, the group sold its interest in the Interconnector pipeline and a power plant at Great Yarmouth in the UK.

### Other businesses and corporate

There were no significant disposals in 2007. During 2006, the group disposed of miscellaneous non-core businesses and assets. 2005 includes the proceeds from the sale of Innovene.

Summarized financial information for the sale of businesses is shown below.

$ million

| | **2007** | 2006 | 2005 |
|---|---|---|---|
| The disposals comprise the following | | | |
| Non-current assets | **753** | 143 | 6,452 |
| Other current assets | **587** | 169 | 4,779 |
| Non-current liabilities | **(64)** | (10) | (364) |
| Current liabilities | **(27)** | (70) | (2,488) |
| Total carrying amount of net assets disposed | **1,249** | 232 | 8,379 |
| Recycling of foreign exchange on disposal | **(147)** | | |
| Costs on disposal | **22** | | |
| | **1,124** | 232 | 8,379 |
| Profit (loss) on sale of businesses | **1,384** | 167 | 18 |
| Total consideration | **2,508** | 399 | 8,397 |
| Consideration received (receivable)[a] | **10** | (74) | |
| Closing adjustments associated with the sale of Innovene | | (34) | |
| Proceeds from the sale of businesses[b] | **2,518** | 291 | 8,397 |

[a] Consideration received from prior year disposals or not yet received from current year disposals.
[b] Net of cash and cash equivalents disposed of $115 million (2006 $2 million and 2005 $15 million).

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## 5 Segmental analysis

The group s primary format for segment reporting is business segments and the secondary format is geographical segments. The risks and returns of the group s operations are primarily determined by the nature of the different activities that the group engages in, rather than the geographical location of these operations. This is reflected by the group s organizational structure and internal financial reporting systems.

In 2007, BP had three reportable operating segments: Exploration and Production; Refining and Marketing; and Gas, Power and Renewables. Exploration and Production s activities include oil and natural gas exploration, development and production, together with related pipeline, transportation and processing activities. The activities of Refining and Marketing include the supply and trading, refining, manufacturing, marketing and transportation of crude oil, petroleum and chemicals products. Gas, Power and Renewables activities included marketing and trading of gas and power, marketing of liquefied natural gas (LNG), natural gas liquids (NGLs) and low-carbon power generation through our Alternative Energy business. The group is managed on an integrated basis.

Other businesses and corporate comprises Treasury (which in the segmental analysis includes all of the group s cash, cash equivalents and associated interest income), the group s aluminium asset and corporate activities worldwide.

The accounting policies of the operating segments are the same as the group s accounting policies described in Note 1.

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.

The group s geographical segments are based on the location of the group s assets. The UK and the US are significant countries of activity for the group; the other geographical segments are groupings of countries determined by geographical location.

Sales to external customers are based on the location of the seller, which in most circumstances is not materially different from the location of the customer. Crude oil and LNG are commodities for which there is an international market and buyers and sellers can be widely separated geographically. The UK segment includes the UK-based international activities of Refining and Marketing.

$ million

| | | | | | | 2007 |
|---|---|---|---|---|---|---|
| By business | Exploration and Production | Refining and Marketing | Gas, Power and Renewables | Other businesss and corporate | Consolidation adjustment and eliminations | Total group |
| **Sales and other operating revenues** | | | | | | |
| Segment sales and other operating revenues | 54,550 | 250,866 | 21,369 | 843 | (43,263) | 284,365 |
| Less: sales between businesses | (38,803) | (2,024) | (2,436) | | 43,263 | |
| Third party sales | 15,747 | 248,842 | 18,933 | 843 | | 284,365 |
| Equity-accounted earnings | 3,061 | 538 | 233 | | | 3,832 |
| Interest and other revenues | 330 | 134 | 123 | 167 | | 754 |
| Total revenues | 19,138 | 249,514 | 19,289 | 1,010 | | 288,951 |
| **Segment results** | | | | | | |
| Profit (loss) before interest and tax | 26,938 | 6,072 | 674 | (1,128) | (204) | 32,352 |
| Finance costs and other finance income/expense | | | | | (741) | (741) |
| Profit (loss) before taxation | 26,938 | 6,072 | 674 | (1,128) | (945) | 31,611 |
| Taxation | | | | | (10,442) | (10,442) |

| | | | | | | |
|---|---|---|---|---|---|---|
| Profit (loss) for the year | **26,938** | **6,072** | **674** | **(1,128)** | **(11,387)** | **21,169** |
| **Assets and liabilities** | | | | | | |
| Segment assets | **108,874** | **95,691** | **19,889** | **17,188** | **(6,271)** | **235,371** |
| Current tax receivable | | | | | **705** | **705** |
| Total assets | **108,874** | **95,691** | **19,889** | **17,188** | **(5,566)** | **236,076** |
| Includes | | | | | | |
| Equity-accounted investments | **16,388** | **5,268** | **1,007** | **29** | | **22,692** |
| Segment liabilities | **(23,792)** | **(41,053)** | **(13,439)** | **(14,940)** | **5,342** | **(87,882)** |
| Current tax payable | | | | | **(3,282)** | **(3,282)** |
| Finance debt | | | | | **(31,045)** | **(31,045)** |
| Deferred tax liabilities | | | | | **(19,215)** | **(19,215)** |
| Total liabilities | **(23,792)** | **(41,053)** | **(13,439)** | **(14,940)** | **(48,200)** | **(141,424)** |
| **Other segment information** | | | | | | |
| Capital expenditure and acquisitions | | | | | | |
| Goodwill and other intangible assets | **2,153** | **581** | **98** | **21** | | **2,853** |
| Property, plant and equipment | **11,360** | **4,565** | **746** | **216** | | **16,887** |
| Other | **393** | **440** | **30** | **38** | | **901** |
| Total | **13,906** | **5,586** | **874** | **275** | | **20,641** |
| Depreciation, depletion and amortization | **7,720** | **2,430** | **215** | **214** | | **10,579** |
| Impairment losses | **292** | **1,186** | **40** | **43** | | **1,561** |
| Impairment reversals | **237** | | | | | **237** |
| Losses on sale of businesses and fixed assets | **42** | **313** | | | | **355** |
| Gains on sale of businesses and fixed assets | **949** | **1,464** | **12** | **62** | | **2,487** |

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## 5 Segmental analysis *continued*

$ million

| | | | | | | | | | 2006 |
|---|---|---|---|---|---|---|---|---|---|
| By business | Exploration and Production | Refining and Marketing | Gas, Power and Renewables | Other businesses and corporate | Consolidation adjustment and eliminations | Total group | Innovene operations | Consolidation adjustment and eliminations[a] | Total continuing operations |
| **Sales and other operating revenues** | | | | | | | | | |
| Segment sales and other operating revenues | 52,600 | 232,855 | 23,708 | 1,009 | (44,266) | 265,906 | | | 265,906 |
| Less: sales between businesses | (36,171) | (4,076) | (4,019) | | 44,266 | | | | |
| Third party sales | 16,429 | 228,779 | 19,689 | 1,009 | | 265,906 | | | 265,906 |
| Equity-accounted earnings | 3,517 | 341 | 138 | (1) | | 3,995 | | | 3,995 |
| Interest and other revenues | 283 | 106 | 77 | 235 | | 701 | | | 701 |
| Total revenues | 20,229 | 229,226 | 19,904 | 1,243 | | 270,602 | | | 270,602 |
| **Segment results** | | | | | | | | | |
| Profit (loss) before interest and tax | 29,629 | 5,541 | 1,321 | (1,069) | 52 | 35,474 | 184 | | 35,658 |
| Finance costs and other finance income/expense | | | | | (516) | (516) | | | (516) |
| Profit (loss) before taxation | 29,629 | 5,541 | 1,321 | (1,069) | (464) | 34,958 | 184 | | 35,142 |
| Taxation | | | | | (12,357) | (12,357) | (159) | | (12,516) |
| Profit (loss) for the year | 29,629 | 5,541 | 1,321 | (1,069) | (12,821) | 22,601 | 25 | | 22,626 |
| **Assets and liabilities** | | | | | | | | | |
| Segment assets | 99,310 | 80,964 | 27,398 | 14,184 | (4,799) | 217,057 | | | |
| Current tax receivable | | | | | 544 | 544 | | | |
| Total assets | 99,310 | 80,964 | 27,398 | 14,184 | (4,255) | 217,601 | | | |
| Includes | | | | | | | | | |
| | 15,510 | 4,675 | 853 | 11 | | 21,049 | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Equity-accounted investments | | | | | | | | |
| Segment liabilities | (21,787) | (33,399) | (21,708) | (14,555) | 4,074 | (87,375) | | |
| Current tax payable | | | | | (2,635) | (2,635) | | |
| Finance debt | | | | | (24,010) | (24,010) | | |
| Deferred tax liabilities | | | | | (18,116) | (18,116) | | |
| Total liabilities | (21,787) | (33,399) | (21,708) | (14,555) | (40,687) | (132,136) | | |
| **Other segment information** | | | | | | | | |
| Capital expenditure and acquisitions | | | | | | | | |
| Goodwill and other intangible assets | 1,614 | 253 | 256 | 43 | | 2,166 | | |
| Property, plant and equipment | 10,227 | 2,733 | 337 | 232 | | 13,529 | | |
| Other | 1,277 | 158 | 95 | 6 | | 1,536 | | |
| Total | 13,118 | 3,144 | 688 | 281 | | 17,231 | | |
| Depreciation, depletion and amortization | 6,533 | 2,244 | 192 | 159 | | 9,128 | | 9,128 |
| Impairment losses | 137 | 155 | 100 | 69 | | 461 | | 461 |
| Impairment reversals | 340 | | | | | 340 | | 340 |
| Loss on remeasurement to fair value less costs to sell and on disposal of Innovene operations | | | | 184 | | 184 | (184) | |
| Losses on sale of businesses and fixed assets | 195 | 228 | | 5 | | 428 | | 428 |
| Gains on sale of businesses and fixed assets | 2,309 | 1,112 | 193 | 100 | | 3,714 | | 3,714 |

## 5 Segmental analysis *continued*

$ million

2005

| By business | Exploration and Production | Refining and Marketing | Gas, Power and Renewables | Other businesses and corporate | Consolidation adjustment and eliminations | Total group | Innovene operations | Consolidation adjustment and eliminations[a] | Total continuing operations |
|---|---|---|---|---|---|---|---|---|---|
| **Sales and other operating revenues** | | | | | | | | | |
| Segment sales and other operating revenues | 47,210 | 213,326 | 25,696 | 21,295 | (55,359) | 252,168 | (20,627) | 8,251 | 239,792 |
| Less: sales between businesses | (32,606) | (11,407) | (3,095) | (8,251) | 55,359 | | 8,251 | (8,251) | |
| Third party sales | 14,604 | 201,919 | 22,601 | 13,044 | | 252,168 | (12,376) | | 239,792 |
| Equity-accounted earnings | 3,232 | 249 | 62 | (14) | | 3,529 | 14 | | 3,543 |
| Interest and other revenues | 290 | 151 | 15 | 233 | | 689 | (76) | | 613 |
| Total revenues | 18,126 | 202,319 | 22,678 | 13,263 | | 256,386 | (12,438) | | 243,948 |
| **Segment results** | | | | | | | | | |
| Profit (loss) before interest and tax | 25,502 | 6,426 | 1,172 | (569) | (208) | 32,323 | (668) | 527 | 32,182 |
| Finance costs and other finance income/expense | | | | | (758) | (758) | (3) | | (761) |
| Profit (loss) before taxation | 25,502 | 6,426 | 1,172 | (569) | (966) | 31,565 | (671) | 527 | 31,421 |
| Taxation | | | | | (9,248) | (9,248) | 133 | (173) | (9,288) |
| Profit (loss) for the year | 25,502 | 6,426 | 1,172 | (569) | (10,214) | 22,317 | (538) | 354 | 22,133 |
| **Other segment information** | | | | | | | | | |
| Depreciation, depletion and amortization | 6,033 | 2,382 | 235 | 533 | | 9,183 | (412) | | 8,771 |
| Impairment losses | 266 | 93 | | 59 | | 418 | (59) | | 359 |
| | | | | 591 | | 591 | (591) | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Loss on remeasurement to fair value less costs to sell and on disposal of Innovene operations | | | | | | | |
| Losses on sale of businesses and fixed assets | 39 | 64 | | 6 | 109 | | 109 |
| Gains on sale of businesses and fixed assets | 1,198 | 241 | 55 | 47 | 1,541 | (3) | 1,538 |

In the circumstances of discontinued operations, IFRS requires that the profits earned by the discontinued operations, in this case the Innovene operations, on sales to the continuing operations be eliminated on consolidation from the discontinued operations and attributed to the continuing operations and vice versa. This adjustment has two offsetting elements: the net margin on crude refined by Innovene as substantially all crude for its refineries was supplied by BP and most of the refined products manufactured were taken by BP; and the margin on sales of feedstock from BP s US refineries to Innovene s manufacturing plants. The profits attributable to individual segments are not affected by this adjustment. This representation does not indicate the profits earned by continuing or Innovene operations, as if they were standalone entities, for past periods or likely to be earned in future periods.

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## 5 Segmental analysis *continued*

$ million

| | | | | | | 2007 |
|---|---|---|---|---|---|---|
| By geographical area | UK | Rest of Europe | US | Rest of World | Consolidation adjustment and eliminations | Total |
| **Sales and other operating revenues** | | | | | | |
| Segment sales and other operating revenues | 109,800 | 78,366 | 105,120 | 74,462 | | 367,748 |
| Less: sales between areas | (48,651) | (12,024) | (2,801) | (19,907) | | (83,383) |
| Third party sales | 61,149 | 66,342 | 102,319 | 54,555 | | 284,365 |
| Equity-accounted earnings | 1 | 55 | 144 | 3,632 | | 3,832 |
| Interest and other revenues | 222 | 78 | 142 | 312 | | 754 |
| Total revenues | 61,372 | 66,475 | 102,605 | 58,499 | | 288,951 |
| **Segment results** | | | | | | |
| Profit (loss) before interest and tax | 4,613 | 4,164 | 7,439 | 16,136 | | 32,352 |
| Finance costs and other finance income/expense | (17) | (287) | (524) | 87 | | (741) |
| Profit before taxation | 4,596 | 3,877 | 6,915 | 16,223 | | 31,611 |
| Taxation | (2,027) | (949) | (2,593) | (4,873) | | (10,442) |
| Profit for the year | 2,569 | 2,928 | 4,322 | 11,350 | | 21,169 |
| **Assets and liabilities** | | | | | | |
| Segment assets | 53,065 | 34,658 | 81,911 | 76,504 | (10,767) | 235,371 |
| Current tax receivable | 3 | 27 | 468 | 207 | | 705 |
| Total assets | 53,068 | 34,685 | 82,379 | 76,711 | (10,767) | 236,076 |
| Includes | | | | | | |
| Equity-accounted investments | 142 | 1,970 | 1,659 | 18,921 | | 22,692 |
| Segment liabilities | (30,043) | (18,985) | (31,314) | (18,307) | 10,767 | (87,882) |
| Current tax payable | (963) | (658) | (104) | (1,557) | | (3,282) |
| Finance debt | (20,085) | (200) | (8,238) | (2,522) | | (31,045) |
| Deferred tax liabilities | (3,397) | (1,124) | (10,656) | (4,038) | | (19,215) |
| Total liabilities | (54,488) | (20,967) | (50,312) | (26,424) | 10,767 | (141,424) |

**Other segment information**

| | | | | | |
|---|---|---|---|---|---|
| Capital expenditure and acquisitions | | | | | |
| Goodwill and other intangible assets | **453** | **298** | **817** | **1,285** | **2,853** |
| Property, plant and equipment | **1,141** | **2,489** | **6,516** | **6,741** | **16,887** |
| Other | **78** | **253** | **154** | **416** | **901** |
| Total | **1,672** | **3,040** | **7,487** | **8,442** | **20,641** |
| Depreciation, depletion and amortization | **2,133** | **959** | **3,558** | **3,929** | **10,579** |
| Exploration expense | **46** | | **252** | **458** | **756** |
| Impairment losses | **315** | **136** | **723** | **387** | **1,561** |
| Impairment reversals | | | **237** | | **237** |
| Losses on sale of businesses and fixed assets | **2** | **77** | **233** | **43** | **355** |
| Gains on sale of businesses and fixed assets | **893** | **655** | **770** | **169** | **2,487** |

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## 5 Segmental analysis *continued*

$ million

| By geographical area | UK | Rest of Europe | US | Rest of World | Consolidation adjustment and eliminations | Total |
|---|---|---|---|---|---|---|
| | | | | | | 2006 |
| **Sales and other operating revenues** | | | | | | |
| Segment sales and other operating revenues | 105,518 | 76,768 | 99,935 | 71,547 | | 353,768 |
| Less: sales between areas | (50,942) | (14,821) | (5,032) | (17,067) | | (87,862) |
| Third party sales | 54,576 | 61,947 | 94,903 | 54,480 | | 265,906 |
| Equity-accounted earnings | 5 | 13 | 127 | 3,850 | | 3,995 |
| Interest and other revenues | 258 | 7 | 107 | 329 | | 701 |
| Total revenues | 54,839 | 61,967 | 95,137 | 58,659 | | 270,602 |
| **Segment results** | | | | | | |
| Profit (loss) before interest and tax from continuing operations | 5,897 | 3,282 | 11,664 | 14,815 | | 35,658 |
| Finance costs and other finance income/expense | 43 | (262) | (331) | 34 | | (516) |
| Profit before taxation from continuing operations | 5,940 | 3,020 | 11,333 | 14,849 | | 35,142 |
| Taxation | (3,158) | (1,176) | (3,738) | (4,444) | | (12,516) |
| Profit for the year from continuing operations | 2,782 | 1,844 | 7,595 | 10,405 | | 22,626 |
| Profit (loss) from Innovene operations | 31 | (76) | (2) | 22 | | (25) |
| Profit for the year | 2,813 | 1,768 | 7,593 | 10,427 | | 22,601 |
| **Assets and liabilities** | | | | | | |
| Segment assets | 49,018 | 28,059 | 78,586 | 69,479 | (8,085) | 217,057 |
| Current tax receivable | 13 | 65 | 450 | 16 | | 544 |
| Total assets | 49,031 | 28,124 | 79,036 | 69,495 | (8,085) | 217,601 |
| Includes | | | | | | |
| Equity-accounted investments | 78 | 1,538 | 1,529 | 17,904 | | 21,049 |
| Segment liabilities | (26,048) | (18,484) | (32,979) | (17,949) | 8,085 | (87,375) |
| Current tax payable | (757) | (570) | 11 | (1,319) | | (2,635) |
| Finance debt | (12,666) | (328) | (7,201) | (3,815) | | (24,010) |
| Deferred tax liabilities | (3,335) | (938) | (9,946) | (3,897) | | (18,116) |

| | | | | | | |
|---|---|---|---|---|---|---|
| Total liabilities | (42,806) | (20,320) | (50,115) | (26,980) | 8,085 | (132,136) |
| **Other segment information** | | | | | | |
| Capital expenditure and acquisitions | | | | | | |
| Goodwill and other intangible assets | 421 | 53 | 969 | 723 | | 2,166 |
| Property, plant and equipment | 1,120 | 916 | 5,531 | 5,962 | | 13,529 |
| Other | 46 | 22 | 92 | 1,376 | | 1,536 |
| Total | 1,587 | 991 | 6,592 | 8,061 | | 17,231 |
| Depreciation, depletion and amortization | 2,139 | 840 | 3,459 | 2,690 | | 9,128 |
| Exploration expense | 20 | | 633 | 392 | | 1,045 |
| Impairment losses | | 171 | 114 | 176 | | 461 |
| Impairment reversals | 176 | | 90 | 74 | | 340 |
| Loss on remeasurement to fair value less costs to sell and on disposal of Innovene operations | 185 | 36 | (16) | (21) | | 184 |
| Losses on sale of businesses and fixed assets | 12 | 96 | 217 | 103 | | 428 |
| Gains on sale of businesses and fixed assets | 337 | 577 | 2,530 | 270 | | 3,714 |

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## 5 Segmental analysis *continued*

$ million

| | | | | | | 2005 |
|---|---|---|---|---|---|---|
| By geographical area | UK | Rest of Europe | US | Rest of World | Consolidation adjustment and eliminations | Total |
| **Sales and other operating revenues** | | | | | | |
| Segment sales and other operating revenues | 95,375 | 72,972 | 101,190 | 60,314 | | 329,851 |
| Less: sales attributable to Innovene operations | (2,610) | (8,667) | (4,309) | (686) | | (16,272) |
| Segment revenues from continuing operations | 92,765 | 64,305 | 96,881 | 59,628 | | 313,579 |
| Less: sales between areas | (38,081) | (5,013) | (2,362) | (16,541) | | (61,997) |
| Less: sales by continuing operations to Innovene | (5,599) | (4,640) | (1,508) | (43) | | (11,790) |
| Third party sales of continuing operations | 49,085 | 54,652 | 93,011 | 43,044 | | 239,792 |
| Equity-accounted earnings | (8) | 18 | 86 | 3,447 | | 3,543 |
| Interest and other revenues | (533) | 152 | 695 | 299 | | 613 |
| Total revenues | 48,544 | 54,822 | 93,792 | 46,790 | | 243,948 |
| **Segment results** | | | | | | |
| Profit before interest and tax from continuing operations | 1,167 | 5,206 | 12,639 | 13,170 | | 32,182 |
| Finance costs and other finance expense | (80) | (268) | (366) | (47) | | (761) |
| Profit before taxation from continuing operations | 1,087 | 4,938 | 12,273 | 13,123 | | 31,421 |
| Taxation | (289) | (1,646) | (3,798) | (3,555) | | (9,288) |
| Profit for the year from continuing operations | 798 | 3,292 | 8,475 | 9,568 | | 22,133 |
| Profit (loss) from Innovene operations | 234 | 109 | (165) | 6 | | 184 |
| Profit for the year | 1,032 | 3,401 | 8,310 | 9,574 | | 22,317 |
| **Other segment information** | | | | | | |
| Depreciation, depletion and amortization | 2,080 | 932 | 3,685 | 2,074 | | 8,771 |
| Exploration expense | 32 | 2 | 425 | 225 | | 684 |
| Impairment losses | 53 | 7 | 238 | 61 | | 359 |
| Loss on remeasurement to fair value less costs to sell and on disposal of Innovene operations | 24 | 273 | 262 | 32 | | 591 |
| Losses on sale of businesses and fixed assets | | 37 | 8 | 64 | | 109 |
| Gains on sale of businesses and fixed assets | 107 | 1,017 | 282 | 132 | | 1,538 |

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## 6 Interest and other revenues

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Related to financial instruments | | | |
| Interest income from available-for-sale financial assets | **5** | 13 | 14 |
| Dividend income from available-for-sale financial assets | **29** | 32 | 25 |
| Interest income from loans and receivables | **175** | 186 | 101 |
| | **209** | 231 | 140 |
| Not related to financial instruments | | | |
| Interest from equity-accounted investments | **172** | 176 | 141 |
| Other interest | **97** | 62 | 116 |
| Other income | **276** | 232 | 292 |
| | **545** | 470 | 549 |
| | **754** | 701 | 689 |
| Innovene operations | | | (76) |
| Continuing operations | **754** | 701 | 613 |

## 7 Gains on sale of businesses and fixed assets

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Gains on sale of businesses | | | |
| Exploration and Production | **534** | | |
| Refining and Marketing | **850** | 104 | 18 |
| Other businesses and corporate | | 63 | |
| | **1,384** | 167 | 18 |
| Gains on sale of fixed assets | | | |
| Exploration and Production | **415** | 2,309 | 1,198 |
| Refining and Marketing | **614** | 1,008 | 223 |
| Gas, Power and Renewables | **12** | 193 | 55 |
| Other businesses and corporate | **62** | 37 | 47 |
| | **1,103** | 3,547 | 1,523 |
| | **2,487** | 3,714 | 1,541 |

| | | | |
|---|---|---|---|
| Innovene operations | | | (3) |
| Continuing operations | **2,487** | 3,714 | 1,538 |

The principal transactions giving rise to these gains for each business segment are described below.

## Exploration and Production

The group divested interests in a number of oil and natural gas properties in all three years. The major divestments during 2007 that resulted in gains were the disposal of an exploration and production and gas infrastructure business in the Netherlands and the divestments of our interests in non-core Permian assets in the US and in the Entrada field in the Gulf of Mexico.

The major divestments during 2006 that resulted in gains were the sales of our interest in the Shenzi discovery in the Gulf of Mexico in the US and interests in the North Sea. In 2005 the major divestment was the sale of the group s interest in the Ormen Lange field in Norway. BP also sold various oil and gas properties in Trinidad & Tobago, Canada and the Gulf of Mexico.

## Refining and Marketing

During 2007, the group divested the Coryton refinery in the UK, its interest in the West Texas Pipeline in the US and its interest in the Samsung Petrochemical Company in South Korea.

During 2006, the group divested its retail business in the Czech Republic and fixed assets including its shareholding in Zhenhai Refining and Chemicals Company in China, its shareholding in Eiffage, the French-based construction company, and pipeline assets. In 2005, the group divested a number of regional retail networks in the US.

## Gas, Power and Renewables

There were no significant disposals in 2007.

In 2006, the group divested its shareholding in Enagas. In 2005, transactions included the disposal of the group s interest in the Interconnector pipeline and power plant at Great Yarmouth in the UK.

## Other businesses and corporate

There were no significant disposals in 2007.

During 2006, the group disposed of its ethylene oxide business.

Additional information on the sale of businesses and fixed assets is given in Note 4.

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## 8 Production and similar taxes

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| UK | **197** | 260 | 495 |
| Overseas | **3,816** | 3,361 | 2,515 |
| | **4,013** | 3,621 | 3,010 |

## 9 Depreciation, depletion and amortization

| | | | $ million |
|---|---|---|---|
| By business | **2007** | 2006 | 2005 |
| Exploration and Production[a] | | | |
| UK | **1,683** | 1,720 | 1,663 |
| Rest of Europe | **211** | 223 | 228 |
| US | **2,273** | 2,236 | 2,426 |
| Rest of World | **3,553** | 2,354 | 1,716 |
| | **7,720** | 6,533 | 6,033 |
| Refining and Marketing | | | |
| UK[b] | **286** | 303 | 316 |
| Rest of Europe | **729** | 603 | 687 |
| US | **1,077** | 1,048 | 1,082 |
| Rest of World | **338** | 290 | 297 |
| | **2,430** | 2,244 | 2,382 |
| Gas, Power and Renewables | | | |
| UK | **15** | 18 | 47 |
| Rest of Europe | **17** | 13 | 20 |
| US | **148** | 117 | 109 |
| Rest of World | **35** | 44 | 59 |
| | **215** | 192 | 235 |
| Other businesses and corporate | | | |
| UK | **149** | 98 | 203 |
| Rest of Europe | **2** | 1 | 130 |
| US | **60** | 58 | 187 |
| Rest of World | **3** | 2 | 13 |

| | | | |
|---|---|---|---|
| | **214** | 159 | 533 |
| By geographical area | | | |
| UK[b] | **2,133** | 2,139 | 2,229 |
| Rest of Europe | **959** | 840 | 1,065 |
| US | **3,558** | 3,459 | 3,804 |
| Rest of World | **3,929** | 2,690 | 2,085 |
| | **10,579** | 9,128 | 9,183 |
| Innovene operations | | | (412) |
| Continuing operations | **10,579** | 9,128 | 8,771 |

[a] At the end of 2006, BP adopted the US Securities and Exchange Commission (SEC) rules for estimating oil and natural gas reserves instead of the UK accounting rules contained in the Statement of Recommended Practice Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities (UK SORP).
This change in accounting estimate had a direct impact on the amount of depreciation, depletion and amortization (DD&A) charged in the income statement in respect of oil and natural gas properties which are depreciated on a unit-of-production basis as described in Note 1. The change in estimate was applied prospectively, with no restatement of prior periods results. The group s actual DD&A charge for 2006 was $9,128 million, whereas the charge based on UK SORP reserves would have been $9,057 million, i.e. an increase of $71 million due to the change in reserves estimates that was used to calculate DD&A for the last three months of 2006. For 2007, it was estimated that the DD&A charge would increase by approximately $400 million to $500 million as a result of the change. Over the life of a field this change would have no overall effect on DD&A.
The main differences between the UK SORP and SEC rules relate to the SEC requirement to use year-end prices, the application of SEC interpretations of SEC regulations relating to the use of technology (mainly seismic) to estimate reserves in the reservoir away from wellbores and the reporting of fuel gas (i.e. gas used for fuel in operations) within proved reserves. Consequently, reserves quantities under SEC rules differ from those that would be reported under application of the UK SORP.
The change to SEC reserves in 2006 represented a simplification of the group s reserves reporting, as only one set of reserves estimates is disclosed. In addition, the use of SEC reserves for accounting purposes makes our results more comparable with those of our major competitors.

[b] UK area includes the UK-based international activities of Refining and Marketing.

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## 10 Impairment and losses on sale of businesses and fixed assets

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Impairment losses | | | |
| Exploration and Production | **292** | 137 | 266 |
| Refining and Marketing | **1,186** | 155 | 93 |
| Gas, Power and Renewables | **40** | 100 | |
| Other businesses and corporate | **43** | 69 | 59 |
| | **1,561** | 461 | 418 |
| Impairment reversals | | | |
| Exploration and Production | **(237)** | (340) | |
| | **(237)** | (340) | |
| Loss on sale of fixed assets | | | |
| Exploration and Production | **42** | 195 | 39 |
| Refining and Marketing | **313** | 228 | 64 |
| Other businesses and corporate | | 5 | 6 |
| | **355** | 428 | 109 |
| Loss on remeasurement to fair value less costs to sell and on disposal of Innovene operations | | 184 | 591 |
| | **1,679** | 733 | 1,118 |
| Innovene operations | | (184) | (650) |
| Continuing operations | **1,679** | 549 | 468 |

### Impairment

In assessing whether a write-down is required in the carrying value of a potentially impaired asset, its 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. Given the nature of the group s activities, information on the fair value of an asset is usually difficult to obtain unless negotiations with potential purchasers are taking place. Consequently, unless indicated otherwise, the recoverable amount used in assessing the impairment charges described below is value in use. The group generally estimates value in use using a discounted cash flow model. The future cash flows are usually adjusted for risks specific to the asset and discounted using a pre-tax discount rate of 11% (2006 10% and 2005 10%). This discount rate is derived from the group s post-tax weighted average cost of capital. In some cases the group s pre-tax discount rate may be adjusted to account for political risk in the country where the asset is located.

#### Exploration and Production

During 2007, the Exploration and Production segment recognized impairment losses of $292 million. The main elements were a charge of $112 million relating to the cancellation of the DF1 project in Scotland, a $103 million partner loan write-off as a result of unsuccessful drilling in the West Shmidt licence block in Sakhalin and a $52 million write-off of the Whitney Canyon gas plant in US Lower 48 driven by management s decision to abandon this facility. In addition, there were several individually insignificant impairment charges, triggered by downward reserves revisions, amounting to $25 million in total.

These charges were largely offset by reversals of previously recognized impairment charges amounting to $237 million. Of this total, $208 million resulted from a reassessment of the decommissioning liability for damaged platforms in the Gulf of Mexico Shelf. The remaining $29 million related to other individually insignificant impairment reversals, resulting from favourable revisions to the estimates used in determining the assets recoverable amounts.

During 2006, Exploration and Production recognized a net gain on impairment. The main element was a $340 million credit for reversals of previously booked impairments relating to the UK North Sea, US Lower 48 and China. These reversals resulted from a positive change in the estimates used to determine the assets recoverable amount since the impairment losses were recognized. This was partially offset by impairment losses totalling $137 million. The major element was a charge of $109 million against intangible assets relating to properties in Alaska. The trigger for the impairment test was the decision of the Alaska Department of Natural Resources to terminate the Point Thompson Unit Agreement. We are defending our right through the appeal process. The remaining $28 million relates to other individually insignificant impairments, the impairment tests for which were triggered by downward reserves revisions and increased tax burden.

During 2005, Exploration and Production recognized total charges of $266 million for impairment in respect of producing oil and gas properties. The major element of this was a charge of $226 million relating to fields in the Shelf and Coastal areas of the Gulf of Mexico. The triggers for the impairment tests were primarily the effect of Hurricane Rita, which extensively damaged certain offshore and onshore production facilities, leading to repair costs and higher estimates of the eventual cost of decommissioning the production facilities and, in addition, reduced estimates of the quantities of hydrocarbons recoverable from some of these fields. The recoverable amount was based on management s estimate of fair value less costs to sell consistent with recent transactions in the area. The remainder related to fields in the UK North Sea, which were tested for impairment following a review of the economic performance of these assets.

### Refining and Marketing

The main component of the 2007 impairment charge arose because of a decision to sell our company-owned and company-operated sites in the US resulting in a $610 million write-down of the carrying amount of the sites to fair value less costs to sell. Following a decision to sell certain assets at our Acetyls plant in Hull, UK, we wrote down the carrying amount of these assets to fair value less costs to sell leading to an impairment charge of $186 million. Changing marketing conditions led to impairments in Samsung Petrochemical Company, to fair value less costs to sell, and in China American Petrochemical Company amounting in total to $165 million. The balance relates principally to the write-downs of assets elsewhere in the segment portfolio.

During 2006, certain assets in our Retail and Aromatics & Acetyls businesses were written down to fair value less costs to sell. During 2005, certain retail assets were written down to fair value less costs to sell.

## 10 Impairment and losses on sale of businesses and fixed assets *continued*

### Gas, Power and Renewables

There were no significant impairments in 2007.

The impairment charge for 2006 relates to certain North American pipeline assets. The trigger for impairment testing was the reduction in future pipeline tariff revenues and increased ongoing operational costs.

### Other businesses and corporate

There were no significant impairments in 2007.

The impairment charge for 2006 relates to remaining chemical assets after the sale of Innovene. The impairment charge for 2005 relates to the write-off of additional goodwill on the Solvay transactions.

### Loss on sale of fixed assets

The principal transactions that give rise to the losses for each business segment are described below.

### Exploration and Production

The group divested interests in a number of oil and natural gas properties in all three years.

For 2006, the largest component of the loss is attributed to the sale of properties in the Gulf of Mexico Shelf, which included increases in decommissioning liability estimates associated with the hurricane-damaged fields that were divested during the year.

### Refining and Marketing

For 2007, the principal transactions contributing to the loss were related to the decision to withdraw from the company-owned and company-operated channel of trade in the US and retail churn. 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.

For 2006, the principal transactions contributing to the loss were retail churn.

## 11 Impairment of goodwill

| | | $ million |
|---|---|---|
| Goodwill at 31 December | **2007** | 2006 |
| Exploration and Production | **4,247** | 4,282 |
| Refining and Marketing | **6,626** | 6,390 |
| Gas, Power and Renewables | **133** | 108 |
| | **11,006** | 10,780 |

Goodwill acquired through business combinations has been allocated first to business segments and then down to the next level of cash-generating unit that is expected to benefit from the synergies of the acquisition. For Exploration and Production, goodwill has been allocated to each geographic region, that is UK, Rest of Europe, US and Rest of World, and for Refining and Marketing, goodwill has been allocated to the following cash-generating units, namely Refining, Retail, 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 generally estimates value in use using a discounted cash flow model. The future cash flows are usually adjusted for risks specific to the asset and discounted using a pre-tax discount rate of 11% (2006 10%). This discount rate is derived from the group s post-tax weighted average cost of capital. In some cases the group s pre-tax discount rate may be adjusted to account for political risk in the country where the asset is located.

The five year business segment plans, which are approved on an annual basis by senior management, are the source of information for the determination of the various values in use. They contain implicit 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.

For the purposes of impairment testing, the group s Brent oil price assumption is an average $90 per barrel in 2008, $86 per barrel in 2009, $84 per barrel in 2010, $84 per barrel in 2011, $84 per barrel in 2012 and $60 per barrel in 2013 and beyond (2006 average $65 per barrel in 2007, $68 per barrel in 2008, $67 per barrel in 2009, $66 per barrel in 2010, $64 per barrel in 2011 and $40 per barrel in 2012 and beyond). Similarly, the group s assumption for Henry Hub natural gas prices is an average of $7.87 per mmBtu in 2008, $8.33 per mmBtu in 2009, $8.26 per mmBtu in 2010, $8.12 per mmBtu in 2011, $8.00 per mmBtu in 2012 and $7.50 per mmBtu in 2013 and beyond (2006 average of $8.10 per mmBtu in 2007, $8.31 per mmBtu in 2008, $7.88 per mmBtu in 2009, $8.21 per mmBtu in 2010, $7.50 per mmBtu in 2011 and $5.50 per mmBtu in 2012 and beyond). These prices are adjusted to arrive at appropriate consistent price assumptions for different qualities of oil and gas.

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## 11 Impairment of goodwill *continued*

### Exploration and Production

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. 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. Cash outflows and hydrocarbon production quantities for the first five years are agreed as part of the annual planning process. Thereafter, estimated production quantities and cash outflows up to the date of cessation of production are developed to be consistent with this.

Consistent with prior years, the review for impairment was carried out during the fourth quarter of 2007 using data that was appropriate at that time. As permitted by IAS 36, the detailed calculations made in 2005 and 2006 were used for the 2007 impairment test on the goodwill in each geographical segment as the criteria of IAS 36 were considered to be satisfied: the excess of the recoverable amount over the carrying amount was substantial for Rest of World in 2005 and the UK and the US in 2006; 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 following table shows the carrying value of the goodwill allocated to each of the regions of the Exploration and Production segment and, where required, the amount by which the recoverable amount (value in use) exceeds the carrying amount of the goodwill and other non-current assets in the cash-generating units to which the goodwill has been allocated. No impairment charge is required.

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 excess of the recoverable amount over the carrying amount of goodwill and other non-current assets (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.

In the prior year, it was estimated that the long-term price of Brent that would cause the total recoverable amount to be equal to the total carrying amount of goodwill and related non-current assets for individual cash-generating units would be of the order of $31 per barrel for the UK and $28 per barrel for the US, and that no reasonably possible change in oil and gas prices would cause the headroom in Rest of World to be reduced to zero. Since that time, oil prices have continued to rise and the group has increased its price assumptions as disclosed above. Management now believes that no reasonably possible change in oil and gas prices would cause the headroom in any of the geographical segments 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. It is 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 the individual cash-generating units to zero. Consequently, management believes no reasonably possible change in the production assumption would cause the carrying amount of goodwill and other non-current assets to exceed their recoverable amount.

Management also believes that currently there is no reasonably possible change in discount rate that would reduce the group s headroom to zero.

| | | | | $ million |
|---|---|---|---|---|
| | | | | **2007** |
| | **UK** | **US** | **Rest of World** | **Total** |
| Goodwill | **341** | **3,391** | **515** | **4,247** |

$ million

| | | | | 2006 |
|---|---|---|---|---|
| | UK | US | Rest of World | Total |
| Goodwill | 341 | 3,426 | 515 | 4,282 |
| Excess of recoverable amount over carrying amount | 7,886 | 28,856 | n/a | n/a |

**Refining and Marketing**

For all cash-generating units, the cash flows for the next five years are derived from the five-year business segment plan. The cost inflation rate is assumed to be 2.5% (2006 2.5%) throughout the period. In determining the value in use for each of the cash-generating units, cash flows for a period of 10 years have been discounted and aggregated with its terminal value.

*Refining*

Cash flows beyond the five-year period are extrapolated using a 2% growth rate (2006 2%).

The key assumptions to which the calculation of value in use for the Refining unit is most sensitive are gross margins, production volumes and the terminal value. The average value assigned to the gross margin during the plan period is based on a $7.90 per barrel global indicator margin (GIM), which is then adjusted for specific refinery configurations (2006 $7.25 per barrel). The average value assigned to the production volume is 850mmbbl a year (2006 850mmbbl) over the plan period. The value assigned to the terminal value assumption is 6 times earnings (2006 6 times), which is indicative of similar assets in the current market. These key assumptions reflect past experience and are consistent with external sources.

The Refining unit s recoverable amount exceeds its carrying amount by $11.4 billion. Based on sensitivity analysis, it is estimated that if the GIM changes by $1 per barrel, the Refining unit s value in use changes by $7.6 billion and, if there was an adverse change in the GIM of $1.50 per barrel, the recoverable amount of the Refining unit would equal its carrying amount. If the volume assumption changes by 5%, the Refining unit s value in use changes by $5.1 billion and, if there was an adverse change in Refining volumes of 95mmbbl a year, the recoverable amount of the Refining unit would equal its carrying amount. If the multiple of earnings used in the terminal value changes by 1 then the Refining unit s value in use changes by $1.7 billion. Management believes no reasonably possible change in the multiple of earnings used in the terminal value would lead to the Refining unit s value in use being equal to its carrying amount.

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## 11 Impairment of goodwill *continued*

*Retail*

Cash flows beyond the five-year period are extrapolated using a 0.9% growth rate (2006 assumption was 1.3%) reflecting a competitive marketplace within a growing global economy.

The key assumptions to which the calculation of value in use for the Retail unit is most sensitive are unit gross margins, marketing volumes, the terminal value and discount rate. The weighted average Retail fuel margin used in the plan was 3.1 cents per litre (2006 2.6 cents per litre). The value assigned to the unit gross margin varies between markets. For the purpose of planning, each market develops a gross margin based upon the different income streams within the market and other market-specific factors. In 2007, all markets were provided with the same reference price, which was then adjusted for specific market factors and income streams in each operating unit. The gross margin assumption quoted this year is the weighted average of the margins used by each operating unit. The comparative has been prepared on the same basis. In the prior year each operating unit was provided with a market-specific reference price as a starting point. The weighted average of these assumptions was disclosed as the gross margin assumption in the prior year. The average value assigned to the marketing volume assumption is 125 billion litres a year (2006 134 billion litres a year). The unit gross margin assumptions increase on average by 1% a year over the plan period and marketing volume assumptions grow by an average of 1% a year over the plan period. The value assigned to the terminal value assumption is 6.5 times earnings (2006 6.5 times), which is indicative of similar assets in the current market. These key assumptions reflect past experience and are consistent with external sources.

The Retail unit s recoverable amount exceeds its carrying amount by $4.1 billion. Based on sensitivity analysis, it is estimated that if there is an adverse change in the weighted average fuel margin of 11%, the recoverable amount of the Retail unit would equal its carrying amount. It is estimated that, if the volume assumption changes by 5% the Retail unit s value in use changes by $1.8 billion and, if there is an adverse change in marketing volumes of 14 billion litres a year, the recoverable amount of the Retail unit would equal its carrying amount. If the multiple of earnings used in the terminal value changes by 1 then the Retail unit s value in use changes by $0.8 billion and, if the multiple of earnings falls to 1 then the Retail value in use would equal its carrying amount. A change of 1% in the discount rate would change the Retail value in use by $0.9 billion and, if the discount rate increases to 17%, the value in use of the Retail unit would equal its carrying amount.

*Lubricants*

Cash flows beyond the five-year period are extrapolated using a 3% margin growth rate (2006 3%), which is lower than the long-term average growth rate for the first five years. The terminal value for the Lubricants unit represents cash flows discounted to perpetuity.

For the Lubricants unit, the key assumptions to which the calculation of value in use is most sensitive are operating margin, sales volumes and the discount rate. The average values assigned to the operating margin and sales volumes over the plan period are 65 cents per litre (2006 53 cents per litre) and 3.3 billion litres a year (2006 3.5 billion litres) respectively. These key assumptions reflect past experience.

The Lubricants unit s recoverable amount exceeds its carrying amount by $5.0 billion. Based on sensitivity analysis, it is estimated that if there is an adverse change in the operating margin of 14 cents per litre, the recoverable amount of the Lubricants unit would equal its carrying amount. If the sales volume assumption changes by 5%, the Lubricants unit s value in use changes by $1.2 billion and, if there is an adverse change in Lubricants sales volumes of 700 million litres a year, the recoverable amount of the Lubricants unit would equal its carrying amount. A change of 1% in the discount rate would change the Lubricants unit s value in use by $1.2 billion and, if the discount rate increases to 19% the value in use of the Lubricants unit would equal its carrying amount.

$ million

| | | | | | 2007 |
|---|---|---|---|---|---|
| | **Refining** | **Retail** | **Lubricants** | **Other** | **Total** |
| Goodwill | **1,515** | **827** | **4,175** | **109** | **6,626** |
| Excess of recoverable amount over carrying amount | **11,443** | **4,062** | **5,028** | **n/a** | **n/a** |

| | | | | | $ million |
|---|---|---|---|---|---|
| | | | | | 2006 |
| | Refining | Retail | Lubricants | Other | Total |
| Goodwill | 1,328 | 841 | 4,098 | 123 | 6,390 |
| Excess of recoverable amount over carrying amount | n/a | 2,100 | 2,012 | n/a | n/a |

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## 12 Distribution and administration expenses

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Distribution | **14,028** | 13,174 | 13,187 |
| Administration | **1,343** | 1,273 | 1,325 |
| | **15,371** | 14,447 | 14,512 |
| Innovene operations | | | (806) |
| Continuing operations | **15,371** | 14,447 | 13,706 |

## 13 Currency exchange gains and losses

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Currency exchange (gains) losses (credited) charged to income | **(189)** | 222 | 94 |
| Innovene operations | | | (80) |
| Continuing operations | **(189)** | 222 | 14 |

## 14 Research and development

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Expenditure on research and development | **566** | 395 | 502 |
| Innovene operations | | | (128) |
| Continuing operations | **566** | 395 | 374 |

## 15 Operating leases

The table below shows the expense for the year in respect of operating leases. Where an operating lease is entered into solely by the group as the operator of a jointly controlled asset, the total cost is included in this analysis, irrespective of any amounts that have been or will be reimbursed by joint venture partners. Where BP is not the operator of a jointly controlled asset, operating lease costs and future minimum lease payments are excluded from the information given below.

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Minimum lease payments | **4,152** | 3,647 | 2,743 |
| Contingent rentals | **105** | 13 | (6) |
| Sub-lease rentals | **(191)** | (131) | (114) |
| | **4,066** | 3,529 | 2,623 |
| Innovene operations | | | (49) |
| Continuing operations | **4,066** | 3,529 | 2,574 |

In addition to the above, 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. For 2007, $1,300 million (2006 $895 million) of the cost for the year has been capitalized.

The future minimum lease payments at 31 December, before deducting related rental income from operating sub-leases of $618 million (2006 $626 million and 2005 $718 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 | **2007** | 2006 |
| Payable within | | |
| 1 year | **3,780** | 3,428 |
| 2 to 5 years | **7,660** | 8,440 |
| Thereafter | **5,498** | 5,684 |
| | **16,938** | 17,552 |

The following additional disclosures represent the net operating lease expense and 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, operating lease costs and future minimum lease payments are excluded from the information given below.

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Minimum lease payments | **3,100** | 2,924 | 1,847 |

| | | | |
|---|---|---|---|
| Contingent rentals | **80** | 13 | (6) |
| Sub-lease rentals | **(183)** | (131) | (110) |
| | **2,997** | 2,806 | 1,731 |
| Innovene operations | | | (49) |
| Continuing operations | **2,997** | 2,806 | 1,682 |

| | | $ million |
|---|---|---|
| Future minimum lease payments | **2007** | 2006 |
| Payable within | | |
| 1 year | **2,826** | 2,732 |
| 2 to 5 years | **6,519** | 7,290 |
| Thereafter | **5,050** | 5,221 |
| | **14,395** | 15,243 |

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 20 |
| 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, but the amounts of such contingent rentals are not significant for the years presented. 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. 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 |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Exploration and evaluation costs | | | |
| Exploration expenditure written off | **347** | 624 | 305 |
| Other exploration costs | **409** | 421 | 379 |
| Exploration expense for the year | **756** | 1,045 | 684 |
| Intangible assets exploration expenditure | **5,252** | 4,110 | 4,008 |
| Net assets | **5,252** | 4,110 | 4,008 |
| Capital expenditure | **2,000** | 1,537 | 950 |
| Net cash used in operating activities | **409** | 421 | 379 |
| Net cash used in investing activities | **2,000** | 1,498 | 950 |

## 17 Auditors remuneration

| | | | $ million |
|---|---|---|---|
| Fees Ernst & Young | **2007** | 2006 | 2005 |
| Fees payable to the company s auditors for the audit of the company s accounts[a] | **18** | 15 | 19 |
| Fees payable to the company s auditors and its associates for other services | | | |
| Audit of the company s subsidiaries pursuant to legislation | **31** | 31 | 34 |
| Other services pursuant to legislation | **14** | 15 | 6 |

| | | | |
|---|---|---|---|
| | **63** | 61 | 59 |
| Tax services | **2** | 1 | 10 |
| Services relating to corporate finance transactions | **1** | 2 | 3 |
| All other services | **8** | 9 | 23 |
| Audit fees in respect of the BP pension plans | **1** | | 1 |
| | **75** | 73 | 96 |
| Innovene operations | | | (9) |
| Continuing operations | **75** | 73 | 87 |

[a] Fees in respect of the audit of the accounts of BP p.l.c. including the group s consolidated financial statements.

Total fees for 2007 include $7 million of additional fees for 2006 (2006 includes $5 million of additional fees for 2005 and 2005 includes $4 million of additional fees for 2004). Auditors remuneration is included in the income statement within distribution and administration expenses.

The tax services relate to income tax and indirect tax compliance, employee tax services and tax advisory services.

The audit committee has established pre-approval policies and procedures for the engagement of Ernst & Young to render audit and certain assurance and 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.

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## 18 Finance costs

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Bank loans and overdrafts | **89** | 130 | 44 |
| Other loans | **1,302** | 1,020 | 828 |
| Finance leases | **42** | 46 | 38 |
| Interest payable | **1,433** | 1,196 | 910 |
| Capitalized at 5.70% (2006 5.25% and 2005 4.25%)[a] | **(323)** | (478) | (351) |
| Early redemption of borrowings and finance leases | | | 57 |
| | **1,110** | 718 | 616 |

[a] Tax relief on capitalized interest is $81 million (2006 $182 million and 2005 $123 million).

## 19 Other finance income and expense

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Interest on pension and other post-retirement benefit plan liabilities | **2,203** | 1,940 | 2,022 |
| Expected return on pension and other post-retirement benefit plan assets | **(2,855)** | (2,410) | (2,138) |
| Interest net of expected return on plan assets | **(652)** | (470) | (116) |
| Unwinding of discount on provisions | **283** | 245 | 201 |
| Unwinding of discount on deferred consideration for acquisition of investment in TNK-BP | | 23 | 57 |
| | **(369)** | (202) | 142 |
| Innovene operations | | | 3 |
| Continuing operations | **(369)** | (202) | 145 |

## 20 Taxation

| | | | $ million |
|---|---|---|---|
| **Tax on profit** | **2007** | 2006 | 2005 |
| Current tax | | | |
| Charge for the year | **10,006** | 11,199 | 10,511 |
| Adjustment in respect of prior years | **(171)** | 442 | (977) |
| | **9,835** | 11,641 | 9,534 |
| Innovene operations | | 159 | (910) |

| | | | |
|---|---|---|---|
| Continuing operations | **9,835** | 11,800 | 8,624 |
| Deferred tax | | | |
| Origination and reversal of temporary differences in the current year | **671** | 1,956 | 164 |
| Adjustment in respect of prior years | **(64)** | (1,240) | (450) |
| | **607** | 716 | (286) |
| Innovene operations | | | 950 |
| Continuing operations | **607** | 716 | 664 |
| Tax on profit from continuing operations | **10,442** | 12,516 | 9,288 |

Tax on profit from continuing operations may be analysed as follows:

| | | | |
|---|---|---|---|
| Current tax charge | | | |
| UK | **2,067** | 2,657 | 880 |
| Overseas | **7,768** | 9,143 | 7,744 |
| | **9,835** | 11,800 | 8,624 |
| Deferred tax charge | | | |
| UK | **216** | 500 | (489) |
| Overseas | **391** | 216 | 1,153 |
| | **607** | 716 | 664 |
| Total | | | |
| UK | **2,283** | 3,157 | 391 |
| Overseas | **8,159** | 9,359 | 8,897 |
| | **10,442** | 12,516 | 9,288 |

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## 20 Taxation *continued*

| Tax included in the statement of recognized income and expense | 2007 | 2006 | 2005 |
|---|---|---|---|
| | | | $ million |
| Current tax | **(178)** | (51) | 45 |
| Deferred tax | **241** | 985 | 214 |
| | **63** | 934 | 259 |
| This comprises: | | | |
| Currency translation differences | **(139)** | 201 | (11) |
| Exchange gain on translation of foreign operations transferred to loss on sale of businesses | | | (95) |
| Actuarial gain relating to pensions and other post-retirement benefits | **427** | 820 | 356 |
| Share-based payments | **(213)** | (26) | |
| Cash flow hedges | **(26)** | 47 | (63) |
| Available-for-sale investments | **14** | (108) | 72 |
| | **63** | 934 | 259 |

### 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 before taxation from continuing operations.

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| | | | $ million |
| Profit before taxation from continuing operations | **31,611** | 35,142 | 31,421 |
| Tax on profit from continuing operations | **10,442** | 12,516 | 9,288 |
| Effective tax rate | **33%** | 36% | 30% |
| | % of profit before taxation from continuing operations | | |
| UK statutory corporation tax rate | **30** | 30 | 30 |
| Increase (decrease) resulting from | | | |
| UK supplementary and overseas taxes at higher rates | **7** | 11 | 9 |
| Tax reported in equity-accounted entities | **(2)** | (3) | (3) |
| Adjustments in respect of prior years | **(1)** | (2) | (3) |
| Restructuring benefits | | | (1) |
| Current year losses unrelieved (prior year losses utilized) | **(1)** | (1) | (3) |
| Other | | 1 | 1 |

| | | | |
|---|---|---|---|
| Effective tax rate | **33** | 36 | 30 |

## Deferred tax

$ million

| | Income statement | | | Balance sheet | |
|---|---|---|---|---|---|
| | **2007** | 2006 | 2005 | **2007** | 2006 |
| Deferred tax liability | | | | | |
| Depreciation | **(54)** | 1,484 | (778) | **21,757** | 21,463 |
| Pension plan surplus | **127** | 173 | 170 | **2,136** | 1,733 |
| Other taxable temporary differences | **1,371** | 417 | 887 | **5,998** | 4,895 |
| | **1,444** | 2,074 | 279 | **29,891** | 28,091 |
| Deferred tax asset | | | | | |
| Petroleum revenue tax | **139** | 4 | 121 | **(325)** | (457) |
| Pension plan and other post-retirement benefit plan deficits | **(72)** | 71 | 220 | **(1,545)** | (1,824) |
| Decommissioning, environmental and other provisions | **(759)** | (615) | (329) | **(3,746)** | (2,960) |
| Derivative financial instruments | **450** | (115) | (629) | **(541)** | (974) |
| Tax credit and loss carry forward | **(466)** | 220 | (245) | **(1,822)** | (1,118) |
| Other deductible temporary differences | **(129)** | (923) | 297 | **(2,697)** | (2,642) |
| | **(837)** | (1,358) | (565) | **(10,676)** | (9,975) |
| Net deferred tax liability | **607** | 716 | (286) | **19,215** | 18,116 |

$ million

| Analysis of movements during the year | **2007** | 2006 |
|---|---|---|
| At 1 January | **18,116** | 16,258 |
| Exchange adjustments | **42** | 175 |
| Charge for the year on ordinary activities | **607** | 716 |
| Charge for the year in the statement of recognized income and expense | **241** | 985 |
| Acquisitions | **199** | |
| Other movements | **10** | (18) |
| At 31 December | **19,215** | 18,116 |

## 20 Taxation *continued*

### Factors that may affect future tax charges

The group earns income in many different countries and, on average, pays taxes at rates higher than the rate of UK corporation tax. The overall impact of these higher taxes, which include the supplementary charge on UK North Sea profits, is subject to changes in enacted tax rates and the country mix of the group s income.

The 2007 effective tax rate for the group reflects the impact of the use of capital and other losses in the UK and mainland Europe and audit closure of a variety of worldwide issues. The enactment of a 2% reduction in the rate of UK corporation tax on profits arising from activities outside the North Sea reduced the tax charge by $189 million.

Under IFRS, the results of equity-accounted entities are reported within the group s profit before taxation on a post-tax basis. The impact of this treatment in 2007 has been to reduce the reported effective tax rate by around 2%. This effect is expected to continue for the foreseeable future assuming similar income levels from the entities.

At 31 December 2007, deferred tax liabilities were 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 timing of the reversal of the temporary differences can be controlled by the group and it is probable that the temporary differences will not reverse in the foreseeable future.

At 31 December 2007, deferred tax assets were recognized for all deductible temporary differences, carry forward of unused tax assets 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 assets 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 only recognized 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 group has around $5.0 billion (2006 $4.9 billion) of carry-forward tax losses, predominantly in Europe, which would be available to offset against future taxable income. These tax losses do not have a fixed expiry date. At the end of 2007, a net deferred tax asset of $286 million was recognized on these losses (2006 $216 million). The gross deferred tax asset recognized for the losses was $972 million (2006 $680 million), of which $686 million (2006 $458 million) was offset by deferred tax liabilities. Deferred tax assets are recognized only to the extent that it is considered more likely than not that suitable taxable income will arise.

At the end of 2007, the group had around $4.1 billion (2006 $2.0 billion) of unused tax credits in the UK and US, in respect of which no net deferred tax assets have been recognized. A gross deferred tax asset of $820 million has been recognized in 2007 for these credits (2006 $459 million), which is offset by a gross deferred tax liability associated with unremitted profits from overseas entities in jurisdictions with a lower tax rate than the UK. The UK tax credits do not have a fixed expiry date. The US tax credits expire ten years after generation. In 2007, $411 million of tax credits were utilized (2006 $828 million and 2005 $774 million).

The major components of temporary differences at the end of the current year are tax depreciation, US inventory holding gains (classified under other taxable temporary differences) and provisions.

## 21 Dividends

| | pence per share | | | cents per share | | | $ million | | |
|---|---|---|---|---|---|---|---|---|---|
| | **2007** | 2006 | 2005 | **2007** | 2006 | 2005 | **2007** | 2006 | 2005 |
| Dividends announced and paid | | | | | | | | | |
| Preference shares | | | | | | | **2** | 2 | 2 |
| Ordinary shares | | | | | | | | | |
| March | **5.258** | 5.288 | 4.522 | **10.325** | 9.375 | 8.500 | **2,000** | 1,922 | 1,823 |
| June | **5.151** | 5.251 | 4.450 | **10.325** | 9.375 | 8.500 | **1,983** | 1,893 | 1,808 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| September | **5.278** | 5.324 | 5.119 | **10.825** | 9.825 | 8.925 | **2,065** | 1,943 | 1,871 |
| December | **5.308** | 5.241 | 5.061 | **10.825** | 9.825 | 8.925 | **2,056** | 1,926 | 1,855 |
| | **20.995** | 21.104 | 19.152 | **42.300** | 38.400 | 34.850 | **8,106** | 7,686 | 7,359 |
| Dividend announced per ordinary share, payable in March 2008 | **6.813** | | | **13.525** | | | **2,554** | | |

The group does not account for dividends until they are paid. The accounts for the year ended 31 December 2007 do not reflect the dividend announced on 5 February 2008 and payable in March 2008; this will be treated as an appropriation of profit in the year ended 31 December 2008.

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## 22 Earnings per ordinary share

| | | | cents per share |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Basic earnings per share | **108.76** | 111.41 | 104.25 |
| Diluted earnings per share | **107.84** | 110.56 | 103.05 |

Basic earnings per ordinary share amounts are calculated by dividing the profit 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.

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 would be issued in connection with employee share-based payment plans using the treasury stock method. In addition, for 2006 and 2005, the profit attributable to ordinary shareholders has been adjusted for the unwinding of the discount on the deferred consideration for the acquisition of our interest in TNK-BP and the weighted average number of shares outstanding during the year has been adjusted for the number of shares to be issued for the deferred consideration for the acquisition of our interest in TNK-BP.

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Profit from continuing operations attributable to BP shareholders | **20,845** | 22,340 | 21,842 |
| Less dividend requirements on preference shares | **2** | 2 | 2 |
| Profit from continuing operations attributable to BP ordinary shareholders | **20,843** | 22,338 | 21,840 |
| Profit (loss) from discontinued operations | | (25) | 184 |
| | **20,843** | 22,313 | 22,024 |
| Unwinding of discount on deferred consideration for acquisition of investment in TNK-BP (net of tax) | | 16 | 40 |
| Diluted profit for the year attributable to BP ordinary shareholders | **20,843** | 22,329 | 22,064 |

| | | | shares thousand |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Basic weighted average number of ordinary shares | **19,163,389** | 20,027,527 | 21,125,902 |
| Potential dilutive effect of ordinary shares issuable under employee share schemes | **163,486** | 109,813 | 87,743 |
| Potential dilutive effect of ordinary shares issuable as consideration for BP s interest in the TNK-BP joint venture | | 58,118 | 197,802 |
| | **19,326,875** | 20,195,458 | 21,411,447 |

The number of ordinary shares outstanding at 31 December 2007, excluding treasury shares, was 18,922,785,598. Between 31 December 2007 and 19 February 2008, the latest practicable date before the completion of these financial statements, there has been a net decrease of 44,539,157 in the number of ordinary shares outstanding as a result of share buybacks net of share issues. The number of potential ordinary shares issuable through the exercise of employee share schemes was 154,039,764 at 31 December 2007. There has been a decrease of 10,797,601 in the number of potential ordinary shares between 31 December 2007 and 19 February 2008.

Earnings (loss) per share for the discontinued operations is derived from the net profit (loss) attributable to ordinary shareholders from discontinued operations of $nil (2006 $25 million loss and 2005 $184 million profit), divided by the weighted average number of ordinary shares for both basic and diluted amounts as shown above.

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## 23 Property, plant and equipment

$ million

| | Land and land improvements | Buildings | Oil and gas properties | Plant, machinery and equipment | Fixtures, fittings and office equipment | Transportation | Oil depots, storage tanks and service stations | Total |
|---|---|---|---|---|---|---|---|---|
| Cost | | | | | | | | |
| At 1 January 2007 | **4,442** | **3,129** | **123,493** | **32,203** | **3,006** | **11,930** | **11,076** | **189,279** |
| Exchange adjustments | **271** | **148** | **22** | **1,182** | **73** | **32** | **733** | **2,461** |
| Acquisitions | | | | **910** | | | | **910** |
| Additions | **78** | **171** | **12,107** | **3,662** | **466** | **181** | **643** | **17,308** |
| Transfers | | | **422** | | | | | **422** |
| Reclassified as assets held for sale | **(16)** | | | **(1,114)** | | | | **(1,130)** |
| Deletions | **(259)** | **(298)** | **(1,429)** | **(478)** | **(376)** | **(277)** | **(1,042)** | **(4,159)** |
| At 31 December 2007 | **4,516** | **3,150** | **134,615** | **36,365** | **3,169** | **11,866** | **11,410** | **205,091** |
| Depreciation | | | | | | | | |
| At 1 January 2007 | **675** | **1,470** | **66,189** | **16,189** | **1,762** | **6,876** | **5,119** | **98,280** |
| Exchange adjustments | **25** | **89** | **19** | **556** | **45** | **16** | **299** | **1,049** |
| Charge for the year | **52** | **98** | **7,370** | **1,266** | **341** | **373** | **741** | **10,241** |
| Impairment losses | **86** | **62** | **189** | **236** | **9** | **14** | **643** | **1,239** |
| Impairment reversals | | | **(237)** | | | | | **(237)** |
| Reclassified as assets held for sale | **(9)** | | | **(486)** | | | | **(495)** |
| Deletions | **(111)** | **(186)** | **(1,044)** | **(344)** | **(337)** | **(153)** | **(800)** | **(2,975)** |
| At 31 December 2007 | **718** | **1,533** | **72,486** | **17,417** | **1,820** | **7,126** | **6,002** | **107,102** |
| Net book amount at 31 December 2007 | **3,798** | **1,617** | **62,129** | **18,948** | **1,349** | **4,740** | **5,408** | **97,989** |
| Cost | | | | | | | | |
| At 1 January 2006 | 4,576 | 2,835 | 114,413 | 30,341 | 2,247 | 13,196 | 11,100 | 178,708 |
| Exchange adjustments | 255 | 239 | 72 | 1,028 | 138 | 27 | 517 | 2,276 |
| Acquisitions | | | | 16 | | | | 16 |
| Additions | 81 | 381 | 11,264 | 2,146 | 841 | 22 | 918 | 15,653 |
| Transfers[a] | | | (628) | | (1) | | | (629) |
| Reclassified as assets held for sale | (15) | (1) | | (842) | | (1) | (47) | (906) |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Deletions | (455) | (325) | (1,628) | (486) | (219) | (1,314) | (1,412) | (5,839) |
| At 31 December 2006 | 4,442 | 3,129 | 123,493 | 32,203 | 3,006 | 11,930 | 11,076 | 189,279 |
| Depreciation | | | | | | | | |
| At 1 January 2006 | 709 | 1,437 | 62,192 | 14,978 | 1,450 | 7,034 | 4,961 | 92,761 |
| Exchange adjustments | 15 | 147 | 54 | 552 | 107 | 12 | 154 | 1,041 |
| Charge for the year | 52 | 149 | 6,214 | 1,059 | 418 | 301 | 718 | 8,911 |
| Impairment losses | 87 | 5 | 4 | 98 | | 1 | 9 | 204 |
| Impairment reversals | | | (340) | | | | | (340) |
| Transfers[b] | | | (887) | | (1) | | | (888) |
| Reclassified as assets held for sale | | (1) | | (325) | | (1) | (15) | (342) |
| Deletions | (188) | (267) | (1,048) | (173) | (212) | (471) | (708) | (3,067) |
| At 31 December 2006 | 675 | 1,470 | 66,189 | 16,189 | 1,762 | 6,876 | 5,119 | 98,280 |
| Net book amount at 31 December 2006 | 3,767 | 1,659 | 57,304 | 16,014 | 1,244 | 5,054 | 5,957 | 90,999 |
| Assets held under finance leases at net book amount included above | | | | | | | | |
| At 31 December 2007 | | **17** | **155** | **185** | | **11** | **24** | **392** |
| At 31 December 2006 | 5 | 18 | 42 | 341 | 1 | 9 | 29 | 445 |

Decommissioning asset at net book amount included above

| | Cost | Depreciation | Net |
|---|---|---|---|
| At 31 December 2007 | **7,851** | **3,328** | **4,523** |
| At 31 December 2006 | 6,391 | 2,558 | 3,833 |

Assets under construction included above

| | |
|---|---|
| At 31 December 2007 | **18,658** |
| At 31 December 2006 | 17,800 |

[a] Includes $1,087 million transferred to equity-accounted investments.
[b] Includes $890 million transferred to equity-accounted investments.

## 24 Goodwill

| | | $ million |
|---|---|---|
| | **2007** | 2006 |
| Cost and net book amount | | |
| At 1 January | **10,780** | 10,371 |
| Exchange adjustments | **126** | 524 |
| Acquisitions | **270** | 64 |
| Reclassified as assets held for sale | **(90)** | (60) |
| Deletions | **(80)** | (119) |
| At 31 December | **11,006** | 10,780 |

## 25 Intangible assets

| | | | | | | $ million |
|---|---|---|---|---|---|---|
| | | | **2007** | | | 2006 |
| | **Exploration expenditure** | **Other intangibles** | **Total** | Exploration expenditure | Other intangibles | Total |
| Cost | | | | | | |
| At 1 January | **4,590** | **2,128** | **6,718** | 4,661 | 1,740 | 6,401 |
| Exchange adjustments | **3** | **49** | **52** | 2 | 50 | 52 |
| Acquisitions | | **35** | **35** | | 187 | 187 |
| Additions | **2,000** | **548** | **2,548** | 1,537 | 378 | 1,915 |
| Transfers[a] | **(506)** | | **(506)** | (698) | | (698) |
| Deletions | **(450)** | **(130)** | **(580)** | (912) | (227) | (1,139) |
| At 31 December | **5,637** | **2,630** | **8,267** | 4,590 | 2,128 | 6,718 |
| Amortization | | | | | | |
| At 1 January | **480** | **992** | **1,472** | 653 | 976 | 1,629 |
| Exchange adjustments | | **25** | **25** | | 20 | 20 |
| Charge for the year | **347** | **338** | **685** | 624 | 217 | 841 |
| Transfers | | | | (2) | | (2) |
| Impairment losses | | | | 109 | | 109 |
| Deletions | **(442)** | **(125)** | **(567)** | (904) | (221) | (1,125) |
| At 31 December | **385** | **1,230** | **1,615** | 480 | 992 | 1,472 |
| Net book amount at 31 December | **5,252** | **1,400** | **6,652** | 4,110 | 1,136 | 5,246 |

[a] Included in transfers of exploration expenditure is $84 million (2006 $240 million) transferred to equity-accounted investments.

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## 26 Investments in jointly controlled entities

The significant jointly controlled entities of the BP group at 31 December 2007 are shown in Note 46. The principal joint venture is the TNK-BP joint venture. Summarized financial information for the group s share of jointly controlled entities is shown below.

$ million

| | 2007 | | | 2006 | | | 2005 | | |
|---|---|---|---|---|---|---|---|---|---|
| | **TNK-BP** | **Other** | **Total** | TNK-BP | Other | Total | TNK-BP | Other | Total |
| Sales and other operating revenues | **19,463** | **7,245** | **26,708** | 17,863 | 6,119 | 23,982 | 15,122 | 4,255 | 19,377 |
| Profit before interest and taxation | **3,743** | **1,299** | **5,042** | 4,616 | 1,218 | 5,834 | 3,817 | 779 | 4,596 |
| Finance costs and other finance expense | **264** | **176** | **440** | 192 | 169 | 361 | 128 | 104 | 232 |
| Profit before taxation | **3,479** | **1,123** | **4,602** | 4,424 | 1,049 | 5,473 | 3,689 | 675 | 4,364 |
| Taxation | **993** | **259** | **1,252** | 1,467 | 260 | 1,727 | 976 | 220 | 1,196 |
| Minority interest | **215** | | **215** | 193 | | 193 | 104 | | 104 |
| Profit for the year[a] | **2,271** | **864** | **3,135** | 2,764 | 789 | 3,553 | 2,609 | 455 | 3,064 |
| Innovene operations | | | | | | | | 19 | 19 |
| Continuing operations | **2,271** | **864** | **3,135** | 2,764 | 789 | 3,553 | 2,609 | 474 | 3,083 |
| Non-current assets | **12,433** | **9,841** | **22,274** | 11,243 | 7,612 | 18,855 | | | |
| Current assets | **6,073** | **2,642** | **8,715** | 5,403 | 2,184 | 7,587 | | | |
| Total assets | **18,506** | **12,483** | **30,989** | 16,646 | 9,796 | 26,442 | | | |
| Current liabilities | **3,547** | **1,552** | **5,099** | 3,594 | 1,272 | 4,866 | | | |
| Non-current liabilities | **5,562** | **3,620** | **9,182** | 4,226 | 3,370 | 7,596 | | | |
| Total liabilities | **9,109** | **5,172** | **14,281** | 7,820 | 4,642 | 12,462 | | | |
| Minority interest | **580** | | **580** | 473 | | 473 | | | |
| | **8,817** | **7,311** | **16,128** | 8,353 | 5,154 | 13,507 | | | |
| Group investment in jointly controlled entities | | | | | | | | | |
| Group share of net assets (as above) | **8,817** | **7,311** | **16,128** | 8,353 | 5,154 | 13,507 | | | |
| Loans made by group companies to jointly controlled entities | | **1,985** | **1,985** | | 1,567 | 1,567 | | | |
| | **8,817** | **9,296** | **18,113** | 8,353 | 6,721 | 15,074 | | | |

[a] BP s share of the profit of TNK-BP in 2006 includes a net gain of $892 million (2005 $270 million) on the disposal of certain assets.

Transactions between the significant jointly controlled entities and the group are summarized below. In addition to the amount receivable at 31 December 2005 shown below, a further $771 million was receivable from TNK-BP in respect of dividends: there was no dividend receivable at 31 December 2007 or at 31 December 2006.

Sales to jointly controlled entities $ million

| | | **2007** | | 2006 | | 2005 | |
|---|---|---|---|---|---|---|---|
| | Product | **Sales** | **Amount receivable at 31 December** | Sales | Amount receivable at 31 December | Sales | Amount receivable at 31 December |
| Atlantic 4 Holdings | LNG | **583** | **142** | 227 | 35 | | |
| Atlantic LNG 2/3 Company of Trinidad and Tobago | LNG | **989** | **137** | 1,123 | 99 | 1,157 | |
| Pan American Energy | Crude oil | **240** | **1** | 389 | | 75 | 2 |
| Ruhr Oel | Employee services | **374** | **539** | 330 | 597 | 169 | 527 |
| TNK-BP | Employee services | **150** | **69** | 189 | 99 | 125 | 14 |

Purchases from jointly controlled entities $ million

| | | **2007** | | 2006 | | 2005 | |
|---|---|---|---|---|---|---|---|
| | Product | **Purchases** | **Amount payable at 31 December** | Purchases | Amount payable at 31 December | Purchases | Amount payable at 31 December |
| Atlantic LNG 2/3 Company of Trinidad and Tobago | Plant processing fee/natural gas | **241** | | 254 | | 190 | |
| Pan American Energy | Crude oil | **6** | **2** | 4 | 2 | 661 | 81 |
| Ruhr Oel | Refinery operating costs | **902** | **18** | 758 | 32 | 384 | 134 |
| TNK-BP | Crude oil and oil products | **918** | **46** | 2,662 | 85 | 908 | 17 |

The terms of the outstanding balances receivable from jointly controlled entities are typically 30 to 45 days, except for the receivable from Ruhr Oel, 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.

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## 27 Investments in associates

The significant associates of the group are shown in Note 46. Summarized financial information for the group s share of associates is set out below.

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Sales and other operating revenues | **9,855** | 8,792 | 6,879 |
| Profit before interest and taxation | **947** | 669 | 665 |
| Finance costs and other finance expense | **57** | 63 | 57 |
| Profit before taxation | **890** | 606 | 608 |
| Taxation | **193** | 164 | 143 |
| Profit for the year | **697** | 442 | 465 |
| Innovene operations | | | (5) |
| Continuing operations | **697** | 442 | 460 |
| Non-current assets | **5,012** | 6,573 | |
| Current assets | **2,308** | 2,294 | |
| Total assets | **7,320** | 8,867 | |
| Current liabilities | **1,801** | 2,029 | |
| Non-current liabilities | **2,423** | 2,600 | |
| Total liabilities | **4,224** | 4,629 | |
| Net assets | **3,096** | 4,238 | |
| Group investment in associates | | | |
| Group share of net assets (as above) | **3,096** | 4,238 | |
| Loans made by group companies to associates | **1,483** | 1,737 | |
| | **4,579** | 5,975 | |

Transactions between the significant associates and the group are summarized below.

| Sales to associates | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| | **Amount** | Amount | Amount |

| | Product | **Sales** | **receivable at 31 December** | Sales | receivable at 31 December | Sales | receivable at 31 December |
|---|---|---|---|---|---|---|---|
| Atlantic LNG Company of Trinidad and Tobago | LNG | **611** | **58** | 635 | 62 | 579 | |
| The Baku-Tbilisi-Ceyhan Pipeline Co. | Crude oil/employee services | **86** | **2** | 112 | 4 | 99 | 3 |

Purchases from associates

$ million

| | | **2007** | | 2006 | | 2005 | |
|---|---|---|---|---|---|---|---|
| | Product | **Purchases** | **Amount payable at 31 December** | Purchases | Amount payable at 31 December | Purchases | Amount payable at 31 December |
| Abu Dhabi Marine Areas | Crude oil | **547** | **303** | 866 | 91 | 1,355 | 164 |
| Abu Dhabi Petroleum Co. | Crude oil | **1,964** | **229** | 1,547 | 145 | 2,260 | 214 |
| The Baku-Tbilisi-Ceyhan Pipeline Co. | Transportation tariff | **394** | **42** | 155 | | | |

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.

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## 28 Financial instruments and financial risk factors

The accounting classification of each category of financial instruments, and their carrying amounts, are set out below.

$ million

2007

| | 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 listed | 29 | | 1,617 | | | | 1,617 |
| Other investments unlisted | 29 | | 213 | | | | 213 |
| Loans | | 1,164 | | | | | 1,164 |
| Trade and other receivables | 31 | 38,710 | | | | | 38,710 |
| Derivative financial instruments | 34 | | | 9,155 | 907 | | 10,062 |
| Cash at bank and in hand | 32 | 2,996 | | | | | 2,996 |
| Cash equivalents listed | 32 | | 3 | | | | 3 |
| Cash equivalents unlisted | 32 | | 563 | | | | 563 |
| Financial liabilities | | | | | | | |
| Trade and other payables | 33 | | | | | (40,062) | (40,062) |
| Derivative financial instruments | 34 | | | (11,284) | (123) | | (11,407) |
| Accruals | | | | | | (7,599) | (7,599) |
| Finance debt | 35 | | | | | (31,045) | (31,045) |
| | | 42,870 | 2,396 | (2,129) | 784 | (78,706) | (34,785) |

$ million

2006

| | 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 listed | 29 | | 1,516 | | | | 1,516 |
| Other investments unlisted | 29 | | 181 | | | | 181 |
| Loans | | 958 | | | | | 958 |
| Trade and other receivables | 31 | 38,474 | | | | | 38,474 |
| Derivative financial instruments | 34 | | | 12,811 | 587 | | 13,398 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Cash at bank and in hand | 32 | 2,052 | | | | | 2,052 |
| Cash equivalents listed | 32 | | 29 | | | | 29 |
| Cash equivalents unlisted | 32 | | 509 | | | | 509 |
| Financial liabilities | | | | | | | |
| Trade and other payables | 33 | | | | | (38,227) | (38,227) |
| Derivative financial instruments | 34 | | | (13,490) | (137) | | (13,627) |
| Accruals | | | | | | (7,108) | (7,108) |
| Finance debt | 35 | | | | | (24,010) | (24,010) |
| | | 41,484 | 2,235 | (679) | 450 | (69,345) | (25,855) |

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 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 activities in the financial markets are managed by the treasury function. All derivative activity, whether for risk management or entrepreneurial purposes, is carried out by specialist teams that have the appropriate skills, experience and supervision. These teams are subject to close financial and management control, meeting generally accepted industry practice and reflecting the principles of the Group of Thirty Global Derivatives Study recommendations.

The integrated supply and trading function maintains formal governance processes that provide oversight of market risk. 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.

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## 28 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 market price movements that the group is exposed to include oil, natural gas and power prices (commodity price risk), foreign currency exchange rates, interest rates, equity prices and other indices that could adversely affect the value of the group s financial assets, liabilities or expected future cash flows. The group has developed policies aimed at managing the volatility inherent in certain of its natural business exposures and in accordance with these policies the group enters into various transactions using derivative financial and commodity instruments (derivatives). Derivatives are contracts whose value is derived from one or more underlying financial or commodity instruments, indices or prices that are defined in the contract. The group also trades derivatives in conjunction with its risk management activities.

The group mainly measures its market risk exposure using value-at-risk techniques. These techniques are based on a variance/covariance model or a Monte Carlo simulation and make a statistical assessment of the market risk arising from possible future changes in market prices over a 24-hour 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 trading value-at-risk model takes account of derivative financial instrument types such as: interest rate forward and futures contracts, swap agreements, options and swaptions; foreign exchange forward and futures contracts, swap agreements and options; and oil, natural gas and power price forwards, futures, swap agreements and options. Additionally, where physical commodities or non-derivative forward contracts are held as part of a trading position, they are also included in these calculations. For options, a linear approximation is included in the value-at-risk models when full revaluation is not possible. Market risk exposure in respect of embedded derivatives is not included in the value-at-risk table. A separate sensitivity analysis is 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 an increase or a decrease in fair values greater than the trading value at risk on one occasion per month if the portfolio were left unchanged.

Value at risk for 1 day at 95% confidence interval

| | | | | | | | | $ million |
|---|---|---|---|---|---|---|---|---|
| | | | | **2007** | | | | 2006 |
| | **High** | **Low** | **Average** | **Year end** | High | Low | Average | Year end |
| Group trading | **50** | **24** | **35** | **38** | 57 | 22 | 34 | 30 |
| Oil price trading | **46** | **16** | **26** | **34** | 56 | 16 | 29 | 22 |
| Natural gas price trading | **32** | **9** | **16** | **15** | 29 | 10 | 19 | 15 |
| Power price trading | **6** | **1** | **3** | **5** | 11 | 2 | 6 | 3 |
| Currency trading | **6** | **1** | **3** | **2** | 5 | | 2 | |
| Interest rate trading | **11** | | **5** | **2** | 1 | | 1 | |
| Other trading | **7** | | **2** | **1** | | | | |

*(i) Commodity price risk*

The group s risk management policy requires the management of only certain short-term exposures in respect of its equity share of oil and natural gas production and certain of its refinery and marketing activities. The group s integrated supply and trading function uses conventional financial and commodity instruments and physical cargoes available in the related commodity markets. 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.

In addition, the group has embedded derivatives relating to certain natural gas and LNG contracts. Key information on these contracts is given below.

| | **At 31 December 2007** | At 31 December 2006 |
|---|---|---|
| Remaining contract terms | **9 months to 11 years** | 2 to 12 years |
| Contractual/notional amount | **3,889 million therms** | 4,968 million therms |
| Discount rate nominal risk free | **4.5%** | 4.5% |
| Net fair value liability | **$2,085 million** | $2,064 million |

For these derivatives the sensitivity of the fair value to an immediate 10% favourable or adverse change in the key assumptions is as follows.

$ million

| | **2007** | | | | 2006 | | | |
|---|---|---|---|---|---|---|---|---|
| | **Gas price** | **Gas oil and fuel oil price** | **Power price** | **Discount rate** | Gas price | Gas oil and fuel oil price | Power price | Discount rate |
| Favourable 10% change | **317** | **72** | **37** | **31** | 332 | 7 | 45 | 31 |
| Unfavourable 10% change | **(368)** | **(84)** | **(34)** | **(32)** | (341) | (7) | (41) | (32) |

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## 28 Financial instruments and financial risk factors *continued*

These sensitivities are hypothetical and should not be considered to be predictive of future performance. Changes in fair value generally cannot be extrapolated because the relationship of change in assumption to change in fair value may not be linear. In addition, for the purposes of this analysis, in this 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 described as currency 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 conversion 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 managing such risk to keep the 12-month foreign currency value at risk below $200 million. At 31 December 2007, the foreign currency value at risk was $60 million (2006 $107 million). At no point over the past two 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 futures. The main exposures are sterling and euro, and at 31 December 2007 open contracts were in place for $732 million sterling and $931 million euro capital expenditures, with over 80% of the deals maturing within two years (2006 $630 million sterling and $957 million euro capital expenditures with over 95% of the deals maturing within two years).

For other UK and European operational requirements the group predominantly uses cylinders to hedge the estimated exposures on a 12-month rolling basis at minimal cost. At 31 December 2007, the main open positions consisted of receive sterling, pay US dollar, purchased call and sold put options for $2,800 million; and receive euro, pay US dollar cylinders for $1,400 million.

In addition, most of the group s borrowings are in US dollars or are hedged with respect to the US dollar. At 31 December 2007, the total of foreign currency borrowings not swapped into US dollars amounted to $1,045 million (2006 $957 million). Of this total, $268 million (2006 $300 million) of these borrowings were denominated in currencies other than the functional currency of the individual operating unit, $191 million in Canadian dollars and $77 million in Trinidad & Tobago dollars (2006 $224 million in Canadian dollars and $76 million in Trinidad & Tobago 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 $27 million (2006 $30 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 described as interest rate 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 US dollar exposure with an overall profile of one-third fixed rate to two-thirds floating rate. The proportion of floating rate debt net of interest rate swaps at 31 December 2007 was 68% of total finance debt outstanding (2006 73%). The weighted average interest rate on finance debt is 5% (2006 5%).

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 2008, it is estimated that the group s profit before taxation for 2008 would decrease by approximately $168 million (2006 $180 million). 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 2007 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 an overall reduction in economic activity that could accompany such an increase in interest rates.

### *(iv) Equity price risk*

The group holds equity investments that are classified as non-current available-for-sale financial assets and are measured initially at fair value with changes in fair value recognized directly in equity. On disposal, accumulated fair value changes are recycled to the income statement. Such investments are typically made for strategic purposes. At 31 December 2007, it is estimated that a change of 10% in equity prices would result in an immediate charge or credit to equity of $162 million (2006 $152 million).

At 31 December 2007, 70% of the carrying amount of non-current available-for-sale financial assets represented one equity investment, thus the group s exposure is concentrated on changes in the share prices of this equity in particular. For further information see Note 29.

### (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.

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## 28 Financial instruments and financial risk factors *continued*

The group has a credit policy, approved by the CFO, that is designed to ensure that consistent processes are in place throughout the group to measure and control credit risk. Credit risk is considered as part of the risk-reward balance of doing business. On entering into any business contract the extent to which the arrangement exposes the group to credit risk is considered. Key requirements of the policy 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.

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 the group by the counterparty, together with external credit ratings, if any, including ratings prepared by Moody s Investor Service and Standard & Poor s. Creditworthiness continues to be evaluated after transactions have been initiated and a watchlist of higher-risk counterparties is maintained. Once assigned a credit rating, each counterparty is allocated a maximum exposure limit.

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 and other 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 2007, the maximum credit exposure was $53,498 million (2006 $55,420 million). This does not take into account collateral held of $474 million (2006 $689 million). In addition, credit exposure exists in relation to guarantees issued by group companies under which amounts outstanding at 31 December 2007 were $443 million (2006 $1,123 million) in respect of liabilities of jointly controlled entities and associates and $601 million (2006 $789 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.

It is estimated that over 80% of the counterparties to the contracts comprising the derivative financial instruments in an asset position are of investment grade credit quality.

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 65-70% of the trade receivables portfolio exposure are of investment grade 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 2007 or 31 December 2006.

| | | $ million |
|---|---|---|
| Trade and other receivables at 31 December | **2007** | 2006 |
| Neither impaired nor past due | **35,167** | 34,737 |
| Impaired (net of valuation allowance) | **145** | 101 |
| Not impaired and past due in the following periods | | |
| within 30 days | **2,350** | 2,404 |

| | | |
|---|---|---|
| 31 to 60 days | **273** | 475 |
| 61 to 90 days | **311** | 253 |
| over 90 days | **464** | 504 |
| | **38,710** | 38,474 |

The movement in the valuation allowance for trade receivables is set out below.

| | | $ million |
|---|---|---|
| | **2007** | 2006 |
| At 1 January | **421** | 374 |
| Exchange adjustments | **34** | 32 |
| Charge for the year | **175** | 158 |
| Utilization | **(224)** | (143) |
| At 31 December | **406** | 421 |

## 28 Financial instruments and financial risk factors *continued*

### (c) Liquidity risk

Liquidity risk is the risk that suitable sources of funding for the group s business activities may not be available. The group s liquidity is managed centrally with operating units forecasting their cash and currency requirements to the central treasury function. Unless restricted by local regulations, subsidiaries pool their cash surpluses to treasury, which will then arrange to fund other subsidiaries requirements, or invest any net surplus in the market or arrange for necessary external borrowings, while managing the group s overall net currency positions.

In managing its liquidity risk, the group has access to a wide range of funding at competitive rates through capital markets and banks. The group s treasury function centrally co-ordinates relationships with banks, borrowing requirements, foreign exchange requirements and cash management. The group believes it has access to sufficient funding through the commercial paper markets and by using undrawn committed borrowing facilities to meet foreseeable borrowing requirements. At, 31 December 2007, the group had substantial amounts of undrawn borrowing facilities available, including committed facilities of $4,950 million, of which $4,550 million are in place for at least four years (2006 $4,700 million of which $4,300 million are in place for at least five years). 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 $15 billion of debt for maturities of one month or longer. At 31 December 2007, the amount drawn down against the DIP was $10,438 million (2006 $7,893 million). In addition, the group has in place a US Shelf Registration under which it may raise $10 billion of debt with maturities of one month or longer. At 31 December 2007, the amount drawn down under the US Shelf was $2,500 million (2006 nil).

The group has long-term debt ratings of Aa1 (stable outlook) and AA+ (negative outlook), assigned respectively by Moody s and Standard and Poor s.

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.

There are amounts included within finance debt that we show in the table below as due within one year to reflect the earliest contractual repayment dates but that are expected to be repaid over the maximum long-term maturity profiles of the contracts as described in Note 35. US Industrial Revenue/Municipal Bonds of $2,880 million (2006 $2,744 million) with earliest contractual repayment dates within one year have expected repayment dates ranging from 1 to 35 years (2006 1 to 34 years). The bondholders typically have the option to tender these bonds for repayment on interest reset dates; however, any bonds that are tendered are usually remarketed and BP has not experienced any significant repurchases. BP considers these bonds to represent long-term funding when internally assessing the maturity profile of its finance debt. Similar treatment is applied for loans associated with long-term gas supply contracts totalling $1,899 million (2006 $1,976 million) that mature over 10 years.

The table also shows the timing of cash outflows relating to trade and other payables and accruals.

| | | | | | | $ million |
|---|---|---|---|---|---|---|
| | | | **2007** | | | 2006 |
| | **Trade and other payables** | **Accruals** | **Finance debt** | Trade and other payables | Accruals | Finance debt |
| Within one year | **39,576** | **6,640** | **16,561** | 37,696 | 6,147 | 13,864 |
| 1 to 2 years | **147** | **351** | **8,011** | 100 | 349 | 4,146 |
| 2 to 3 years | **62** | **245** | **3,515** | 80 | 227 | 4,354 |
| 3 to 4 years | **26** | **78** | **1,447** | 57 | 81 | 723 |
| 4 to 5 years | **30** | **49** | **2,352** | 68 | 61 | 776 |
| 5 to 10 years | **197** | **200** | **1,100** | 226 | 240 | 1,778 |
| Over 10 years | **24** | **36** | **1,447** | | 3 | 1,650 |
| | **40,062** | **7,599** | **34,433** | 38,227 | 7,108 | 27,291 |

The group manages liquidity risk associated with derivative contracts on a portfolio basis, considering both physical commodity sale and purchase contracts together with financially-settled derivative assets and liabilities.

The held-for-trading derivatives amounts in the table below represent the total contractual cash outflows by period for the purchases of physical commodities under derivative contracts and the estimated cash outflows of financially-settled derivative liabilities. The group also holds derivative contracts for the sale of physical commodities and financially-settled derivative assets that are expected to generate cash inflows that will be available to the group to meet cash outflows on purchases and liabilities. These contracts are excluded from the table below. The amounts disclosed for embedded derivatives represent the contractual cash outflows of purchase contracts. The embedded derivatives associated with these contracts are all financial assets. There are no cash outflows associated with embedded derivatives that are financial liabilities because these are all related to sales contracts.

| | | | | $ million |
|---|---|---|---|---|
| | | **2007** | | 2006 |
| | **Embedded derivatives** | **Held-for-trading derivatives** | Embedded derivatives | Held-for-trading derivatives |
| Within one year | **699** | **82,465** | 707 | 68,369 |
| 1 to 2 years | **659** | **8,541** | 602 | 8,535 |
| 2 to 3 years | **641** | **2,906** | 472 | 2,852 |
| 3 to 4 years | **627** | **707** | 483 | 913 |
| 4 to 5 years | **624** | **338** | 490 | 413 |
| 5 to 10 years | **2,342** | **592** | 2,335 | 1,626 |
| Over 10 years | | **447** | | 280 |
| | **5,592** | **95,996** | **5,089** | 82,988 |

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## 28 Financial instruments and financial risk factors *continued*

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 to 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.

| | | $ million |
|---|---|---|
| | **2007** | 2006 |
| Within one year | **1,708** | 1,228 |
| 1 to 2 years | **1,220** | 1,711 |
| 2 to 3 years | **3,759** | 2,772 |
| 3 to 4 years | **365** | 117 |
| 4 to 5 years | **1,650** | |
| 5 to 10 years | **105** | 220 |
| Over 10 years | | |
| | **8,807** | 6,048 |

## 29 Other investments

| | | $ million |
|---|---|---|
| | **2007** | 2006 |
| Listed | **1,617** | 1,516 |
| Unlisted | **213** | 181 |
| | **1,830** | 1,697 |

Other 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.

The fair value of listed investments has been determined by reference to quoted market bid prices. Unlisted investments are stated at cost less accumulated impairment losses.

The most significant investment is the group s stake in Rosneft which had a fair value of $1,285 million at 31 December 2007.

## 30 Inventories

| | | $ million |
|---|---|---|
| | **2007** | 2006 |
| Crude oil | **8,157** | 5,357 |
| Natural gas | **160** | 127 |
| Refined petroleum and petrochemical products | **14,723** | 10,817 |

| | | |
|---|---|---|
| | **23,040** | 16,301 |
| Supplies | **1,517** | 1,222 |
| | **24,557** | 17,523 |
| Trading inventories | **1,997** | 1,392 |
| | **26,554** | 18,915 |
| Cost of inventories expensed in the income statement | **200,766** | 187,183 |

## 31 Trade and other receivables

$ million

Trade and other receivables are predominantly non-interest bearing.

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## 32 Cash and cash equivalents

$ million

| | 2007 | 2006 |
|---|---|---|
| Cash at bank and in hand | **2,996** | 2,052 |
| Cash equivalents | | |
| Listed | **3** | 29 |
| Unlisted | **563** | 509 |
| | **3,562** | 2,590 |

Cash and cash equivalents comprise cash in hand; current balances 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.

Cash and cash equivalents at 31 December 2007 includes $1,294 million (2006 $773 million) that is restricted. This relates principally to amounts on deposit to cover initial margins on trading exchanges.

## 33 Trade and other payables

$ million

| | 2007 | | 2006 | |
|---|---|---|---|---|
| | **Current** | **Non-current** | Current | Non-current |
| Financial liabilities | | | | |
| Trade payables | **30,735** | | 28,319 | |
| Amounts payable to jointly controlled entities | **66** | | 119 | |
| Amounts payable to associates | **650** | | 273 | |
| Other payables | **8,125** | **486** | 8,985 | 531 |
| | **39,576** | **486** | 37,696 | 531 |
| Non-financial liabilities | | | | |
| Production and similar taxes | **803** | **765** | 852 | 899 |
| Other payables | **2,773** | | 3,688 | |
| | **3,576** | **765** | 4,540 | 899 |
| | **43,152** | **1,251** | 42,236 | 1,430 |

Trade and other payables are predominantly interest free.

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## 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 28.

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 profit or loss.

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.

The fair values of derivative financial instruments at 31 December are set out below.

| | | | | $ million |
|---|---|---|---|---|
| | | **2007** | | 2006 |
| | **Fair value asset** | **Fair value liability** | Fair value asset | Fair value liability |
| Derivatives held for trading | | | | |
| Currency derivatives | **147** | **(317)** | 137 | (32) |
| Oil price derivatives | **3,214** | **(3,432)** | 2,664 | (2,368) |
| Natural gas price derivatives | **4,388** | **(4,022)** | 6,558 | (5,703) |
| Power price derivatives | **1,121** | **(1,140)** | 3,232 | (3,190) |
| Other derivatives | **30** | | 113 | |
| | **8,900** | **(8,911)** | 12,704 | (11,293) |
| Embedded derivatives | | | | |
| Natural gas and LNG contracts | **255** | **(2,340)** | 107 | (2,171) |
| Interest rate contracts | | **(33)** | | (26) |
| | **255** | **(2,373)** | 107 | (2,197) |
| Cash flow hedges | **348** | **(97)** | 219 | (33) |
| Fair value hedges | | | | |
| Currency forwards, futures and swaps | **430** | **(9)** | 228 | (13) |
| Interest rate swaps | **89** | **(17)** | 33 | (91) |
| | **519** | **(26)** | 261 | (104) |
| Hedges of net investments in foreign operations | **40** | | 107 | |
| | **10,062** | **(11,407)** | 13,398 | (13,627) |
| Of which current | **6,321** | **(6,405)** | 10,373 | (9,424) |

| | | | | |
|---|---|---|---|---|
| non-current | **3,741** | **(5,002)** | 3,025 | (4,203) |

## 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 28.

The following tables show further information on the fair value of derivatives and other financial instruments held for trading purposes. The fair values at the year end are not materially unrepresentative of the position throughout the year.

Changes during the year in the net fair value of derivatives held for trading purposes were as follows.

$ million

| | **Currency** | **Oil price** | **Natural gas price** | **Power price** | **Other** |
|---|---|---|---|---|---|
| Fair value of contracts at 1 January 2007 | **105** | **296** | **855** | **42** | **113** |
| Contracts realized or settled in the year | **(109)** | **(289)** | **(602)** | **(68)** | **(83)** |
| Fair value of options at inception | | **28** | **168** | **36** | |
| Fair value of other new contracts entered into during the year | | | **1** | | |
| Changes in fair values relating to price | **(167)** | **(253)** | **(58)** | **(20)** | |
| Exchange adjustments | **1** | | **2** | **(9)** | |
| Fair value of contracts at 31 December 2007 | **(170)** | **(218)** | **366** | **(19)** | **30** |

$ million

| | Currency | Oil price | Natural gas price | Power price | Other |
|---|---|---|---|---|---|
| Fair value of contracts at 1 January 2006 | 23 | (61) | 529 | 183 | |
| Contracts realized or settled in the year | (16) | 85 | (327) | (37) | (106) |
| Fair value of options at inception | | 36 | 247 | (70) | 45 |
| Fair value of other new contracts entered into during the year | | | 2 | 1 | |
| Change in fair value due to changes in valuation techniques or key assumptions | | 1 | | | |
| Changes in fair values relating to price | 98 | 231 | 421 | (22) | 174 |
| Exchange adjustments | | 4 | (17) | (13) | |
| Fair value of contracts at 31 December 2006 | 105 | 296 | 855 | 42 | 113 |

If at inception of a contract the valuation cannot be supported by observable market data, any gain 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 . This deferred gain 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 is recognized in income. Changes in valuation from this initial valuation are recognized immediately through income.

## 34 Derivative financial instruments *continued*

The following table shows the changes in the day-one profits deferred on the balance sheet.

| | | | | $ million |
|---|---|---|---|---|
| | **2007** | | 2006 | |
| | **Natural gas price** | **Power price** | Natural gas price | Power price |
| Fair value of contracts not recognized through the income statement at 1 January | **36** | | 39 | 10 |
| Fair value of new contracts at inception not recognized in the income statement | **1** | | 2 | 1 |
| Fair value recognized in the income statement | **(1)** | | (5) | (11) |
| Fair value of contracts not recognized through profit at 31 December | **36** | | 36 | |

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

| | | | | | | | $ million |
|---|---|---|---|---|---|---|---|
| | | | | | | | **2007** |
| | **Less than 1 year** | **1-2 years** | **2-3 years** | **3-4 years** | **4-5 years** | **Over 5 years** | **Total** |
| Currency derivatives | **123** | **10** | **6** | **5** | **1** | **2** | **147** |
| Oil price derivatives | **2,545** | **471** | **113** | **39** | **26** | **20** | **3,214** |
| Natural gas price derivatives | **2,170** | **677** | **333** | **283** | **216** | **709** | **4,388** |
| Power price derivatives | **819** | **250** | **52** | | | | **1,121** |
| Other derivatives | **12** | **18** | | | | | **30** |
| | **5,669** | **1,426** | **504** | **327** | **243** | **731** | **8,900** |

| | | | | | | | $ million |
|---|---|---|---|---|---|---|---|
| | | | | | | | 2006 |
| | Less than 1 year | 1-2 years | 2-3 years | 3-4 years | 4-5 years | Over 5 years | Total |
| Currency derivatives | 117 | | 12 | 3 | 2 | 3 | 137 |
| Oil price derivatives | 2,520 | 116 | 20 | 7 | 1 | | 2,664 |
| Natural gas price derivatives | 4,532 | 919 | 374 | 166 | 114 | 453 | 6,558 |
| Power price derivatives | 2,845 | 274 | 86 | 27 | | | 3,232 |
| Other derivatives | 64 | 26 | 23 | | | | 113 |
| | 10,078 | 1,335 | 515 | 203 | 117 | 456 | 12,704 |

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

$ million

**2007**

| | **Less than 1 year** | **1-2 years** | **2-3 years** | **3-4 years** | **4-5 years** | **Over 5 years** | **Total** |
|---|---|---|---|---|---|---|---|
| Currency derivatives | **(145)** | **(99)** | **(32)** | **(16)** | **(15)** | **(10)** | **(317)** |
| Oil price derivatives | **(2,735)** | **(512)** | **(135)** | **(25)** | **(22)** | **(3)** | **(3,432)** |
| Natural gas price derivatives | **(2,089)** | **(527)** | **(298)** | **(219)** | **(185)** | **(704)** | **(4,022)** |
| Power price derivatives | **(832)** | **(246)** | **(61)** | **(1)** | | | **(1,140)** |
| | **(5,801)** | **(1,384)** | **(526)** | **(261)** | **(222)** | **(717)** | **(8,911)** |

$ million

2006

| | Less than 1 year | 1-2 years | 2-3 years | 3-4 years | 4-5 years | Over 5 years | Total |
|---|---|---|---|---|---|---|---|
| Currency derivatives | (8) | (7) | (12) | (2) | (2) | (1) | (32) |
| Oil price derivatives | (2,230) | (89) | (29) | (19) | (1) | | (2,368) |
| Natural gas price derivatives | (3,931) | (875) | (273) | (109) | (86) | (429) | (5,703) |
| Power price derivatives | (2,777) | (289) | (98) | (26) | | | (3,190) |
| | (8,946) | (1,260) | (412) | (156) | (89) | (430) | (11,293) |

## 34 Derivative financial instruments *continued*

The following tables show the net fair value of derivatives held for trading at 31 December analysed by maturity period and by methodology of fair value estimation.

$ million

| | | | | | | | **2007** |
|---|---|---|---|---|---|---|---|
| | **Less than 1 year** | **1-2 years** | **2-3 years** | **3-4 years** | **4-5 years** | **Over 5 years** | **Total** |
| Prices actively quoted | **119** | **3** | **49** | **2** | **(9)** | **1** | **165** |
| Prices sourced from observable data or market corroboration | **(212)** | **58** | **(57)** | **82** | **37** | | **(92)** |
| Prices based on models and other valuation methods | **(39)** | **(19)** | **(14)** | **(18)** | **(7)** | **13** | **(84)** |
| | **(132)** | **42** | **(22)** | **66** | **21** | **14** | **(11)** |

$ million

| | | | | | | | 2006 |
|---|---|---|---|---|---|---|---|
| | Less than 1 year | 1-2 years | 2-3 years | 3-4 years | 4-5 years | Over 5 years | Total |
| Prices actively quoted | 191 | 62 | 60 | 33 | | 2 | 348 |
| Prices sourced from observable data or market corroboration | 911 | 29 | 54 | 19 | 36 | 4 | 1,053 |
| Prices based on models and other valuation methods | 30 | (14) | (12) | (6) | (8) | 20 | 10 |
| | 1,132 | 77 | 102 | 46 | 28 | 26 | 1,411 |

Prices actively quoted refers to the fair value of contracts valued solely using quoted prices in an active market. Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data, for example, swaps and physical forward contracts. Prices based on models and other valuation methods refers to the fair value of a contract valued in part using internal models due to the absence of quoted prices, including over-the-counter options. The net change in fair value of contracts based on models and other valuation methods during the year was a loss of $94 million (2006 $117 million loss and 2005 $130 million gain).

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 gain of $376 million (2006 $2,842 million gain and 2005 $838 million 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. 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.

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 in 2018 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 data is also an input for the models.

## 34 Derivative financial instruments *continued*

The following table shows the changes during the year in the net fair value of embedded derivatives.

| | | | | $ million |
|---|---|---|---|---|
| | **2007** | | 2006 | |
| | **Natural gas and LNG price** | **Interest rate** | Natural gas and LNG price | Interest rate |
| Fair value of contracts at 1 January | **(2,064)** | **(26)** | (2,511) | (30) |
| Contracts realized or settled in the year | **449** | | 762 | |
| Changes in valuation techniques or key assumptions | **130** | | | |
| Changes in fair values relating to price | **(567)** | **(7)** | 21 | 4 |
| Exchange adjustments | **(33)** | | (336) | |
| Fair value of contracts at 31 December | **(2,085)** | **(33)** | (2,064) | (26) |

Embedded derivative assets have the following fair values and maturities.

| | | | | | | | $ million |
|---|---|---|---|---|---|---|---|
| | | | | | | | **2007** |
| | **Less than 1 year** | **1-2 years** | **2-3 years** | **3-4 years** | **4-5 years** | **Over 5 years** | **Total** |
| Natural gas and LNG embedded derivatives | **193** | **18** | **15** | **7** | **10** | **12** | **255** |

| | | | | | | | $ million |
|---|---|---|---|---|---|---|---|
| | | | | | | | 2006 |
| | Less than 1 year | 1-2 years | 2-3 years | 3-4 years | 4-5 years | Over 5 years | Total |
| Natural gas and LNG embedded derivatives | 49 | 58 | | | | | 107 |

Embedded derivative liabilities have the following fair values and maturities.

| | | | | | | | $ million |
|---|---|---|---|---|---|---|---|
| | | | | | | | **2007** |
| | **Less than 1 year** | **1-2 years** | **2-3 years** | **3-4 years** | **4-5 years** | **Over 5 years** | **Total** |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Natural gas and LNG embedded derivatives | **(554)** | **(437)** | **(299)** | **(244)** | **(219)** | **(587)** | **(2,340)** |
| Interest rate embedded derivatives | **(33)** | | | | | | **(33)** |
| | **(587)** | **(437)** | **(299)** | **(244)** | **(219)** | **(587)** | **(2,373)** |

$ million

| | | | | | | | 2006 |
|---|---|---|---|---|---|---|---|
| | Less than 1 year | 1-2 years | 2-3 years | 3-4 years | 4-5 years | Over 5 years | Total |
| Natural gas and LNG embedded derivatives | (444) | (433) | (320) | (218) | (186) | (570) | (2,171) |
| Interest rate embedded derivatives | | (26) | | | | | (26) |
| | (444) | (459) | (320) | (218) | (186) | (570) | (2,197) |

The following tables show the net fair value of embedded derivatives at 31 December analysed by maturity period and by methodology of fair value estimation.

$ million

| | | | | | | | **2007** |
|---|---|---|---|---|---|---|---|
| | **Less than 1 year** | **1-2 years** | **2-3 years** | **3-4 years** | **4-5 years** | **Over 5 years** | **Total** |
| Prices actively quoted | | | | | | | |
| Prices sourced from observable data or market corroboration | **61** | | | | | | **61** |
| Prices based on models and other valuation methods | **(455)** | **(419)** | **(284)** | **(237)** | **(209)** | **(575)** | **(2,179)** |
| | **(394)** | **(419)** | **(284)** | **(237)** | **(209)** | **(575)** | **(2,118)** |

$ million

| | | | | | | | 2006 |
|---|---|---|---|---|---|---|---|
| | Less than 1 year | 1-2 years | 2-3 years | 3-4 years | 4-5 years | Over 5 years | Total |
| Prices actively quoted | | | | | | | |
| Prices sourced from observable data or market corroboration | 49 | 58 | | | | | 107 |
| Prices based on models and other valuation methods | (444) | (459) | (320) | (218) | (186) | (570) | (2,197) |
| | (395) | (401) | (320) | (218) | (186) | (570) | (2,090) |

The net change in fair value of contracts based on models and other valuation methods during the year is a gain of $18 million (2006 gain of $423 million and 2005 loss of $1,773 million).

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## 34 Derivative financial instruments *continued*

The fair value gain (loss) on embedded derivatives is shown below.

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Natural gas and LNG embedded derivatives | | 604 | (2,034) |
| Interest rate embedded derivatives | **(7)** | 4 | (13) |
| Fair value gain (loss) | **(7)** | 608 | (2,047) |

The fair value gain (loss) in the above table includes $12 million of exchange losses (2006 $179 million of exchange losses and 2005 $115 million of exchange gains) arising on contracts that are denominated in a currency other than the functional currency of the individual operating unit.

### Cash flow hedges

At 31 December 2007, the group held futures currency 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 28 outlines the management of risk aspects for currency and interest rate risk. For cash flow hedges the group only claims for the intrinsic value on the currency with any fair value attributable to time value taken immediately to profit or loss. 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 $74 million (2006 $93 million and 2005 $36 million loss). Of this, a gain of $143 million is included in production and manufacturing expenses (2006 $162 million gain and 2005 $33 million gain) and a loss of $69 million is included in finance costs (2006 $69 million loss and 2005 $69 million loss). The amount removed from equity during the period and included in the carrying amount of non-financial assets was a gain of $40 million (2006 $6 million gain and nil for 2005).

The amounts retained in equity at 31 December 2007 are expected to mature and affect the income statement by a $48 million gain in 2008, a loss of $10 million in 2009 and a gain of $28 million in 2010 and beyond.

### Fair value hedges

At 31 December 2007, the group held interest rate and currency swap contracts as fair value hedges of the interest rate risk on fixed rate debt issued by the group. The receive leg of the swap contracts is largely identical for all critical aspects to the terms of the underlying debt and thus the hedging is highly effective. The gain on the hedging derivative instruments taken to the income statement in 2007 was $334 million (2006 $257 million) offset by a loss on the fair value of the finance debt of $327 million (2006 $257 million loss).

The interest rate and currency swaps have an average maturity of one to two years, (2006 two to three years) and are used to convert sterling, euro, Swiss franc and Australian dollar denominated borrowings into US dollar floating rate debt. Note 28 outlines the group s approach to interest rate risk management.

### Hedges of net investments in foreign operations

The group holds currency swap contracts as a hedge of a long-term investment in a UK subsidiary expiring in 2009. At 31 December 2007, the hedge had a fair value of $40 million (2006 $107 million) and the loss on the hedge recognized in equity in 2007 was $67 million (2006 $105 million gain, 2005 $58 million gain). US dollars have been sold forward for sterling purchased and match the underlying liability with no significant ineffectiveness reflected in the income statement.

## 35 Finance debt

$ million

| | **2007** | | | 2006 | | |
|---|---|---|---|---|---|---|
| | **Within 1 year[a]** | **After 1 year** | **Total** | Within 1 year[a] | After 1 year | Total |
| Bank loans | **542** | **978** | **1,520** | 543 | 806 | 1,349 |
| Other loans | **14,607** | **14,026** | **28,633** | 12,321 | 9,525 | 21,846 |
| Total borrowings | **15,149** | **15,004** | **30,153** | 12,864 | 10,331 | 23,195 |
| Net obligations under finance leases | **245** | **647** | **892** | 60 | 755 | 815 |
| | **15,394** | **15,651** | **31,045** | 12,924 | 11,086 | 24,010 |

[a] Amounts due within one year include current maturities of long-term debt and borrowings that are expected to be repaid later than the earliest contractual repayment dates of within one year. US Industrial Revenue/Municipal Bonds of $2,880 million (2006 $2,744 million) with earliest contractual repayment dates within one year have expected repayment dates ranging from 1 to 35 years (2006 1 to 34 years). The bondholders typically have the option to tender these bonds for repayment on interest reset dates; however, any bonds that are tendered are usually remarketed and BP has not experienced any significant repurchases. BP considers these bonds to represent long-term funding when internally assessing the maturity profile of its finance debt. Similar treatment is applied for loans associated with long-term gas supply contracts totalling $1,899 million (2006 $1,976 million) that mature over 10 years.

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## 35 Finance debt *continued*

The following table shows, by major currency, the group s finance debt at 31 December 2007 and 2006 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.

| | Fixed rate debt | | | Floating rate debt | | |
|---|---|---|---|---|---|---|
| | **Weighted average interest rate %** | **Weighted average time for which rate is fixed Years** | **Amount $ million** | **Weighted average interest rate %** | **Amount $ million** | **Total $ million** |
| | | | | | | **2007** |
| US dollar | **5** | **2** | **9,541** | **5** | **20,460** | **30,001** |
| Sterling | | | | **6** | **35** | **35** |
| Euro | **4** | **4** | **81** | **5** | **107** | **188** |
| Other currencies | **7** | **13** | **268** | **7** | **553** | **821** |
| | | | **9,890** | | **21,155** | **31,045** |
| | | | | | | 2006 |
| US dollar | 5 | 3 | 5,998 | 6 | 17,055 | 23,053 |
| Sterling | | | | 5 | 35 | 35 |
| Euro | 3 | 8 | 61 | 4 | 134 | 195 |
| Other currencies | 7 | 8 | 299 | 8 | 428 | 727 |
| | | | 6,358 | | 17,652 | 24,010 |

### 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 |
|---|---|---|
| | **2007** | 2006 |
| Future minimum lease payments payable within | | |
| 1 year | **268** | 82 |
| 2 to 5 years | **393** | 376 |
| Thereafter | **630** | 873 |
| | **1,291** | 1,331 |
| Less finance charges | **399** | 516 |

| | | | |
|---|---|---|---|
| Net obligations | | **892** | 815 |
| Of which | payable within 1 year | **245** | 60 |
| | payable within 2 to 5 years | **217** | 164 |
| | payable thereafter | **430** | 591 |

## 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 2007, whereas in the balance sheet the amount would be reported as current liabilities.

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

| | **2007** | | 2006 | |
|---|---|---|---|---|
| | **Fair value** | **Carrying amount** | Fair value | Carrying amount |
| Short-term borrowings | **11,212** | **11,212** | 9,661 | 9,661 |
| Long-term borrowings | **19,094** | **18,941** | 13,580 | 13,534 |
| Net obligations under finance leases | **908** | **892** | 832 | 815 |
| Total finance debt | **31,214** | **31,045** | 24,073 | 24,010 |

## 36 Capital disclosures and analysis of changes in net debt

The group defines capital as the total equity of the group. The group s objective for managing capital is to deliver competitive, secure and sustainable returns to maximize long-term shareholder value. BP is not subject to any externally-imposed capital requirements.

The group s approach to managing capital is set out in its financial framework. The group aims to maintain capital discipline in relation to investing activities while progressively growing the dividend per share. A managed share buyback programme is used to return to shareholders all sustainable free cash flow in excess of the group s investment and dividend needs. From 2008, the group intends to rebalance returns to shareholders by increasing the dividend component. As a result, the level of free cash flow allocated to share buybacks is likely to be lower; however, we will continue to use share buybacks as a mechanism to return excess cash to shareholders when appropriate.

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, less cash and cash equivalents. All components of equity are included in the denominator of the calculation. We believe that a net debt ratio in the range 20-30% provides an efficient capital structure and an appropriate level of financial flexibility.

At 31 December 2007 the net debt ratio was 23% (2006 20%).

$ million

| | **2007** | 2006 |
|---|---|---|
| Gross debt | **31,045** | 24,010 |
| Cash and cash equivalents | **3,562** | 2,590 |
| Net debt | **27,483** | 21,420 |
| Equity | **94,652** | 85,465 |
| Net debt ratio | **23%** | 20% |

An analysis of changes in net debt is provided below.

$ million

| | 2007 | | | 2006 | | |
|---|---|---|---|---|---|---|
| Movement in net debt | **Finance debt** | **Cash and cash equivalents** | **Net debt** | Finance debt | Cash and cash equivalents | Net debt |
| At 1 January | **(24,010)** | **2,590** | **(21,420)** | (19,162) | 2,960 | (16,202) |
| Exchange adjustments | **(122)** | **135** | **13** | (172) | 47 | (125) |
| Debt acquired | | | | (13) | | (13) |
| Net cash flow | **(6,411)** | **837** | **(5,574)** | (4,049) | (417) | (4,466) |
| Fair value hedge adjustment | **(368)** | | **(368)** | (581) | | (581) |
| Other movements | **(134)** | | **(134)** | (33) | | (33) |
| At 31 December | **(31,045)** | **3,562** | **(27,483)** | (24,010) | 2,590 | (21,420) |
| Equity | | | **94,652** | | | 85,465 |

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## 37 Provisions

$ million

| | | Decommissioning | Environmental | Litigation and other | Total |
|---|---|---|---|---|---|
| At 1 January 2007 | | **8,365** | **2,127** | **3,152** | **13,644** |
| Exchange adjustments | | **168** | **19** | **11** | **198** |
| New or increased provisions | | **1,163** | **373** | **1,376** | **2,912** |
| Write-back of unused provisions | | | **(151)** | **(196)** | **(347)** |
| Unwinding of discount | | **195** | **44** | **44** | **283** |
| Utilization | | **(297)** | **(305)** | **(899)** | **(1,501)** |
| Deletions | | **(93)** | | **(1)** | **(94)** |
| At 31 December 2007 | | **9,501** | **2,107** | **3,487** | **15,095** |
| Of which | expected to be incurred within 1 year | **447** | **431** | **1,317** | **2,195** |
| | expected to be incurred in more than 1 year | **9,054** | **1,676** | **2,170** | **12,900** |

$ million

| | | Decommissioning | Environmental | Litigation and other | Total |
|---|---|---|---|---|---|
| At 1 January 2006 | | 6,450 | 2,311 | 2,795 | 11,556 |
| Exchange adjustments | | 13 | 31 | 44 | 88 |
| New or increased provisions | | 2,142 | 423 | 1,611 | 4,176 |
| Write-back of unused provisions | | | (355) | (270) | (625) |
| Unwinding of discount | | 153 | 45 | 47 | 245 |
| Utilization | | (179) | (324) | (1,068) | (1,571) |
| Deletions | | (214) | (4) | (7) | (225) |
| At 31 December 2006 | | 8,365 | 2,127 | 3,152 | 13,644 |
| Of which | expected to be incurred within 1 year | 324 | 444 | 1,164 | 1,932 |
| | expected to be incurred in more than 1 year | 8,041 | 1,683 | 1,988 | 11,712 |

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 and discounted using a real discount rate of 2.0% (2006 2.0%) . 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 incurring these costs.

Provisions for environmental remediation are made when a clean-up is probable and the amount is reliably determinable. Generally, this coincides with commitment to a formal plan of action or, if earlier, on divestment or 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 2.0% (2006 2.0%) . 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.

Included within the litigation and other category at 31 December 2007 are provisions for litigation of $1,737 million (2006 $1,474 million) for deferred employee compensation of $761 million (2006 $760 million) and provisions for expected rental shortfalls on surplus properties of $320 million (2006 $320 million). New or increased provisions made for 2007 included an amount of $500 million (2006 $425 million) in respect of the Texas City incident, of which, disbursements to claimants in 2007 were $314 million (2006 $863 million) and the provision at 31 December 2007 was $456 million (2006 $270 million).

To the extent that these liabilities are not expected to be settled within the next three years, the provisions are discounted using either a nominal discount rate of 4.5% (2006 4.5%) or a real discount rate of 2.0% (2006 2.0%), as appropriate.

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## 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 that remains open to new employees. Retired employees draw the majority of their benefit as an annuity.

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 2007, contributions of $524 million (2006 $438 million and 2005 $340 million) and $97 million (2006 $181 million and 2005 $279 million) were made to the UK plans and US plans respectively. In addition, contributions of $127 million (2006 $136 million and 2005 $140 million) were made to other funded defined benefit plans. The aggregate level of contributions in 2008 is expected to be approximately $500 million.

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 2007.

The material financial assumptions used for estimating the benefit obligations of the various plans are set out below. The assumptions used to evaluate accrued pension and other post-retirement benefits at 31 December in any year are used to determine pension and other post-retirement expense for the following year, that is, the assumptions at 31 December 2007 are used to determine the pension liabilities at that date and the pension cost for 2008.

| | | | | | | | | | % |
|---|---|---|---|---|---|---|---|---|---|
| Financial assumptions | | | UK | | | US | | | Other |
| | **2007** | 2006 | 2005 | **2007** | 2006 | 2005 | **2007** | 2006 | 2005 |
| Discount rate for pension plan liabilities | **5.7** | 5.1 | 4.75 | **6.1** | 5.7 | 5.50 | **5.6** | 4.8 | 4.00 |
| Discount rate for post-retirement benefit plans | **n/a** | n/a | n/a | **6.4** | 5.9 | 5.50 | **n/a** | n/a | n/a |
| Rate of increase in salaries[a] | **5.1** | 4.7 | 4.25 | **4.2** | 4.2 | 4.25 | **3.7** | 3.6 | 3.25 |
| Rate of increase for pensions in payment | **3.2** | 2.8 | 2.50 | | | | **1.8** | 1.8 | 1.75 |
| Rate of increase in deferred pensions | **3.2** | 2.8 | 2.50 | | | | **1.2** | 1.1 | 1.00 |
| Inflation | **3.2** | 2.8 | 2.50 | **2.4** | 2.4 | 2.50 | **2.2** | 2.2 | 2.00 |

[a] This assumption includes an 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. 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 assumptions are as follows:

| Mortality assumptions | UK | | | US | | | Germany | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | Years |
| | **2007** | 2006 | 2005 | **2007** | 2006 | 2005 | **2007** | 2006 | 2005 |
| Life expectancy at age 60 for a male currently aged 60 | **24.0** | 23.9 | 23.0 | **24.3** | 24.2 | 21.9 | **22.4** | 22.2 | 22.1 |
| Life expectancy at age 60 for a female currently aged 60 | **26.9** | 26.8 | 26.0 | **26.1** | 26.0 | 25.6 | **27.0** | 26.9 | 26.7 |
| Life expectancy at age 60 for a male currently aged 40 | **25.1** | 25.0 | 23.9 | **25.8** | 25.8 | 21.9 | **25.3** | 25.2 | 25.0 |
| Life expectancy at age 60 for a female currently aged 40 | **27.9** | 27.8 | 26.9 | **27.0** | 26.9 | 25.6 | **29.7** | 29.6 | 29.4 |

The assumed future US healthcare cost trend rate is as follows:

| | | | % |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Initial US healthcare cost trend rate | **9.0** | 9.3 | 10.3 |
| Ultimate US healthcare cost trend rate | **5.0** | 5.0 | 5.0 |
| Year in which ultimate trend rate is reached | **2013** | 2013 | 2013 |

Pension plan assets are generally held in trusts. The primary objective of the trusts is to accumulate pools of assets sufficient to meet the obligation 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.

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## 38 Pensions and other post-retirement benefits *continued*

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:

| Asset category | Policy range % |
|---|---|
| Total equity | 55-85 |
| Fixed income/cash | 15-35 |
| Property/real estate | 0-10 |

Some of the group s pension funds use derivatives as part of their asset mix and to manage the level of risk. The group s main pension funds do not directly invest 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.

The expected long-term rates of return and market values of the various categories of asset held by the defined benefit plans at 31 December are set out below. The market values shown include the effects of derivative financial instruments.

| | **2007** | | 2006 | | 2005 | |
|---|---|---|---|---|---|---|
| | **Expected long-term rate of return** | **Market value** | Expected long-term rate of return | Market value | Expected long-term rate of return | Market value |
| | **%** | **$ million** | % | $ million | % | $ million |
| UK pension plans | | | | | | |
| Equities | **8.0** | **24,106** | 7.5 | 23,631 | 7.50 | 18,465 |
| Bonds | **4.4** | **5,279** | 4.7 | 3,881 | 4.25 | 2,719 |
| Property | **6.5** | **1,259** | 6.5 | 1,370 | 6.50 | 1,097 |
| Cash | **5.6** | **977** | 3.8 | 379 | 3.50 | 1,001 |
| | **7.3** | **31,621** | 7.0 | 29,261 | 7.00 | 23,282 |
| US pension plans | | | | | | |
| Equities | **8.5** | **6,610** | 8.5 | 6,528 | 8.50 | 5,961 |
| Bonds | **5.0** | **1,347** | 5.0 | 1,371 | 4.75 | 1,079 |
| Property | **8.0** | **16** | 8.0 | 15 | 8.00 | 21 |
| Cash | **3.6** | **72** | 3.2 | 41 | 3.00 | 256 |
| | **8.0** | **8,045** | 8.0 | 7,955 | 8.00 | 7,317 |
| US other post-retirement benefit plans | | | | | | |
| Equities | **8.5** | **17** | 8.5 | 19 | 8.50 | 20 |
| Bonds | **5.0** | **6** | 5.0 | 7 | 4.75 | 8 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | **7.6** | **23** | 7.5 | 26 | 7.25 | 28 |
| Other plans | | | | | | |
| Equities | **8.1** | **1,260** | 7.6 | 1,158 | 7.50 | 991 |
| Bonds | **5.0** | **1,491** | 4.6 | 1,199 | 4.00 | 943 |
| Property | **5.7** | **145** | 4.7 | 120 | 5.75 | 130 |
| Cash | **4.2** | **214** | 3.0 | 191 | 1.50 | 216 |
| | **6.4** | **3,110** | 5.8 | 2,668 | 5.50 | 2,280 |

The assumed rate of investment return and discount rate have a significant effect on the amounts reported. A one-percentage point change in these assumptions for the group s plans would have had the following effects:

| | | $ million |
|---|---|---|
| | One-percentage point | |
| | Increase | Decrease |
| Investment return | | |
| Effect on pension and other post-retirement benefit expense in 2008 | (419) | 415 |
| Discount rate | | |
| Effect on pension and other post-retirement benefit expense in 2008 | (84) | 114 |
| Effect on pension and other post-retirement benefit obligation at 31 December 2007 | (5,039) | 6,459 |

The assumed US healthcare cost trend rate has a significant effect on the amounts reported. A one-percentage point change in the assumed US healthcare cost trend rate would have had the following effects:

| | | $ million |
|---|---|---|
| | One-percentage point | |
| | Increase | Decrease |
| Effect on US other post-retirement benefit expense in 2008 | 32 | (26) |
| Effect on US other post-retirement obligation at 31 December 2007 | 358 | (295) |

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## 38 Pensions and other post-retirement benefits *continued*

| | | | | | |
|---|---|---|---|---|---|
| Current service cost[a] | 492 | 227 | 43 | 132 | 894 |
| Past service cost | 5 | 10 | | | 15 |
| Settlement, curtailment and special termination benefits | 36 | | | 2 | 38 |
| Payments to defined contribution plans | | 184 | | 25 | 209 |
| Total operating charge[b] | 533 | 421 | 43 | 159 | 1,156 |

### Analysis of the amount credited (charged) to other finance expense

| | | | | | |
|---|---|---|---|---|---|
| Expected return on plan assets | 2,075 | 613 | 2 | 165 | 2,855 |
| Interest on plan liabilities | (1,198) | (425) | (190) | (390) | (2,203) |
| Other finance income (expense) | 877 | 188 | (188) | (225) | 652 |

### Analysis of the amount recognized in the statement of recognized income and expense

| | | | | | |
|---|---|---|---|---|---|
| Actual return less expected return on pension plan assets | 406 | (28) | | (76) | 302 |
| Change in assumptions underlying the present value of the plan liabilities | 513 | 358 | 137 | 607 | 1,615 |
| Experience gains and losses arising on the plan liabilities | (162) | (27) | 29 | (40) | (200) |
| Actuarial gain recognized in statement of recognized income and expense | 757 | 303 | 166 | 491 | 1,717 |

### Movements in benefit obligation during the year

| | | | | | |
|---|---|---|---|---|---|
| Benefit obligation at 1 January | 23,289 | 7,695 | 3,300 | 8,149 | 42,433 |
| Exchange adjustments | 394 | | | 917 | 1,311 |
| Current service cost[a] | 492 | 227 | 43 | 132 | 894 |
| Past service cost | 5 | 10 | | | 15 |
| Interest cost | 1,198 | 425 | 190 | 390 | 2,203 |
| Curtailment | (7) | | | | (7) |
| Settlement | (3) | | | | (3) |
| Special termination benefits[c] | 46 | | | 2 | 48 |
| Contributions by plan participants | 43 | | | 12 | 55 |
| Benefit payments (funded plans)[d] | (1,085) | (580) | (5) | (182) | (1,852) |
| Benefit payments (unfunded plans)[d] | (3) | (37) | (184) | (379) | (603) |
| Acquisitions | | | | 141 | 141 |
| Disposals | (91) | | | (29) | (120) |
| Actuarial gain on obligation | (351) | (331) | (166) | (567) | (1,415) |
| Benefit obligation at 31 December[a] | 23,927 | 7,409 | 3,178 | 8,586 | 43,100 |

### Movements in fair value of plan assets during the year

| | | | | | |
|---|---|---|---|---|---|
| Fair value of plan assets at 1 January | 29,261 | 7,955 | 26 | 2,668 | 39,910 |
| Exchange adjustments | 488 | | | 316 | 804 |
| Expected return on plan assets[a, e] | 2,075 | 613 | 2 | 165 | 2,855 |

| | | | | | |
|---|---|---|---|---|---|
| Contributions by plan participants | **43** | | | **12** | **55** |
| Contributions by employers (funded plans) | **524** | **97** | | **127** | **748** |
| Benefit payments (funded plans)[d] | **(1,085)** | **(580)** | **(5)** | **(182)** | **(1,852)** |
| Acquisitions | | | | **101** | **101** |
| Disposals | **(91)** | **(12)** | | **(21)** | **(124)** |
| Actuarial gain on plan assets[e] | **406** | **(28)** | | **(76)** | **302** |
| Fair value of plan assets at 31 December | **31,621** | **8,045** | **23** | **3,110** | **42,799** |
| Surplus (deficit) at 31 December | **7,694** | **636** | **(3,155)** | **(5,476)** | **(301)** |
| Represented by | | | | | |
| Asset recognized | **7,818** | **989** | | **107** | **8,914** |
| Liability recognized | **(124)** | **(353)** | **(3,155)** | **(5,583)** | **(9,215)** |
| | **7,694** | **636** | **(3,155)** | **(5,476)** | **(301)** |
| The surplus (deficit) may be analysed between funded and unfunded plans as follows | | | | | |
| Funded | **7,818** | **978** | **(29)** | **(263)** | **8,504** |
| Unfunded | **(124)** | **(342)** | **(3,126)** | **(5,213)** | **(8,805)** |
| | **7,694** | **636** | **(3,155)** | **(5,476)** | **(301)** |
| The defined benefit obligation may be analysed between funded and unfunded plans as follows | | | | | |
| Funded | **(23,803)** | **(7,067)** | **(52)** | **(3,373)** | **(34,295)** |
| Unfunded | **(124)** | **(342)** | **(3,126)** | **(5,213)** | **(8,805)** |
| | **(23,927)** | **(7,409)** | **(3,178)** | **(8,586)** | **(43,100)** |

[a] The costs of managing the fund 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 benefits 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 a restructuring programme in the UK.

[d] The benefit payments amount shown above comprises $2,398 million benefits plus $57 million of fund 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.

At 31 December 2007 reimbursement balances due from or to other companies in respect of pensions amounted to $496 million reimbursement assets (2006 $479 million) and $72 million reimbursement liabilities (2006 $71 million). These balances are not included as part of the pension liability, but are reflected elsewhere in the group balance sheet.

## 38 Pensions and other post-retirement benefits *continued*

$ million

| | | | | | 2006 |
|---|---|---|---|---|---|
| **Analysis of the amount charged to profit before interest and taxation** | UK pension plans | US pension plans | US other post-retirement benefit plans | Other plans | Total |
| Current service cost[a] | 432 | 216 | 42 | 139 | 829 |
| Past service cost | (74) | 38 | | 39 | 3 |
| Settlement, curtailment and special termination benefits | 4 | | | 227 | 231 |
| Payments to defined contribution plans | | 161 | | 16 | 177 |
| Total operating charge[b] | 362 | 415 | 42 | 421 | 1,240 |
| **Analysis of the amount credited (charged) to other finance expense** | | | | | |
| Expected return on plan assets | 1,711 | 564 | 2 | 133 | 2,410 |
| Interest on plan liabilities | (1,006) | (423) | (186) | (325) | (1,940) |
| Other finance income (expense) | 705 | 141 | (184) | (192) | 470 |
| **Analysis of the amount recognized in the statement of recognized income and expense** | | | | | |
| Actual return less expected return on pension plan assets | 1,305 | 521 | | 141 | 1,967 |
| Change in assumptions underlying the present value of the plan liabilities | 114 | 195 | 111 | 352 | 772 |
| Experience gains and losses arising on the plan liabilities | (24) | 17 | 80 | (197) | (124) |
| Actuarial gain recognized in statement of recognized income and expense | 1,395 | 733 | 191 | 296 | 2,615 |
| **Movements in benefit obligation during the year** | | | | | |
| Benefit obligation at 1 January | 20,063 | 7,900 | 3,478 | 7,414 | 38,855 |
| Exchange adjustments | 2,748 | | | 632 | 3,380 |
| Current service cost | 432 | 216 | 42 | 139 | 829 |
| Past service cost | (74) | 38 | | 39 | 3 |
| Interest cost | 1,006 | 423 | 186 | 325 | 1,940 |
| Curtailment | (20) | | | | (20) |
| Settlement | (22) | | | | (22) |
| Special termination benefits[c] | 46 | | | 227 | 273 |

| | | | | | |
|---|---|---|---|---|---|
| Contributions by plan participants | 38 | | | 5 | 43 |
| Benefit payments (funded plans)[d] | (981) | (615) | (4) | (149) | (1,749) |
| Benefit payments (unfunded plans)[d] | | (37) | (211) | (321) | (569) |
| Acquisitions | | | | | |
| Disposals | 143 | (18) | | (7) | 118 |
| Actuarial gain on obligation | (90) | (212) | (191) | (155) | (648) |
| Benefit obligation at 31 December | 23,289 | 7,695 | 3,300 | 8,149 | 42,433 |
| **Movements in fair value of plan assets during the year** | | | | | |
| Fair value of plan assets at 1 January | 23,282 | 7,317 | 28 | 2,280 | 32,907 |
| Exchange adjustments | 3,325 | | | 122 | 3,447 |
| Expected return on plan assets[a, e] | 1,711 | 564 | 2 | 133 | 2,410 |
| Contributions by plan participants | 38 | | | 5 | 43 |
| Contributions by employers (funded plans) | 438 | 181 | | 136 | 755 |
| Benefit payments (funded plans)[d] | (981) | (615) | (4) | (149) | (1,749) |
| Acquisitions | | | | | |
| Disposals | 143 | (13) | | | 130 |
| Actuarial gain on plan assets[e] | 1,305 | 521 | | 141 | 1,967 |
| Fair value of plan assets at 31 December | 29,261 | 7,955 | 26 | 2,668 | 39,910 |
| Surplus (deficit) at 31 December | 5,972 | 260 | (3,274) | (5,481) | (2,523) |
| Represented by | | | | | |
| Asset recognized | 6,089 | 617 | | 47 | 6,753 |
| Liability recognized | (117) | (357) | (3,274) | (5,528) | (9,276) |
| | 5,972 | 260 | (3,274) | (5,481) | (2,523) |
| The surplus (deficit) may be analysed between funded and unfunded plans as follows | | | | | |
| Funded | 6,089 | 601 | (30) | (379) | 6,281 |
| Unfunded | (117) | (341) | (3,244) | (5,102) | (8,804) |
| | 5,972 | 260 | (3,274) | (5,481) | (2,523) |
| The defined benefit obligation may be analysed between funded and unfunded plans as follows | | | | | |
| Funded | (23,172) | (7,354) | (56) | (3,047) | (33,629) |
| Unfunded | (117) | (341) | (3,244) | (5,102) | (8,804) |
| | (23,289) | (7,695) | (3,300) | (8,149) | (42,433) |

[a] The costs of managing the fund 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 benefits 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 a restructuring programme in the UK and Europe.

[d] The benefit payments amount shown above comprises $2,266 million benefits plus $52 million of fund 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.

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## 38 Pensions and other post-retirement benefits *continued*

$ million

| | | | | | 2005 |
|---|---|---|---|---|---|
| **Analysis of the amount charged to profit before interest and taxation** | UK pension plans | US pension plans | US other post-retirement benefit plans | Other plans | Total |
| Current service cost[a] | 379 | 216 | 50 | 140 | 785 |
| Past service cost | 5 | (10) | (5) | 51 | 41 |
| Settlement, curtailment and special termination benefits | 37 | | | 10 | 47 |
| Payments to defined contribution plans | | 158 | | 14 | 172 |
| Total operating charge | 421 | 364 | 45 | 215 | 1,045 |
| Innovene operations | (38) | (24) | (3) | (21) | (86) |
| Continuing operations[b] | 383 | 340 | 42 | 194 | 959 |
| **Analysis of the amount credited (charged) to other finance expense** | | | | | |
| Expected return on plan assets | 1,456 | 557 | 2 | 123 | 2,138 |
| Interest on plan liabilities | (1,003) | (444) | (207) | (368) | (2,022) |
| Other finance income (expense) | 453 | 113 | (205) | (245) | 116 |
| Innovene operations | (10) | (5) | 2 | 10 | (3) |
| Continuing operations | 443 | 108 | (203) | (235) | 113 |
| **Analysis of the amount recognized in the statement of recognized income and expense** | | | | | |
| Actual return less expected return on pension plan assets | 3,111 | 96 | | 157 | 3,364 |
| Change in assumptions underlying the present value of the plan liabilities | (1,884) | (59) | 236 | (470) | (2,177) |
| Experience gains and losses arising on the plan liabilities | (14) | (197) | (17) | 16 | (212) |
| Actuarial gain (loss) recognized in statement of recognized income and expense | 1,213 | (160) | 219 | (297) | 975 |

[a] The costs of managing the fund 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 benefits are included in the benefit obligation.

[b] Included within production and manufacturing expenses and distribution and administration expenses.

$ million

| **History of surplus (deficit) and of experience gains and losses** | **2007** | 2006 | 2005 | 2004 | 2003 |
|---|---|---|---|---|---|

| | | | | | |
|---|---|---|---|---|---|
| Benefit obligation at 31 December | **43,100** | 42,433 | 38,855 | 39,945 | 35,995 |
| Fair value of plan assets at 31 December | **42,799** | 39,910 | 32,907 | 31,712 | 27,853 |
| Surplus (deficit) | **(301)** | (2,523) | (5,948) | (8,233) | (8,142) |
| Experience gains and losses on plan liabilities | **(200)** | (124) | (212) | (468) | 873 |
| Actual return less expected return on pension plan assets | **302** | 1,967 | 3,364 | 1,349 | 2,392 |
| Actual return on plan assets | **3,157** | 4,377 | 5,502 | 3,332 | 3,892 |
| Actuarial gain recognized in statement of recognized income and expense | **1,717** | 2,615 | 975 | 107 | 76 |
| Cumulative amount recognized in statement of recognized income and expense | **5,490** | 3,773 | 1,158 | 183 | 76 |

### Estimated future benefit payments

The expected benefit payments, which reflect expected future service, as appropriate, but exclude fund expenses, up until 2017 are as follows:

$ million

| | UK pension plans | US pension plans | US other post-retirement benefit plans | Other plans | Total |
|---|---|---|---|---|---|
| 2008 | **1,112** | **629** | **224** | **534** | **2,499** |
| 2009 | **1,183** | **656** | **227** | **533** | **2,599** |
| 2010 | **1,252** | **670** | **235** | **529** | **2,686** |
| 2011 | **1,334** | **681** | **240** | **521** | **2,776** |
| 2012 | **1,378** | **716** | **242** | **516** | **2,852** |
| 2013-2017 | **7,650** | **3,301** | **1,243** | **2,551** | **14,745** |

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## 39 Called up share capital

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

| Issued | **2007** Shares (thousand) | **2007** $ million | 2006 Shares (thousand) | 2006 $ million | 2005 Shares (thousand) | 2005 $ 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 | **21,457,301** | **5,364** | 20,657,045 | 5,164 | 21,525,978 | 5,382 |
| Issue of new shares for employee share schemes | **69,273** | **18** | 64,854 | 16 | 82,144 | 20 |
| Issue of ordinary share capital for TNK-BP | | | 111,151 | 28 | 108,629 | 27 |
| Repurchase of ordinary share capital | **(663,150)** | **(166)** | (358,374) | (90) | (1,059,706) | (265) |
| Other[a] | | | 982,625 | 246 | | |
| At 31 December | **20,863,424** | **5,216** | 21,457,301 | 5,364 | 20,657,045 | 5,164 |
| | | **5,237** | | 5,385 | | 5,185 |
| 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] Reclassification in respect of share repurchases in 2005.

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 purchased 663,149,528 ordinary shares (2006 1,334,362,750 and 2005 1,059,706,481 ordinary shares) for a total consideration of $7,497 million (2006 $15,481 million and 2005 $11,597 million), of which all were for cancellation. At 31 December 2007 150,966,096 (2006 99,045,000 and 2005 nil) ordinary shares bought back were awaiting cancellation. These shares have been excluded from ordinary shares in issue shown above. At 31 December 2007, 1,940,638,808 shares of nominal value $485 million were held in treasury (2006 1,946,804,533 shares of nominal value $487 million). The maximum number of shares held in treasury during the year was 1,946,804,533 shares of nominal value $487 million, representing 9.1% of the called up ordinary share capital of the company. During 2007, 1,700,000 treasury shares were gifted to the ESOP trust and 4,465,725 treasury shares were re-issued in relation to employee share schemes, in total representing less than 0.1% of the ordinary share capital of the company. The nominal value of these shares was $2 million and the total proceeds received were $35 million.

Transaction costs of share repurchases amounted to $40 million (2006 $83 million and 2005 $63 million).

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## 40 Capital and reserves

| | Share capital | Share premium account | Capital redemption reserve | Merger reserve |
|---|---|---|---|---|
| At 1 January 2007 | **5,385** | **9,074** | **839** | **27,201** |
| Currency translation differences (net of tax) | | | | |
| Exchange gain on translation of foreign operations transferred to (profit) or loss on sale (net of tax) | | | | |
| Actuarial gain relating to pension and other post-retirement benefits (net of tax) | | | | |
| Available-for-sale investments marked to market (net of tax) | | | | |
| Available-for-sale investments recycling (net of tax) | | | | |
| Repurchase of ordinary share capital | **(166)** | | **166** | |
| Share-based payments (net of tax) | **18** | **507** | | **5** |
| Cash flow hedges marked to market (net of tax) | | | | |
| Cash flow hedges recycling (net of tax) | | | | |
| Profit for the year | | | | |
| Dividends | | | | |
| At 31 December 2007 | **5,237** | **9,581** | **1,005** | **27,206** |

| | Share capital | Share premium account | Capital redemption reserve | Merger reserve |
|---|---|---|---|---|
| At 1 January 2006 | 5,185 | 7,371 | 749 | 27,190 |
| Currency translation differences (net of tax) | | | | |
| Actuarial gain relating to pension and other post-retirement benefits (net of tax) | | | | |
| Issue of ordinary share capital for TNK-BP | 28 | 1,222 | | |
| Available-for-sale investments marked to market (net of tax) | | | | |
| Available-for-sale investments recycling (net of tax) | | | | |
| Repurchase of ordinary share capital | (90) | | 90 | |
| Share-based payments (net of tax) | 16 | 481 | | 11 |
| Cash flow hedges marked to market (net of tax) | | | | |
| Cash flow hedges recycling (net of tax) | | | | |
| Profit for the year | | | | |
| Dividends | | | | |
| Other[b] | 246 | | | |
| At 31 December 2006 | 5,385 | 9,074 | 839 | 27,201 |

| | Share capital | Share premium account | Capital redemption reserve | Merger reserve |
|---|---|---|---|---|
| At 31 December 2004 | 5,403 | 5,636 | 730 | 27,162 |
| Adoption of IAS 39 | | | | |
| At 1 January 2005 | 5,403 | 5,636 | 730 | 27,162 |
| Currency translation differences (net of tax) | | | | |
| Exchange gain on translation of foreign operations transferred to (profit) or loss on sale (net of tax) | | | | |
| Actuarial gain relating to pension and other post retirement benefits (net of tax) | | | | |
| Issue of ordinary share capital for TNK-BP | 27 | 1,223 | | |
| Available-for-sale investments marked to market (net of tax) | | | | |
| Available-for-sale investments recycling (net of tax) | | | | |
| Repurchase of ordinary share capital | (265) | | 19 | |
| Share-based payments (net of tax) | 20 | 512 | | 28 |
| Cash flow hedges marked to market (net of tax) | | | | |
| Cash flow hedges recycling (net of tax) | | | | |
| Profit for the year | | | | |
| Dividends | | | | |
| At 31 December 2005 | 5,185 | 7,371 | 749 | 27,190 |

[a] At 31 December 2006, the foreign currency translation reserve included $122 million relating to non-current assets held for sale. During 2007, this was included in the $147 million recycled to the income statement relating to disposals in 2007. For further details see Note 4.
[b] Reclassification in respect of share repurchases in 2005.

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$ million

| Other reserve | 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 |
|---|---|---|---|---|---|---|---|---|---|---|
| **5** | **(154)** | **(22,182)** | **4,685** | **386** | **39** | **859** | **58,487** | **84,624** | **841** | **85,465** |
| | | | **2,002** | | | | | **2,002** | **24** | **2,026** |
| | | | **(147)** | | | | | **(147)** | | **(147)** |
| | | | | | | | **1,290** | **1,290** | | **1,290** |
| | | | | **152** | | | | **152** | | **152** |
| | | | | **(57)** | | | | **(57)** | | **(57)** |
| | | | | | | | **(7,997)** | **(7,997)** | | **(7,997)** |
| **(5)** | **94** | **70** | | | | **337** | **(9)** | **1,017** | | **1,017** |
| | | | | | **138** | | | **138** | | **138** |
| | | | | | **(71)** | | | **(71)** | | **(71)** |
| | | | | | | | **20,845** | **20,845** | **324** | **21,169** |
| | | | | | | | **(8,106)** | **(8,106)** | **(227)** | **(8,333)** |
| | **(60)** | **(22,112)** | **6,540** | **481** | **106** | **1,196** | **64,510** | **93,690** | **962** | **94,652** |

$ million

| Other reserve | Own shares | Treasury shares | Foreign currency translation reserve[a] | Available-for-sale investments | Cash flow hedges | Share-based payment reserve | Profit and loss account | BP shareholders equity | Minority interest | Total equity |
|---|---|---|---|---|---|---|---|---|---|---|
| 16 | (140) | (10,598) | 2,943 | 385 | (234) | 643 | 46,151 | 79,661 | 789 | 80,450 |
| | (19) | | 1,742 | 27 | 6 | | | 1,756 | 49 | 1,805 |
| | | | | | | | 1,795 | 1,795 | | 1,795 |
| | | | | | | | | 1,250 | | 1,250 |
| | | | | 478 | | | | 478 | | 478 |
| | | | | (504) | | | | (504) | | (504) |
| | | (11,472) | | | | | (4,009) | (15,481) | | (15,481) |
| (11) | 5 | 134 | | | | 216 | (79) | 773 | | 773 |
| | | | | | 313 | | | 313 | | 313 |
| | | | | | (46) | | | (46) | | (46) |
| | | | | | | | 22,315 | 22,315 | 286 | 22,601 |
| | | | | | | | (7,686) | (7,686) | (283) | (7,969) |
| | | (246) | | | | | | | | |
| 5 | (154) | (22,182) | 4,685 | 386 | 39 | 859 | 58,487 | 84,624 | 841 | 85,465 |

$ million

| Other reserve | 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 |
|---|---|---|---|---|---|---|---|---|---|---|
| 44 | (82) | | 5,616 | | | 443 | 31,940 | 76,892 | 1,343 | 78,235 |
| | | | | 230 | (118) | | (355) | (243) | | (243) |
| 44 | (82) | | 5,616 | 230 | (118) | 443 | 31,585 | 76,649 | 1,343 | 77,992 |
| | 12 | | (2,453) | (35) | (3) | | | (2,479) | (18) | (2,497) |
| | | | (220) | | | | | (220) | | (220) |
| | | | | | | | 619 | 619 | | 619 |
| | | | | | | | | 1,250 | | 1,250 |
| | | | | 232 | | | | 232 | | 232 |
| | | | | (42) | | | | (42) | | (42) |
| | | (10,601) | | | | | (750) | (11,597) | | (11,597) |
| (28) | (70) | 3 | | | | 200 | 30 | 695 | | 695 |
| | | | | | (149) | | | (149) | | (149) |
| | | | | | 36 | | | 36 | | 36 |
| | | | | | | | 22,026 | 22,026 | 291 | 22,317 |
| | | | | | | | (7,359) | (7,359) | (827) | (8,186) |
| 16 | (140) | (10,598) | 2,943 | 385 | (234) | 643 | 46,151 | 79,661 | 789 | 80,450 |

## 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.

### Other reserve

The balance on the other reserve represents the fair value of the consideration given in excess of the nominal value of the ordinary shares to be issued in the ARCO acquisition on the exercise of ARCO share options.

### 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 arrangements.

### 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 translations 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 on available-for-sale investments. On disposal, the cumulative changes in fair value are recycled to the income statement.

### Cash flow hedges

This reserve records the portion of the gain or loss on a hedging instrument in a cash flow hedge that is determined to be an effective hedge. When the hedged transaction occurs, the gain or loss on the hedging instrument is transferred out of equity to either profit or loss or the carrying value of assets, as appropriate. If the forecast transaction is no longer expected to occur the gain or loss recognized in equity is transferred to profit or loss.

### Share-based payment reserve

This reserve represents cumulative amounts charged to profit in respect of employee share-based payment arrangements 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.

## 41 Share-based payments

$ million

| **Effect of share-based payment transactions on the group s result and financial position** | **2007** | 2006 | 2005 |
|---|---|---|---|
| Total expense recognized for equity-settled share-based payment transactions | **412** | 405 | 348 |
| Total expense recognized for cash-settled share-based payment transactions | **16** | 14 | 20 |
| Total expense recognized for share-based payment transactions | **428** | 419 | 368 |
| Closing balance of liability for cash-settled share-based payment transactions | **40** | 38 | 48 |
| Total intrinsic value for vested cash-settled share-based payments | **22** | 23 | 41 |

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 (2005 onwards)

An equity-settled incentive share plan for executive directors driven by one performance measure over a three-year performance period. The award of shares is determined by comparing BP s total shareholder return (TSR) against the other oil majors. In addition, for the group chief executive, 27% of the grant is based on long-term leadership (LTL) measures. After the performance period, the shares that vest (net of tax) are then subject to a three-year retention period. The director s remuneration report on pages 62-72 includes full details of this plan.

**41 Share-based payments** *continued*

Executive Directors Incentive Plan (EDIP) share element (pre-2005)

An equity-settled incentive share plan for executive directors driven by three performance measures over a three-year performance period. The primary measure is BP s shareholder return against the market (SHRAM) versus that of the companies within the FTSE All World Oil & Gas Index. This accounts for nearly two-thirds of the potential total award, with the remainder being assessed on BP s relative return on average capital employed (ROACE) and earnings per share (EPS) growth compared with the other oil majors. After the performance period, the shares that vest (net of tax) are then subject to a three-year retention period. The director s remuneration report on pages 62-72 includes full details of this plan. For 2005 and subsequent years, the share element of EDIP was amended as described above.

Executive Directors Incentive Plan (EDIP) share option element (pre-2005)

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. Options vest over three years (one-third each after one, two and three years respectively) and must be exercised within seven years of the date of grant. 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**

Medium Term Performance Plan (MTPP) (2005 onwards)

An equity-settled incentive share plan for senior employees driven by two performance measures over a three-year performance period. The award of shares is determined by comparing BP s TSR against the other oil majors and, additionally, by comparing free cash flow (FCF) against a threshold established for the period. For a small group of particularly senior employees, only the TSR measure is applicable in determining the award. The number of shares awarded is increased to take account of the net dividends that would have been received during the performance period, assuming that such dividends had been reinvested. With regard to leaver provisions, the general rule is that leaving employment during the performance period will preclude an award of shares. However, special arrangements apply where the participant leaves for a qualifying reason and employment ceases after completion of the first year of the performance period. The current policy of the company, which is reflected in the terms of the MTPP, is that senior employees subject to the plan should meet a minimum shareholding requirement.

Long Term Performance Plan (LTPP) (pre-2005)

An equity-settled incentive share plan for senior employees driven by three performance measures over a three-year performance period. The primary measure is BP s SHRAM versus that of the companies within the FTSE All World Oil & Gas Index. This accounts for nearly two-thirds of the potential total award, with the remainder being assessed on BP s relative ROACE and EPS growth compared with the other oil majors. Shares are awarded at the end of the performance period and are then subject to a three-year retention period. With regard to leaver provisions, the general rule is that leaving during the performance period will preclude an award of shares. However, special arrangements apply where the participant leaves for a qualifying reason and employment ceases after completion of the first year of the performance period. This plan was replaced by the MTPP for 2005 onwards.

Deferred Annual Bonus Plan (DAB)

An equity-settled restricted share plan for senior employees. The award value is equal to 50% of the annual cash bonus awarded for the preceding performance year (the performance period ). The shares are restricted for a period of three years (the restriction period ). Shares accrue dividends during the restriction period and these are reinvested. With regard to leaver provisions, if a participant ceases to be employed by BP prior to the end of the performance period, the general rule is that this will preclude an award of shares. However, special arrangements apply where the participant leaves for a qualifying reason. Similarly, if a participant ceases to be employed by BP prior to the end of the restriction period, the general rule is that the restricted shares will be forfeited. Special arrangements apply where the participant leaves for a qualifying reason.

Performance Share Plan (PSP)

An equity-settled restricted share plan for senior professionals and team leaders. The award takes into account the recipient s performance in the prior calendar year (the performance period ). Shares, provided initially as share units, are restricted for a period of three years (the restriction period ). Share units accrue notional dividends during the restriction period and these are reinvested. At the end of the restriction period additional units may be awarded based on BP s TSR performance against the other oil majors. At award, share units are converted into shares. With regard to leaver provisions, the general rule is that leaving during the performance period will preclude an award of share units. If a participant ceases to be employed by BP prior to the end of the restriction period, the general rule is that share units will lapse. Special arrangements apply where the participant leaves for a qualifying reason.

### Restricted Share Plan (RSP)

An equity-settled restricted share plan used predominantly for senior employees in special circumstances (such as recruitment and retention). There are no performance conditions but the shares are subject to a three-year restriction period. During the restriction period, shares accrue dividends, which are reinvested. With regard to leaver provisions, the general rule is that ceasing employment during the restriction period will result in the forfeit of shares. However, special arrangements apply where the participant leaves for a qualifying reason.

### BP Share Option Plan (BPSOP)

An equity-settled share option plan that applies to certain categories of employees. Participants are granted share options with an exercise price no lower than the market price of a share immediately preceding the date of grant. There are no performance conditions and the options are exercisable between the third and 10th anniversaries of the grant date. The general rule is that the options will lapse if the participant leaves employment before the end of the third calendar year from the date of grant (and that vested options are exercisable within 3 1/2 years from the date of leaving). However, special arrangements apply where the participant leaves for a qualifying reason and employment ceases after the end of the calendar year of the date of grant. From 2007, share options no longer form a regular element of our incentive plans.

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## 41 Share-based payments *continued*

### 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 70 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.

The above share plans are indicated as being equity-settled. In certain countries, however, it is not possible to award shares to employees owing to local legislation. In these instances the award will be settled in cash, calculated as the cash equivalent of the value to the employee of an equity-settled plan.

### Cash plans

Cash-settled share-based payments / Stock Appreciation Rights (SARs)

These are cash-settled share-based payments available to certain employees that require the group to pay the intrinsic value of the cash option/SAR/ restricted shares to the employee at the date of exercise or on maturity. The cash options/SARs have the same rules as the BPSOP plan and the cash restricted share plans (MTPP, DAB, PSP, RSP) have the same rules as their equity-settled counterparts.

### Employee Share Ownership Plans (ESOPs)

ESOPs have been established to acquire BP shares to satisfy any awards made to participants under EDIP, MTPP, LTPP, DAB and the BP ShareMatch Plans. 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 2007, the ESOPs held 6,448,838 shares (2006 12,795,887 shares and 2005 14,560,003 shares) for potential future awards, which had a market value of $79 million (2006 $142 million and 2005 $156 million).

| Share option transactions | | **2007** | | 2006 | | 2005 |
|---|---|---|---|---|---|---|
| | **Number of options** | **Weighted average exercise price $** | Number of options | Weighted average exercise price $ | Number of options | Weighted average exercise price $ |
| Outstanding at beginning of the year | **426,471,462** | **8.25** | 450,453,502 | 7.64 | 470,263,808 | 7.16 |
| Granted during the year | **6,004,025** | **9.11** | 53,977,639 | 11.18 | 54,482,053 | 10.24 |
| Forfeited during the year | **(3,924,714)** | **9.10** | (7,169,710) | 8.69 | (4,844,827) | 8.30 |
| Exercised during the year | **(69,715,558)** | **6.94** | (70,658,480) | 6.52 | (68,687,976) | 6.40 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Expired during the year | **(740,972)** | **8.68** | (131,489) | 7.99 | (759,556) | 6.75 |
| Outstanding at the end of the year | **358,094,243** | **8.51** | 426,471,462 | 8.25 | 450,453,502 | 7.64 |
| Exercisable at the end of the year | **238,707,055** | **7.70** | 236,726,966 | 7.41 | 222,729,398 | 7.54 |

As share options are exercised continuously throughout the year, the weighted average share price during the year of $11.72 (2006 $11.85 and 2005 $10.77) is representative of the weighted average share price at the date of exercise. For the options outstanding at 31 December 2007, 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 $** |
| $5.10 $6.79 | **66,360,194** | **3.88** | **6.15** | **55,509,664** | **6.23** |
| $6.80 $8.50 | **162,364,928** | **4.00** | **8.02** | **156,236,204** | **8.04** |
| $8.51 $10.21 | **55,021,656** | **4.89** | **9.28** | **26,961,187** | **8.78** |
| $10.22 $11.92 | **74,347,465** | **7.80** | **11.13** | | |
| | **358,094,243** | **4.90** | **8.51** | **238,707,055** | **7.70** |

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## 41 Share-based payments *continued*

### Fair values and associated details for options and shares granted

| Options granted in 2007 | **ShareSave 3 year** | **ShareSave 5 year** |
|---|---|---|
| Option pricing model used | **Binomial** | **Binomial** |
| Weighted average fair value | **$3.57** | **$3.79** |
| Weighted average share price | **$12.10** | **$12.10** |
| Weighted average exercise price | **$9.13** | **$9.13** |
| Expected volatility | **21%** | **21%** |
| Option life | **3.5 years** | **5.5 years** |
| Expected dividends | **3.48%** | **3.48%** |
| Risk free interest rate | **5.75%** | **5.75%** |
| Expected exercise behaviour | **100% year 4** | **100% year 6** |

| Options granted in 2006 | BPSOP | ShareSave 3 year | ShareSave 5 year |
|---|---|---|---|
| Option pricing model used | Binomial | Binomial | Binomial |
| Weighted average fair value | $2.46 | $2.88 | $3.08 |
| Weighted average share price | $11.07 | $11.08 | $11.08 |
| Weighted average exercise price | $11.17 | $9.10 | $9.10 |
| Expected volatility | 22% | 24% | 24% |
| Option life | 10 years | 3.5 years | 5.5 years |
| Expected dividends | 3.23% | 3.40% | 3.40% |
| Risk free interest rate | 4.50% | 5.00% | 4.75% |
| Expected exercise behaviour | 5% years 4-9, 70% year 10 | 100% year 4 | 100% year 6 |

| Options granted in 2005 | BPSOP | ShareSave 3 year | ShareSave 5 year |
|---|---|---|---|
| Option pricing model used | Binomial | Binomial | Binomial |
| Weighted average fair value | $2.34 | $2.76 | $2.94 |
| Weighted average share price | $10.85 | $10.49 | $10.49 |
| Weighted average exercise price | $10.63 | $7.96 | $7.96 |
| Expected volatility | 18% | 18% | 18% |
| Option life | 10 years | 3.5 years | 5.5 years |
| Expected dividends | 2.72% | 3.00% | 3.00% |
| Risk free interest rate | 4.25% | 4.00% | 4.25% |
| Expected exercise behaviour | 5% years 4-9, 70% year 10 | 100% year 4 | 100% year 6 |

The group uses an appropriate valuation model of expected volatility of US ADSs for the quarter within which the grant date of the relevant plan falls. Management is responsible for all inputs and assumptions in relation to that model, including the determination of expected volatility.

| Shares granted in 2007 | **MTPP-TSR** | **MTPP-FCF** | **EDIP-TSR** | **EDIP-LTL** | **RSP** | **DAB** | **PSP** |
|---|---|---|---|---|---|---|---|
| Number of equity instruments granted (million) | **9.4** | **8.5** | **4.5** | **0.5** | **7.7** | **4.4** | **14.8** |
| Weighted average fair value | **$4.73** | **$10.02** | **$2.81** | **$9.92** | **$11.93** | **$10.02** | **$12.37** |
| Fair value measurement basis | **Monte Carlo** | **Market value** | **Monte Carlo** | **Market value** | **Market value** | **Market value** | **Monte Carlo** |

| Shares granted in 2006 | MTPP-TSR | MTPP-FCF | EDIP-TSR | EDIP-LTL | RSP | DAB |
|---|---|---|---|---|---|---|
| Number of equity instruments granted (million) | 8.7 | 7.8 | 3.3 | 0.5 | 0.5 | 3.5 |
| Weighted average fair value | $7.28 | $11.23 | $4.87 | $11.23 | $11.07 | $11.06 |
| Fair value measurement basis | Monte Carlo | Market value | Monte Carlo | Market value | Market value | Market value |

| Shares granted in 2005 | MTPP-TSR | MTPP-FCF | EDIP-TSR | EDIP-LTL | RSP |
|---|---|---|---|---|---|
| Number of equity instruments granted (million) | 9.3 | 8.4 | 3.7 | 0.5 | 0.3 |
| Weighted average fair value | $5.72 | $11.04 | $3.87 | $10.13 | $11.04 |
| Fair value measurement basis | Monte Carlo | Market value | Monte Carlo | Market value | Market value |

The group used a Monte Carlo simulation to fair value the TSR element of the 2007, 2006 and 2005 PSP, MTPP and EDIP plans. 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.

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## 42 Employee costs and numbers

| | | | $ million |
|---|---|---|---|
| Employee costs | **2007** | 2006 | 2005 |
| Wages and salaries[a] | **9,560** | 8,411 | 8,695 |
| Social security costs | **771** | 751 | 754 |
| Share-based payments | **428** | 419 | 368 |
| Pension and other post-retirement benefit costs | **504** | 770 | 929 |
| | **11,263** | 10,351 | 10,746 |
| Innovene operations | | | (892) |
| Continuing operations | **11,263** | 10,351 | 9,854 |

| Number of employees at 31 December | **2007** | 2006 | 2005 |
|---|---|---|---|
| Exploration and Production | **19,800** | 19,000 | 17,000 |
| Refining and Marketing[b] | **69,000** | 69,500 | 70,800 |
| Gas, Power and Renewables | **4,500** | 4,500 | 4,100 |
| Other businesses and corporate | **4,300** | 4,000 | 4,300 |
| | **97,600** | 97,000 | 96,200 |

| By geographical area | | | |
|---|---|---|---|
| UK | **17,000** | 16,900 | 16,500 |
| Rest of Europe | **19,900** | 20,200 | 21,300 |
| US | **33,000** | 33,700 | 34,400 |
| Rest of World | **27,700** | 26,200 | 24,000 |
| | **97,600** | 97,000 | 96,200 |

| | | | | | **2007** | | | | | 2006 |
|---|---|---|---|---|---|---|---|---|---|---|
| Average number of employees | **UK** | **Rest of Europe** | **US** | **Rest of World** | **Total** | UK | Rest of Europe | US | Rest of World | Total |
| Exploration and Production | **3,700** | **700** | **6,600** | **8,700** | **19,700** | 3,300 | 700 | 6,100 | 8,100 | 18,200 |
| Refining and Marketing | **10,600** | **18,600** | **23,500** | **16,300** | **69,000** | 11,300 | 19,300 | 24,900 | 15,000 | 70,500 |
| Gas, Power and Renewables | **300** | **700** | **1,800** | **1,500** | **4,300** | 300 | 700 | 1,600 | 1,700 | 4,300 |
| Other businesses and corporate | **2,100** | **200** | **1,700** | **200** | **4,200** | 1,900 | 200 | 1,900 | 100 | 4,100 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **16,700** | **20,200** | **33,600** | **26,700** | **97,200** | 16,800 | 20,900 | 34,500 | 24,900 | 97,100 |

| | | | | | 2005 |
|---|---|---|---|---|---|
| Average number of employees | UK | Rest of Europe | US | Rest of World | Total |
| Exploration and Production | 3,000 | 600 | 5,300 | 7,300 | 16,200 |
| Refining and Marketing | 11,100 | 19,700 | 26,200 | 14,000 | 71,000 |
| Gas, Power and Renewables | 200 | 800 | 1,500 | 1,400 | 3,900 |
| Other businesses and corporate | 3,800 | 3,900 | 3,600 | 300 | 11,600 |
| | 18,100 | 25,000 | 36,600 | 23,000 | 102,700 |

[a] Includes termination payments of $422 million (2006 $257 million and 2005 $348 million). A restructuring was announced in October 2007, the implementation of which is expected to continue through 2008 and into 2009. Additional restructuring charges to the income statement of around $1 billion are expected in 2008.

[b] Includes 25,900 (2006 26,100 and 2005 27,800) service station staff.

## 43 Remuneration of directors and senior management

### Remuneration of directors

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Total for all directors | | | |
| Emoluments | **26** | 14 | 18 |
| Gains made on the exercise of share options | **2** | 12 | |
| Amounts awarded under incentive schemes | **10** | 14 | 8 |

*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. This includes an ex gratia superannuation payment of $3 million (2006 and 2005 nil) and compensation for loss of office of $1 million (2006 and 2005 nil).

*Pension contributions*

Six 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. One US executive director participated in the US BP Retirement Accumulation Plan during 2007.

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## 43 Remuneration of directors and senior management *continued*

*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 62-72.

**Remuneration of senior management** $ million

| | **2007** | 2006 | 2005 |
|---|---|---|---|
| Total for all senior management | | | |
| Short-term employee benefits | **37** | 30 | 25 |
| Post-retirement benefits | **7** | 4 | 4 |
| Share-based payments | **22** | 26 | 27 |

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 bonuses awarded for the year. This includes an ex gratia superannuation payment of $3 million (2006 and 2005 nil) and compensation for loss of office of $1 million (2006 $5 million, 2005 nil).

*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, MTPP and LTPP. For details of these plans refer to Note 41.

## 44 Contingent liabilities

There were contingent liabilities at 31 December 2007 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 28.

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 47% interest (reduced during 2001 from 50% by a sale of 3% 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 which it has incurred. If any claims are asserted by Exxon that affect Alyeska and its owners, BP will defend the claims vigorously. It is not possible to estimate any financial effect.

Since 1987, Atlantic Richfield, a current 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 as against Atlantic Richfield. Atlantic Richfield is named in these lawsuits as alleged successor to International

Smelting & Refining, which, along with a predecessor company, 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 (depending on plaintiff) 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 on 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 and it intends to defend such actions vigorously and thus the incurrence of a liability by Atlantic Richfield is remote. Consequently, BP believes that the impact of these lawsuits on the group s results of operations, financial position or liquidity will not be material.

In addition, various group companies are parties to legal actions and claims that arise in the ordinary course of the group s business. While the outcome of such legal proceedings cannot be readily foreseen, BP believes that they will be resolved without material effect on the group s results of operations, financial position or liquidity. 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 on the group s results of operations, financial position or liquidity.

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## 44 Contingent liabilities *continued*

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 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 2007 amounted to $8,263 million (2006 $9,773 million). In addition, at 31 December 2007, the group had contracts in place for future capital expenditure relating to investments in jointly controlled entities of $1,039 million (2006 $32 million) and investments in associates of $74 million (2006 $36 million).

Capital commitments of jointly controlled entities amounted to $2,273 million (2006 $1,217 million).

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## 46 Subsidiaries, jointly controlled entities and associates

The more important subsidiaries, jointly controlled entities and associates of the group at 31 December 2007 and the group percentage of ordinary share capital or joint venture interest (to 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. 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 Chemicals Investments | 100 | England | Petrochemicals |
| *BP Corporate Holdings | 100 | England | Investment holding |
| BP Exploration Op. Co. | 100 | England | Exploration and production |
| *BP Global Investments | 100 | England | Investment holding |
| *BP International | 100 | England | Integrated oil operations |
| BP Oil International | 100 | England | Integrated oil operations |
| *BP Shipping | 100 | England | Shipping |
| *Burmah Castrol | 100 | Scotland | Lubricants |
| 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 | Exploration and production |
| Australia | | | |
| BP Oil Australia | 100 | Australia | Integrated oil operations |
| BP Australia Capital Markets | 100 | Australia | Finance |
| BP Developments | | | |

| Subsidiaries | % | Country of incorporation | Principal activities |
|---|---|---|---|
| Netherlands | | | |
| BP Capital | 100 | Netherlands | Finance |
| BP Nederland | 100 | Netherlands | Refining and marketing |
| 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 (LNG) | 100 | Netherlands | Exploration and production |
| BP Trinidad and Tobago | 70 | US | Exploration and production |
| UK | | | |
| BP Capital Markets | 100 | England | Finance |
| BP Chemicals | 100 | England | Petrochemicals |
| BP Oil UK | 100 | England | Refining and marketing |

| | | | |
|---|---|---|---|
| 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 | 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 |
| BP Egypt Gas Co. | 100 | US | Exploration and production |
| **Germany** | | | |
| Deutsche BP | 100 | Germany | Refining and marketing and petrochemicals |
| **Indonesia** | | | |
| BP Berau | 100 | US | Exploration and production |
| BP West Java | 100 | US | Exploration and production |

| | | | |
|---|---|---|---|
| Britoil | 100 | Scotland | Exploration and production |
| Jupiter Insurance | 100 | Guernsey | Insurance |
| **US** | | | |
| *BP Holdings North America | 100 | England | Investment holding |
| Atlantic Richfield Co. | | | |
| BP America | | | |
| BP America Production Company | | | |
| BP Amoco Chemical Company | | | |
| BP Company North America | | | |
| BP Corporation North America | 100 | US | Exploration and production, gas, power and renewables, refining and marketing, pipelines and petrochemicals |
| BP Exploration (Alaska) Inc. | | | |
| BP Products North America | | | |
| BP West Coast Products | | | |
| Standard Oil Co. | | | |
| BP Capital Markets America | | | Finance |

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## 46 Subsidiaries, jointly controlled entities and associates *continued*

| Jointly controlled entities | % | Country of incorporation or registration | Principal activities |
|---|---|---|---|
| Atlantic 4 Holdings | 38 | US | LNG manufacture |
| Atlantic LNG 2/3 Company of Trinidad and Tobago | 43 | Trinidad & Tobago | LNG manufacture |
| Elvary Neftegaz Holdings BV | 49 | Netherlands | Exploration and appraisal |
| LukArco | 46 | Netherlands | Exploration and production, pipelines |
| Pan American Energy[a] | 60 | US | Exploration and production |
| Ruhr Oel | 50 | Germany | Refining and marketing and petrochemicals |
| Shanghai SECCO Petrochemical Co. | 50 | China | Petrochemicals |
| TNK-BP | 50 | British Virgin Islands | Integrated oil operations |

[a] Pan American Energy 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.

| Associates | % | Country of incorporation | Principal activities |
|---|---|---|---|
| Abu Dhabi | | | |
| Abu Dhabi Marine Areas | 37 | England | Crude oil production |
| Abu Dhabi Petroleum Co. | 24 | England | Crude oil production |
| Azerbaijan | | | |
| The Baku-Tbilisi-Ceyhan Pipeline Co. | 30 | Cayman Islands | Pipelines |
| South Caucasus Pipeline Co. | 26 | Cayman Islands | Pipelines |
| Trinidad & Tobago | | | |
| Atlantic LNG Company of Trinidad and Tobago | 34 | Trinidad & Tobago | LNG manufacture |

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## 47 Oil and natural gas exploration and production activities[a]

$ million

2007

| | UK | Rest of Europe | US | Rest of Americas | Asia Pacific | Africa | Russia | Other | Total |
|---|---|---|---|---|---|---|---|---|---|
| **Capitalized costs at 31 December** | | | | | | | | | |
| Gross capitalized costs | | | | | | | | | |
| Proved properties | **34,774** | **4,925** | **53,079** | **10,627** | **3,528** | **18,333** | | **7,596** | **132,862** |
| Unproved properties | **606** | | **1,660** | **297** | **1,188** | **1,533** | **4** | **349** | **5,637** |
| | **35,380** | **4,925** | **54,739** | **10,924** | **4,716** | **19,866** | **4** | **7,945** | **138,499** |
| Accumulated depreciation | **25,515** | **2,925** | **25,500** | **5,528** | **1,508** | **8,315** | | **2,553** | **71,844** |
| Net capitalized costs | **9,865** | **2,000** | **29,239** | **5,396** | **3,208** | **11,551** | **4** | **5,392** | **66,655** |

The group s share of jointly controlled entities and associates net capitalized costs at 31 December 2007 was $11,787 million.

| | UK | Rest of Europe | US | Rest of Americas | Asia Pacific | Africa | Russia | Other | Total |
|---|---|---|---|---|---|---|---|---|---|
| **Costs incurred for the year ended 31 December** | | | | | | | | | |
| Acquisition of properties | | | | | | | | | |
| Proved | | | **245** | | | | | **232** | **477** |
| Unproved | | | **54** | **16** | | **321** | | **126** | **517** |
| | | | **299** | **16** | | **321** | | **358** | **994** |
| Exploration and appraisal costs[b] | **209** | **16** | **646** | **72** | **51** | **677** | **119** | **102** | **1,892** |
| Development costs | **804** | **443** | **3,861** | **1,057** | **333** | **2,634** | | **1,021** | **10,153** |
| Total costs | **1,013** | **459** | **4,806** | **1,145** | **384** | **3,632** | **119** | **1,481** | **13,039** |

The group s share of jointly controlled entities and associates costs incurred in 2007 was $2,552 million: in Russia $1,787 million, Rest of Americas $569 million, Asia Pacific $17 million and other $179 million.

| | UK | Rest of Europe | US | Rest of Americas | Asia Pacific | Africa | Russia | Other | Total |
|---|---|---|---|---|---|---|---|---|---|
| **Results of operations for the year ended 31 December** | | | | | | | | | |
| Sales and other operating revenues | | | | | | | | | |
| Third parties | **4,503** | **434** | **1,436** | **2,142** | **1,148** | **2,219** | | **921** | **12,803** |
| Sales between businesses | **2,260** | **902** | **14,353** | **3,142** | **970** | **3,223** | | **9,983** | **34,833** |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 6,763 | 1,336 | 15,789 | 5,284 | 2,118 | 5,442 | | 10,904 | 47,636 |
| Exploration expenditure | 46 | | 252 | 134 | 11 | 183 | 116 | 14 | 756 |
| Production costs | 1,658 | 147 | 2,782 | 770 | 190 | 637 | 2 | 344 | 6,530 |
| Production taxes | 227 | 3 | 1,260 | 273 | 56 | | | 2,224 | 4,043 |
| Other costs (income) | (419) | 123 | 2,505 | 395 | 378 | 200 | 169 | 3,018 | 6,369 |
| Depreciation, depletion and amortization | 1,569 | 207 | 2,118 | 822 | 205 | 1,372 | | 995 | 7,288 |
| Impairments and (gains) losses on sale of businesses and fixed assets | 112 | (534) | (413) | (43) | | (76) | | | (954) |
| | 3,193 | (54) | 8,504 | 2,351 | 840 | 2,316 | 287 | 6,595 | 24,032 |
| Profit before taxation[c,d] | 3,570 | 1,390 | 7,285 | 2,933 | 1,278 | 3,126 | (287) | 4,309 | 23,604 |
| Allocable taxes | 1,664 | 611 | 2,560 | 1,202 | 321 | 1,462 | 3 | 1,079 | 8,902 |
| Results of operations | 1,906 | 779 | 4,725 | 1,731 | 957 | 1,664 | (290) | 3,230 | 14,702 |

The group s share of jointly controlled entities and associates results of operations (including the group s share of total TNK-BP results) in 2007 was a profit of $2,704 million after deducting interest of $401 million, taxation of $1,355 million and minority interest of $215 million.

[a] This note contains 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. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia. The group s share of jointly controlled entities and associates acitivies are excluded from the tables and included in the footnotes with the exception of the Abu Dhabi operations, which are included in the results of operations above.

[b] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible fixed assets, and geological and geophysical exploration costs, which are charged to income as incurred.

[c] Includes property taxes, other government take and the fair value gain on embedded derivatives of $47 million. The UK Region includes a $409 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme.

[d] The Exploration and Production profit before interest and tax is set out below.

| | | | | | | | | | $ million |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | 2007 |
| Exploration and production activities | | | | | | | | | |
| Group (as above) | 3,570 | 1,390 | 7,285 | 2,933 | 1,278 | 3,126 | (287) | 4,309 | 23,604 |
| Jointly controlled entities and associates | | | 1 | 381 | 21 | | 2,292 | 9 | 2,704 |
| Mid-stream activities | 123 | (7) | 472 | 42 | 6 | (10) | (112) | 116 | 630 |
| Total profit before interest and tax | 3,693 | 1,383 | 7,758 | 3,356 | 1,305 | 3,116 | 1,893 | 4,434 | 26,938 |

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## 47 Oil and natural gas exploration and production activities[a] *continued*

$ million

2006

| | UK | Rest of Europe | US | Rest of Americas | Asia Pacific | Africa | Russia | Other | Total |
|---|---|---|---|---|---|---|---|---|---|
| **Capitalized costs at 31 December** | | | | | | | | | |
| Gross capitalized costs | | | | | | | | | |
| Proved properties | 32,528 | 4,951 | 44,856 | 9,404 | 3,569 | 15,516 | | 6,278 | 117,102 |
| Unproved properties | 423 | 116 | 1,443 | 379 | 1,155 | 936 | 1 | 137 | 4,590 |
| | 32,951 | 5,067 | 46,299 | 9,783 | 4,724 | 16,452 | 1 | 6,415 | 121,692 |
| Accumulated depreciation | 22,908 | 3,175 | 19,724 | 4,618 | 1,709 | 6,944 | | 1,708 | 60,786 |
| Net capitalized costs | 10,043 | 1,892 | 26,575 | 5,165 | 3,015 | 9,508 | 1 | 4,707 | 60,906 |

The group s share of jointly controlled entities and associates net capitalized costs at 31 December 2006 was $10,870 million.

| | UK | Rest of Europe | US | Rest of Americas | Asia Pacific | Africa | Russia | Other | Total |
|---|---|---|---|---|---|---|---|---|---|
| **Costs incurred for the year ended 31 December** | | | | | | | | | |
| Acquisition of properties | | | | | | | | | |
| Proved | | | | | | | | | |
| Unproved | | | 74 | 8 | 2 | 70 | | | 154 |
| | | | 74 | 8 | 2 | 70 | | | 154 |
| Exploration and appraisal costs[b] | 132 | 26 | 838 | 135 | 45 | 434 | 73 | 82 | 1,765 |
| Development costs | 794 | 214 | 3,579 | 820 | 238 | 2,356 | | 1,108 | 9,109 |
| Total costs | 926 | 240 | 4,491 | 963 | 285 | 2,860 | 73 | 1,190 | 11,028 |

The group s share of jointly controlled entities and associates costs incurred in 2006 was $1,688 million: in Russia $1,109 million, Rest of Americas $424 million, Asia Pacific $16 million and other $139 million.

| | UK | Rest of Europe | US | Rest of Americas | Asia Pacific | Africa | Russia | Other | Total |
|---|---|---|---|---|---|---|---|---|---|
| **Results of operations for the year ended 31 December** | | | | | | | | | |
| Sales and other operating revenues | | | | | | | | | |
| Third parties | 5,378 | 628 | 1,381 | 2,196 | 1,159 | 1,647 | | 768 | 13,157 |
| Sales between businesses | 2,329 | 1,024 | 14,572 | 3,229 | 807 | 2,875 | | 7,640 | 32,476 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 7,707 | 1,652 | 15,953 | 5,425 | 1,966 | 4,522 | | 8,408 | 45,633 |
| Exploration expenditure | 20 | (1) | 634 | 132 | 11 | 132 | 17 | 100 | 1,045 |
| Production costs | 1,312 | 145 | 2,311 | 638 | 155 | 509 | | 238 | 5,308 |
| Production taxes | 492 | 38 | 887 | 295 | 63 | | | 2,079 | 3,854 |
| Other costs (income)[c] | (867) | 90 | 2,561 | 478 | 154 | 104 | 32 | 3,121 | 5,673 |
| Depreciation, depletion and amortization | 1,612 | 213 | 2,083 | 685 | 175 | 865 | | 510 | 6,143 |
| Impairments and (gains) losses on sale of businesses and fixed assets | (450) | (57) | (1,880) | 42 | (99) | (31) | | | (2,475) |
| | 2,119 | 428 | 6,596 | 2,270 | 459 | 1,579 | 49 | 6,048 | 19,548 |
| Profit before taxation[d,e] | 5,588 | 1,224 | 9,357 | 3,155 | 1,507 | 2,943 | (49) | 2,360 | 26,085 |
| Allocable taxes | 2,567 | 793 | 3,136 | 1,443 | 472 | 1,328 | 3 | 737 | 10,479 |
| Results of operations | 3,021 | 431 | 6,221 | 1,712 | 1,035 | 1,615 | (52) | 1,623 | 15,606 |

The group s share of jointly controlled entities and associates results of operations (including the group s share of total TNK-BP results) in 2006 was a profit of $3,302 million after deducting interest of $324 million, taxation of $1,804 million and minority interest of $193 million.

[a] This note contains information relating to oil and natural gas exploration and production activities. Midstream activities of natural gas gathering and distribution and the operation of the main pipelines and tankers are excluded. The main midstream activities are the Alaskan transportation facilities, the Forties Pipeline system and the Central Area Transmission System. The group s share of jointly controlled entities and associates activities is excluded from the tables and included in the footnotes with the exception of the Abu Dhabi operations, which are included in the income and expenditure items above.
[b] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible fixed assets, and geological and geophysical exploration costs, which are charged to income as incurred.
[c] Includes the value of royalty oil sold on behalf of others where royalty is payable in cash, property taxes, other government take and the fair value gain on embedded derivatives $515 million.
[d] Excludes accretion expense attributable to exploration and production activities amounting to $153 million. Under IFRS, accretion expense is included in other finance expense in the group income statement.
[e] The Exploration and Production profit before interest and tax is set out below.

| | | | | | | | | | $ million |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | 2006 |
| Exploration and production activities | | | | | | | | | |
| Group (as above) | 5,588 | 1,224 | 9,357 | 3,155 | 1,507 | 2,943 | (49) | 2,360 | 26,085 |
| Jointly controlled entities and associates | | | 1 | 535 | 33 | 1 | 2,730 | 2 | 3,302 |
| Mid-stream activities | 250 | (14) | (31) | 85 | (31) | (11) | (24) | 18 | 242 |
| Total profit before interest and tax | 5,838 | 1,210 | 9,327 | 3,775 | 1,509 | 2,933 | 2,657 | 2,380 | 29,629 |

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## 47 Oil and natural gas exploration and production activities[a] *continued*

$ million

2005

| | UK | Rest of Europe | US | Rest of Americas | Asia Pacific | Africa | Russia | Other | Total |
|---|---|---|---|---|---|---|---|---|---|
| **Capitalized costs at 31 December** | | | | | | | | | |
| Gross capitalized costs | | | | | | | | | |
| Proved properties | 31,552 | 4,608 | 46,288 | 9,585 | 2,922 | 12,183 | | 5,184 | 112,322 |
| Unproved properties | 276 | 135 | 1,547 | 583 | 1,124 | 656 | 185 | 155 | 4,661 |
| | 31,828 | 4,743 | 47,835 | 10,168 | 4,046 | 12,839 | 185 | 5,339 | 116,983 |
| Accumulated depreciation | 22,302 | 2,949 | 22,016 | 4,919 | 1,508 | 6,112 | | 1,200 | 61,006 |
| Net capitalized costs | 9,526 | 1,794 | 25,819 | 5,249 | 2,538 | 6,727 | 185 | 4,139 | 55,977 |

The group s share of jointly controlled entities and associates net capitalized costs at 31 December 2005 was $10,670 million.

| | UK | Rest of Europe | US | Rest of Americas | Asia Pacific | Africa | Russia | Other | Total |
|---|---|---|---|---|---|---|---|---|---|
| **Costs incurred for the year ended 31 December** | | | | | | | | | |
| Acquisition of properties | | | | | | | | | |
| Proved | | | | | | | | | |
| Unproved | | | 29 | 34 | | | | | 63 |
| | | | 29 | 34 | | | | | 63 |
| Exploration and appraisal costs[b] | 51 | 7 | 606 | 133 | 11 | 264 | 126 | 68 | 1,266 |
| Development costs | 790 | 188 | 2,965 | 681 | 186 | 1,691 | | 1,177 | 7,678 |
| Total costs | 841 | 195 | 3,600 | 848 | 197 | 1,955 | 126 | 1,245 | 9,007 |

The group s share of jointly controlled entities and associates costs incurred in 2005 was $1,205 million: in Russia $845 million and Rest of Americas $360 million.

| | UK | Rest of Europe | US | Rest of Americas | Asia Pacific | Africa | Russia | Other | Total |
|---|---|---|---|---|---|---|---|---|---|
| **Results of operations for the year ended 31 December** | | | | | | | | | |
| Sales and other operating revenues | | | | | | | | | |
| Third parties | 4,667 | 635 | 2,048 | 2,260 | 1,045 | 1,350 | | 690 | 12,695 |
| Sales between businesses | 2,458 | 976 | 14,842 | 2,863 | 782 | 2,402 | | 4,796 | 29,119 |
| | 7,125 | 1,611 | 16,890 | 5,123 | 1,827 | 3,752 | | 5,486 | 41,814 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Exploration expenditure | 32 | 1 | 426 | 84 | 6 | 81 | 37 | 17 | 684 |
| Production costs | 1,082 | 118 | 1,814 | 578 | 159 | 460 | | 180 | 4,391 |
| Production taxes | 485 | 33 | 610 | 281 | 54 | | | 1,536 | 2,999 |
| Other costs (income)[c] | 1,857 | (55) | 2,200 | 537 | 170 | 98 | 8 | 2,042 | 6,857 |
| Depreciation, depletion and amortization | 1,548 | 220 | 2,288 | 675 | 162 | 542 | | 193 | 5,628 |
| Impairments and (gains) losses on sale of businesses and fixed assets | 44 | (1,038) | 232 | (133) | | | 2 | | (893) |
| | 5,048 | (721) | 7,570 | 2,022 | 551 | 1,181 | 47 | 3,968 | 19,666 |
| Profit before taxation[d,e] | 2,077 | 2,332 | 9,320 | 3,101 | 1,276 | 2,571 | (47) | 1,518 | 22,148 |
| Allocable taxes | 405 | 880 | 3,377 | 1,390 | 447 | 1,043 | (1) | 409 | 7,950 |
| Results of operations | 1,672 | 1,452 | 5,943 | 1,711 | 829 | 1,528 | (46) | 1,109 | 14,198 |

The group s share of jointly controlled entities and associates results of operations (including the group s share of total TNK-BP results) in 2005 was a profit of $3,029 million after deducting interest of $226 million, taxation of $1,250 million and minority interest of $104 million.

[a] This note contains information relating to oil and natural gas exploration and production activities. Midstream activities of natural gas gathering and distribution and the operation of the main pipelines and tankers are excluded. The main midstream activities are the Alaskan transportation facilities, the Forties Pipeline system and the Central Area Transmission System. The group s share of jointly controlled entities and associates activities is excluded from the tables and included in the footnotes with the exception of the Abu Dhabi operations, which are included in the income and expenditure items above.

[b] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible fixed assets, and geological and geophysical exploration costs, which are charged to income as incurred.

[c] Includes the value of royalty oil sold on behalf of others where royalty is payable in cash, property taxes, other government take, the fair value loss on embedded derivatives $1,688 million and a $265 million charge incurred on the cancellation of an intragroup gas supply contract. The UK region includes a $530 million charge offset by corresponding gains primarily in the US, relating to the group s self-insurance programme.

[d] Excludes accretion expense attributable to exploration and production activities amounting to $122 million. Under IFRS, accretion expense is included in other finance expense in the group income statement.

[e] The Exploration and Production profit before interest and tax is set out below.

| | | | | | | | | | $ million |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | 2005 |
| Exploration and production activities | | | | | | | | | |
| Group (as above) | 2,077 | 2,332 | 9,320 | 3,101 | 1,276 | 2,571 | (47) | 1,518 | 22,148 |
| Jointly controlled entities and associates | | | | 309 | 35 | | 2,685 | | 3,029 |
| Mid-stream activities | 52 | (11) | 172 | 148 | (20) | (39) | (1) | 24 | 325 |
| Total profit before interest and tax | 2,129 | 2,321 | 9,492 | 3,558 | 1,291 | 2,532 | 2,637 | 1,542 | 25,502 |

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## Additional information for US reporting

BP has taken advantage of the SEC ruling of 15 November 2007 that eliminated the requirement to provide a reconciliation from IFRS to US GAAP.

### 48 Suspended exploration well costs

Included within the total exploration expenditure of $5,252 million (2006 $4,110 million and 2005 $4,008 million) shown as part of intangible assets (see Note 25) is an amount of $2,342 million (2006 $1,863 million and 2005 $1,931 million) representing costs directly associated with exploration wells.

The carried costs of exploration wells are subject to technical, commercial and management review at least once per year to confirm the continued intent to develop or otherwise extract value from the discovery. In evaluating whether costs incurred meet the criteria for initial and continued capitalization, management uses two main criteria: (i) that exploration drilling is still under way or firmly planned, or (ii) 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.

The following table provides the year-end balances and movements for suspended exploration well costs.

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Capitalized exploration well costs | | | |
| At 1 January | **1,863** | 1,931 | 1,680 |
| Additions pending determination of proved reserves | **773** | 590 | 565 |
| Exploration well costs written off in the year | **(94)** | (168) | (81) |
| Costs of exploration wells divested in the year | **(27)** | (36) | (72) |
| Reclassified to tangible assets following determination of proved reserves | **(173)** | (251) | (161) |
| Reclassified to investment in jointly controlled entity | | (203) | |
| At 31 December | **2,342** | 1,863 | 1,931 |

The following table provides an ageing profile of suspended exploration wells.

| At 31 December | | **2007** | | 2006 | | 2005 |
|---|---|---|---|---|---|---|
| | **Cost $ million** | **Wells gross** | Cost $ million | Wells gross | Cost $ million | Wells gross |
| Age | | | | | | |
| Less than 1 year | **761** | **35** | 611 | 45 | 593 | 46 |
| 1 to 5 years | **1,081** | **73** | 736 | 64 | 823 | 69 |
| 6 to 10 years | **224** | **30** | 267 | 37 | 309 | 42 |
| More than 10 years | **276** | **35** | 249 | 26 | 206 | 20 |
| Total | **2,342** | **173** | 1,863 | 172 | 1,931 | 177 |

The following table provides an analysis of the amount of drilling costs directly associated with exploration wells.

| | **2007** | | | 2006 | | | 2005 | | |
|---|---|---|---|---|---|---|---|---|---|
| | **Cost $ million** | **Wells gross** | **Projects** | Cost $ million | Wells gross | Projects | Cost $ million | Wells gross | Projects |
| Exploration well costs | | | | | | | | | |
| Projects with first capitalized exploration well drilled in the 12 months ending 31 December | **168** | **11** | **7** | 188 | 17 | 12 | 451 | 31 | 14 |
| Other projects with recent or planned drilling activity | **1,502** | **92** | **24** | 894 | 86 | 21 | 718 | 65 | 20 |
| Projects with completed exploration activity | **672** | **70** | **27** | 781 | 69 | 27 | 762 | 81 | 28 |
| At 31 December | **2,342** | **173** | **58** | 1,863 | 172 | 60 | 1,931 | 177 | 62 |

Exploration projects frequently involve the drilling of multiple wells over a number of years and several discoveries may be grouped into a single development project. The table above shows a total of 51 projects that have exploration well costs that have been capitalized for more than twelve months as at 31 December 2007. Of these, there are 24 projects where exploratory wells have been drilled in the preceding 12 months or further exploratory drilling is planned in the next year. Projects with completed exploration activity comprise a total of 27 projects, whose costs totalled $672 million at 31 December 2007. Details of the activities being undertaken to progress these projects towards development are shown below.

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## 48 Suspended exploration well costs *continued*

| Country | Project | Cost $ million | 2007 wells gross | Years wells drilled | Anticipated year of development project sanction | Comment |
|---|---|---|---|---|---|---|
| Angola | Chumbo | 26 | 2 | 2003-2005 | 2011-2014 | Assessment of hydrocarbon quantities as potentially commercial completed; development option identified and under evaluation; development plan for FPSO submitted. |
| | Plutao/Saturno/Marte/Venus | 51 | 5 | 2002-2005 | 2008 | Assessment of hydrocarbon quantities as potentially commercial completed; development option using FPSO identified and under evaluation. |
| | Cravo/Lirio/Orquidea/Violeta | 32 | 7 | 1998-2006 | 2009 | Assessment of hydrocarbon quantities as potentially commercial completed; development option using FPSO identified and under evaluation. |
| | | 109 | 14 | | | |
| Egypt | Ras El Bar Seth | 3 | 1 | 1995 | 2008 | Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; development planned through tie-back to existing infrastructure; gas sale agreement in place. |
| | Western Mediterranean Block B | 13 | 3 | 2002-2004 | 2008-2010 | Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; seismic survey completed and under review; concession agreement amendment negotiations under way. |
| | East Delta Deep Marine | 11 | 2 | 2002-2006 | 2011 | Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation involving tie-back to existing infrastructure. |
| | | 27 | 6 | | | |
| Indonesia | Tangguh Phase II | 51 | 9 | 1994-1997 | 2009-2011 | Assessment of hydrocarbon quantities as potentially |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | commercial completed; assessment of economic aspects of project in progress; onshore and offshore development options identified and under evaluation. This is the second phase of the LNG project that is currently under development. |
| | | 51 | 9 | | | |
| Trinidad | Coconut | 47 | 1 | 2005 | 2014 | Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project in progress; development options identified and under evaluation; planned subsea tie-back to existing infrastructure. |
| | Corallita/Lantana | 24 | 2 | 1996 | 2008 | Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; planned subsea tie-back to existing infrastructure fields dedicated to LNG gas contract delivery; dependent upon capacity in existing infrastructure. |
| | Manakin | 22 | 1 | 2000 | 2011 | Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project in progress; development options identified and under evaluation; planned subsea tie-back to existing production facilities and LNG train; inter-governmental discussions on unitization continue. |
| | | 93 | 4 | | | |

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## 48 Suspended exploration well costs *continued*

| Country | Project | Cost $ million | 2007 wells gross | Years wells drilled | Anticipated year of development project sanction | Comment |
|---|---|---|---|---|---|---|
| UK | Andrew | 14 | 1 | 1998 | 2008 | Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; development awaiting capacity in existing infrastructure; negotiations under way for gas sales contract. |
| | Devenick | 90 | 3 | 1983-2001 | 2008-2009 | Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project in progress; development options identified and under evaluation; development may be in conjunction with Harding Gas project nearby. |
| | Puffin | 29 | 9 | 1982-1991 | 2009-2010 | Assessment of hydrocarbon quantities as potentially commercial completed; further assessment of economic and developmental aspects of project to be undertaken; sub-surface and feasibility review under way; development awaiting capacity in existing infrastructure. |
| | Kessog | 35 | 4 | 1986-1987 | 2010 | Assessment of hydrocarbon quantities as potentially commercial completed; further assessment of economic and developmental aspects of project in progress. |
| | Suilven | 20 | 3 | 1995-1998 | 2010-2011 | Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic and developmental aspects of project in progress; development anticipated to be by tie-back to existing production vessel; awaiting capacity in existing infrastructure. |
| | | 188 | 20 | | | |
| US | Liberty | 20 | 1 | 1997 | 2008 | Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; planned tie-back via extended reach drilling from existing infrastructure; memoranda of understanding with two key permitting agencies have been secured. |
| | Mad Dog Deep | 48 | 1 | 2005 | 2009-2011 | Assessment of hydrocarbon quantities as potentially commercial completed; |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | assessment of economic and developmental aspects of project under way. |
| | Mad Dog Southwest Ridge | 34 | 3 | 2005 | 2010 | Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project under way; development options identified and under evaluation; development expected to be by subsea tieback. |
| | | 102 | 5 | | | |
| Vietnam | Hai Thach | 65 | 3 | 1995-2002 | 2009 | Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project in place; development options identified and under evaluation; licence extension secured. |
| | Kim Cuong Tay | 13 | 1 | 1995 | 2010-2012 | Initial assessment of hydrocarbon quantities as potentially commercial completed; further assessment of developmental aspects of project to be undertaken; further seismic study planned for 2008. |
| | | 78 | 4 | | | |
| Miscellaneous smaller projects | | 24 | 8 | | | |
| | | 672 | 70 | | | |

Certain projects that were classified as projects with completed exploration drilling activity at 31 December 2006 are not classified as such at 31 December 2007:

The following projects were sanctioned for development in 2007: Skarv in Norway and Chachalaca in Trinidad & Tobago.

In Colombia, $43 million relating to the Volcanera project was written off.

In the US, the Entrada field was disposed of.

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## 49 Auditors remuneration for US reporting

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Audit fees Ernst & Young | | | |
| Group audit | **37** | 36 | 31 |
| Audit-related regulatory reporting | **7** | 9 | 6 |
| Statutory audit of subsidiaries | **19** | 19 | 23 |
| | **63** | 64 | 60 |
| Innovene operations | | | (8) |
| Continuing operations | **63** | 64 | 52 |
| Fees for other services Ernst & Young | | | |
| Further assurance services | | | |
| Acquisition and disposal due diligence | **1** | 3 | 2 |
| Pension plan audits | **1** | | 1 |
| Other further assurance services | **8** | 5 | 23 |
| Tax services | | | |
| Compliance services | | 1 | 10 |
| Advisory services | **2** | | |
| | **12** | 9 | 36 |
| Innovene operations | | | (1) |
| Continuing operations | **12** | 9 | 35 |

Audit fees for 2007 include $7 million of additional fees for 2006 (2006 $5 million of additional fees for 2005 and 2005 $4 million of additional fees for 2004). Audit fees are included in the income statement within distribution and administration expenses.

Other further assurance services include $1 million (2006 $nil and 2005 $4 million) in respect of advice on accounting, auditing and financial reporting matters; $nil (2006 $nil and 2005 $16 million) in respect of internal accounting and risk management control reviews; $5 million (2006 $5 million and 2005 $3 million) in respect of non-statutory audits and $2 million (2006 $nil and 2005 $nil) in respect of project assurance and advice on business and accounting process improvement.

The tax services relate to income tax and indirect tax compliance, employee tax services and tax advisory services.

The audit committee has established pre-approval policies and procedures for the engagement of Ernst & Young to render audit and certain assurance and tax services. The audit fees payable to Ernst & Young are reviewed by the audit committee in the context of other global companies for cost-effectiveness. Ernst & Young performed further assurance and tax services that were not prohibited by regulatory or other professional requirements and were pre-approved by the committee. Ernst & Young is engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit nature. Tax services were awarded either through a full competitive tender process or following an assessment of the expertise of Ernst & Young compared with that of other potential service providers. These services are for a fixed term.

## 50 Valuation and qualifying accounts

$ million

| | | | Additions | | | |
|---|---|---|---|---|---|---|
| | | Balance at 1 January | Charged to costs and expenses | Charged to other accounts[a] | Deductions | Balance at 31 December |
| 2007 | | | | | | |
| Fixed assets | Investments[b] | **151** | **158** | **2** | **(165)** | **146** |
| Doubtful debts[b] | | **421** | **175** | **34** | **(224)** | **406** |
| 2006 | | | | | | |
| Fixed assets | Investments[b] | 172 | 26 | (3) | (44) | 151 |
| Doubtful debts[b] | | 374 | 158 | 32 | (143) | 421 |
| 2005 | | | | | | |
| Fixed assets | Investments[b] | 168 | 18 | (13) | (1) | 172 |
| Doubtful debts[b] | | 526 | 67 | (30) | (189) | 374 |

[a] Principally currency transactions.
[b] Deducted in the balance sheet from the assets to which they apply.

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## 51 Computation of ratio of earnings to fixed charges (unaudited)

$ million, except ratios

| For the year ended 31 December | **2007** | 2006 | 2005 | 2004 | 2003 |
|---|---|---|---|---|---|
| Profit before taxation | **31,611** | 35,142 | 31,421 | 24,966 | 17,731 |
| Group s share of income in excess of dividends from equity-accounted entities | **(1,359)** | | (710) | (81) | (666) |
| Capitalized interest, net of amortization | **(183)** | (341) | (193) | (133) | (123) |
| | **30,069** | 34,801 | 30,518 | 24,752 | 16,942 |
| Fixed charges | | | | | |
| Interest expense | **1,110** | 718 | 559 | 440 | 482 |
| Rental expense representative of interest | **1,033** | 946 | 605 | 619 | 460 |
| Capitalized interest | **323** | 478 | 351 | 204 | 190 |
| | **2,466** | 2,142 | 1,515 | 1,263 | 1,132 |
| Total adjusted earnings available for payment of fixed charges | **32,535** | 36,943 | 32,033 | 26,015 | 18,074 |
| Ratio of earnings to fixed charges | **13.2** | 17.2 | 21.1 | 20.6 | 16.0 |

## 52 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., and 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 operating 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. BP p.l.c. also fully and unconditionally guarantees securities issued by BP Canada Finance Company, 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 | | | | | **2007** |
|---|---|---|---|---|---|
| | **Issuer** | **Guarantor** | | | |
| | **BP Exploration (Alaska) Inc.** | **BP p.l.c.** | **Other subsidiaries** | **Eliminations and reclassifications** | **BP group** |
| Sales and other operating revenues | **5,243** | | **284,365** | **(5,243)** | **284,365** |
| | | | **3,135** | | **3,135** |

| | | | | | |
|---|---|---|---|---|---|
| Earnings from jointly controlled entities after interest and tax | | | | | |
| Earnings from associates after interest and tax | | | 697 | | 697 |
| Equity-accounted income of subsidiaries after interest and tax | 586 | 21,201 | | (21,787) | |
| Interest and other revenues | 758 | 205 | 377 | (586) | 754 |
| Total revenues | 6,587 | 21,406 | 288,574 | (27,616) | 288,951 |
| Gains on sale of businesses and fixed assets | 1 | | 2,486 | | 2,487 |
| Total revenues and other income | 6,588 | 21,406 | 291,060 | (27,616) | 291,438 |
| Purchases | 650 | | 205,359 | (5,243) | 200,766 |
| Production and manufacturing expenses | 897 | | 25,018 | | 25,915 |
| Production and similar taxes | 1,052 | | 2,961 | | 4,013 |
| Depreciation, depletion and amortization | 388 | | 10,191 | | 10,579 |
| Impairment and losses on sale of businesses and fixed assets | | | 1,679 | | 1,679 |
| Exploration expense | | | 756 | | 756 |
| Distribution and administration expenses | 22 | 921 | 14,536 | (108) | 15,371 |
| Fair value (gain) loss on embedded derivatives | | | 7 | | 7 |
| Profit before interest and taxation | 3,579 | 20,485 | 30,553 | (22,265) | 32,352 |
| Finance costs | | 381 | 1,207 | (478) | 1,110 |
| Other finance expense (income) | 49 | (820) | 402 | | (369) |
| Profit before taxation | 3,530 | 20,924 | 28,944 | (21,787) | 31,611 |
| Taxation | 1,081 | 79 | 9,282 | | 10,442 |
| Profit for the year | 2,449 | 20,845 | 19,662 | (21,787) | 21,169 |
| Attributable to | | | | | |
| BP shareholders | 2,449 | 20,845 | 19,338 | (21,787) | 20,845 |
| Minority interest | | | 324 | | 324 |
| | 2,449 | 20,845 | 19,662 | (21,787) | 21,169 |

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## 52 Condensed consolidating information on certain US subsidiaries *continued*

### Income statement *(continued)*

$ million

| For the year ended 31 December | | | | | 2006 |
|---|---|---|---|---|---|
| | Issuer | Guarantor | | | |
| | BP Exploration (Alaska) Inc. | BP p.l.c. | Other subsidiaries | Eliminations and reclassifications | BP group |
| Sales and other operating revenues | 4,812 | | 265,906 | (4,812) | 265,906 |
| Earnings from jointly controlled entities after interest and tax | | | 3,553 | | 3,553 |
| Earnings from associates after interest and tax | | | 442 | | 442 |
| Equity-accounted income of subsidiaries after interest and tax | 570 | 23,119 | | (23,689) | |
| Interest and other revenues | 627 | 187 | 881 | (994) | 701 |
| Total revenues | 6,009 | 23,306 | 270,782 | (29,495) | 270,602 |
| Gains on sale of businesses and fixed assets | | 105 | 3,714 | (105) | 3,714 |
| Total revenues and other income | 6,009 | 23,411 | 274,496 | (29,600) | 274,316 |
| Purchases | 566 | | 191,429 | (4,812) | 187,183 |
| Production and manufacturing expenses | 814 | | 22,479 | | 23,293 |
| Production and similar taxes | 665 | | 2,956 | | 3,621 |
| Depreciation, depletion and amortization | 374 | | 8,754 | | 9,128 |
| Impairment and losses on sale of businesses and fixed assets | 109 | | 440 | | 549 |
| Exploration expense | 14 | | 1,031 | | 1,045 |
| Distribution and administration expenses | 20 | 278 | 14,264 | (115) | 14,447 |
| Fair value (gain) loss on embedded derivatives | | | (608) | | (608) |
| Profit before interest and taxation from continuing operations | 3,447 | 23,133 | 33,751 | (24,673) | 35,658 |
| Finance costs | | 702 | 895 | (879) | 718 |
| Other finance expense (income) | 11 | (675) | 462 | | (202) |
| Profit before taxation from continuing operations | 3,436 | 23,106 | 32,394 | (23,794) | 35,142 |
| Taxation | 1,243 | 686 | 10,587 | | 12,516 |
| Profit from continuing operations | 2,193 | 22,420 | 21,807 | (23,794) | 22,626 |
| Profit (loss) from Innovene operations | | | (25) | | (25) |
| Profit for the year | 2,193 | 22,420 | 21,782 | (23,794) | 22,601 |

Attributable to

| | | | | | |
|---|---|---|---|---|---|
| BP shareholders | 2,193 | 22,420 | 21,496 | (23,794) | 22,315 |
| Minority interest | | | 286 | | 286 |
| | 2,193 | 22,420 | 21,782 | (23,794) | 22,601 |

**Income statement** $ million

For the year ended 31 December 2005

| | Issuer | Guarantor | | | |
|---|---|---|---|---|---|
| | BP Exploration (Alaska) Inc. | BP p.l.c. | Other subsidiaries | Eliminations and reclassifications | BP group |
| Sales and other operating revenues | 5,052 | | 239,792 | (5,052) | 239,792 |
| Earnings from jointly controlled entities after interest and tax | &#150 | | 3,083 | | 3,083 |
| Earnings from associates after interest and tax | &#150 | | 460 | | 460 |
| Equity-accounted income of subsidiaries after interest and tax | 576 | 22,255 | | (22,831) | |
| Interest and other revenues | 454 | 556 | 749 | (1,146) | 613 |
| Total revenues | 6,082 | 22,811 | 244,084 | (29,029) | 243,948 |
| Gains on sale of businesses and fixed assets | 1 | | 1,537 | | 1,538 |
| Total revenues and other income | 6,083 | 22,811 | 245,621 | (29,029) | 245,486 |
| Purchases | 729 | | 167,349 | (5,052) | 163,026 |
| Production and manufacturing expenses | 536 | | 21,056 | | 21,592 |
| Production and similar taxes | 352 | | 2,658 | | 3,010 |
| Depreciation, depletion and amortization | 445 | | 8,326 | | 8,771 |
| Impairment and losses on sale of businesses and fixed assets | | | 468 | | 468 |
| Exploration expense | 1 | | 683 | | 684 |
| Distribution and administration expenses | 19 | 629 | 13,163 | (105) | 13,706 |
| Fair value (gain) loss on embedded derivatives | | | 2,047 | | 2,047 |
| Profit before interest and taxation from continuing operations | 4,001 | 22,182 | 29,871 | (23,872) | 32,182 |
| Finance costs | 169 | 590 | 898 | (1,041) | 616 |
| Other finance expense (income) | 14 | (443) | 574 | | 145 |
| Profit before taxation from continuing operations | 3,818 | 22,035 | 28,399 | (22,831) | 31,421 |
| Taxation | 1,138 | 9 | 8,141 | | 9,288 |
| Profit from continuing operations | 2,680 | 22,026 | 20,258 | (22,831) | 22,133 |
| Profit (loss) from Innovene operations | | | 184 | | 184 |
| Profit for the year | 2,680 | 22,026 | 20,442 | (22,831) | 22,317 |

Attributable to

| | | | | | |
|---|---|---|---|---|---|
| BP shareholders | 2,680 | 22,026 | 20,151 | (22,831) | 22,026 |
| Minority interest | | | 291 | | 291 |
| | 2,680 | 22,026 | 20,442 | (22,831) | 22,317 |

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## 52 Condensed consolidating information on certain US subsidiaries
*continued*

### Balance sheet

$ million

| At 31 December | | | | | 2007 |
|---|---|---|---|---|---|
| | Issuer | Guarantor | | | |
| | BP Exploration (Alaska) Inc. | BP p.l.c. | Other subsidiaries | Eliminations and reclassifications | BP group |
| Non-current assets | | | | | |
| Property, plant and equipment | 6,310 | | 91,679 | | 97,989 |
| Goodwill | | | 11,006 | | 11,006 |
| Intangible assets | 349 | | 6,303 | | 6,652 |
| Investments in jointly controlled entities | | | 18,113 | | 18,113 |
| Investments in associates | | 2 | 4,577 | | 4,579 |
| Other investments | | | 1,830 | | 1,830 |
| Subsidiaries equity-accounted basis | 3,117 | 115,476 | | (118,593) | |
| Fixed assets | 9,776 | 115,478 | 133,508 | (118,593) | 140,169 |
| Loans | 2,151 | 1,192 | 1,541 | (3,885) | 999 |
| Other receivables | | | 968 | | 968 |
| Derivative financial instruments | | | 3,741 | | 3,741 |
| Prepayments | | | 1,083 | | 1,083 |
| Defined benefit pension plan surplus | | 7,265 | 1,649 | | 8,914 |
| | 11,927 | 123,935 | 142,490 | (122,478) | 155,874 |
| Current assets | | | | | |
| Loans | | | 165 | | 165 |
| Inventories | 202 | | 26,352 | | 26,554 |
| Trade and other receivables | 15,986 | 840 | 44,686 | (23,492) | 38,020 |
| Derivative financial instruments | | | 6,321 | | 6,321 |
| Prepayments | 24 | | 3,565 | | 3,589 |
| Current tax receivable | | | 705 | | 705 |
| Cash and cash equivalents | (10) | 244 | 3,328 | | 3,562 |
| | 16,202 | 1,084 | 85,122 | (23,492) | 78,916 |
| Assets classified as held for sale | | | 1,286 | | 1,286 |
| | 16,202 | 1,084 | 86,408 | (23,492) | 80,202 |

| | | | | | |
|---|---|---|---|---|---|
| Total assets | **28,129** | **125,019** | **228,898** | **(145,970)** | **236,076** |
| Current liabilities | | | | | |
| Trade and other payables | **5,233** | **3,115** | **58,296** | **(23,492)** | **43,152** |
| Derivative financial instruments | | | **6,405** | | **6,405** |
| Accruals | | **10** | **6,630** | | **6,640** |
| Finance debt | **55** | | **15,339** | | **15,394** |
| Current tax payable | **306** | | **2,976** | | **3,282** |
| Provisions | | | **2,195** | | **2,195** |
| | **5,594** | **3,125** | **91,841** | **(23,492)** | **77,068** |
| Liabilities directly associated with assets classified as held for sale | | | **163** | | **163** |
| | **5,594** | **3,125** | **92,004** | **(23,492)** | **77,231** |
| Non-current liabilities | | | | | |
| Other payables | **559** | **27** | **4,550** | **(3,885)** | **1,251** |
| Derivative financial instruments | | | **5,002** | | **5,002** |
| Accruals | | **44** | **915** | | **959** |
| Finance debt | | | **15,651** | | **15,651** |
| Deferred tax liabilities | **1,765** | **1,885** | **15,565** | | **19,215** |
| Provisions | **946** | | **11,954** | | **12,900** |
| Defined benefit pension plan and other post-retirement benefit plan deficits | | | **9,215** | | **9,215** |
| | **3,270** | **1,956** | **62,852** | **(3,885)** | **64,193** |
| Total liabilities | **8,864** | **5,081** | **154,856** | **(27,377)** | **141,424** |
| Net assets | **19,265** | **119,938** | **74,042** | **(118,593)** | **94,652** |
| Equity | | | | | |
| BP shareholders equity | **19,265** | **119,938** | **73,080** | **(118,593)** | **93,690** |
| Minority interest | | | **962** | | **962** |
| Total equity | **19,265** | **119,938** | **74,042** | **(118,593)** | **94,652** |

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## 52 Condensed consolidating information on certain US subsidiaries *continued*

**Balance sheet** *(continued)*

$ million

| At 31 December | | | | | 2006 |
|---|---|---|---|---|---|
| | Issuer | Guarantor | | | |
| | BP Exploration (Alaska) Inc. | BP p.l.c. | Other subsidiaries | Eliminations and reclassifications | BP group |
| Non-current assets | | | | | |
| Property, plant and equipment | 5,838 | | 85,161 | | 90,999 |
| Goodwill | | | 10,780 | | 10,780 |
| Intangible assets | 309 | | 4,937 | | 5,246 |
| Investments in jointly controlled entities | | | 15,074 | | 15,074 |
| Investments in associates | | 2 | 5,973 | | 5,975 |
| Other investments | | | 1,697 | | 1,697 |
| Subsidiaries equity-accounted basis | 2,586 | 107,717 | | (110,303) | |
| Fixed assets | 8,733 | 107,719 | 123,622 | (110,303) | 129,771 |
| Loans | 1,735 | 1,196 | 1,052 | (3,166) | 817 |
| Other receivables | | | 862 | | 862 |
| Derivative financial instruments | | | 3,025 | | 3,025 |
| Prepayments | | | 1,034 | | 1,034 |
| Defined benefit pension plan surplus | | 5,662 | 1,091 | | 6,753 |
| | 10,468 | 114,577 | 130,686 | (113,469) | 142,262 |
| Current assets | | | | | |
| Loans | | | 141 | | 141 |
| Inventories | 154 | | 18,761 | | 18,915 |
| Trade and other receivables | 15,710 | 3,074 | 47,450 | (27,542) | 38,692 |
| Derivative financial instruments | | | 10,373 | | 10,373 |
| Prepayments | 15 | | 2,991 | | 3,006 |
| Current tax receivable | | | 544 | | 544 |
| Cash and cash equivalents | (5) | (21) | 2,616 | | 2,590 |
| | 15,874 | 3,053 | 82,876 | (27,542) | 74,261 |
| Assets classified as held for sale | | | 1,078 | | 1,078 |
| | 15,874 | 3,053 | 83,954 | (27,542) | 75,339 |
| Total assets | 26,342 | 117,630 | 214,640 | (141,011) | 217,601 |

| | | | | | |
|---|---|---|---|---|---|
| Current liabilities | | | | | |
| Trade and other payables | 4,908 | 5,185 | 59,685 | (27,542) | 42,236 |
| Derivative financial instruments | | | 9,424 | | 9,424 |
| Accruals | | 10 | 6,137 | | 6,147 |
| Finance debt | 55 | | 12,869 | | 12,924 |
| Current tax payable | 1,705 | | 930 | | 2,635 |
| Provisions | | | 1,932 | | 1,932 |
| | 6,668 | 5,195 | 90,977 | (27,542) | 75,298 |
| Liabilities directly associated with assets classified as held for sale | | | 54 | | 54 |
| | 6,668 | 5,195 | 91,031 | (27,542) | 75,352 |
| Non-current liabilities | | | | | |
| Other payables | 249 | 27 | 4,320 | (3,166) | 1,430 |
| Derivative financial instruments | | | 4,203 | | 4,203 |
| Accruals | | 30 | 931 | | 961 |
| Finance debt | | | 11,086 | | 11,086 |
| Deferred tax liabilities | 1,780 | 1,506 | 14,830 | | 18,116 |
| Provisions | 640 | | 11,072 | | 11,712 |
| Defined benefit pension plan and other post-retirement benefit plan deficits | | | 9,276 | | 9,276 |
| | 2,669 | 1,563 | 55,718 | (3,166) | 56,784 |
| Total liabilities | 9,337 | 6,758 | 146,749 | (30,708) | 132,136 |
| Net assets | 17,005 | 110,872 | 67,891 | (110,303) | 85,465 |
| Equity | | | | | |
| BP shareholders equity | 17,005 | 110,872 | 67,050 | (110,303) | 84,624 |
| Minority interest | | | 841 | | 841 |
| Total equity | 17,005 | 110,872 | 67,891 | (110,303) | 85,465 |

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## 52 Condensed consolidating information on certain US subsidiaries
*continued*

### Cash flow statement

$ million

| | Issuer | Guarantor | | | 2007 |
|---|---|---|---|---|---|
| | **BP Exploration (Alaska) Inc.** | **BP p.l.c.** | **Other subsidiaries** | **Eliminations and reclassifications** | **BP group** |
| Net cash provided by operating activities | **3,072** | **15,403** | **22,839** | **(16,605)** | **24,709** |
| Net cash used in investing activities | **(532)** | **1** | **(14,306)** | | **(14,837)** |
| Net cash used in financing activities | **(2,545)** | **(15,139)** | **(7,956)** | **16,605** | **(9,035)** |
| Currency translation differences relating to cash and cash equivalents | | | **135** | | **135** |
| (Decrease) increase in cash and cash equivalents | **(5)** | **265** | **712** | | **972** |
| Cash and cash equivalents at beginning of year | **(5)** | **(21)** | **2,616** | | **2,590** |
| Cash and cash equivalents at end of year | **(10)** | **244** | **3,328** | | **3,562** |

$ million

| | Issuer | Guarantor | | | 2006 |
|---|---|---|---|---|---|
| | BP Exploration (Alaska) Inc. | BP p.l.c. | Other subsidiaries | Eliminations and reclassifications | BP group |
| Net cash provided by operating activities | 3,522 | 20,628 | 29,030 | (25,008) | 28,172 |
| Net cash used in investing activities | (379) | 843 | (9,982) | | (9,518) |
| Net cash used in financing activities | (3,141) | (21,495) | (19,443) | 25,008 | (19,071) |
| Currency translation differences relating to cash and cash equivalents | | | 47 | | 47 |
| (Decrease) increase in cash and cash equivalents | 2 | (24) | (348) | | (370) |
| Cash and cash equivalents at beginning of year | (7) | 3 | 2,964 | | 2,960 |
| Cash and cash equivalents at end of year | (5) | (21) | 2,616 | | 2,590 |

$ million

| | | | | | 2005 |
|---|---|---|---|---|---|
| | Issuer | Guarantor | | | |
| | BP Exploration (Alaska) Inc. | BP p.l.c. | Other subsidiaries | Eliminations and reclassifications | BP group |
| Net cash provided by operating activities of continuing operations | 3,558 | 19,835 | 23,592 | (21,234) | 25,751 |
| Net cash provided by (used in) operating activities of Innovene operations | | | 970 | | 970 |
| Net cash provided by operating activities | 3,558 | 19,835 | 24,562 | (21,234) | 26,721 |
| Net cash used in investing activities | (346) | (2,410) | 1,027 | | (1,729) |
| Net cash used in financing activities | (3,218) | (17,426) | (23,893) | 21,234 | (23,303) |
| Currency translation differences relating to cash and cash equivalents | | | (88) | | (88) |
| (Decrease) increase in cash and cash equivalents | (6) | (1) | 1,608 | | 1,601 |
| Cash and cash equivalents at beginning of year | (1) | 4 | 1,356 | | 1,359 |
| Cash and cash equivalents at end of year | (7) | 3 | 2,964 | | 2,960 |

## Supplementary information on oil and natural gas (unaudited)

### Movements in estimated net proved reserves

For details of BP s governance process for the booking of oil and natural gas reserves, see page 14.

| | | | | | | | | | 2007 |
|---|---|---|---|---|---|---|---|---|---|
| **Crude oil**[a] | | | | | | | | | **million barrels** |
| | **UK** | **Rest of Europe** | **US** | **Rest of Americas** | **Asia Pacific** | **Africa** | **Russia** | **Other** | **Total** |
| **Subsidiaries** | | | | | | | | | |
| At 1 January 2007 | | | | | | | | | |
| Developed | 458 | 189 | 1,916 | 130 | 67 | 193 | | 88 | 3,041 |
| Undeveloped | 146 | 97 | 1,292 | 237 | 86 | 512 | | 482 | 2,852 |
| | 604 | 286 | 3,208 | 367 | 153 | 705 | | 570 | 5,893 |
| Changes attributable to | | | | | | | | | |
| Revisions of previous estimates | (1) | (25) | 18 | (29) | (7) | (133) | | (27) | (204) |
| Purchases of reserves-in-place | | | 25 | | | | | 8 | 33 |
| Discoveries and extensions | | 31 | 60 | 1 | 2 | 93 | | | 187 |
| Improved recovery | 7 | 1 | 99 | 6 | 5 | 12 | | 1 | 131 |
| Production[b] | (73) | (19) | (169) | (27) | (15) | (71) | | (80) | (454) |
| Sales of reserves-in-place | | | (94) | | | | | | (94) |
| | (67) | (12) | (61) | (49) | (15) | (99) | | (98) | (401) |
| **At 31 December 2007**[c] | | | | | | | | | |
| Developed | 414 | 105 | 1,882 | 115 | 61 | 256 | | 104 | 2,937 |
| Undeveloped | 123 | 169 | 1,265 | 203 | 77 | 350 | | 368 | 2,555 |
| | 537 | 274 | 3,147[f] | 318 | 138 | 606 | | 472 | 5,492 |
| **Equity-accounted entities (BP share)**[d] | | | | | | | | | |
| At 1 January 2007 | | | | | | | | | |
| Developed | | | | 221 | 1 | | 2,200 | 520 | 2,942 |
| Undeveloped | | | | 139 | | | 644 | 163 | 946 |
| | | | | 360 | 1 | | 2,844 | 683 | 3,888 |
| Changes attributable to | | | | | | | | | |
| Revisions of previous estimates | | | | 178 | | | 413 | 167 | 758 |
| Purchases of reserves-in-place | | | | | | | 16 | | 16 |
| Discoveries and extensions | | | | 2 | | | 283 | | 285 |
| Improved recovery | | | | 59 | | | | 1 | 60 |

| | | | | | |
|---|---|---|---|---|---|
| Production | **(28)** | | **(304)** | **(73)** | **(405)** |
| Sales of reserves-in-place | | | **(21)** | | **(21)** |
| | **211** | | **387** | **95** | **693** |
| **At 31 December 2007**[e] | | | | | |
| Developed | **328** | **1** | **2,094** | **573** | **2,996** |
| Undeveloped | **243** | | **1,137** | **205** | **1,585** |
| | **571** | **1** | **3,231** | **778** | **4,581** |

[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 54 thousand barrels a day.

[c] Includes 739 million barrels of NGLs. Also includes 20 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[d] The BP group holds interests, through associates, in onshore and offshore concessions in Abu Dhabi, expiring in 2014 and 2018 respectively. During the second quarter of 2007, we updated our reporting policy in Abu Dhabi to be consistent with general industry practice and as a result have started reporting production and reserves there gross of production taxes. This change resulted in an increase in our reserves of 153 million barrels and in our production of 33mb/d.

[e] Includes 26 million barrels of NGLs. Also includes 210 million barrels of crude oil in respect of the 6.51% minority interest in TNK-BP.

[f] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 98 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.

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## Supplementary information on oil and natural gas (unaudited) *continued*

### Movements in estimated net proved reserves

2007

**Natural gas**[a] billion cubic feet

| | UK | Rest of Europe | US | Rest of Americas | Asia Pacific | Africa | Russia | Other | Total |
|---|---|---|---|---|---|---|---|---|---|
| **Subsidiaries** | | | | | | | | | |
| At 1 January 2007 | | | | | | | | | |
| Developed | 1,968 | 242 | 10,438 | 3,932 | 1,359 | 1,032 | | 331 | 19,302 |
| Undeveloped | 825 | 56 | 4,660 | 9,194 | 5,202 | 1,675 | | 1,254 | 22,866 |
| | 2,793 | 298 | 15,098 | 13,126 | 6,561 | 2,707 | | 1,585 | 42,168 |
| Changes attributable to | | | | | | | | | |
| Revisions of previous estimates | 93 | (37) | 744 | (276) | 140 | (146) | | (21) | 497 |
| Purchases of reserves-in-place | | | 23 | | | | | 109 | 132 |
| Discoveries and extensions | | 293 | 95 | 249 | 88 | 17 | | | 742 |
| Improved recovery | 15 | 1 | 326 | 32 | 111 | 9 | | 5 | 499 |
| Production[b] | (299) | (14) | (879) | (1,047) | (261) | (187) | | (114) | (2,801) |
| Sales of reserves-in-place | | (68) | (32) | (7) | | | | | (107) |
| | (191) | 175 | 277 | (1,049) | 78 | (307) | | (21) | (1,038) |
| **At 31 December 2007**[c] | | | | | | | | | |
| Developed | 2,049 | 63 | 10,670 | 3,683 | 1,822 | 990 | | 583 | 19,860 |
| Undeveloped | 553 | 410 | 4,705 | 8,394 | 4,817 | 1,410 | | 981 | 21,270 |
| | 2,602 | 473 | 15,375 | 12,077 | 6,639 | 2,400 | | 1,564 | 41,130 |
| **Equity-accounted entities (BP share)** | | | | | | | | | |
| At 1 January 2007 | | | | | | | | | |
| Developed | | | | 1,460 | 52 | | 1,087 | 170 | 2,769 |
| Undeveloped | | | | 735 | 23 | | 184 | 52 | 994 |
| | | | | 2,195 | 75 | | 1,271 | 222 | 3,763 |
| Changes attributable to | | | | | | | | | |
| Revisions of previous estimates | | | | 73 | (2) | | 61 | 11 | 143 |
| Purchases of reserves-in-place | | | | | | | 8 | | 8 |
| Discoveries and extensions | | | | 22 | | | | | 22 |
| Improved recovery | | | | 195 | 16 | | | | 211 |
| Production[b] | | | | (176) | (13) | | (179) | (9) | (377) |
| Sales of reserves-in-place | | | | | | | | | |
| | | | | 114 | 1 | | (110) | 2 | 7 |
| **At 31 December 2007**[d] | | | | | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| Developed | **1,478** | **39** | **808** | **148** | **2,473** |
| Undeveloped | **831** | **37** | **353** | **76** | **1,297** |
| | **2,309** | **76** | **1,161** | **224** | **3,770** |

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind where the royally owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Includes 202 billion cubic feet of natural gas consumed in operations, 161 billion cubic feet in subsidiaries, 41 billion cubic feet in equity-accounted entities and excludes 10.9 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.
[c] Includes 3,211 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 68 billion cubic feet of natural gas in respect of the 5.88% minority interest in TNK-BP.

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## Supplementary information on oil and natural gas (unaudited) *continued*

### Movements in estimated net proved reserves

2006

**Crude oil**[a] — million barrels

| | UK | Rest of Europe | US | Rest of Americas | Asia Pacific | Africa | Russia | Other | Total |
|---|---|---|---|---|---|---|---|---|---|
| **Subsidiaries** | | | | | | | | | |
| At 1 January 2006 | | | | | | | | | |
| Developed | 496 | 225 | 1,984 | 215 | 70 | 142 | | 69 | 3,201 |
| Undeveloped | 184 | 86 | 1,429 | 286 | 95 | 536 | | 543 | 3,159 |
| | 680 | 311 | 3,413 | 501 | 165 | 678 | | 612 | 6,360 |
| Changes attributable to | | | | | | | | | |
| Revisions of previous estimates | (3) | (11) | (108) | (9) | | 2 | | 16 | (113) |
| Purchases of reserves-in-place | | | | | | | | | |
| Discoveries and extensions | 3 | | 48 | | 1 | 67 | | | 119 |
| Improved recovery | 26 | 9 | 95 | 13 | 4 | 22 | | | 169 |
| Production[b] | (92) | (23) | (178) | (39) | (17) | (64) | | (58) | (471) |
| Sales of reserves-in-place | (10) | | (62) | (99) | | | | | (171) |
| | (76) | (25) | (205) | (134) | (12) | 27 | | (42) | (467) |
| **At 31 December 2006**[c] | | | | | | | | | |
| Developed | 458 | 189 | 1,916 | 130 | 67 | 193 | | 88 | 3,041 |
| Undeveloped | 146 | 97 | 1,292 | 237 | 86 | 512 | | 482 | 2,852 |
| | 604 | 286 | 3,208[e] | 367 | 153 | 705 | | 570 | 5,893 |
| **Equity-accounted entities (BP share)** | | | | | | | | | |
| At 1 January 2006 | | | | | | | | | |
| Developed | | | | 207 | 1 | | 1,688 | 590 | 2,486 |
| Undeveloped | | | | 124 | | | 431 | 164 | 719 |
| | | | | 331 | 1 | | 2,119 | 754 | 3,205 |
| Changes attributable to | | | | | | | | | |
| Revisions of previous estimates | | | | (2) | | | 1,215 | (8) | 1,205 |
| Purchases of reserves-in-place | | | | 28 | | | | | 28 |
| Discoveries and extensions | | | | 1 | | | | | 1 |
| Improved recovery | | | | 34 | | | | | 34 |
| Production | | | | (28) | | | (320) | (63) | (411) |

| | | | | | |
|---|---|---|---|---|---|
| Sales of reserves-in-place | (4) | | (170) | | (174) |
| | 29 | | 725 | (71) | 683 |
| **At 31 December 2006**[d] | | | | | |
| Developed | 221 | 1 | 2,200 | 520 | 2,942 |
| Undeveloped | 139 | | 644 | 163 | 946 |
| | 360 | 1 | 2,844 | 683 | 3,888 |

[a] Crude oil includes natural gas liquids (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 to make lifting and sales arrangements independently.
[b] Excludes NGLs from processing plants in which an interest is held of 55 thousand barrels a day.
[c] Includes 779 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 28 million barrels of NGLs. Also includes 179 million barrels of crude oil in respect of the 6.29% minority interest in TNK-BP.
[e] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 81 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.

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## Supplementary information on oil and natural gas (unaudited) *continued*

### Movements in estimated net proved reserves

2006

**Natural gas**[a] billion cubic feet

| | UK | Rest of Europe | US | Rest of Americas | Asia Pacific | Africa | Russia | Other | Total |
|---|---|---|---|---|---|---|---|---|---|
| **Subsidiaries** | | | | | | | | | |
| At 1 January 2006 | | | | | | | | | |
| Developed | 2,382 | 245 | 11,184 | 3,560 | 1,459 | 934 | | 281 | 20,045 |
| Undeveloped | 904 | 80 | 4,198 | 10,504 | 5,375 | 2,000 | | 1,342 | 24,403 |
| | 3,286 | 325 | 15,382 | 14,064 | 6,834 | 2,934 | | 1,623 | 44,448 |
| Changes attributable to | | | | | | | | | |
| Revisions of previous estimates | (343) | 11 | (922) | (291) | (92) | (69) | | 33 | (1,673) |
| Purchases of reserves-in-place | | | | | | | | | |
| Discoveries and extensions | 101 | | 116 | | 21 | 5 | | 2 | 245 |
| Improved recovery | 144 | | 1,755 | 344 | 71 | 6 | | 9 | 2,329 |
| Production[b] | (370) | (38) | (941) | (982) | (273) | (169) | | (82) | (2,855) |
| Sales of reserves-in-place | (25) | | (292) | (9) | | | | | (326) |
| | (493) | (27) | (284) | (938) | (273) | (227) | | (38) | (2,280) |
| **At 31 December 2006**[c] | | | | | | | | | |
| Developed | 1,968 | 242 | 10,438 | 3,932 | 1,359 | 1,032 | | 331 | 19,302 |
| Undeveloped | 825 | 56 | 4,660 | 9,194 | 5,202 | 1,675 | | 1,254 | 22,866 |
| | 2,793 | 298 | 15,098 | 13,126 | 6,561 | 2,707 | | 1,585 | 42,168 |
| **Equity-accounted entities (BP share)** | | | | | | | | | |
| At 1 January 2006 | | | | | | | | | |
| Developed | | | | 1,492 | 50 | | 1,089 | 130 | 2,761 |
| Undeveloped | | | | 848 | 26 | | 169 | 52 | 1,095 |
| | | | | 2,340 | 76 | | 1,258 | 182 | 3,856 |
| Changes attributable to | | | | | | | | | |
| Revisions of previous estimates | | | | 7 | 13 | | 217 | 47 | 284 |
| Purchases of reserves-in-place | | | | | | | | | |
| Discoveries and extensions | | | | 23 | | | | | 23 |
| Improved recovery | | | | 73 | 1 | | | | 74 |
| Production[b] | | | | (171) | (15) | | (204) | (7) | (397) |

| | | | | | |
|---|---|---|---|---|---|
| Sales of reserves-in-place | (77) | | | | (77) |
| | (145) | (1) | 13 | 40 | (93) |
| **At 31 December 2006**[d] | | | | | |
| Developed | 1,460 | 52 | 1,087 | 170 | 2,769 |
| Undeveloped | 735 | 23 | 184 | 52 | 994 |
| | 2,195 | 75 | 1,271 | 222 | 3,763 |

[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 to make lifting and sales arrangements independently.
[b] Includes 178 billion cubic feet of natural gas consumed in operations, 147 billion cubic feet in subsidiaries, 31 billion cubic feet in equity-accounted entities and excludes 8.3 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.
[c] Includes 3,537 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 99 billion cubic feet of natural gas in respect of the 7.77% minority interest in TNK-BP.

## Supplementary information on oil and natural gas (unaudited) *continued*

### Movement in estimated net proved reserves

2005

**Crude oil[a]** million barrels

| | UK | Rest of Europe | US | Rest of Americas | Asia Pacific | Africa | Russia | Other | Total |
|---|---|---|---|---|---|---|---|---|---|
| **Subsidiaries** | | | | | | | | | |
| At 1 January 2005 | | | | | | | | | |
| Developed | 559 | 231 | 2,041 | 311 | 65 | 204 | | 62 | 3,473 |
| Undeveloped | 210 | 109 | 1,211 | 299 | 85 | 643 | | 725 | 3,282 |
| | 769 | 340 | 3,252 | 610 | 150 | 847 | | 787 | 6,755 |
| Changes attributable to | | | | | | | | | |
| Revisions of previous estimates | (31) | (8) | 103 | (21) | 21 | (190) | | (148) | (274) |
| Purchases of reserves-in-place | | | 2 | | | | | | 2 |
| Discoveries and extensions | 11 | | 40 | 3 | 11 | 83 | | | 148 |
| Improved recovery | 32 | 21 | 217 | 1 | | 2 | | 7 | 280 |
| Production[b] | (101) | (27) | (200) | (53) | (17) | (64) | | (34) | (496) |
| Sales of reserves-in-place | | (15) | (1) | (39) | | | | | (55) |
| | (89) | (29) | 161 | (109) | 15 | (169) | | (175) | (395) |
| **At 31 December 2005[c]** | | | | | | | | | |
| Developed | 496 | 225 | 1,984 | 215 | 70 | 142 | | 69 | 3,201 |
| Undeveloped | 184 | 86 | 1,429 | 286 | 95 | 536 | | 543 | 3,159 |
| | 680 | 311 | 3,413[e] | 501 | 165 | 678 | | 612 | 6,360 |
| **Equity-accounted entities (BP share)** | | | | | | | | | |
| At 1 January 2005 | | | | | | | | | |
| Developed | | | | 204 | 1 | | 1,863 | 592 | 2,660 |
| Undeveloped | | | | 125 | | | 294 | 100 | 519 |
| | | | | 329 | 1 | | 2,157 | 692 | 3,179 |
| Changes attributable to | | | | | | | | | |
| Revisions of previous estimates | | | | 1 | | | 319 | 119 | 439 |
| Purchases of reserves-in-place | | | | | | | | | |
| Discoveries and extensions | | | | 2 | | | | | 2 |
| Improved recovery | | | | 25 | | | | | 25 |
| Production | | | | (26) | | | (333) | (57) | (416) |
| Sales of reserves-in-place | | | | | | | (24) | | (24) |

| | | | | | |
|---|---|---|---|---|---|
| | 2 | | (38) | 62 | 26 |
| **At 31 December 2005[d]** | | | | | |
| Developed | 207 | 1 | 1,688 | 590 | 2,486 |
| Undeveloped | 124 | | 431 | 164 | 719 |
| | 331 | 1 | 2,119 | 754 | 3,205 |

[a] Crude oil includes natural gas liquids (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 to make lifting and sales arrangements independently.
[b] Excludes NGLs from processing plants in which an interest is held of 58 thousand barrels a day.
[c] Includes 818 million barrels of NGLs. Also includes 29 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 33 million barrels of NGLs. Also includes 95 million barrels of crude oil in respect of the 4.47% minority interest in TNK-BP.
[e] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 85 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.

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## Supplementary information on oil and natural gas (unaudited) *continued*

### Movement in estimated net proved reserves

2005

| Natural gas[a] | | | | | | | | | billion cubic feet |
|---|---|---|---|---|---|---|---|---|---|
| | UK | Rest of Europe | US | Rest of Americas | Asia Pacific | Africa | Russia | Other | Total |
| **Subsidiaries** | | | | | | | | | |
| At 1 January 2005 | | | | | | | | | |
| Developed | 2,498 | 248 | 10,811 | 4,101 | 1,624 | 1,015 | | 282 | 20,579 |
| Undeveloped | 1,183 | 1,254 | 3,270 | 10,663 | 5,419 | 1,886 | | 1,396 | 25,071 |
| | 3,681 | 1,502 | 14,081 | 14,764 | 7,043 | 2,901 | | 1,678 | 45,650 |
| Changes attributable to | | | | | | | | | |
| Revisions of previous estimates | (102) | 11 | 447 | 104 | (133) | 152 | | 15 | 494 |
| Purchases of reserves-in-place | | | 66 | 2 | | | | | 68 |
| Discoveries and extensions | 21 | 19 | 47 | 225 | 204 | 44 | | | 560 |
| Improved recovery | 111 | 19 | 1,773 | 87 | | | | 10 | 2,000 |
| Production[b] | (425) | (44) | (1,018) | (888) | (280) | (163) | | (80) | (2,898) |
| Sales of reserves-in-place | | (1,182) | (14) | (230) | | | | | (1,426) |
| | (395) | (1,177) | 1,301 | (700) | (209) | 33 | | (55) | (1,202) |
| **At 31 December 2005[c]** | | | | | | | | | |
| Developed | 2,382 | 245 | 11,184 | 3,560 | 1,459 | 934 | | 281 | 20,045 |
| Undeveloped | 904 | 80 | 4,198 | 10,504 | 5,375 | 2,000 | | 1,342 | 24,403 |
| | 3,286 | 325 | 15,382 | 14,064 | 6,834 | 2,934 | | 1,623 | 44,448 |
| **Equity-accounted entities (BP share)** | | | | | | | | | |
| At 1 January 2005 | | | | | | | | | |
| Developed | | | | 1,397 | 107 | | 214 | 60 | 1,778 |
| Undeveloped | | | | 977 | 69 | | 10 | 23 | 1,079 |
| | | | | 2,374 | 176 | | 224 | 83 | 2,857 |
| Changes attributable to | | | | | | | | | |
| Revisions of previous estimates | | | | 26 | (81) | | 1,337 | 102 | 1,384 |
| Purchases of reserves-in-place | | | | | | | | | |
| Discoveries and extensions | | | | 28 | | | | | 28 |
| Improved recovery | | | | 66 | | | | | 66 |
| Production[b] | | | | (154) | (19) | | (184) | (3) | (360) |
| Sales of reserves-in-place | | | | | | | (119) | | (119) |

| | | | | | |
|---|---|---|---|---|---|
| | (34) | (100) | 1,034 | 99 | 999 |
| **At 31 December 2005[d]** | | | | | |
| Developed | 1,492 | 50 | 1,089 | 130 | 2,761 |
| Undeveloped | 848 | 26 | 169 | 52 | 1,095 |
| | 2,340 | 76 | 1,258 | 182 | 3,856 |

[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 to make lifting and sales arrangements independently.
[b] Includes 174 billion cubic feet of natural gas consumed in operations, 147 billion cubic feet in subsidiaries and 27 billion cubic feet in equity-accounted entities.
[c] Includes 3,812 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 57 billion cubic feet of natural gas in respect of the 4.47% minority interest in TNK-BP.

## 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 measures of discounted future net cash flows, and changes therein, relating to crude oil and natural gas production from the group s estimated proved reserves. This information is prepared in compliance with the requirements of FASB Statement of Financial Accounting Standards No. 69 Disclosures about Oil and Gas Producing Activities .

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 year-end crude oil and natural gas prices and exchange rates. Furthermore, both 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 assumptions on which it is based and its lack of comparability with the historical cost information presented in the financial statements.

$ million

| | UK | Rest of Europe | US | Rest of Americas | Asia Pacific | Africa | Other | Total |
|---|---|---|---|---|---|---|---|---|
| At 31 December 2007 | | | | | | | | |
| Future cash inflows[a] | **72,100** | **29,500** | **350,100** | **67,700** | **47,600** | **63,300** | **49,400** | **679,700** |
| Future production cost[b] | **27,500** | **7,500** | **109,800** | **17,900** | **12,800** | **9,900** | **8,500** | **193,900** |
| Future development cost[b] | **4,000** | **3,300** | **21,900** | **6,500** | **4,100** | **8,300** | **3,500** | **51,600** |
| Future taxation[c] | **20,200** | **13,000** | **71,600** | **21,700** | **9,700** | **17,100** | **8,700** | **162,000** |
| Future net cash flows | **20,400** | **5,700** | **146,800** | **21,600** | **21,000** | **28,000** | **28,700** | **272,200** |
| 10% annual discount[d] | **6,500** | **2,800** | **76,000** | **9,500** | **10,300** | **9,400** | **11,500** | **126,000** |
| Standardized measure of discounted future net cash flows[e] | **13,900** | **2,900** | **70,800** | **12,100** | **10,700** | **18,600** | **17,200** | **146,200** |
| At 31 December 2006 | | | | | | | | |
| Future cash inflows[a] | 45,300 | 18,200 | 218,900 | 46,800 | 36,800 | 47,700 | 36,200 | 449,900 |
| Future production cost[b] | 20,700 | 4,700 | 71,300 | 14,900 | 9,400 | 8,700 | 7,200 | 136,900 |
| Future development cost[b] | 3,300 | 1,500 | 18,600 | 4,900 | 3,800 | 6,600 | 3,900 | 42,600 |
| Future taxation[c] | 10,300 | 9,400 | 43,100 | 12,900 | 7,000 | 10,600 | 5,800 | 99,100 |
| Future net cash flows | 11,000 | 2,600 | 85,900 | 14,100 | 16,600 | 21,800 | 19,300 | 171,300 |
| 10% annual discount[d] | 3,200 | 1,000 | 45,600 | 6,200 | 9,000 | 8,400 | 7,300 | 80,700 |
| Standardized measure of discounted future net cash flows[e] | 7,800 | 1,600 | 40,300 | 7,900 | 7,600 | 13,400 | 12,000 | 90,600 |
| At 31 December 2005 | | | | | | | | |
| Future cash inflows[a] | 68,200 | 18,600 | 261,800 | 75,600 | 34,600 | 46,300 | 38,200 | 543,300 |
| Future production cost[b] | 21,700 | 3,900 | 55,800 | 15,200 | 6,900 | 7,800 | 7,400 | 118,700 |
| Future development cost[b] | 2,200 | 1,000 | 16,300 | 4,300 | 3,500 | 6,100 | 4,600 | 38,000 |
| Future taxation[c] | 17,600 | 10,200 | 65,300 | 28,800 | 7,300 | 10,600 | 6,000 | 145,800 |
| Future net cash flows | 26,700 | 3,500 | 124,400 | 27,300 | 16,900 | 21,800 | 20,200 | 240,800 |
| 10% annual discount[d] | 8,500 | 1,400 | 63,700 | 12,600 | 9,600 | 8,700 | 8,100 | 112,600 |
| Standardized measure of discounted future net cash flows[e] | 18,200 | 2,100 | 60,700 | 14,700 | 7,300 | 13,100 | 12,100 | 128,200 |

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

| | | | $ million |
|---|---|---|---|
| | **2007** | 2006 | 2005 |
| Sales and transfers of oil and gas produced, net of production costs | **(28,300)** | (35,800) | (24,300) |
| Development costs incurred during the year | **9,400** | 8,200 | 7,100 |
| Extensions, discoveries and improved recovery, less related costs | **12,300** | 7,900 | 10,100 |
| Net changes in prices and production cost | **102,100** | (43,900) | 84,200 |
| Revisions of previous reserves estimates | **(12,200)** | (9,500) | (17,400) |
| Net change in taxation | **(28,300)** | 32,200 | (20,500) |
| Future development costs | **(7,800)** | (7,000) | (5,800) |
| Net change in purchase and sales of reserves-in-place | **(700)** | (2,500) | (2,500) |
| Addition of 10% annual discount | **9,100** | 12,800 | 8,800 |
| Total change in the standardized measure during the year[f] | **55,600** | (37,600) | 39,700 |

[a] The year-end marker prices used were Brent $96.02/bbl, Henry Hub $7.10/mmBtu (2006 Brent $58.93/bbl, Henry Hub $5.52/mmBtu; 2005 Brent $58.21/bbl, Henry Hub $9.52/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 $2,300 million at 31 December 2007 ($1,300 million at 31 December 2006 and $2,700 million at 31 December 2005).

[f] Total change in the standardized measure during the year includes the effect of exchange rate movements.

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## Supplementary information on oil and natural gas (unaudited) *continued*

### Equity-accounted entities

In addition, at 31 December 2007, the group s share of the standardized measure of discounted future net cash flows of equity-accounted entities amounted to $28,300 million ($14,700 million at 31 December 2006 and $19,300 million at 31 December 2005).

## Operational and statistical information

The following tables present operational and statistical information related to production, drilling, productive wells and acreage.

### Crude oil and natural gas production

The following table shows crude oil and natural gas production for the years ended 31 December 2007, 2006 and 2005.

**Production for the year**[a]

| | UK | Rest of Europe | US | Rest of Americas | Asia Pacific | Africa | Russia | Other | Total |
|---|---|---|---|---|---|---|---|---|---|
| Subsidiaries | | | | | | | | | |
| Crude oil[b] | | | | | | | | | thousand barrels per day |
| **2007** | **201** | **51** | **513** | **82** | **41** | **195** | | **221** | **1,304** |
| 2006 | 253 | 61 | 547 | 108 | 44 | 177 | | 161 | 1,351 |
| 2005 | 277 | 75 | 612 | 144 | 47 | 175 | | 93 | 1,423 |
| Natural gas[c] | | | | | | | | | million cubic feet per day |
| **2007** | **768** | **29** | **2,174** | **2,798** | **699** | **468** | | **286** | **7,222** |
| 2006 | 936 | 91 | 2,376 | 2,645 | 727 | 430 | | 207 | 7,412 |
| 2005 | 1,090 | 108 | 2,546 | 2,384 | 751 | 422 | | 211 | 7,512 |
| Equity-accounted entities (BP share) | | | | | | | | | |
| Crude oil[b] | | | | | | | | | thousand barrels per day |
| **2007** | | | | **77** | **1** | | **832** | **200** | **1,110** |
| 2006 | | | | 77 | 1 | | 876 | 170 | 1,124 |
| 2005 | | | | 71 | | | 911 | 157 | 1,139 |
| Natural gas[c] | | | | | | | | | million cubic feet per day |
| **2007** | | | | **429** | **33** | | **451** | **8** | **921** |
| 2006 | | | | 416 | 37 | | 544 | 8 | 1,005 |
| 2005 | | | | 375 | 47 | | 482 | 8 | 912 |

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 of 31 December 2007. 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.

| | | UK | Rest of Europe | US | Rest of Americas | Asia Pacific | Africa | Russia | Other | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Number of productive wells at 31 December 2007 | | | | | | | | | | |
| Oil wells[a] | gross | **274** | **81** | **5,885** | **3,524** | **352** | **646** | **19,393** | **1,536** | **31,691** |
| | net | **147** | **26** | **2,093** | **1,925** | **152** | **538** | **8,252** | **255** | **13,388** |
| Gas wells[b] | gross | **303** | | **18,173** | **2,274** | **681** | **90** | **47** | **131** | **21,699** |
| | net | **140** | | **11,462** | **1,383** | **249** | **42** | **23** | **88** | **13,387** |

[a] Includes approximately 1,016 gross (289 net) multiple completion wells (more than one formation producing into the same well bore).
[b] Includes approximately 2,489 gross (1,591 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.

| | | UK | Rest of Europe | US | Rest of Americas | Asia Pacific | Africa | Russia | Other | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Oil and natural gas acreage at 31 December 2007 | | | | | | | | | | Thousands of acres |
| Developed | gross | **428** | **143** | **7,414** | **2,793** | **1,235** | **541** | **4,071** | **1,870** | **18,495** |
| | net | **201** | **34** | **4,742** | **1,310** | **319** | **225** | **1,768** | **690** | **9,289** |
| Undeveloped[a] | gross | **1,696** | **505** | **6,451** | **11,529** | **7,450** | **15,759** | **13,821** | **14,412** | **71,623** |
| | net | **967** | **227** | **4,574** | **5,912** | **2,782** | **9,755** | **5,777** | **5,969** | **35,963** |

[a] Undeveloped acreage includes leases and concessions.

## Supplementary information on oil and natural gas (unaudited) *continued*

### 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.

| | UK | Rest of Europe | US | Rest of Americas | Asia Pacific | Africa | Russia | Other | Total |
|---|---|---|---|---|---|---|---|---|---|
| 2007 | | | | | | | | | |
| Exploratory | | | | | | | | | |
| Productive | **1.6** | | **4.1** | **0.5** | **1.1** | **6.1** | **16.0** | **1.7** | **31.1** |
| Dry | | | **0.7** | **0.5** | **0.4** | **1.6** | **9.0** | **1.0** | **13.2** |
| Development | | | | | | | | | |
| Productive | **0.4** | **0.8** | **401.2** | **46.0** | **13.8** | **15.3** | **246.0** | **15.8** | **739.3** |
| Dry | **0.6** | | **4.2** | **8.8** | | | **9.5** | | **23.1** |
| 2006 | | | | | | | | | |
| Exploratory | | | | | | | | | |
| Productive | 0.1 | 0.1 | 2.9 | 0.5 | 1.0 | 3.2 | 15.6 | 1.4 | 24.8 |
| Dry | | | 7.4 | 1.0 | 1.5 | 0.5 | 5.7 | 0.3 | 16.4 |
| Development | | | | | | | | | |
| Productive | 4.9 | 1.6 | 418.8 | 154.0 | 12.4 | 23.8 | 227.2 | 14.5 | 857.2 |
| Dry | | | 4.5 | 5.0 | 0.2 | | 20.8 | 1.0 | 31.5 |
| 2005 | | | | | | | | | |
| Exploratory | | | | | | | | | |
| Productive | 0.5 | 0.8 | 10.7 | 2.0 | 0.3 | 2.0 | 14.5 | | 30.8 |
| Dry | 0.3 | | 6.4 | 1.0 | 0.3 | 1.3 | 5.2 | | 14.5 |
| Development | | | | | | | | | |
| Productive | 10.6 | 3.5 | 473.9 | 151.7 | 22.7 | 17.9 | 212.8 | 12.1 | 905.2 |
| Dry | | 0.3 | 5.0 | 3.3 | 0.4 | 1.0 | 17.7 | 0.3 | 28.0 |

### 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 2007. Suspended development wells and long-term suspended exploratory wells are also included in the table.

| | UK | Rest of Europe | US | Rest of Americas | Asia Pacific | Africa | Russia | Other | Total |
|---|---|---|---|---|---|---|---|---|---|
| At 31 December 2007 | | | | | | | | | |
| Exploratory | | | | | | | | | |
| Gross | | **1** | **26** | **5** | **1** | **3** | **28** | **2** | **66** |
| Net | | **0.5** | **12.1** | **1.9** | **0.2** | **1.3** | **13.5** | **0.5** | **30.0** |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Development | | | | | | | | | |
| Gross | **6** | **2** | **258** | **39** | **12** | **25** | **30** | **9** | **381** |
| Net | **2.5** | **0.5** | **130.5** | **23.1** | **5.0** | **8.9** | **12.5** | **2.7** | **185.7** |

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## 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: 4 March 2008