BP PLC
Form 20-F
March 06, 2007

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 20-F

(Mark One)

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

For the fiscal year ended 31 December 2006
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)

Title of each class	Name of each exchange on which registered
Ordinary Shares of 25c each	**New York Stock Exchange***
	Chicago Stock Exchange*
	NYSE Arca*

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

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

None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act.

None

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

Ordinary Shares of 25c each	**19,510,496,490**
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 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

Proved oil and gas reserves Proved reserves are defined by the Securities and Exchange Commission (SEC) in Rule 4-10(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 are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are 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 of 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

ADR American depositary receipt.

ADS American depositary share.

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 a 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.

Barrel 42 US gallons.

b/d Barrels per day.

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.

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.

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.

mmcf/d million cubic feet per day.

MTBE Methyl tertiary butyl ether.

NGLs Natural gas liquids.

OPEC Organisation 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.

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.

UK GAAP Generally Accepted Accounting Practice in the UK.

US or USA United States of America.

US GAAP Generally Accepted Accounting Principles in the US.

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Performance review

Selected financial and operating information

This information, insofar as it relates to 2006, has been extracted or derived from the audited financial statements of the BP group presented on pages 85-193. The selected information should be read in conjunction with the audited financial statements and related Notes elsewhere herein.

The financial information for 2005 and 2004 has been restated to reflect the following, all with effect from 1 January 2006: (a) the transfer of three equity-accounted entities from Other businesses and corporate to Refining and Marketing following the sale of Innovene; (b) the transfer of certain mid-stream assets and activities from Refining and Marketing and Exploration and Production to Gas, Power and Renewables; and (c) the transfer of Hydrogen for Transport activities from Gas, Power and Renewables to Refining and Marketing. *(See Financial statements — Note 2 on page 101 for further details.)*

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. Under US GAAP, Innovene operations would not be classified as discontinued operations due to BP’s continuing customer/supplier arrangements with Innovene. For a full description of the differences between IFRS and US GAAP, see Financial statements — Note 53 on page 169.

IFRS $ million except per share amounts

	2006	2005	2004	2003
Income statement data				
Sales and other operating revenues from continuing operations[a]	**265,906**	239,792	192,024	164,653
Profit before interest and taxation from continuing operations[a]	**35,658**	32,182	25,746	18,776
Profit from continuing operations[a]	**22,626**	22,133	17,884	12,681
Profit for the year	**22,601**	22,317	17,262	12,618
Profit for the year attributable to BP shareholders	**22,315**	22,026	17,075	12,448
Capital expenditure and acquisitions[b]	**17,231**	14,149	16,651	19,623
Per ordinary share — cents				
Profit for the year attributable to BP shareholders				
Basic	**111.41**	104.25	78.24	56.14
Diluted	**110.56**	103.05	76.87	55.61
Profit from continuing operations attributable to BP shareholders				
Basic	**111.54**	103.38	81.09	56.42
Diluted	**110.68**	102.19	79.66	55.89
Dividends per share — cents	**38.40**	34.85	27.70	25.50

Dividends per share pence	**21.104**	19.152	15.251	15.658
Ordinary share data[c]				
Average number outstanding of 25 cent ordinary shares (shares million undiluted)	**20,028**	21,126	21,821	22,171
Average number outstanding of 25 cent ordinary shares (shares million diluted)	**20,195**	21,411	22,293	22,424
Balance sheet data				
Total assets	**217,601**	206,914	194,630	172,491
Net assets	**85,465**	80,450	78,235	70,264
Share capital	**5,385**	5,185	5,403	5,552
BP shareholders equity	**84,624**	79,661	76,892	69,139
Finance debt due after more than one year	**11,086**	10,230	12,907	12,869
Net debt to net debt plus equity	**20%**	17%	22	22%

Selected historical financial data is based on financial statements prepared in accordance with IFRS and accordingly is shown for the four years subsequent to the date of transition to IFRS.

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US GAAP

	$ million except per share amounts				
	2006	2005	2004	2003	2002
Income statement data					
Revenues[d]	**265,906**	252,168	203,303	173,615	145,991
Profit for the year attributable to BP shareholders[d]	**21,116**	19,642	17,090	12,941	8,109
Comprehensive income	**23,125**	17,053	17,371	19,689	10,256
Profit per ordinary share cents					
Basic	**105.42**	92.96	78.31	58.36	36.20
Diluted	**104.63**	91.91	76.88	57.79	36.02
Profit per American depositary share cents					
Basic	**632.52**	557.76	469.86	350.16	217.20
Diluted	**627.78**	551.46	461.28	346.74	216.12
Balance sheet data					
Total assets	**219,288**	213,722	206,139	186,576	164,103
Net assets	**87,358**	85,936	86,435	80,292	67,274
BP shareholders equity	**86,517**	85,147	85,092	79,167	66,636

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 5 on page 103)*. Under US GAAP, Innovene is not treated as a discontinued operation.

b There were no significant acquisitions in 2006 or in 2005. Capital expenditure in 2006 includes $1 billion in respect of our investment in Rosneft. Capital expenditure and acquisitions for 2004 includes $1,354 million for including TNKs interest in Slavneft within TNK-BP and $1,355 million for the acquisition of Solvays interests in BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America. 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 last five years have been financed from cash flow from operations, disposal proceeds and external financing.

c The number of ordinary shares shown have been used to calculate per share amounts for both IFRS and US GAAP.

d Under US GAAP, Innovene is not treated as a discontinued operation. *(See Financial statements Note 5 on page 103)*. As such, the results of Innovene are included within revenues and profit for the year, as adjusted to accord with US GAAP.

Production and net proved oil and natural gas reserves

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

	2006	2005	2004	2003	2002
Crude oil production for subsidiaries (thousand barrels per day)	1,351	1,423	1,480	1,615	1,766
Crude oil production for equity-accounted entities (thousand barrels per day)	1,124	1,139	1,051	506	252
Natural gas production for subsidiaries (million cubic feet per day)	7,412	7,512	7,624	8,092	8,324
Natural gas production for equity-accounted entities (million cubic feet per day)	1,005	912	879	521	383
Estimated net proved crude oil reserves for subsidiaries (million barrels)a b	5,893	6,360	6,755	7,214	7,762
Estimated net proved crude oil reserves for equity-accounted entities (million barrels)a c	3,888	3,205	3,179	2,867	1,403
Estimated net proved natural gas reserves for subsidiaries (billion cubic feet)a d	42,168	44,448	45,650	45,155	45,844
Estimated net proved natural gas reserves for equity-accounted entities (billion cubic feet)a e	3,763	3,856	2,857	2,869	2,945

a Net proved reserves of crude oil and natural gas exclude production royalties due to others, whether royalty is payable in cash or in kind.

b Includes 23 million barrels (29 million barrels at 31 December 2005 and 40 million barrels at 31 December 2004) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

c Includes 179 million barrels (95 million barrels at 31 December 2005 and 127 million barrels at 31 December 2004) in respect of the 6.29% minority interest in TNK-BP (4.47% at 31 December 2005 and 5.9% at 31 December 2004).

d Includes 3,537 billion cubic feet of natural gas (3,812 billion cubic feet at 31 December 2005 and 4,064 billion cubic feet at 31 December 2004) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

e Includes 99 billion cubic feet (57 billion cubic feet at 31 December 2005 and 13 billion cubic feet at 31 December 2004) in respect of the 7.77% minority interest in TNK-BP (4.47% at 31 December 2005 and 5.9% at 31 December 2004).

During 2006, 329 million barrels of oil and natural gas, on an oil equivalent* basis (mmboe), were added to BPs proved reserves for subsidiaries (excluding purchases and sales). After allowing for production, which amounted to 963mmboe, BPs proved reserves for subsidiaries were 13,163mmboe at 31 December 2006. These proved reserves are mainly located in the US (44%), Rest of Americas (20%), Asia Pacific (10%), Africa (9%) and the UK (8%).

For equity-accounted entities, 1,306mmboe were added to proved reserves (excluding purchases and sales), production was 479mmboe and proved reserves were 4,537mmboe at 31 December 2006.

* 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. Inability to complete planned disposals and/or lack of material positions in new markets 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 (especially in the Middle East) and the outcome of meetings of OPEC can particularly affect world supply and oil prices. 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.

Socio-political

We have operations in developing 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.

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 adequately to determine 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.

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.

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

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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 or sea. 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 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 *(see page 10)* 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 implementation of our plans. Inability to develop the human capacity and capability across the organization could jeopardize performance delivery.

Forward-looking statement

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, (i) certain statements in Performance review (pages 6-57) with regard to management aims and objectives, future capital expenditure, future hydrocarbon production volume, date or period(s) in which production is scheduled or expected to come on stream or a project or action is scheduled or expected to be completed, capacity of planned plants or facilities, the timing of divestments and impact of health, safety and environmental regulations; (ii) the statements in Performance review (pages 10-39) with regard to planned expansion, investment or other projects and future regulatory actions; (iii) the statements in Performance review (pages 40-57) with regard to the plans of the group, cash flows, opportunities for material acquisitions, the cost of 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 cash flows, future levels of capital expenditure and divestments, working capital, future production volumes, the renewal of borrowing facilities, shareholder distributions and share buybacks and expected payments under contractual and commercial commitments; and (iv) under "Outlook" with regard to global and certain regional economies, oil and gas prices and realizations, expectations for supply and demand, refining and marketing margins; 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 on stream; 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" above. 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 British Petroleum Company p.l.c., 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. Telephone +44 (0)20 7496 4000. Our agent in the US is BP America Inc., 4101 Winfield Road, Warrenville, Illinois 60555. Telephone +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 cover three business segments, supported by a number of organizational elements comprising group functions or regions.

The three business segments are 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 (upstream activities), together with related pipeline, transportation and processing activities (midstream activities). The activities of Refining and Marketing include oil supply and trading and the manufacture and marketing of petroleum products, including aromatics and acetyls, as well as refining and marketing. Gas, Power and Renewables activities include 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 management framework addresses risks and how to respond to them. Each component of the framework 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 five-year and annual plans (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 BPs performance.

As the groups business segments are managed on a global, not on a 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 70% of the groups 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 the UK and the Rest of Europe.

We believe that BP has a strong portfolio of assets in each of its main segments:

- In Exploration and Production, we have upstream interests in 26 countries. In addition to our drive to maximize the value of our existing portfolio, we are continuing to develop new profit centres. Exploration and Production activities are managed through operating units that are accountable for the day-to-day management of the segments 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 new profit centres are in Asia Pacific (Australia, Vietnam, Indonesia and China), Azerbaijan, North Africa (Algeria), Angola, Trinidad & Tobago and the deepwater Gulf of Mexico; and in Russia/Kazakhstan (including our operations in TNK-BP, Sakhalin and LukArco), where we believe we have competitive advantage and which 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. We market under the Amoco and BP brands in the Midwest, East and Southeast and under the ARCO brand on the West Coast of the US, 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 and 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 growing markets such as China and India.
- In Gas, Power and Renewables, we have a growing marketing and trading business in the US, Canada, UK and continental Europe. Our marketing and trading activities include natural gas, power and NGLs. Our international natural gas monetization activities identify and capture worldwide opportunities for our upstream natural gas resources and are focused on growing natural gas markets, including the US, Canada, Spain and many of the emerging markets of the Asia Pacific region, notably China. We have a significant NGLs processing and marketing business in North America. In 2005, we established BP Alternative Energy, which aims to extend significantly our capabilities in solar, wind, hydrogen power and gas-fired power generation. Alternative Energy has solar production facilities in US, Spain and India and Australia, wind farms in the Netherlands and a substantial portfolio of development projects in the US. We are advancing development of hydrogen power plants and are involved in power projects in the US, UK, Spain and South Korea.

Through non-US subsidiaries or other entities, BP conducts or has conducted limited marketing, licensing and trading activities and technical studies in certain countries subject to US sanctions, in particular in Iran and with Iranian counterparties, including the National Iranian Oil Company (NIOC) and affiliated entities, and has a small representative office in Iran. BP believes that these activities are immaterial to the group. In addition, BP has interests in, and is the operator of, two fields outside Iran in which NIOC and an affiliated entity have interests. However, BP does not seek to obtain from the government of Iran licences or agreements for oil and gas projects in Iran and does not own or operate any refineries or chemicals plants in Iran.

Acquisitions and disposals

In 2006, there were no significant acquisitions. BP purchased 9.6% of the shares issued under Rosnefts IPO for a consideration of $1 billion (included in capital expenditure). This represents 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.

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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.

On 2 November 2004, Solvay exercised its option to sell its interests in BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America to BP. Solvay held 50% of BP Solvay Polyethylene Europe and 51% of BP Solvay Polyethylene North America. On completion, the two entities, which manufactured and marketed high-density polyethylene, became wholly owned subsidiaries of BP. The total consideration for the acquisition was $1,391 million. These two entities were subsequently included as part of the sale of Innovene to INEOS *(see above).*

During 2004, BP China and Sinopec announced the establishment of the BP-Sinopec (Zhejiang) Petroleum Co. Ltd, a retail joint venture between BP and Sinopec. Based on the existing service station network of Sinopec, the 30-year dual-branded joint venture has plans to build, operate and manage a network of 500 service stations in Hangzhou, Ningbo and Shaoxing. Also during 2004, BP China and PetroChina announced the establishment of BP-PetroChina Petroleum Company Limited. Located in Guangdong, one of the most developed provinces in China, the 30-year dual-branded joint venture is intended to acquire, build, operate and manage 500 service stations in the province within three years of establishment. The initial investment in both joint ventures amounted to $106 million. *(See Refining and Marketing on page 27 for further details.)*

Disposal proceeds in 2004 were $4,961 million, which included $2.3 billion from the sale of the group's investments in PetroChina and Sinopec. Additionally, it included proceeds from the sale of various oil and gas properties, the sale of our interest in Singapore Refining Company Private Limited, the sale of our specialty intermediate chemicals and Fabrics and Fibres businesses and the sale of two NGLs plants.

Recent development

In March 2007, BP announced its intention to acquire Chevron’s Netherlands manufacturing company, Texaco Raffinaderij Pernis B.V., subject to required regulatory approvals. The acquisition includes 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 22.8% shareholding in the TEAM joint venture crude terminal and shareholdings in two local pipelines linking the TEAM terminal to the refinery. Completion is expected by April 2007.

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Exploration and production

Our Exploration and Production business includes upstream and midstream activities in 26 countries, including the US, the UK, Angola, Azerbaijan, Canada, Egypt, Russia, Trinidad & Tobago (Trinidad) and locations within Asia Pacific, Latin America 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, Angola, Egypt, Russia and Algeria. Major development areas include the deepwater Gulf of Mexico, Azerbaijan, Algeria, Angola, Egypt and Asia Pacific. During 2006, 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
	2006	2005[a]	2004[a]
Sales and other operating revenues from continuing operations	**52,600**	47,210	34,700
Profit before interest and tax from continuing operations	**29,629**	25,502	18,085
Total assets	**99,310**	93,447	85,808
Capital expenditure and acquisitions	**13,118**	10,237	11,002

			$ per barrel
Average BP crude oil realizations[b]	**61.91**	50.27	36.45
Average BP NGL realizations[b]	**37.17**	33.23	26.75
Average BP liquids realizationsbc	**59.23**	48.51	35.39
Average West Texas Intermediate oil price	**66.02**	56.58	41.49
Average Brent oil price	**65.14**	54.48	38.27

			$ per thousand cubic feet
Average BP natural gas realizations[b]	**4.72**	4.90	3.86
Average BP US natural gas realizations[b]	**5.74**	6.78	5.11

$ per mmBtu

Average Henry Hub gas price[d]	**7.24**	8.65	6.13

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

a With effect from 1 January 2006, we transferred the Phu My Phase 3 combined cycle gas turbine plant in Vietnam to the Gas, Power and Renewables segment. The 2005 and 2004 data above has been restated to reflect this transfer.
b The Exploration and Production business does not undertake any hedging activity. Consequently, realizations reflect the market price achieved. Realizations are based on sales of consolidated subsidiaries only this excludes equity-accounted entities.
c Crude oil and natural gas liquids.
d Henry Hub First of Month Index.

Our activities are divided among existing profit centres our operations in Alaska, Egypt, Latin America (including Argentina, Bolivia, Colombia and Venezuela), Middle East (including Abu Dhabi, India, Sharjah and Pakistan), North America Gas (onshore US and Canada) and the North Sea (UK, Netherlands and Norway); and new profit centres our operations in Asia Pacific (Australia, Vietnam, Indonesia and China), Azerbaijan, North Africa (Algeria), Angola, Trinidad and the deepwater Gulf of Mexico; and Russia/Kazakhstan (this includes our operations in TNK-BP, Sakhalin and LukArco).

Operations in Argentina, Bolivia, Abu Dhabi, Kazakhstan and the TNK-BP and 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 with improving returns by:

- Focusing on finding the largest fields, concentrating our involvement in a limited number of the worlds 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.

This strategy is underpinned by a focused exploration strategy in areas with the potential for large oil and natural gas fields as new profit centres. Through the application of advanced technology and significant investment, we have gained a strong position in many of these areas. Within our existing profit centres, we seek to manage the decline through the application of technology, reservoir management, maintaining operating efficiency and investing in new projects. We also continually review our existing assets and dispose of them when the opportunities for future investment are no longer competitive compared with other opportunities within our portfolio and offer greater value to another operator.

In support of growth, total capital expenditure and acquisitions in 2006 was $13.1 billion (2005 $10.2 billion and 2004 $11.0 billion). Capital expenditure in 2006 included our investment in Rosnefts IPO of $1 billion. There were no significant acquisitions in 2006 or 2005. Acquisitions in 2004 included some $1.4 billion of additional investment in TNK-BP. Capital expenditure in 2007 is planned to be around $13 billion. 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 2006, excluding midstream activities, was $9,109 million, compared with $7,678 million in 2005 and $7,270 million in 2004. This increase reflects the investment we have been making in our new profit centres and the development phase of many of our major projects.

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 2006 were $1,765 million, compared with $1,266 million in 2005 and $1,039 million in 2004. 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. About 41% of 2006 exploration and appraisal costs were directed towards appraisal activity. In 2006, we participated in 85 gross (37 net) exploration and appraisal wells in 14 countries. The principal areas of activity were deepwater Gulf of Mexico, Angola, Egypt, the UK North Sea, Trinidad and Russia (outside TNK-BP).

Total exploration expense in 2006 of $1,045 million (2005 $684 million and 2004 $637 million) included the write-off of unsuccessful drilling activity in the deepwater Gulf of Mexico ($343 million), in Trinidad ($85 million), in Turkey ($80 million), onshore North America ($44 million) and others ($16 million).

In 2006, we obtained upstream rights in several new tracts, which include the following:

-

In the Gulf of Mexico, we were awarded 101 blocks (BP 100%) through the Outer Continental Shelf Lease Sales 198 and 200.

- In India, we were awarded (BP 100%) the Coal Bed Methane block BB-CBM-2005/III located in the Birbhum district of West Bengal.
- In Pakistan, we were awarded three new blocks (BP 100%), covering approximately 20,000 km^2 of the offshore Indus delta.

In early 2007:

- In Oman, we signed a production-sharing agreement to appraise and develop the Khazzan/Makarem gas fields.

In 2006, we were involved in a number of discoveries. In most cases, reserves bookings from these fields will depend on the results of ongoing

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technical and commercial evaluations, including appraisal drilling. Our most significant discoveries in 2006 included the following:

- In Angola, we made further discoveries in the ultra deepwater (greater than 1,500 metres) in Block 31 (BP 26.7% and operator) with Urano, Titania and Terra wells, bringing the total number of discoveries in Block 31 to 12.
- In the deepwater Gulf of Mexico, we made a discovery with the Kaskida well.

Reserves and production

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 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.

BP has an internal process to control the quality of reserves bookings that forms part of a holistic and integrated system of internal control. BP's process to manage reserves bookings has been centrally controlled for more than 15 years and it currently has several key elements.

The first element is the accountabilities of certain officers of the company to ensure that there are effective controls in the proved reserves verification and approval process of the group's reserves estimates and the timely reporting of the related financial impacts of proved reserves changes. These officers of the company are responsible for carrying out verification of proved reserves estimates and are independent of the operating business unit to ensure integrity and accuracy of reporting.

The second element is the 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.

The third element is 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.

The fourth element is a quarterly due diligence review, which is separate and independent from the operating business units, of proved reserves associated with properties where technical, operational or commercial issues have arisen.

The fifth element is the established criteria whereby proved reserves changes above certain thresholds require central authorization. Furthermore, the volumes booked under these authorization levels are reviewed on a periodic basis. 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 business 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 business 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.

Details of our net proved reserves of crude oil, condensate, natural gas liquids and natural gas at 31 December 2006, 2005 and 2004 and reserves changes for each of the three years then ended are set out in the

Supplementary information on oil and natural gas section beginning on page 194. We separately disclose our share of reserves held in equity-accounted companies (jointly controlled entities and associates), although we do not control these entities or the assets held by such entities.

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 2006, 17% were based on estimates prepared by group petroleum engineers and 83% were based on estimates prepared by independent engineering consultants, although all the group's oil and gas reserves held in equity-accounted companies 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 production-sharing agreements (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. Fifteen 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.

At the end of 2006, BP adopted the SEC rules for estimating reserves for all accounting and reporting purposes. Previously, BP applied the UK accounting rules contained in the Statement of Recommended Practice 'Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities' (UK SORP). These changes are explained in Financial statements – Note 3 on page 102. The company's proved reserves estimates for the year ended 31 December 2006 reflect year-end prices and 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 on the lease) within proved reserves. Consequently, these reserves quantities differ from those that would be reported under application of the UK SORP. The 2006 year-end marker prices used were Brent $58.93/bbl (2005 $58.21/bbl and 2004 $40.24/bbl) and Henry Hub $5.52/mmBtu (2005 $9.52/mmBtu and 2004 $6.01/mmBtu) . The other 2006 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 194-195.

Total hydrocarbon proved reserves, on an oil equivalent basis and excluding equity-accounted entities, comprised 13,163mmboe at 31 December 2006, a decrease of 6.1% compared with 31 December 2005. Natural gas represents about 55% of these reserves. This reduction includes net sales of 227mmboe, largely comprising a number of assets in Latin America, the UK and the US.

The proved reserves replacement ratio, excluding equity-accounted entities, was 34% (2005 68% and 2004 78%). 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

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ratio is expressed in oil equivalent terms and includes changes resulting from revisions to previous estimates, improved recovery, extensions, discoveries and other additions, excluding the impact of sales and purchases of reserves-in-place and excluding reserves related to equity-accounted entities. The proved reserves replacement ratio, including sales and purchases of reserves-in-place but excluding equity-accounted entities, was 11% (2005 40% and 2004 64%). 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.

In 2006, net additions to the group's proved reserves (excluding sales and purchases of reserves-in-place and equity-accounted entities) amounted to 329mmboe, principally through improved recovery from existing fields. Of the reserves additions through improved recovery from, and extensions to, existing fields and discoveries of new fields, approximately half 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. Major new development projects typically take one to four years from the time of initial booking to the start of production. The principal reserves additions were in the UK (Devenick, Foinaven), the US (San Juan, Seminole, Great White, Horn Mountain, Mars) and Angola (Rosa, Greater Plutonio).

Total hydrocarbon proved reserves, on an oil equivalent basis for equity-accounted entities alone, comprised 4,537mmboe at 31 December 2006, an increase of 17.2% compared with 31 December 2005. Natural gas represents about 14% of these reserves. The proved reserves replacement ratio for equity-accounted entities alone was 272% (2005 151% and 2004 114%) and the proved reserves replacement ratio for equity-accounted entities alone but including sales and purchases of reserves-in-place was 239% (2005 141% and 2004 170%).

Additions to proved developed reserves in 2006 for subsidiaries were 675mmboe, including sales and purchases. This included some reserves that were previously classified as proved undeveloped. The proved developed reserves replacement ratio (including both sales and purchases of reserves-in-place) was 70% (2005 63% and 2004 70%).

Additions to proved developed reserves in 2006 for equity-accounted entities were 936mmboe. This included some reserves that were previously classified as proved undeveloped. The proved developed reserves replacement ratio (including both sales and purchases of reserves-in-place) was 195% (2005 99% and 2004 180%).

Our total hydrocarbon production during 2006 averaged 2,629 thousand barrels of oil equivalent per day (mboe/d) for subsidiaries and 1,297mboe/d for equity-accounted entities, a decrease of 3.3% and an increase of 0.1% respectively compared with 2005. For subsidiaries, 36% of our production was in the US and 16% in the UK. For equity-accounted entities, 75% of production was from TNK-BP.

Total production for 2007 is expected to remain broadly the same as in 2006 after allowing for the impact on 2007 of divestments made in 2006. This estimate is based on the group's asset portfolio at 1 January 2007, expected start-ups in 2007 and Brent at $60/bbl, before any 2007 disposal effects and before any effects of prices above $60/bbl on volumes in PSAs.

The anticipated decline in production volumes from subsidiaries in our existing profit centres is partly mitigated by the development of new projects and the investment in incremental reserves in and around existing fields. We expect that this overall decline in production from subsidiaries in our existing profit centres will be more than compensated for by strong increases in production from subsidiaries in our new profit centres over the next few years. Production in our equity-accounted joint venture TNK-BP is expected to remain broadly constant to 2009.

The most important determinants of cash flows in relation to our oil and natural gas production are the prices of these commodities. At constant prices, cash flows from currently developed proved reserves are expected to decline in a manner consistent with anticipated production decline rates. Development activities associated with recent discoveries, as well as continued investment in these producing fields, are expected to more than offset this decline, resulting in increased operating cash flows over the next few years. Cash flows from equity-accounted entities are expected to be in the form of dividend payments. *(See Liquidity and capital resources on page 47.)*

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The following tables show BPs estimated net proved reserves as at 31 December 2006.

Estimated net proved reserves of liquids at 31 December 2006[a] [b]

	Developed	Undeveloped	million barrels Total
UK	458	146	604
Rest of Europe	189	97	286
USA	1,916	1,292	3,208
Rest of Americas	130	237	367[c]
Asia Pacific	67	86	153
Africa	193	512	705
Russia			
Other	88	482	570
Group	3,041	2,852	5,893
Equity-accounted entities			3,888[d]

Estimated net proved reserves of natural gas at 31 December 2006[a] [b]

	Developed	Undeveloped	billion cubic feet Total
UK	1,968	825	2,793
Rest of Europe	242	56	298
USA	10,438	4,660	15,098
Rest of Americas	3,932	9,194	13,126[e]
Asia Pacific	1,359	5,202	6,561
Africa	1,032	1,675	2,707
Russia			
Other	331	1,254	1,585
Group	19,302	22,866	42,168
Equity-accounted entities			3,763[f]

Net proved reserves on an oil equivalent basis (mmboe)

Group	13,163
Equity-accounted entities	4,537

a Net proved reserves of crude oil and natural gas, stated as at 31 December 2006, exclude production royalties due to others, whether payable in cash or in kind, 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 2006, 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, 18 have been in production and two, Atlantis and Thunder Horse, are expected to begin production by the end of 2007 and by the end of 2008 respectively. Two other fields are in the early stages of development.

c Includes 23 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
d Includes 179 million barrels of crude oil in respect of the 6.29% minority interest in TNK-BP.
e Includes 3,537 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
f Includes 99 billion cubic feet of natural gas in respect of the 7.77% minority interest in TNK-BP.

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The following tables show BPs production by major field for 2006, 2005 and 2004.

Liquids		%	thousand barrels per day		
			BP net share of production[a]		
Production	Field or Area	Interest	**2006**	2005	2004
Alaska	Prudhoe Bayb	26.4	**71**	89	97
	Kuparuk	39.2	**57**	62	68
	Northstarb	98.6	**38**	46	49
	Milne Pointb	100.0	**31**	37	44
	Other	Various	**27**	34	37
Total Alaska			**224**	268	295
Lower 48 onshorec	Various	Various	**125**	130	142
Gulf of Mexico deepwaterc	Na Kikab	50.0	**41**	44	27
	Horn Mountainb	66.6	**23**	26	41
	Kingb	100.0	**28**	24	26
	Mars	28.5	**19**	21	35
	Ursa	22.7	**21**	19	29
	Other	Various	**63**	64	47
Gulf of Mexico Shelfc	Other	Various	**3**	16	24
Total Gulf of Mexico			**198**	214	229
Total USA			**547**	612	666
UK offshorec	ETAPd	Various	**49**	49	55
	Foinavenb	Various	**37**	39	48
	Magnusb	85.0	**30**	30	34
	Schiehallion/Loyalb	Various	**26**	28	39
	Hardingb	70.0	**17**	22	27
	Andrewb	62.8	**7**	12	12
	Other	Various	**69**	75	89
Total UK offshore			**235**	255	304
Onshore	Wytch Farmb	67.8	**18**	22	26
Total UK			**253**	277	330
Netherlands	Various	Various	**1**	1	1
Norway	Valhallb	28.1	**21**	25	25
	Draugen	18.4	**15**	20	27
	Ulab	80.0	**14**	17	16
	Other	Various	**10**	12	8
Total Rest of Europe			**61**	75	77
Angola	Kizomba A	26.7	**54**	56	16
	Girassol	16.7	**17**	34	31
	Xikomba	26.7	**4**	10	18
	Other	Various	**58**	28	6
Australia	Various	15.8	**34**	36	36
Azerbaijan	Azeri-Chirag-Gunashlib	34.1	**145**	76	39
Canadac	Various	Various	**8**	10	11
Colombia	Variousb	Various	**34**	41	48
Egypt	Various	Various	**42**	47	57
Trinidad & Tobagoc	Variousb	100.0	**40**	40	59
Venezuelac	Various	Various	**26**	55	55
Otherc	Various	Various	**28**	26	31

Total Rest of World			**490**	459	407
Total groupe			**1,351**	1,423	1,480
Equity-accounted entities (BP share)					
Abu Dhabif	Various	Various	**163**	148	142
Argentina Pan American Energy	Various	Various	**69**	67	64
Russia TNK-BPc	Various	Various	**876**	911	831
Otherc	Various	Various	**16**	13	14
Total equity-accounted entities			**1,124**	1,139	1,051

a Net of royalty, whether payable in cash or in kind.
b BP-operated.
c 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 Urdmurtneft 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 McGees interest in the Arkoma Red Oak and Williburton fields. TNK-BP disposed of non-core producing assets in the Saratov region. In 2004, BP agreed with AAR to incorporate their 50% interest in Slavneft into TNK-BP, an equity-accounted entity. BP also acquired minor additional working interests in Canada and the US. BP diluted its working interests in Kings Peak and divested the Swordfish assets in the deepwater Gulf of Mexico. Additionally, BP sold various properties including its interest in the South Pass 60 in the Gulf of Mexico Shelf, various assets in Alberta, Canada and the Kangean PSA in Indonesia.
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 55 thousand net barrels of oil equivalent per day (mboe/d) of NGLs from processing plants in which BP has an interest (2005 58mboe/d and 2004 67mboe/d).
f The BP group holds proportionate interests, through associates, in onshore and offshore concessions in Abu Dhabi expiring in 2014 and 2018, respectively.

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Natural gas

Production	Field or Area	% Interest	BP net share of production[a] (million cubic feet per day) 2006	2005	2004
Lower 48 onshore[b]	San Juan[c]	Various	**765**	753	772
	Arkoma[c]	Various	**225**	198	183
	Hugoton[c]	Various	**137**	151	158
	Tuscaloosa[c]	Various	**86**	111	96
	Wamsutter[c]	70.5	**113**	110	105
	Jonah[c]	65.0	**133**	97	114
	Other	Various	**461**	465	514
Total Lower 48 onshore			**1,920**	1,885	1,942
Gulf of Mexico deepwater[b]	Na Kika[c]	50.0	**97**	133	133
	Marlin[c]	78.2	**16**	52	43
	Other	Various	**210**	235	313
Gulf of Mexico Shelf[b]	Other	Various	**66**	160	240
Total Gulf of Mexico			**389**	580	729
Alaska	Various	Various	**67**	81	78
Total USA			**2,376**	2,546	2,749
UK offshore[b]	Braes[d]	Various	**101**	165	147
	Bruce[c]	37.0	**107**	161	163
	West Sole[c]	100.0	**56**	55	67
	Marnock[c]	62.0	**42**	47	70
	Britannia	9.0	**42**	46	54
	Shearwater	27.5	**31**	37	76
	Armada	18.2	**28**	30	50
	Other	Various	**529**	549	547
Total UK			**936**	1,090	1,174
Netherlands	P/18-2[c]	48.7	**23**	25	34
	Other	Various	**33**	37	46
Norway	Various	Various	**35**	46	45
Total Rest of Europe			**91**	108	125
Australia	Various	15.8	**364**	367	308
Canada[b]	Various	Various	**282**	307	349
China	Yacheng[c]	34.3	**102**	98	99
Egypt	Ha’py[c]	50.0	**99**	106	80
	Other	Various	**172**	83	115
Indonesia[b]	Sanga-Sanga(direct)[c]	26.3	**84**	110	137
	Other[c]	46.0	**80**	128	144
Sharjah	Sajaa[c]	40.0	**111**	113	103
	Other	40.0	**9**	10	14
Trinidad & Tobago[b]	Kapok[c]	100.0	**946**	1,005	553
	Mahogany[c]	100.0	**321**	303	453
	Amherstia[c]	100.0	**176**	289	408
	Parang[c]	100.0	**120**	154	137
	Immortelle[c]	100.0	**219**	132	172
	Cassia[c]	100.0	**30**	83	85
	Other[c]	100.0	**453**	21	111
Other[b]	Various	Various	**441**	459	308
Total Rest of World			**4,009**	3,768	3,576
Total group[e]			**7,412**	7,512	7,624
Equity-accounted entities (BP share)					
Argentina – Pan American Energy	Various	Various	**362**	343	317
Russia – TNK-BP[b]	Various	Various	**544**	482	458
Other[b]	Various	Various	**99**	87	104
Total equity-accounted entities[b]			**1,005**	912	879

a Net of royalty, whether payable in cash or in kind.

b 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 Urdmurtneft 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. TNK-BP disposed of non-core producing assets in the Saratov region. In 2004, BP agreed with AAR to incorporate their 50% interest in Slavneft into TNK-BP, an equity-accounted entity. BP also acquired minor additional working interests in Canada and the US. BP diluted its working interests in King’s Peak and divested the Swordfish assets in the deepwater Gulf of Mexico. Additionally, BP sold various properties including its interest in the South Pass 60 in the Gulf of Mexico Shelf, various assets in Alberta, Canada and the Kangean PSA in Indonesia.

c BP-operated.

d Includes 4 million and 7 million cubic feet a day of natural gas received as in-kind tariff payments in 2005 and 2004 respectively.

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

2006 liquids production at 547 thousand barrels per day (mb/d) decreased 11% from 2005, while natural gas production at 2,376 million cubic feet per day (mmcf/d) decreased 7% compared with 2005.

Crude oil production decreased 63mb/d from 2005, with production from new projects being offset by divestments and natural reservoir decline. The NGLs component of liquids production remained essentially flat compared with 2005, with a slight decline of 2mb/d. Gas production was lower (170mmcf/d) because of divestments and natural reservoir decline.

Development expenditure in the US (excluding midstream) during 2006 was $3,579 million, compared with $2,965 million in 2005 and $3,247 million in 2004. The annual increase is the result of various development projects in progress.

On 19 April 2006, BP announced the sale of its producing properties on the Outer Continental Shelf of the Gulf of Mexico to Apache Corporation for $1.3 billion. The major part of the sale was completed in June 2006 after receiving regulatory approval. In the third quarter of 2006, we completed the sale of our remaining Gulf of Mexico Shelf assets that were subject to pre-emption rights. BP retained certain decommissioning obligations related to the disposed assets.

Our activities within the US take place in three main areas. Significant events during 2006 within each of these are indicated below.

Deepwater Gulf of Mexico

Deepwater Gulf of Mexico is one of our new profit centres and our largest area of growth in the US. In 2006, our deepwater Gulf of Mexico crude oil production was 195mb/d and gas production was 323mmcf/d.

Significant events were:

- Offshore repair work on the Thunder Horse platform (BP 75% and operator) was completed during 2006. However, tests conducted during the commissioning of the platform revealed metallurgical failure in components of the subsea system. In September 2006, we announced our plan to retrieve and replace all the subsea components we believed could be at risk. We currently estimate that this will cost around $650 million (BP net). Production is expected to start up by the end of 2008.
- The Mars platform (BP 28.5%) suffered heavy damage from Hurricane Katrina in August 2005. Production resumed in May 2006 and was 190mboe/d gross by September 2006, a 20% increase over pre- Katrina rates.
- Expansion of the Mars and Na Kika fields also continued during 2006 and first production from these projects is expected in 2007.
- Progress continued on the Atlantis project (BP 56% and operator) during 2006. The semi-submersible platform will be the deepest moored floating production facility in the world in approximately 7,100 feet of water. First oil is expected by the end of 2007.
- On 31 August 2006, we announced a significant oil exploration discovery on the Kaskida prospect in approximately 5,900 feet of water.
- Development of the King Subsea Pump project (BP 100% and operator) continued during 2006, with first production expected by the end of 2007. This is the first subsea multi-phase pump application in water depths greater than 3,000 feet.
- In July 2006, we completed the sale of our 28% interest in the Shenzi discovery to Repsol for $2,145 million.

Lower 48 states

In the Lower 48 states (Onshore), our 2006 natural gas production was 1,920mmcf/d, which was up 2% compared with 2005. Liquids production was 125mb/d, down 4% compared with 2005 as a result of normal field decline. In 2006, we drilled approximately 330 wells as operator and continued to maintain a level 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 218mboe/d in 2006.
- In the Gulf Coast and Mid-Continental basins (Kansas, Louisiana, Oklahoma and Texas), our assets produced 183mboe/d in 2006.
- 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:

- Drilling continued during 2006 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.

- In January 2007, we announced our investment of up to $2.4 billion over the next 13 years in the Coal Bed Methane Field development project in the San Juan Basin of Colorado. The project includes the drilling of more than 700 wells, nearly all from existing well sites, and the installation of associated field facilities.
- In October 2006, we completed the sale of five onshore properties in South Louisiana to Swift Energy for approximately $160 million.

Alaska

In Alaska, BP net crude oil production in 2006 was 224mb/d, a decrease of 16% from 2005, due to mature field decline and operational issues associated with transit pipelines described below.

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. Our 26.4% interest in the Prudhoe Bay natural gas resource is a large undeveloped source of natural gas.

Developing viscous oil is an important part of the Alaska business. We are continually looking to develop viscous oil production in various fields through the application of advanced technology.

Significant events were:

- BP, along with ExxonMobil, ConocoPhillips and the Executive Branch of the State of Alaska, reached agreement on a gas pipeline fiscal contract. Two special sessions of the legislature called by the former governor ended without legislative ratification of the contract. The change of governor, which took place in December 2006, has temporarily delayed continued negotiations with the State of Alaska until a clear process leading to ratification of the gas pipeline fiscal contract is defined by the new administration. BP stands ready to execute a modified fiscal contract that is agreeable to all the parties.
- The State of Alaska significantly increased production taxes by adopting a new Petroleum Production Tax (PPT) bill on 19 August 2006, effective from 1 April 2006. The key terms of the PPT include a 22.5% oil tax rate with capital credits and a clause whereby the oil tax rate increases as the net margin rises above $40/bbl.
- On 27 November 2006, the State of Alaska Department of Natural Resources (DNR) issued a decision regarding the Plan of Development (POD) submitted by ExxonMobil on behalf of the Point Thompson Unit owners (BP 32%) on 18 October 2006. The DNR decision was to reject the modified POD, deny the proposed settlement of the expansion lease acreage and terminate the Point Thompson Unit. BP, along with the other owners, is studying options available in response to this decision. BP intends to pursue vigorously the retention of its interest in the Point Thompson Unit and remains committed to its development in conjunction with our broader gas strategy and the proposal to construct a gas pipeline from Alaska, through Canada, to the Midwest US.
- Alaska viscous and heavy oil assets produced their 100 millionth barrel (gross) in November 2006. West Sak 1J Phase 1 viscous project has drilled more than half the planned 31 development wells, Milne Point is planning the NW Schrader Bluff winter appraisal programme and the Orion Phase II sanction in Prudhoe Bay is expected in the first quarter of 2007. Orion Phase II completes GC-2 viscous oil facility modifications and develops eight additional producer wells and 22 injector wells; first oil is planned for 2009.
- On 2 March 2006, a transit pipeline in the Western operating area of the Prudhoe Bay field was discovered to have spilled approximately 4,800 barrels of crude oil over approximately two acres. The processing facility that feeds into the transit line was immediately shut down. An investigation team determined that the leak was caused by internal corrosion. Spill clean-up was completed and business operations resumed in April 2006 using a separate bypass line. (*See also Environmental Protection Health, Safety and Environmental Regulation on page 35.*)

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- On 7 August 2006, an orderly and phased shutdown of the Eastern Operating Area of the Prudhoe Bay oil field began following the discovery of unexpected corrosion and a small spill from a Prudhoe Bay oil transit line. In September, we determined that the oil transit lines in the Eastern Operating Area of Prudhoe Bay could be returned to service for the purposes of in-line inspection. By the end of October we had returned to service all three flow stations previously shut down.
- Current production from Prudhoe Bay is more than 400,000 barrels of oil and natural gas liquids per day (gross). BP has a 26.4% interest in the Prudhoe Bay field.
- In response to the recent corrosion discoveries, BP has decided to replace the main oil transit lines (16 miles) in both the Eastern and Western Operating Areas of Prudhoe Bay. In addition, BP plans to spend over $550 million (net) over the next two years on integrity management in Alaska. BP has retained three eminent corrosion experts to evaluate independently and make recommendations for improving the corrosion programme in Alaska. BP has also asked an independent ombudsman to undertake a review of worker allegations raised on the North Slope of Alaska since the acquisition of ARCO in 2000 to determine whether the problems have been addressed and rectified.
- In February 2007, BP temporarily shut down its Northstar production facility to repair welds in the low pressure gas piping system. BP is currently finalising inspections and has begun repairs.

United Kingdom

We are the largest producer of oil and second largest producer of gas in the UK. BP remains the largest overall producer of hydrocarbons in the UK. In 2006, total liquids production was 253mb/d, a 9% decrease on 2005, and gas production was 936mmcf/d, a 14% decrease on 2005. This decrease in production was driven by the natural decline, operational issues and lower seasonal gas demand. 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 $794 million in 2006, compared with $790 million in 2005 and $679 million in 2004.

Significant events were:

- Drilling continued during 2006 on the Clair Phase 1 development (BP 28.6% and operator) programme and is scheduled to continue through 2008.
- In September 2006, BP reached an agreement, subject to Department of Trade and Industry (DTI) approval, to acquire acreage in the UK

  Central North Sea that contains two discovered fields and further exploration potential.
- BP and its partner approved the front end engineering and design for the Harding Area Gas Project (BP 70% and operator) in July 2006.

  This represents the first stage of a development project to allow the production of gas from the Harding area and prolong the life of the field beyond 2015.
- Progress continued during the year on the Magnus Expansion Project (BP 85% and operator), with first oil achieved in October 2006.
- The UK government approved the North West Hutton decommissioning programme in April 2006. BP, on behalf of the owners of North West Hutton (BP 26% and operator), awarded a contract in October 2006 for the offshore removal and onshore recycling of the installation. Detailed engineering work for removal has begun. Platform removal is expected to start in 2008 and to be completed by the end of 2009.
- In December 2005, the UK government announced a 10% supplemental tax increase on North Sea oil profits, taking the total corporate tax rate to 50%. This tax increase became law in July 2006, with effect from 1 January 2006.
- In March 2006, we reached agreement for the sale of our 4.84% interest in the Statfjord oil and gas field. This sale was completed in June 2006.

Rest of Europe

Development expenditure, excluding midstream, in the Rest of Europe was $214 million, compared with $188 million in 2005 and $262 million in 2004.

Norway

In 2006, our total production in Norway was 66mboe/d, a 20% decrease on 2005. 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 2006. 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.

- Drilling continued through 2006 on the Valhall flank development and water injection projects. The flank drilling programme was completed in September 2006 and water injection drilling will continue during 2007.
- In March 2006, we reached agreement for the sale of our interest in the Luva gas discovery, in the North Sea. This sale was completed in the second quarter of 2006.

Netherlands

In May 2006, we announced our intention to sell our exploration and production and gas infrastructure business in the Netherlands. This includes onshore and offshore production assets and the onshore gas supply facility, Piek Gas Installatie, at Alkmaar. The sale was completed on 1 February 2007 to the Abu Dhabi National Energy Company, TAQA.

Rest of World

Development expenditure, excluding midstream, in Rest of World was $4,522 million in 2006, compared with $3,735 million in 2005 and $3,082 million in 2004.

Rest of Americas

Canada

- In Canada, our natural gas and liquids production was 57mboe/d in 2006, a decrease of 10% compared with 2005. The year-on-year decrease in production is mainly due to natural field decline.
- BP has been successful in obtaining new licences in British Columbia and Alberta land sales. The acquired acreage will form part of the Noel tight gas development project in north-eastern British Columbia. The project will involve drilling up to 180 horizontal wells and innovative fracturing technology to develop the remainder of the resources.

Trinidad

- In Trinidad, natural gas production volumes increased by 14% to 2,265mmcf/d in 2006. The increase was driven by higher demand due to the ramp-up of Atlantic LNG Train 4. Liquids production declined by 2mb/d (5%) to 38mb/d in 2006.
- Cannonball (BP 100%), Trinidad's first major offshore construction project executed locally, started production in March 2006. Production increased during the year and the asset is currently providing gas for the Atlantic LNG trains.
- BP sanctioned the development projects for Red Mango (BP 100%) in April 2006 and for Cashima (BP 100%) in August 2006. First production is expected by the end of 2007 and in 2008 respectively.

Venezuela

- In Venezuela, our 2006 liquids production reduced by 25mb/d compared with 2005, mainly as a result of the enforced reduction of our interests in the non-BP-operated Jusepin property and the Boqueron and Desarollo Zulia Occidental (DZO) reactivation projects, which BP operated until 31 March 2006 under operating service agreements on behalf of the state oil company, Petroleos de Venezuela S.A. (PDVSA).
- In August 2006, BP signed conversion agreements to co-operate with PDVSA in setting up incorporated joint ventures in which PDVSA would be the majority shareholder. The structures for the incorporated joint ventures were established in December 2006 and these are now the operators of the Boqueron and DZO properties.

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- In December 2006, BP, in common with the other partners in the Jusepin property, reached agreement with PDVSA for compensation in return for the relinquishment of our interest in the property.
- Cerro Negro is a non-BP-operated property that is a heavy oil project from which production is sold directly by BP. The Venezuelan government has communicated its intention of converting this strategic association to an incorporated joint venture. It is too early to determine the effect of this.
- In 2005, changes were made by the Venezuelan government to increase corporate income taxes from 34% to 50% on those companies operating under operating service agreements. Changes were also made in 2006 to the taxation of oil extraction companies, such as Cerro Negro. From 1 June 2006, a new extraction tax at a maximum rate of 33.33% was introduced (the existing royalty of 16.67% can be offset against the new extraction tax) and, on 25 September 2006, the corporate income tax rate was raised from 34% to 50% with effect from 1 January 2007.

Colombia

- In Colombia, BPs net production averaged 50mboe/d. 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 March 2006, cumulative production from the BP-operated fields reached 1 billion barrels gross since operations began in 1992.
- In December 2006, the corporate income tax rate was reduced from its current rate of 35% to 34% from 1 January 2007 and to 33% from 1 January 2008.

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 2006, total production of 145mboe/d represented an increase of 7% over 2005, with oil increasing by 4% and gas by 10%. The main increase in oil production came from the continued focus on drilling and waterfloods in Golfo San Jorge in Argentina, where oil production was 60mb/d, compared with 58mb/d in 2005. 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.
- In November 2006, PAE and all other oil and gas companies with operations in Bolivia entered into agreements with the state-owned oil company Yacimientos Petroli´feros Fiscales Bolivianos (YPFB) that establish governmental control over the countrys hydrocarbon resources. The agreements have been approved by the Bolivian Congress. YPFB will be responsible for marketing all hydrocarbons produced in Bolivia and for determining the terms of sales contracts.

Africa

Algeria

- BP, through its joint operatorship of In Salah Gas with Statoil and the Algerian state company, Sonatrach, supplied 300bcf (gross) of gas to markets in Algeria and southern Europe during 2006. The carbon dioxide (CO_2) capture system, part of the In Salah project (BP 33.15%), is one of the worlds largest CO_2 capture projects.
- BP, through its joint operatorship of In Amenas with Statoil and Sonatrach, completed the development of the In Amenas project (BP 12.5%). First production was achieved in June 2006.
- From 1 August 2006, a windfall profit tax was announced that applies to certain producers when the monthly average price of a barrel of oil exceeds $30. At present, the only asset of BP affected by this is the In Amenas project.

Angola

- In Block 15 (BP 26.7%), development of Kizomba C commenced in the first quarter of 2006. Development of Kizomba A Phase II continued, with first production planned for the end of 2007.
- In Block 17 (BP 16.7%), development activities were completed and the FPSO moored on the Dalia project. First production commenced in

December 2006. Development on the Rosa project, a tie-back to the Girassol hub, continued, with first production expected by the end of 2007.
- In Block 18 (BP 50% and operator), work has continued on the Greater Plutonio development in line with expectations to commence production by the end of 2007.
- In Block 31 (BP 26.7% and operator), three additional discoveries were made in 2006. There have been a total of 12 discoveries that are at various stages of assessment of commercial viability.
- We are participating in the Angola LNG project (BP 13.6%).

Egypt
- In Egypt, the Gulf of Suez Petroleum Company (GUPCO) (BP 50%), a joint venture operating company between BP and the Egyptian General Petroleum Corporation, 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 more than 40 fields.
- The Temsah redevelopment project was completed and production achieved in the second quarter of 2006.
- Progress continued on the Saqqara field (BP 100%) development project, with first production expected in the first quarter of 2008.
- In June 2006, the Egyptian Natural Gas Holding Corporation (EGAS), BP, SEGAS and Eni signed a framework agreement marking a major step forward for the development of the second liquefied natural gas (LNG) export train at the Damietta site on the Egyptian Mediterranean coast.

Asia Pacific

Indonesia
- BP produces crude oil and supplies natural gas to the island of Java through its holding in the Offshore Northwest Java Production Sharing Agreement (BP 46%).
- During 2006, progress 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 LNG is expected by the end of 2008.

Vietnam
- BP participates in the country's largest project with foreign investment, the Nam Con Son gas project. This is an integrated resource and infrastructure project, including offshore gas production, pipeline transportation system and power plant. In 2006, natural gas production was 392mmcf/d gross, an increase of 13% over 2005. This increase was mainly due to higher demand resulting from continuing growth in the economy. 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 33.33%).

China
- 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's electricity. 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.

Australia
- We are one of six equal partners in the North West Shelf (NWS) venture. Each partner holds a 16.7% interest in the infrastructure and oil reserves and a 15.8% interest in the gas reserves and condensate. The operation covers offshore production platforms, a floating production and storage vessel, trunklines and onshore gas processing plants. The NWS Venture is currently the principal supplier to the domestic market in Western Australia. During 2006, progress continued on the construction of a fifth LNG train (4.7 million tonnes a year design capacity), with first throughput expected in 2008.

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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 in OAO TNK-BP Holding. Other assets include the BP-branded retail sites in Moscow and the Moscow region, OAO Rusia Petroleum and the OAO Slavneft group. The workforce is about 70,000 people.
- BP's investment in TNK-BP is held by the Exploration and Production business and the results of TNK-BP are accounted for under the equity method in this segment.
- TNK-BP has proved reserves of 6.1 billion boe (including its 49.9% equity share of Slavneft), of which 4.8 billion are developed. In 2006, average liquids production was 1.9mmboe/d, a decrease of just over 2% compared with 2005, reflecting the disposal of the Urdmurt and Saratov assets in 2006 and 2005. The production base is largely centred in West Siberia (Samotlor, Nyagan and Megion), which contributes about 1.4mmboe/d, together with Volga Urals (Orenburg) contributing some 0.4mmboe/d. About 50% of total oil production is currently exported as crude oil and 20% as refined product.
- Downstream, TNK-BP owns five refineries in Russia and the Ukraine (including Ryazan and Lisichansk), with throughput of 0.6 million barrels a day (28 million tonnes a year). In retail, TNK-BP operates more than 1,600 filling stations in Russia and the Ukraine, with a share of the Moscow retail market in excess of 20%.
- During 2006, four of TNK-BP's licences were extended by 25 years, including two key licences covering the Samotlor field and the Khokhryakovskoye and Permyakovskoye licences.
- In October, TNK-BP's subsidiary Rusia Petroleum received a letter from the Russian authorities alleging a number of violations of the conditions related to a licence covering part of the Kovykta field in East Siberia. In February 2007, the status of the licence was reviewed by the authorities, who we anticipate will issue formal findings shortly. Rusia Petroleum continues to discuss this matter with the authorities in order to address any outstanding concerns.
- In November, following a review of the results of an inspection by the licensing authorities, regional prosecutors made a request for revocation of the two licences held by TNK-BP subsidiary Rospan International on grounds of violation of licence conditions and applicable legislation. Following discussion with the licensing authorities, renewal was granted of certain documents associated with the licences for which TNK-BP had previously applied. In addition, Rospan presented a plan to rectify the licence non-compliances, following which the licensing authorities have granted a six-month period to fulfil this plan.
- On 23 October 2006, TNK-BP received decisions from the Russian tax authorities in relation to the tax audits of certain TNK-BP group companies for the years 2002 and 2003, resulting in a payment by TNK-BP of approximately $1.4 billion in settlement of these claims.

  At the present time, BP believes that its provisions are adequate for its share of any liabilities arising from these and other outstanding tax decisions not covered by the indemnities provided by our co-venturers in respect of historical tax liabilities related to assets contributed to the joint venture.
- In August 2006, TNK-BP completed the sale of its interest in OAO Udmurtneft to Sinopec.
- In January 2007, TNK-BP announced the acquisition of Occidental Petroleum's 50% interest in the West Siberian joint venture, Vanyoganneft, for $485 million. The transaction is expected to close during the first quarter of 2007, subject to Russian regulatory approvals. On completion of the purchase, TNK-BP will own 100% of the Vanyoganneft asset.

Sakhalin

- BP participates in exploration activity through Elvaryneftegas (BP 49%), an equity-accounted joint venture with Rosneft in Sakhalin, where three discoveries have been made. Exploratory drilling continued in 2006 and preliminary work is under way to prepare for development if commercial reserves are discovered. Further drilling is planned during 2007.

Other

- In July 2006, BP purchased 9.6% of the shares issued in Rosneft's IPO for $1 billion. This represents an interest of around 1.4% in Rosneft.

Other

Azerbaijan

- 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 2 of the Azeri project delivered first oil from the West Azeri platform to Sangachal terminal on 3 January 2006 and was completed on 21 October 2006 with the delivery of first oil from the East Azeri platform to Sangachal, four months ahead of schedule. Phase 3 of the project, which will develop the deepwater Gunashli area of ACG, remains on schedule to begin production in 2008.
- Construction and the Stage 1 pre-drill programme of the project to develop the Shah Deniz natural gas field (BP 25.5% and operator) were completed in 2006, with first gas in December 2006.

Middle East and Pakistan

- Production in the Middle East consists principally of the production entitlement of associates in Abu Dhabi, where we have equity interests of 9.5% and 14.7% in onshore and offshore concessions respectively. In 2006, production in Abu Dhabi was 164mb/d, up 11% from 2005 as a result of capacity enhancements.
- In Pakistan, BP is one of the leading foreign operators, producing 22% of the country's oil and 6% of its natural gas on a gross basis in 2006.
- In July 2006, BP was awarded three offshore blocks in Pakistan's offshore Indus Delta. The blocks cover an area of approximately 20,000km^2 and include the right to operate any commercially viable discoveries.
- In January 2007, we were awarded development rights to the Khazzan/ Makarem fields in Oman. These provide access to a significant volume of tight gas resource in place, which we believe can be developed using the same technology as we are currently deploying at our Wamsutter field in the US.

India

- In November 2006, BP signed a PSA with the Indian government to explore for coal bed methane in the Birbhun district of India's eastern West Bengal state.

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, which was fully commissioned in July 2006. 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.

Our onshore US crude oil and product pipelines and related transportation assets are included under Refining and Marketing *(see page 23)*. Revenue is earned on pipelines through charging tariffs. Our gas marketing business is included in our Gas, Power and Renewables segment (*see page 31*).

Activity in oil and natural gas transportation during 2006 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 748mb/d during 2006.
- The use of US-built and US-flagged ships is required when transporting Alaskan oil to markets in the US. In September 2006, BP completed the replacement of its US-flagged fleet with the delivery of its fourth ship, the Alaska Legend. BP had contracted for the delivery of four 1.3 million-barrel-capacity double-hulled tankers for use in transporting

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North Slope oil to West Coast refineries. BP took delivery of the first three tankers between August 2004 and November 2005. As existing ships were retired, the replacements were constructed in accordance with the Oil Pollution Act of 1990. For discussion of the Oil Pollution Act of 1990, see Environmental Protection Maritime oil spill regulations on page 37.

- Work progressed during 2006 on the strategic reconfiguration project to upgrade and automate four pump stations. This project will install electrically driven pumps at four critical pump stations, combined with increased automation and upgraded control systems. Start-up of the first pump station is expected to occur in the first quarter of 2007, with the second expected to be online by the end of 2007. The remaining two reconfigured pump stations are expected to come online sequentially after 2007.
- There are a number of unresolved protests regarding intrastate tariffs charged for shipping oil through TAPS. These protests were filed between 1986 and 2003 with the Regulatory Commission of Alaska (RCA). These matters are proceeding through the Alaska judicial and regulatory systems. Pending the resolution of these matters, the RCA has imposed intrastate rates effective 1 July 2003 that are consistent with its 2002 Order requiring refunds to be made to TAPS shippers of intrastate crude oil.
- Tariffs for interstate and intrastate transportation on TAPS are calculated utilizing the Federal Energy Regulatory Commission (FERC) endorsed TAPS Settlement Methodology (TSM) entered into with the State of Alaska in 1985. In February 2006, FERC combined and consolidated all 2005 and 2006 rate complaints filed by the State, Anadarko, Tesoro and Tesoro Alaska. The complaints were filed on a variety of grounds. We are confident that the rates are in accordance with the TSM and are continuing to evaluate the disputes. BP will continue to collect its TSM-based interstate tariffs; however, our tariffs are subject to refund depending on the outcome of the challenges. 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 1mmb/d, with average throughput in 2006 at 545mb/d. In January 2007, FPS completed the tying in of the Buzzard field, which is expected to be a significant user of FPS capacity.
- 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 1.7bcf/d to a natural gas terminal at Teesside in north-east England. CATS offers natural gas transportation and processing services. In 2006, throughput was 1.1bcf/d (gross), 326mmcf/d (net).
- In addition, BP operates the Dimlington/Easington gas processing terminal (BP 100%) on Humberside and the Sullom Voe oil and gas terminal in the Shetlands.

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 is expected to carry 750,000 barrels of oil a day by the end of 2007 from the BP-operated ACG oil field in the Caspian Sea to the eastern Mediterranean port of Ceyhan. Loading of the first tanker at Ceyhan occurred in June 2006 and the official inauguration of the Turkish section of the BTC oil export pipeline, the new Ceyhan marine export terminal and the full BTC pipeline export system was held on 13 July 2006.
- The South Caucasus Pipeline for the transport of gas from Shah Deniz in Azerbaijan to the Turkish border was ready for operation in November 2006. BP is the 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 2006, CPC total throughput reached 31.2 million tonnes. During 2006, negotiations continued between the CPC shareholders towards the approval of an expansion plan. 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 and the Gas, Power and Renewables business is responsible for the subsequent marketing and distribution of LNG. *(See details under Gas, Power and Renewables Liquefied natural gas on page 32)*. BPs 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, 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/15.8% gas and condensate reserves).

Assets and activities:

- We have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company, which in 2006 supplied 5.6 million tonnes (290bcf) of LNG, up 3.6% on 2005.
- In Australia, we are one of six equal partners in the NWS Venture. Each partner holds a 16.7% interest in the infrastructure and oil reserves and a 15.8% interest in the gas reserves and condensate. The joint venture operation covers offshore production platforms, a floating production and storage vessel, trunklines, onshore gas processing plants and LNG carriers. Construction continued during 2006 on a fifth LNG train that is expected to process 4.7 million tonnes of LNG a year and will increase the plants capacity to 16.6 million tonnes a year. The train is expected to be commissioned during the second half of 2008. NWS produced 12.0 million tonnes (544bcf) of LNG, an increase of 2% on 2005.
- In Indonesia, BP is involved in two of the three LNG centres in the country. BP participates in Indonesias LNG exports through its holdings in the Sanga-Sanga PSA (BP 38%). Sanga-Sanga currently delivers around 15.5% of the total gas feed to Bontang, one of the worlds largest LNG plants. The Bontang plant produced 19.5 million tonnes (886bcf) of LNG in 2006, compared with 19.4 million tonnes in 2005.
- 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 2006, construction continued on two trains, with start-up planned late in 2008. Tangguh is expected to be the third LNG centre in Indonesia, with an initial capacity of 7.6 million tonnes (388bcf) a year. Tangguh has signed sales contracts for delivery to China, Korea and North Americas West Coast.
- In Trinidad, construction of the Atlantic LNG Train 4 (BP 37.8%) was completed in December 2005, with the first LNG cargo delivered in January 2006. Train 4 is now the largest producing LNG train in the world and is designed to produce 5.2 million tonnes (253bcf) a year of LNG. BP expects to supply at least two-thirds of the gas to the train. The facilities will be operated under a tolling arrangement, with the equity owners retaining ownership of their respective gas. The LNG is expected to be sold in the US, Dominican Republic and other destinations. BPs net share of the capacity of Atlantic LNG Trains 1, 2,3 and 4 is 6.5 million tonnes (305bcf) of LNG a year.

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Refining and Marketing

Our Refining and Marketing business is responsible for the supply and trading, refining, 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 market our products across Australasia and in parts of Asia, Africa and Central and South America.

Key statistics

			$ million
	2006	2005[a]	2004[a]
Sales and other operating revenues for continuing operations	**232,855**	213,326	170,639
Profit before interest and tax from continuing operations	**5,541**	6,426	6,506
Total assets	**80,964**	77,485	73,582
Capital expenditure and acquisitions	**3,144**	2,860	2,989
			$ per barrel
Global Indicator Refining Margin[b]	**8.39**	8.60	6.31

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

a With effect from 1 January 2006, the following assets were transferred to or from the Refining and Marketing segment:
- Three equity-accounted entities were transferred from Other businesses and corporate following the sale of Innovene;
- The South Houston Green Power co-generation facility (in the Texas City refinery) and the Watson co-generation facility (in the Carson refinery) were transferred to Gas, Power and Renewables as a result of the formation of BP Alternative Energy; and
- Hydrogen for Transport activities were transferred from Gas, Power and Renewables.

The 2005 and 2004 data above has been restated to reflect these transfers.

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

			$ million
	2006	2005	2004
Sale of crude oil through spot and term contracts	**38,577**	36,992	21,989
Marketing, spot and term sales of refined products	**177,995**	155,098	124,458
Other sales including non-oil and to			

other segments	**16,283**	21,236	24,192
	232,855	213,326	170,639
			mb/d
Sale of crude oil through spot and term contracts	**2,110**	2,464	2,312
Marketing, spot and term sales of refined products	**5,801**	5,888	6,398

The Refining and Marketing segment includes a portfolio of businesses, namely Refining, Retail, Lubricants, Business-to-Business Marketing and Aromatics and Acetyls. Our strategy is to continue our focused investment in key assets and market positions. We aim to improve the quality and capability of our manufacturing portfolio. Over 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 the Castellón refinery in Spain, the Kwinana refinery in Australia and all our US refineries (excluding the Carson refinery, which was already producing a full slate of clean fuels). Over the next five years, our refining portfolio will be upgraded further through the construction of a new coker at the Castellón refinery, an increase in the Whiting refinery's ability to process Canadian heavy crude, upgrades to diesel and gasoline desulphurization capability at the Nerefco refinery in the Netherlands, completion of a major upgrade to the olefin cracker at the Gelsenkirchen refinery in Germany and the site reconfiguration and installation of a new hydrocracker at the Bayernoil refinery, also in Germany. In addition, the portfolio will be improved through upgrades implemented during the recommissioning of the Texas City refinery in the US.

Our marketing businesses, underpinned by world-class manufacturing such as our Aromatics and Acetyls portfolio, generate customer value by providing quality products and offers. Our retail strategy 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.

Refining and Marketing manages a portfolio of assets that we believe are competitively advantaged across the chain of downstream activities. Such advantage derives 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. Refining and Marketing also includes the Aromatics and Acetyls business, which maintains manufacturing positions globally, with an emphasis on Asia growth, particularly in China.

During 2006, significant events were:

- BP announced that it had entered the final planning stage of a $3-billion investment in Canadian heavy crude oil processing capability at its Whiting, US, refinery. This project is expected to reposition Whiting competitively as a top-tier refinery by increasing its Canadian heavy crude processing capability by 260,000 barrels per day and modernizing it with equipment of significant size and scale. Reconfiguring the refinery also has the potential to increase its production of motor fuels by about 15%, which is about 1.7 million additional gallons of gasoline and diesel per day. Construction is tentatively scheduled to begin in 2007, pending regulatory approval.
- BP also announced plans to invest $500 million over the next 10 years to establish a dedicated bioscience research laboratory. The BP Energy Biosciences Institute (EBI) is planned to be the first of its kind in the world and to be attached to a major academic centre. On 1 February 2007, BP announced that it had selected the University of California, Berkeley, and its partners the University of Illinois at Urbana-Champaign and the Lawrence Berkeley National Laboratory for the research programme. Further, BP and DuPont announced the creation of a partnership to develop, produce and market a next generation of biofuels. The companies' joint strategy is to deliver advantaged biofuels that will provide improved options for expanding energy supplies and accelerate the move to renewable transportation fuels that lower overall greenhouse gas emissions. The first product to market is expected to be biobutanol, an improved biocomponent for gasoline. Initial introduction activities are currently targeted on the UK market.
- In 2006, plans for a second purified terephthalic acid (PTA) plant at the BP Zhuhai Chemical Company Limited site in Guangdong province, China, were approved by the Chinese government and the plant is expected to

come on stream at the end of 2007.

- BP continues to develop its retailing business in both new markets and new business models. In 2006, developments included:
  - The roll-out of the BP Connect Wild Bean Café brands to its dealer network in a franchise agreement. We are expecting to develop a network of 150 Connect franchise sites along with a further 100 company-owned Connect sites in the UK by the end of 2010.
  - The successful piloting of a Marks & Spencer store partnership in the UK, with the intention of rolling this out to a further 200 stores in 2007.

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- In a study by Corporate Research International, US consumers ranked BPs convenience chain in the US as the best for customer service.

 BP completed the disposal of its shareholding in Zhenhai Refining and Chemicals Company to Sinopec, sold its shareholding in Eiffage, the French-based construction company, and completed the disposal of its network of 70 retail sites in the Czech Republic.

 BP also announced its intention to sell the Coryton refinery in the UK, which processes 172,000 barrels of crude oil per day. On 1 February 2007, we announced that the sale of the refinery to Petroplus Holdings AG had been agreed, subject to required regulatory approvals. The sale includes the adjacent bulk terminal and BPs UK bitumen business which is closely integrated with the refinery. Completion of the sale is expected in mid-2007.

Texas city refinery

Summary

Throughout 2006, BP continued to respond to the 23 March 2005 incident at its Texas City refinery. BP addressed a number of the factors that contributed to the incident, including the announcement of a new policy for the siting of occupied portable buildings and the removal from service at Texas City of all blow-down stacks handling heavier-than-air light hydrocarbons. BP also implemented a number of actions relating to safety and operations, not only at US refineries but also at other facilities worldwide. These actions include a decision to increase spending to an average of $1.7 billion a year over the next four years to improve the integrity and reliability of US refining assets, the formation of a safety and operations function to focus on operations and process safety across the group, the appointment of a new chairman and president of BP America Inc. and the creation of an advisory board to assist BP America Inc.s management in monitoring and assessing BPs US operations. Also in 2006, BP settled a large number of civil suits arising from the Texas City incident. BP established a $1.625 billion provision related to the incident and reached settlements with all the relatives of those who were killed and with hundreds of other persons who filed injury claims. Trials have been scheduled for a number of unresolved claims in mid-2007, although to date all claims scheduled for trial have been resolved in advance of trial.

In 2006, BP continued its co-operation with the governmental entities investigating the incident, including the US Department of Justice (DOJ), the US Environmental Protection Agency (EPA), the US Occupational Safety & Health Administration (OSHA), the US Chemical Safety and Hazard Investigation Board (CSB) and the Texas Commission on Environmental Quality (TCEQ). During 2006, BP also devoted significant time and effort to co-operate with the BP US Refineries Independent Safety Review Panel (the panel), which it chartered in 2005 on the recommendation of the CSB, to assess the effectiveness of corporate oversight of safety management systems at BPs US refineries and the corporate safety culture. The panel published its report in January 2007 and BP has committed to implement its recommendations
(see Report of the BP US Refineries Independent Safety Review Panel on page 25).

Background

The March 2005 explosion and fire at BP Products North America Inc.s Texas City refinery occurred in the isomerization unit of the refinery as the unit was starting up after routine planned maintenance. The incident claimed the lives of 15 workers and injured many others.

An internal BP incident investigation determined that the raffinate splitter at the isomerization unit was overfilled and overheated, causing the relief valves to open into the blow-down system and resulting in an overflow of liquid hydrocarbon from the blow-down stack. The resulting vapour cloud was ignited by a source that has not been definitively identified.

BPs incident investigation team found that the critical factors leading to the incident included over-pressurization of the raffinate splitter, resulting in loss of containment, the failure to follow procedures during the start-up, the placement of temporary trailers too close to the blow-down stack and the design and operation of the blow-down stack. The investigation team issued a comprehensive final report, which is available in full on the BP internet site, www.bpresponse.org. The final report identified a number of underlying causes related to the working environment, process safety

and other management and operational behaviours and processes at the Texas City refinery.

The investigation team recommended numerous changes relating to people, procedures, control of work and trailer siting, design and engineering, underlying systems and investigation and reporting of incidents. The Texas City refinery established a programme office to implement the recommendations from this report and to address other projects needed to enhance the safety and performance of the refinery. In addition, in the immediate wake of the incident, a new Texas City site manager was appointed in May 2005. That manager has been succeeded by a permanent replacement, whose tenure at the refinery began in the first quarter of 2007. Steps were taken following the incident to strengthen the leadership team, clarify responsibilities and introduce systems to improve communication and compliance. All occupied trailers have been removed from specified areas, an enhanced training programme is under way and the site has committed to restarting process units without any blow-down stacks in heavier-than-air light hydrocarbons.

The incident prompted a number of investigations by other state and federal agencies. The TCEQ and OSHA investigations of the incident resulted in settlement agreements between BP and the agencies. In the third quarter of 2005, BP reached a settlement with OSHA that resulted in the payment of a $21.4 million penalty, an agreement to correct all alleged safety violations and the retention of experts to assess the refinery's organization and process safety systems. In the second quarter of 2006, BP settled with the TCEQ, resolving 27 alleged violations by paying a $0.3 million fine and agreeing, among other things, to upgrade its flare system.

In August 2005, the CSB issued an urgent recommendation to BP to establish an independent panel to assess and make recommendations regarding BP's corporate oversight of safety management systems at its five US refineries and its corporate safety culture. BP established the panel in October 2005, chaired by former US Secretary of State James A Baker, III, and co-operated fully with the panel. In order to make a thorough and credible assessment, the panel visited all BP's US refineries, commissioned independent process safety audits, interviewed staff at all levels, including operators and refinery managers and leadership teams, conducted an extensive process safety cultural survey and reviewed tens of thousands of documents.

BP expects the CSB to issue its final report in March 2007, supplementing two interim reports of findings. At a news conference on 31 October 2006, the CSB issued an update on the status of its own 20-month investigation into the causes of the incident and also issued recommendations to the American Petroleum Institute (API) to amend its guidance relating to atmospheric relief systems and to OSHA to establish a national emphasis programme promoting the elimination of unsafe systems in favour of safer alternatives.

The DOJ is investigating whether the Texas City incident involved any criminal conduct. The DOJ has issued Grand Jury subpoenas for documents and testimony. The investigation, with which BP is co-operating, is ongoing.

The refinery was entirely shut down in September 2005 in anticipation of Hurricane Rita. The hurricane caused the loss of steam and power to the refinery and these services were not fully restored until December 2005. The site-wide shut-down of the Texas City refinery also affected the Aromatics and Acetyls business, which has a co-located manufacturing capacity of paraxylene (PX) and metaxylene. The PX unit resumed production in March and the metaxylene unit resumed in April 2006. The remaining PX capacity at Texas City has been restarted in line with the ongoing phased recommissioning of the refining units.

Throughout the period from September 2005 to the end of the first quarter of 2006, BP worked to understand the extent of the damage the hurricane and loss of power had caused and put into place detailed plans to effect repair and safe restart of the process units. This was a considerable task, involving the entire workforce at the site plus significant external engineering resources.

At the end of the first quarter of 2006, the refinery restarted production and reached an average throughput of 248,000 barrels per day in the fourth quarter of 2006. The site started up smoothly and

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safely and is producing gasoline, diesel and chemicals products for the US market.

In parallel, refinery personnel have continued to work to effect the repair and the safe restart of the remaining process units. Additional processing facilities were commissioned in the second and third quarters of 2006. Additional conversion capacity is expected to be brought online in 2007. BPs plan is to bring additional sour crude processing facilities back on-stream in the second half of 2007; these facilities will allow the processing of additional high-sulphur crude. We expect crude throughputs to be approximately 400,000 barrels per day by the end of 2007.

The following milestones have been achieved in returning the refinery to operation with sequenced reconditioning of a multitude of units:

- Major site commissioning involving more than 15 million worker hours to date.
- Refurbishment and safe start-up of 27-mile steam system.
- Extensive mechanical renovation and the installation of a new flare system.
- Creation of a new command centre with interactive audio/visual links to the units, manned 24 hours a day during unit start-up.
- Implementation of a holistic commissioning plan defining behaviours and accountabilities to deliver safe and successful start-up.
- Implementation of a comprehensive systems training programme, coupled with safety accountability roll-out plans.

Several other improvements are either complete or under way:

- A new office building for more than 400 Texas City workers was opened to relocate workers who can work outside our plant fence line.
- A new flue gas scrubber is being added to the FCC unit. This $80-million investment will reduce emissions of sulphur and nitrogen oxide from the refinery.
- A new Employee Services Building (ESB) is under construction. The ESB will include facilities for learning and development and operations training departments, including unit training simulators and nine training rooms, the medical department, some of the sites security team, the Incident Management Team and site union official offices.

Construction has started on a new 250 megawatt (MW) steam turbine power generating plant that will reduce emissions and improve both energy and operational efficiency. The $100-million unit will be located next to the existing South Houston Green Power LP co-generation facility and is expected to boost the total electricity generating capacity located at the Texas City refinery site to 1,000MW.

Report of the BP US Refineries Independent Safety Review Panel

On 16 January 2007, having completed its review, the panel issued its report. The report identified deficiencies in process safety performance at BPs US refineries and called on BP to give process safety the same priority that it had historically given to personal safety and environmental performance. In making its findings and recommendations, the panel stated its objective was excellence in process safety performance, not simply legal compliance. The panel specifically noted that, during the course of its review, it saw no information to suggest that anyone from BPs board members to its hourly workers acted in anything other than good faith.

The panel made 10 recommendations relating to: process safety leadership; integrated and comprehensive process safety management system; process safety knowledge and expertise; process safety culture; clearly defined expectations and accountability for process safety; support for line management; leading and lagging performance indicators for process safety; process safety auditing; board monitoring; and industry leader. The panels report in its entirety can be found at *www.bp.com/ bakerpanelreport*.

The panel acknowledged the measures BP had taken since the Texas City incident, including dedicating significant resources and personnel intended to improve the process safety performance at BPs US refineries. BP has committed to implement the panels recommendations and will consult with the panel on how best to do this across the US refineries and to apply the lessons learned elsewhere in its global operations.

Other refinery investigations

As a result of its investigation of the Texas City refinery, OSHA conducted an inspection of BP Products North America Inc.s Toledo refinery, beginning in October 2005. On 24 April 2006, OSHA issued citations with a total penalty of $2.4 million, alleging 39 separate violations of two different OSHA standards. BP and OSHA have reached a settlement in principle and are working towards finalizing the documentation.

On 15 November 2006, the Indiana Occupational Safety and Health Administration (IOSHA) issued the Whiting refinery with three Safety Orders and Notifications of Penalty alleging 14 separate violations of the OSHA regulations. The total proposed penalty was $0.4 million. On 7 December 2006, BP and IOSHA met to discuss resolution of the matter. Discussions to reach a settlement agreement are ongoing.

Refining

The company'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 low-cost feedstocks in line with the demand of the region. Efficient operations are measured primarily using regional refining surveys conducted by third parties. The surveys assess our competitive position against benchmarked industry measures for margin, energy efficiency and costs per barrel. Investments in our refineries are focused on maintaining and improving our competitive position and developing 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 2006.

				mb/d
			Crude distillation capacities [a]	
	Refinery	Group interest [b] %	Total	BP share
UK	Coryton*[c]	100.0%	172	172
Total UK			172	172
Rest of Europe				
Germany[d]	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	Nerefco*	69.0%	400	276
Spain	Castellón*	100.0%	110	110
Total Rest of Europe			1,669	750
USA				
California	Carson*	100.0%	265	265
Washington	Cherry Point*	100.0%	232	232
Indiana	Whiting*	100.0%	405	405
Ohio	Toledo*	100.0%	155	155
Texas	Texas City*	100.0%	475	475
Total USA			1,532	1,532
Rest of World				
Australia	Bulwer*	100.0%	101	101
	Kwinana*	100.0%	137	137
New Zealand	Whangerei	23.7%	101	24
Kenya	Mombasa	17.1%	94	16
South Africa	Durban	50.0%	182	91
Total Rest of World			615	369
Total			3,988	2,823

* 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 BP has announced the sale of its Coryton refinery, subject to required regulatory approvals.
d BPs share of the Reichstett refinery in Germany was sold in December 2006.

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]	**2006**	2005	2004
UK	**165**	180	208
Rest of Europe	**648**	667	684
USA	**1,110**	1,255	1,373
Rest of World	**275**	297	342
Total	**2,198**	2,399	2,607
Refinery capacity utilization			
Crude distillation capacity at 31 December[b]	**2,823**	2,832	2,823
Crude distillation capacity utilization[c]	**76%**	87%	93%
USA	**70%**	82%	95%
Europe	**87%**	90%	90%
Rest of World	**78%**	88%	87%

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).

BPs 2006 refinery throughput declined as a result of increased turnaround activity during the year. In the US, the year-on-year decline was as a result of the full shutdown of the Texas City refinery in September 2005 and the subsequent maintenance programme that led to a partial and phased start-up during 2006.

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Marketing

Marketing comprises four business areas: Retail, Lubricants, Business-to-Business Marketing and Aromatics and 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 purified terephthalic acid, paraxylene and acetic acid through our Aromatics and Acetyls business.

			thousand barrels per day
Sales of refined products[a]	**2006**	2005	2004
Marketing sales			
UK[b]	**356**	355	322
Rest of Europe	**1,340**	1,354	1,360
USA	**1,595**	1,634	1,682
Rest of World	**581**	599	638
Total marketing sales[c]	**3,872**	3,942	4,002
Trading/supply sales[d]	**1,929**	1,946	2,396
Total refined products	**5,801**	5,888	6,398
			$ million
Proceeds from sale of refined products	**177,995**	155,098	124,458

a Excludes sales to other BP businesses and the sale of Aromatics and 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	**2006**	2005	2004
Aviation fuel	**488**	499	494
Gasolines	**1,603**	1,603	1,675
Middle distillates	**1,170**	1,185	1,255
Fuel oil	**388**	379	343
Other products	**223**	276	235
Total marketing sales	**3,872**	3,942	4,002

Our aim is to increase total margin by focusing on both volumes and margin per unit. We do this by growing our customer base, both in existing and new markets, by attracting new customers and by covering a wider geographic area. We also work to improve the efficiency of our operations through upgrading our transactional and operational processes, reducing costs and improving our product mix. In addition, we recognize that our customers are demanding a wider choice of fuels, particularly fuels that are cleaner and more efficient. Through our integrated refining and marketing operations, we believe we are better able to meet these customer demands.

Marketing sales of refined products were 3,872mb/d in 2006, compared with 3,942mb/d in the previous year. The decrease was due mainly to the effects of the high price environment in certain retail markets and of BP reducing volumes in less profitable business-to-business markets.

BP enjoys a strong market share and leading technologies in the Aromatics and 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.

Retail

Our retail strategy focuses on investment in high-growth metropolitan markets and the upgrading of our retail offers, while driving operational efficiencies through portfolio optimization.

There are two components of our retail offer: convenience and fuels. 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 store format in each of our key markets, whether it is the BP Connect offer in Europe and the eastern US, the am/pm offer west of the Rocky Mountains in the US or the Aral offer in Germany.

Each of these brands carries a very strong offer and we also aim to share best practices between them. Since 2003, we upgraded our fuel offer with the introduction of Ultimate gasoline and diesel products. In 2006, we launched Utimate in South Africa and Russia and now market Ultimate in 15 countries.

We continue to focus on operational efficiencies through targeted portfolio upgrades to drive increases in our fuel throughput per site and our store sales per square metre. In 2006, across the network, same-store sales growth at 4% exceeded estimated market growth of 2%.

			$ million
Store sales[a]	**2006**	2005	2004
UK	**647**	628	655
Rest of Europe	**2,821**	3,069	3,090
USA	**1,755**	1,776	1,715
Rest of World	**591**	610	601
Total	**5,814**	6,083	6,061
Direct-managed	**2,528**	2,489	2,319
Franchise	**3,286**	3,533	3,623
Store alliances	—	61	119
Total	**5,814**	6,083	6,061

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.

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

			Number of retail sites
Retail sites[a]	**2006**	2005	2004
UK	**1,300**	1,300	1,300
Rest of Europe	**7,700**	7,900	8,000
USA (excluding jobbers)	**2,700**	3,100	3,900
USA jobbers	**9,600**	9,700	10,300
Rest of World	**3,300**	3,200	3,300
Total	**24,600**	25,200	26,800

a Retail sites includes all sites operated under a BP brand.

At 31 December 2006, BPs worldwide network consisted of more than 24,000 locations branded BP, Amoco, ARCO and Aral, compared with approximately 25,000 in the previous year. 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 2006, we sold 513 company-owned sites to dealers and jobbers who continue to operate these sites under the BP brand. We also divested an additional 301 company-owned sites (including all company-owned sites in the Czech Republic) to third parties.

In 2006, we continued the rollout of the BP Connect offer at sites in the UK and US, consistent with our retail strategy of building on our advantaged locations, strong market positions and brand. The BP Connect sites include a distinctive food offer, large convenience store and cleaner fuels. The BP Connect sites include both those that are new and those where extensive upgrading and remodelling have taken place. At 31 December 2006, more than 760 BP Connect stations were open worldwide.

Through regular review and execution of business opportunities, we continue to concentrate our ownership of real estate in markets designated for development of the convenience offer. At 31 December 2006, BPs retail network in the US comprised approximately 12,300 sites, of which approximately 9,600 were owned by jobbers. BPs network comprised about 9,000 sites in the UK and the Rest of Europe and 3,300 sites in the Rest of World.

The joint venture between BP and PetroChina (BP-PetroChina Petroleum Company Ltd) started operation in 2004. Located in Guangdong, one of the most developed provinces in China, 387 sites were operational at 31 December 2006. The joint venture plans to operate and manage a total network of 500 locations in the province. A joint venture with Sinopec, approved in the fourth quarter of 2004 with the establishment of BP-Sinopec (Zhejiang) Petroleum Co. Ltd, commenced

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operations with 151 sites in Ningbo in 2005, with a further 72 sites in Shaoxing being transferred into the joint venture in 2006. The joint venture plans to build, operate and manage a network of 500 sites in Hangzhou, Ningbo and Shaoxing within Zhejiang province.

Lubricants

We manufacture and market lubricants products and also supply related products and services to business customers and end-consumers in over 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 business markets such as commercial vehicle fleets, aviation, marine and specialized industrial segments. Customer focus, distinctive brands and superior technology remain the cornerstones of our long-term strategy. BP markets through its two major brands, Castrol and BP, and several secondary brands, including Duckhams, Veedol and Aral.

In the consumer sector of the automotive segment, we supply lubricants, other products and related business services to intermediate customers such as retailers and workshops, who in turn serve end-consumers (e.g. 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. The Castrol brand is recognized worldwide and we believe it provides us with a significant competitive advantage.

In commercial vehicle and general industrial markets, we supply lubricants and lubricant-related services to the transportation industry and to automotive manufacturers.

Business-to-business marketing

Business Marketing markets a comprehensive range of refinery and lubricants products focused on business customers in the aviation fuel, marine fuel, marine and industrial lubricants, LPG and the ground fuels sectors.

Air BP is one of the world's largest aviation businesses, supplying aviation fuel and lubricants to the airline, military and general aviation sectors. It supplies customers in approximately 100 countries, has annual marketing sales of around 26,854 million litres (approximately 463 thousand barrels per day) and has relationships with many of the major commercial airlines. Air BP's strategic aim is to strengthen its position in existing markets (Europe/US/Asia Pacific), while creating opportunities in emerging economies such as South America and China.

The LPG business sells bulk, bottled, automotive and wholesale 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 Marketing Product sales in 2006 were approximately 71 thousand barrels per day.

Marine comprises three global businesses: Marine Fuels, Marine Lubricants, and Power Generation and Offshore, which supplies specialist lubricants to the power generation and offshore industry. Under the BP and Castrol brands, the business is the marine lubricants market leader and has a strong presence in the marine fuels sector. The business has offices in 90 countries and operates in more than 1,150 ports.

The Commercial Fuels business has activities in approximately 14 European countries and marketing sales of approximately 596 thousand barrels per day. The business markets fuels and heating oil, mostly as pick-up business at refineries, terminals and depots.

Our Business Marketing activities also include Industrial Lubricants, selling industrial lubricants and services to manufacturing companies in approximately 40 countries, and the supply of bitumen to the road and roofing industries. The businesses seek to increase value by building from the technology, marketing and sales capabilities of a business to business operation.

BP supports its businesses through a dedicated Strategic Accounts organization. Strategic Accounts develops strategic relationships with carefully selected leading organizations 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. Relationships are held across organizations and involve many senior leaders in the partners' organizations.

Aromatics and acetyls

The Aromatics and Acetyls business is managed along 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 and Acetyls strategy is to invest to maintain our advantaged manufacturing positions globally, with an emphasis on Asia growth, 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 BPs Aromatics and Acetyls production capacity at 31 December 2006. 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			529	633	1,162	
Rest of Europe						
Belgium						
Geel	1,076	552			1,628	
USA						
Cooper River	1,309				1,309	
Decatur	1,043	1,145		29	2,217	
Texas City		1,309	543[a]	123	1,975	
Rest of World						
China						
Chongqing			202[b]	52	254	(51% of YARACO)b
Zhuhai	582				582	
Indonesia						
Merak	252				252	(50% of PT Ami)
Korea						
Ulsan	553[c]		242[d]	57[e]	852	(47% of SPC) c (34% of ASACCO)e (51% of SS-BP)d
Seosan	353[c]				353	(47% of SPC) c
Malaysia						
Kertih			545		545	
Kuantan	699				699	
Taiwan						
Kaohsiung	822[f]				822	(61% of CAPCO) f
Taichung	457[f]				457	(61% of CAPCO) f
Mai Liao			153[g]		153	(50% of FBPC)g
	7,146	3,006	2,214	894	13,260	

a Sterling Chemicals plant, the output of which is marketed by BP.
b Yangtze River Acetyls Company.
c Samsung-Petrochemicals Company Ltd.
d Samsung-BP Chemicals Ltd.
e Asian Acetyls Company Ltd.
f China American Petrochemical Company Ltd.
g Formosa BP Chemicals Corporation.

In addition to the plans for a second PTA plant at the BP Zhuhai Chemical Company Limited site in Guandong province, China, described previously, the following portfolio activity took place in the Aromatics and Acetyls business during the year:

In the third quarter of 2006, BP announced its intent to sell its 47.41% equity interest in Samsung Petrochemical Co. Ltd (SPC), a PTA joint venture with Samsung in South Korea.

In 2004, BP announced the phased closure of two acetic acid plants at Hull, UK. The first plant was shut down in the second quarter of 2005 and the remaining plant was shut down in the third quarter of 2006.

The development of a 350 thousand tonnes per annum (ktepa) PTA expansion at Geel, Belgium, is expected to be operational in early 2008 and to increase the site□s PTA capacity to 1,426ktepa.

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 to our refining assets and sources marketing activities with flexible and competitive supply. Additionally, the function creates incremental trading gains 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 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 the Far East. Over-the-counter 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 over-the-counter contracts pricing in reference to Brent and West Texas Intermediate grades. Over-the-counter 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.

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. The volume of activity in 2006 was similar to 2005.

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 improve selections of crude for refineries further. 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

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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 gas oil. 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.

- Over-the-counter (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 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 77 for further details regarding investigations into various aspects of BP's trading activities.

The independent review, commissioned by BP, of the current compliance approach in the group's US trading organization has been completed. A number of recommendations have been made in regard to the design and effectiveness of the compliance processes and procedures. BP is fully implementing these recommendations.

Transportation

Our Refining and Marketing business 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, the 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 on BP business are subject to our health, safety, security and environmental requirements. In 2006, we continued to expand our operated and time-chartered fleet in order to provide more protection against the risk of a major oil spill. This fleet transformation is ahead of the international requirements for phase-out of single-hulled vessels.

International fleet

In 2005 we managed an international fleet of 52 vessels (44 oil tankers and eight LNG carriers). At the end of 2006, we had 57 international 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). All these ships are double-hulled.

Of the seven LNG carriers, BP manages four on behalf of joint ventures in which it is a participant and operates three LNG carriers, with a further four on order for delivery in 2007 and 2008.

Regional and specialist vessels

In Alaska, we took delivery of the fourth and final ship in a series of new-build double-hulled tankers and redelivered one of our time-chartered vessels back to the owner. The entire Alaskan fleet of six vessels is double-hulled.

In the Lower 48, two of the four heritage Amoco barges remain in service, one of which is due to be phased out of BPs service in 2007. We now intend to retain the other, which is double-hulled, until 2009.

Outside the US, the specialist fleet has grown from six ships in 2005 to 16 in 2006 (three tugs, two double-hulled lubricants oil barges and 11 offshore support vessels).

Time charter vessels

BP has 100 hydrocarbon-carrying vessels above 600 deadweight tonnes on time charter, of which 83 are double-hulled and three are double-bottomed. All these vessels are enrolled in BPs Time Charter Assurance Programme.

Spot charter vessels

To transport the remainder of the groups products, BP spot charters vessels, typically for single voyages. These vessels are always vetted prior to use.

Other vessels

BP uses miscellaneous craft such as tugs, crew boats and seismic vessels in support of the groups business. We also use sub 600 deadweight tonne barges to carry hydrocarbons on inland waterways.

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Gas, Power and Renewables

The Gas, Power and Renewables segment includes four main activities: 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 strategic purpose of the segment comprises four elements:

- Develop a leading low-carbon power generation business across the value chain.
- Access cost competitive supply.
- Capture distinctive world-scale gas market positions by accessing key pieces of infrastructure.
- Expand gross margin by providing distinctive energy products and services to selected customer segments and by optimizing the gas and power value chains.

Key statistics

$ million

	2006	2005[a]	2004[a]
Sales and other operating revenues from continuing operations	**23,708**	25,696	23,969
Profit before interest and tax from continuing operations	**1,321**	1,172	1,003
Total assets	**27,398**	28,952	17,753
Capital expenditure and acquisitions	**688**	235	530

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

a On 1 January 2006, following the formation of the Alternative Energy business, certain mid-stream assets and activities were transferred into Gas, Power and Renewables and the 2005 and 2004 data above has been restated to reflect these transfers:
- South Houston Green Power co-generation facility (in the Texas City refinery) from Refining and Marketing.
- Watson co-generation facility (in the Carson refinery) from Refining and Marketing.
- Phu My Phase 3 combined cycle gas turbine (CCGT) plant in Vietnam from Exploration and Production.

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

$ million

	2006	2005	2004
Gas marketing sales	**11,428**	15,222	13,532
Other sales (including NGLs marketing)	**12,280**	10,474	10,437
	23,708	25,696	23,969

mmcf/d

Gas marketing sales volumes	**3,685**	5,096	5,244
Natural gas sales by Exploration and Production	**5,152**	4,747	3,670

We seek to maximize the value of our 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 continental Europe. Some long-term natural gas contracting activity is included within the Exploration and Production business 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 business. 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 UK, we are building integrated supply chains covering production, liquefaction, shipping, regasification 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 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 BPs refining activities.

Globally, the power sector is the largest source of greenhouse gas (GHG) emissions, which are responsible for about twice the emissions from transport. Creating low-carbon power is therefore critical in the effort to stabilize global GHG emissions. BP is focused on power generation activities with low-carbon emissions. In 2005, we announced our plans to invest in a new business called BP Alternative Energy, which aims to extend significantly our capabilities in solar, wind power, hydrogen power and gas-fired power generation.

Capital expenditure and acquisitions for 2006 was $688 million, compared with $235 million in 2005 and $530 million in 2004. In 2006, this included the acquisitions of Orion Energy, LLC, and Greenlight Energy, Inc. In 2005 and 2004, there were no acquisitions. Capital expenditure excluding acquisitions for 2007 is planned to be around $900 million. The increase over the 2006 level primarily reflects our project programme, including continuing investment in the Alternative Energy business.

Marketing and trading activities

Gas and power marketing and trading activity is undertaken primarily in the US, Canada, the UK and continental Europe to market BPs gas and power production and manage market price risk as well as to create incremental trading gains 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 to 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 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. Over-the-counter 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.

- Over-the-counter (OTC) contracts

These contracts are typically in the form of forwards, swaps and options. OTC contracts are negotiated between two parties and are not

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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 is the main variable term. 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 46.

Trading investigations

See Legal proceedings on page 77 for details regarding investigations into various aspects of BP's trading activities.

The independent review, commissioned by BP, of the current compliance approach in the group's US trading organization has been completed. A number of recommendations have been made in regard to the design and effectiveness of the compliance processes and procedures. BP is fully implementing these recommendations.

North America

BP is one of the leading wholesale marketers and traders of natural gas in North America, the world's largest natural gas market. Our business has been built on the foundation of our position as the continent's leading producer of gas based on volumes. Our gas activity in the US and Canada has grown 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.

The scale of our gas and power businesses in North America grew over the period 2004-2006 because of a number of factors: (i) increased access to transport rights; (ii) increase in our trading activities; and (iii) growth from the acquisition of small regional marketing businesses. The OTC market for NGLs also developed during this period but the scale of activity was not significant in the context of the group's overall marketing and trading activity.

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. The majority of natural gas sales are to power-generation companies and to other gas wholesalers via long-term supply deals. Some of the natural gas continues to be sold under long-term supply contracts that were entered into prior to market deregulation. In addition to the marketing of BP gas, commodity derivative contracts are used actively in combination with assets and rights to store and transport gas to generate trading gains. This may include storing physical gas to sell in future periods or moving gas between markets to access higher prices. Commodity contracts such as over-the-counter 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.

As UK gas markets become increasingly connected to continental Europe, it is important that we maintain our understanding of how wider European gas markets work. We therefore trade in continental Europe.

In Europe, our main marketing activities are currently in Spain. The Spanish natural gas market has continued to grow and is now deregulated ahead of the deadlines set by European law. Since April 2000, we have built a market position that currently places us as one of the leading foreign entrants into the Spanish gas market.

Following Spanish deregulation, our 5% shareholding in Enagas, the Spanish gas transport grid operator, was no longer considered strategic and in November 2006 we divested these shares.

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 major existing LNG projects in Trinidad, ADGAS in Abu Dhabi, Bontang in Indonesia and the North West Shelf in Australia. Additional LNG supplies are being pursued through an expansion of the existing LNG facilities at the North West Shelf project in Australia and greenfield developments in Indonesia (Tangguh) and Angola. BP has no proved reserves associated with its interests in LNG projects in Abu Dhabi and Angola.

We continue to access major growth markets for the group's equity gas. In Asia Pacific, agreements for the supply of LNG from the Tangguh project (BP 37.2%) have been signed with POSCO and K-Power for supply to South Korea and with Sempra for supply to the Mexican and US markets. Together with an earlier agreement to supply LNG to China, these agreements mean that markets for more than 7 million tonnes a year (380bcf) of Tangguh LNG have been secured. In March 2005, Tangguh received key government approvals for the two-train launch and the project consortium is now executing the major construction contracts, with start-up planned in late 2008. During 2006, further progress was made in securing contracts for LNG to be derived from the remaining uncontracted reserves at the North West Shelf project.

In the Atlantic and Mediterranean regions, significant progress has also been made in 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 (mtpa) (253bcf), began operations in late 2005. 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 (Cove Point and Elba Island) and the UK (Isle of Grain). These BP-marketed volumes supplement a 2005 long-term agreement with Egyptian Natural Gas Holding Company (EGAS) of Egypt to purchase 1.45 billion cubic metres per year of LNG from the Spanish Egyptian Gas Company (SEGAS) plant at Damietta, short-term contracts to purchase LNG from Oman and Qatar and periodic 'spot' purchases of LNG. We have signed a memorandum of understanding with Brass River LNG in Nigeria to purchase around 2 million tonnes a year of LNG, starting in 2010 for 20 years, which will be supplied to multiple markets in the Atlantic basin.

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In south-east China, the Dapeng LNG import and regasification terminal and Trunkline Project (BP 30%) in Guangdong province received its first commissioning cargo during May 2006 and commenced commercial operations in September. LNG for the terminal is supplied under a long-term contract signed with Australia LNG in October 2002 that involves deliveries from the North West Shelf project (BP 16.7% infrastructure and oil reserves/15.8% gas and condensate reserves).

BP continues to progress options for 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 the 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 court has agreed to hear the case.

Natural gas liquids

With global demand for NGLs, both as a chemicals feedstock and as a cleaner fuel, forecast to grow in excess of 3% a year, this business is expected to offer potential for further growth. Based on sales volumes, we are one of the leading 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. NGLs are sold to petrochemicals plants and refineries, including our own. In addition, a significant amount of NGLs are marketed on a wholesale basis under annual supply contracts that provide for price redetermination based on prevailing market prices.

We operate natural gas processing facilities across North America, with a total capacity of 6.4bcf/d. These facilities, which we own or in which we have an interest, 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 process the natural gas liquids stream into its separate 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 NGL processing capacity utilization in 2006 was 75%. In addition, we have entered into a long-term supply contract with Aux Sable Liquid Products to secure additional NGLs to supply our customers in the US Midwest.

BP operates one plant in the UK (capacity 1.2bcf/d) 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. During the first quarter of 2006, a memorandum of understanding was signed with EGAS for a feasibility study covering construction of a greenfield NGLs plant in the West Nile Delta, Egypt, that would process gas from future BP equity and third-party production offshore.

Alternative energy

BP Alternative Energy is focused on the power generation sector – the largest single source of emissions from the use of fossil fuels – and aims to extend BP’s capabilities in solar, wind, hydrogen and gas-fired power generation to produce low-carbon power. Its activities include the production and marketing of solar panels; development of wind farms; generation of electricity from hydrogen power using sequestration in which carbon is captured and stored; and gas-fired power generation,which typically emits only half as much CO_2 as a conventional coal-fired station. The business brings together the group’s existing activities in these technologies with our power marketing and trading capabilities to form a single business.

In 2005, BP Alternative Energy announced its plans to invest up to $8 billion over 10 years. This investment is expected to be spread in broadly equal proportions between solar, wind, hydrogen and high-efficiency gas-fired power generation.

Solar

BP Solar’s main production facilities are located in Frederick, Maryland, US; Madrid, Spain; Sydney, Australia; and Bangalore, India. During 2006, the expansion of our manufacturing facilities in India and Spain doubled our production capacity from 100MW in 2004 to 200MW, keeping us on track to triple capacity from 2005 levels by 2008. During 2007, expansion of cell capacity will continue at our Madrid and Bangalore facilities, alongside a $70-million project to expand casting capacity at Frederick. BP Solar achieved sales of 93MW (2005 105MW and 2004 99MW).

We made good use of technology to manage the current silicon supply issue last year: developing a new silicon growth process named Mono2, which significantly increases cell efficiency over traditional multi-crystalline-based solar cells. 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 also teamed up with the California Institute of Technology to launch a multi-million dollar research programme to explore a radically new way of producing solar cells, based on the growth of silicon on nanorods, which could improve efficiency and make solar electricity much more competitive. In Germany, we signed a co-operation agreement with the Institute of Crystal Growth (IKZ) to develop a process for depositing silicon on glass that has the potential to reduce the amount of silicon feedstock used in cell production. In Spain, BP Solar and Banco Santander have formed an alliance that will allow for the construction of up to 278 photovoltaic solar power installations in Spain, with total capacity of 18-25 megawatts peak.

Wind

We are building expertise in wind energy and implementing projects. We operate two wind farms in the Netherlands, 9MW at our oil terminal in Amsterdam and 22.5MW at the Nerefco oil refinery (both the refinery and wind farm are jointly owned with Chevron (BP 69%)), providing electricity to the local grid.

In the US, we entered into a long-term supply agreement with Clipper Windpower plc with options to purchase Clipper turbines, with a total capacity of 2,250MW. During 2007, we plan to begin construction of five wind power generation projects, located in four states California, Colorado, North Dakota and Texas. The projects are expected to deliver a combined generation capacity of some 550MW.

During 2006, BP Alternative Energy 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 opportunities to develop almost 100 projects with potential total generating capacity of some 15,000MW.

Gas-fired power

Gas-fired power stations typically emit around half as much CO_2 as conventional coal-fired plants.

We operate a 776MW gas-fired power generation facility and an associated LNG regasification facility at Bilbao, Spain (BP 25% share in each) and a 750MW co-generation plant at Texas City, US (50:50 joint venture with Cinergy Solutions, Inc.), which supplies power and steam to BPs largest refining and petrochemicals complex. BP supplies natural gas to the Texas City plant and will use excess generation capacity to support power marketing and trading activities. Also, a 50MW co-generation plant near Southampton, UK (BP 100%), has been in operation since the first half of 2005. The construction of K-Powers (BP 35%) 1,074MW gas-fired combined cycle power plant at Kwangyang, Korea, was completed and full commercial operations started in the second quarter of 2006.

We have started construction of a new 250MW steam turbine power generating plant at the Texas City refinery site, which is expected to bring the total capacity of the site to 1,000MW when completed in 2008. We also plan to construct a 520MW co-generation facility at Cherry Point, Washington, US.

Hydrogen power

During 2006, we announced a new strategic relationship with General Electric to accelerate the development of hydrogen power technology and the deployment of the concept. Progress on our proposed hydrogen plant at Carson, California, US, continued and we were awarded $90 million in US Federal Investment credits.

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Other businesses and corporate

Other businesses and corporate comprises Finance, the group's aluminium asset, its investments in PetroChina and Sinopec (both divested in early 2004), interest income and costs relating to corporate activities worldwide. Following the sale of Innovene to INEOS in 2005, three equity-accounted entities (Shanghai SECCO Petrochemical Company Limited in China and Polyethylene Malaysia Sdn Bhd and Ethylene Malaysia Sdn Bhd, both in Malaysia) previously reported in Other businesses and corporate were transferred to Refining and Marketing, effective 1 January 2006. The 2005 and 2004 data below has been restated to reflect these transfers.

Key statistics

$ million

	2006	2005	2004
Sales and other operating revenues for continuing operations	**1,009**	668	546
Profit (loss) before interest and tax from continuing operations[a]	**(885)**	(1,237)	155
Total assets	**14,184**	12,144	21,795
Capital expenditure and acquisitions	**281**	817	2,130

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

Finance

Finance 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.

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.

Across the group, expenditure on research for 2006 was $395 million, compared with $502 million in 2005 and $439 million in 2004.

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.

The sheer range and complexity of technologies that can affect our businesses and the wide variety of sources for these technologies proprietary, energy service sector, universities and research institutions and other industries mean 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 of distinctiveness.
- Develop innovative and 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 and 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.

Our five-year technology plan provides for 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% a year between 2003 and 2006. In 2006, total technology investment was around $890 million.

During 2006, we continued to advance and employ new technologies in drilling and well construction, unconventional gas development, enhanced oil recovery and seismic imaging. These technologies have enabled discoveries in the deepwater Gulf of Mexico and Angola, 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 ever-lower quality crudes and optimize our assets in real time, enhancing the flexibility and reliability of our refineries. Our proprietary technologies in PTA have continued to reduce manufacturing costs and environmental impact.

Our long-term technology priorities fit into three categories of activity: technologies that enhance our capability to identify new hydrocarbon resources and better exploit those we have; technologies that convert hydrocarbon feedstocks into efficient fuels and chemicals; and selected low-carbon technologies for power and transport to minimize CO_2 emissions.

During 2006, we announced plans to establish a dedicated biosciences energy research laboratory and invest $500 million over the next 10 years. On 1 February 2007, BP announced that it had selected the University of California, Berkeley, and its partners the University of Illinois at Urbana-Champaign and the Lawrence Berkeley National Laboratory, for the research programme. The Energy Biosciences Institutes aim will be to explore the application of bioscience and the production of new and cleaner energy, initially focusing on renewable biofuels for road transport. It 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.

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Regulation of the groups business

BPs 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 contract 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 BPs 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, BPs 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.

BPs 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 Environmental protection on this page.

For certain information regarding environmental proceedings, see Environmental protection US regional review on page 37.

Environmental protection

Health, safety and environmental regulation

The group is subject to numerous national and local environmental laws and regulations concerning its products, operations and activities. Current and proposed fuel and product specifications 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 40 on page 143 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. Nineteen 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.

On 23 March 2005, an explosion and fire occurred in the isomerization unit of BP Products North America Inc.’s Texas City refinery as the unit was coming out of planned maintenance. Fifteen workers died in the incident and many others were injured. In 2005 and 2006, BP agreed settlements in respect of all the fatalities and many of the personal injury claims arising from the incident. Trials have been scheduled for a number of unresolved claims in mid-2007, although to date all claims scheduled for trial have been resolved in advance of trial. In 2006, BP continued its co-operation with the governmental entities investigating the incident, including the US Department of Justice (DOJ), the US Environmental Protection Agency (EPA), the US Occupational Safety & Health Administration (OSHA), the US Chemical Safety and Hazard Investigation Board (CSB) and the Texas Commission on Environmental Quality (TCEQ). During 2006, BP also devoted significant time and effort to co-operate with the BP US Refineries Independent Safety Review Panel (the panel), which it chartered in 2005 on the recommendation of the CSB to assess the effectiveness of corporate oversight of safety management systems at BP’s US refineries and the corporate safety culture. The panel published its report in January 2007 and BP has publicly committed to implement its recommendations *(see Report of the BP US Refineries Independent Safety Review Panel on page 25)*.

The incident prompted a number of investigations by other state and federal agencies. The TCEQ and OSHA investigations of the incident resulted in settlement agreements between BP and the agencies. In the third quarter of 2005, BP reached a settlement with OSHA that resulted in the payment of a $21.4 million penalty, an agreement to correct all alleged safety violations and the retention of experts to assess the refinerys organization and process safety systems. In the second quarter of 2006, BP settled with the TCEQ, resolving 27 alleged violations by paying

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a $0.3 million fine and agreeing, among other things, to upgrade its flare system.

The CSB report is expected to be issued in March 2007.

As a result of its investigation of the Texas City refinery, OSHA conducted an inspection of BP Products North America Inc.s Toledo refinery beginning in October 2005. On 24 April 2006, OSHA issued citations with a total penalty of $2.4 million, alleging 39 separate violations of two different OSHA standards. BP and OSHA have reached a settlement in principle and are working towards finalizing the documentation.

On 15 November 2006, the Indiana Occupational Safety and Health Administration (IOSHA) issued the Whiting refinery with three Safety Orders and Notifications of Penalty alleging 14 separate violations of the OSHA regulations. The total proposed penalty was $0.4 million. On 7 December 2006, BP and IOSHA met to discuss resolution of the matter. Discussions to reach a settlement agreement are ongoing.

On 2 March 2006, a crude oil spill 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. The spill was reported to all the appropriate government agencies as soon as it was discovered and the portion of the line with the leak was shut down. The pipeline leak was caused by internal corrosion. The spill affected approximately two acres of frozen tundra. Clean-up and rehabilitation of the area are complete and environmental damage to the tundra is expected to be minimal. On 15 March 2006, the US Department of Transportation (DOT) issued a Corrective Action Order (CAO) that required, among other items, that BP develop a plan to run maintenance pipeline inspection tools (pigs) and smart pigs through the three Prudhoe Bay oil transit lines. The DOT has since issued two amendments to the CAO. Combined, the three orders have required 34 corrective actions. On 6 August 2006, BP Exploration Alaska ordered a phased shutdown of the Prudhoe Bay oil field following the discovery of unexpectedly severe corrosion and a spill of 199 barrels from the oil transit line in the Eastern Operating Area of Prudhoe Bay. The decision was based on the receipt of data from a smart pig run and follow-up inspections where corrosion-related wall thinning appeared to exceed BP criteria for continued operation. It was during these follow-up inspections that BP personnel discovered a leak and a small spill to the tundra. The spill was contained and clean-up began. US and State of Alaska investigations of the incident have been initiated and subpoenas have been issued, including a Federal Grand Jury subpoena. BP continues its discussions with the DOT to assure compliance with the corrective actions outlined in the CADs. In September 2006, BP executives testified before the US House of Representatives and the US Senate.

Management cannot predict future developments, such as increasingly strict requirements of environmental laws and resulting enforcement policies, that might affect the groups 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 groups activities are in compliance in all material respects with applicable environmental laws and regulations.

For a discussion of the groups environmental expenditure see Environmental expenditure on page 47.

BP operates in more than 100 countries worldwide. In all regions of the world, BP has processes designed to ensure compliance with applicable regulations. In addition, each individual in the group is required to comply with BP health, safety and environmental (HSE) policies as embedded in the BP code of conduct. Our partners, suppliers and contractors are also encouraged to adopt them. The group is working with the equity-accounted entity TNK-BP to develop management information to allow for the assessment and measurement of their activities in relation to HSE regulations and obligations.

This Environmental protection section focuses primarily on the US and the EU, where approximately 70% of our property, plant and equipment is located, and on two issues of a global nature: climate change programmes and maritime oil spills regulations.

Climate change programmes

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 internationally legally binding targets for the first commitment period of 2008-2012. In 2005, the Kyoto protocol came into force, committing the 156 participating countries to emissions targets and the EU Emissions Trading Scheme (ETS) came into operation. However, Kyoto was only designed as a first step and policymakers continue to discuss what new agreement might follow it in 2012 and how all significant countries can be involved. This was discussed further by the G8 group of world leaders at their St Petersburg summit in 2006 and at the UNFCC conference in Nairobi, where progress was made on climate impacts adaptation and vulnerability and there was agreement to review the Kyoto protocol by 2008.

Market mechanisms to allow optimum utilization of resources to meet the national Kyoto targets are being considered, developed or implemented by individual countries and also internationally through the EU. The relative success of these systems will determine the extent to which alternative fiscal or regulatory measures may be applied.

In July 2003, final agreement was reached on a European Directive establishing a scheme for GHG emission allowance trading within the EU and, in January 2005, the scheme came into force, capping the CO_2 emissions of major industrial emitters. BP was well prepared for the EU ETS, building on experiences from our own internal emissions trading system (operated between 1999 and 2001) and participation in the UK's own pilot ETS. The EU ETS launched in 2005 covers all BP installations with combustion facilities greater than 20MW thermal input. The first phase of EU ETS will come to completion at the end of 2007, with EU ETS phase II running from 2008 to 2012. By 31 December 2006, member states should have submitted their final national allocation plan (NAP) versions. These are in the process of receiving final approval from the Commission. In 2006, our 18 EU ETS participating installations submitted their verified 2005 CO_2 emission reports, balanced their EU ETS allowance positions using BP's trading resources in London and surrendered the required number of allowances, equal to their 2005 verified annual emissions.

In September 2006, California governor Arnold Schwarzenegger signed the California Global Warming Solutions Act of 2006 (AB 32) into law. AB 32 requires the California Air Resources Board (CARB) to develop regulations that will ultimately reduce California's GHG emissions to 1990 levels by 2020 (an approximately 25% reduction from current levels). Mandatory caps will begin in 2012 for significant sources and will ratchet down over time to meet the 2020 goals. The law specifically targets "sources or categories that contribute the most to statewide emissions" for action. The California Climate Action Team, which the law designates to co-ordinate overall climate policy, has identified transportation as the largest GHG-emitting sector in California, and electricity generation and the oil and gas industry are the two largest GHG-emitting industrial sectors in the state.

The US congressional mid-term elections in November 2006 resulted in a change in control of the US Congress that may increase the prospects for more aggressive federal regulation of GHG emissions. Such future regulation could include stricter Corporate Average Fuel Emissions for automobiles sold in the US, changes in fuel specifications, the promotion of alternative fuels, stricter emissions limits on large GHG sources and/or the introduction of a cap and trade programme on CO_2 or other GHG emissions.

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 aiming to offset, through energy efficiency projects, half the underlying operational GHG emission increases that result from our growing business. After five years, we estimate that emissions growth of some 12 million tonnes has been offset by around 6 million tonnes of sustainable reductions. With regard to our products, our commitment to low-carbon businesses increased in 2006 with the internal establishment of a separate biofuels business and the announcement to establish a dedicated biosciences energy research facility attached to a major academic centre and invest

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$500 million over the next 10 years. Our low-carbon power business, BP Alternative Energy, continued to expand its activities with the purchase of US wind developers Orion Energy, LLC, and Greenlight Energy Inc. and the formation of a strategic alliance with Clipper Windpower, to develop jointly more than 2 gigawatts of wind projects in the US.

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 Marine 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 federal law (OPA 90), which imposes liability for oil spills on the owners 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 2006, the ATC fleet consisted of six 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 Shippings 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 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 $29 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, i.e. an additional liability of up to 273.5 million Special Drawing Rights (around $406 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 Shippings managed and time-chartered vessels will participate in STOPIA and TOPIA.

At the end of 2006, the international fleet we managed numbered 47 oil and product carriers, all double-hulled with an average age of less than three years, seven LNG ships with an average age of nine years and three LPG ships, which are all less than one year old. The international fleet renewal programme will continue and is expected to see one more LPG ship being delivered in mid-2007 and four new LNG ships being delivered between mid-2007 and the end of 2008. In addition to its own fleet, BP will continue to charter quality ships; currently these vessels include both single- and double-hulled designs, but BP Shipping is accelerating the phase-in of only double-hulled vessels by 2008; 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 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, 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 and has the know-how to produce quality and competitive products in compliance with their requirements. 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 then 100% beginning January 2010. By June 2007, all non-road diesel fuel production will have to meet a sulphur cap of 500ppm and then 15ppm by June 2012.

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 Region 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 over 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 certain 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.

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Under the Comprehensive Environmental Response, Compensation, and Liability Act (also known as 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 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 800 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 60 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 (the basin). The estimated future cost of performing selected and proposed remedies in certain areas in the basin are likely to exceed $350 million. Federal and state trustees also seek to recover damages for alleged injuries to natural resources in the basin. In 1999, Atlantic Richfield settled most of the State's claims for damages, as well as all natural resource damage claims asserted by a local Native American tribe. However, the parties have not resolved the claims for natural resource damages on certain federal land or the State's remaining claims for restoration damages. Past settlements among the parties, including consent decree settlements providing for combined remediation and restoration projects in limited areas of the basin, may provide a framework for future settlement of the remaining claims. Atlantic Richfield Company has asserted defences to the remaining claims and has asserted counterclaims.

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 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 Transportation, through the Pipeline and Hazardous Materials Safety Administration, regulates in a comprehensive manner 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 and the Department of Transportation Hazardous Materials 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.

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. Supporting the BART are five Regional Response Incident Management Teams and seven HAZMAT Strike Teams. Collectively, these teams are ready to assist in a response to a major incident.

See also Legal proceedings on page 77.

European Union regional review

Within the EU, European Community directives are proposed by the European Commission (EC) and usually adopted jointly by the European Parliament and the Council of Ministers. They must then be implemented by each EU member state. Less frequently in the field of environment, EC regulations are adopted that apply directly throughout the EU without the need for member state implementation. 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 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 installations 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 must apply for and obtain such a permit by November 2007. Compliance requires capital and revenue expenditure across BP sites. The EC has embarked upon a process of review that is likely to report in 2007 and to result in recommendations for amendments to the IPPC directive.

The EC Large Combustion Plant Directive was adopted in 1988 and subsequently replaced by a new Large Combustion Plant Directive in 2001. The current LCPD imposes a complex range of controls on emissions of sulphur dioxide, nitrogen oxides and particulates from large combustion plants. The nature and stringency of these controls for a particular plant depend principally on its age. Plants permitted between 1987 and 2002 had a requirement for specific emission limit values by 27 November 2002. Plants permitted since then must meet more stringent emission limit values. Plants permitted prior to 1987 must also meet emission limit values unless they have opted out (in which case they must now close after 20,000 hours of further operation starting from 1 January 2008 and ending no later than 31 December 2015) or will participate in a National Emission Reduction Plan designed to deliver equivalent aggregate emission reductions.

The second important set of air quality-related legislation affecting BP European operations is the Air Quality Framework Directive on ambient air quality assessment and management and its daughter Directives, which prescribe, among other things, ambient limit values for sulphur dioxide, oxides of nitrogen, particulate matter, lead, carbon monoxide, ozone, cadmium, arsenic, nickel, mercury and polyaromatic hydrocarbons. If the concentration of a pollutant exceeds air quality limit values plus a margin of tolerance set under a daughter Directive (or there is a risk of such exceedance), a member state is required to take action to reduce emissions. This may affect any BP operations whose emissions contribute to such exceedances.

In 2005, the EC published its Thematic Strategy on Air Pollution a key part of the Clean Air for Europe (CAFÉ) programme and an accompanying proposed directive to consolidate the existing ambient air quality legislation referred to above and to introduce new controls on the

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concentration of fine particles (PM 2.5 particulate matter less than 2.5 microns diameter) in ambient air. The Thematic Strategy outlines EU-wide objectives to reduce the health and environmental impacts of air quality and a wide range of measures to be taken. These measures include: the ambient air quality proposal mentioned above; revisions to the National Emissions Ceilings Directive; new emission limits for light and heavy duty diesel vehicles; new controls on smaller combustion plant; and further control of evaporative losses from vehicle refuelling at service stations.

The EU has set stringent objectives to control exhaust emissions from vehicles, which are being implemented in stages. Maximum sulphur levels for gasoline and diesel of 50ppm and a 35% maximum aromatic content for gasoline were both agreed to apply from 2005. Agreement was reached in December 2002 on a further directive to make petrol and diesel with a maximum sulphur content of 10ppm mandatory throughout the EU from January 2009, and from 2005, member states will also have to supply low-sulphur fuel at enough locations to allow the circulation of new low-emission engines requiring the cleaner fuel. Further measures on sulphur levels of shipping fuels and/or reduction of emissions using such fuels started to take effect during 2006. Restrictions and measures include sulphur levels in fuels of 0.1% for inland vessels by January 2010 and 1.5% for passenger ships by 19 August 2006. The chief impact on BP is likely to arise from installation of flue gas desulphurization on ships and higher cost fuel. The overall impact is not expected to be material to the groups results of operations or financial position.

A new EC programme for European chemical regulation REACH (Registration, Evaluation and Authorization of Chemicals) will come into force on 1 June 2007. All chemical substances manufactured or imported in the EU above 1 tonne per annum (about 30,000) will require a new pre-registration within the following 18 months and a registration within a 3-to 11-year time-phased period from adoption. The actual date depends on volume bands or classification with high volumes and hazardous substances first. Only time-limited authorizations will be given to substances of high concern. A new European Chemical Agency will be established in Helsinki by mid-2008. Crude oil and natural gas are exempt. Fuels will be exempted from authorization but not registration. For BP, REACH will affect all refining petroleum products, petrochemicals, lubricants and other chemicals. An initial estimate suggests costs of about $60,000 each for the internal preparation, pre-registration and registration of nearly 1,000 entities representing manufactured or imported substances or imported preparations for all BP individual entities obligated under REACH. Additional costs for further submission to authorization for relevant substances and the modification of safety data sheets will have to be assessed as further costs once the final regulation is known.

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. The regime is more stringent for operators of specified higher-risk activities, including IPPC-permitted operations. Member states are considering how to implement the regime.

During 2007, the commission is expected to release a communication on Carbon Capture and Storage (CCS), setting out guidelines for the technology and its regulation. The intention of the communication 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.

Other environment-related existing regulations that may have an impact on BPs operations include: 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; the Water Framework Directive, which includes protection of surface waters and groundwater; and the Waste Framework Directive.

The Water Framework Directive requires member states to develop programmes of measures and start implementing them by 2012, the principal objective being to ensure that all water bodies covered by the directive attain at least good quality by 2015. For an individual plant which, for instance, abstracts water or discharges effluent into water, the implications of the directive will depend on local circumstances (including the extent to which the activity might prejudice attaining good quality for a water body) and on the individual member states approach to developing and implementing the relevant programme of measures. The Water Framework Directive also draws together and provides for the replacement (with new directives) of a number of other directives relating to water quality, such as those on groundwater and discharge of dangerous substances.

The Waste Framework Directive requires member states to operate a permitting regime for waste disposal and recovery and to ensure that waste is recovered or disposed without endangering human health and without using processes or methods that could harm the environment. A European Court of Justice ruling in 2004 (Van de Walle) interpreted these requirements widely, in a way that raised potentially significant implications for soil and groundwater contamination; however, a proposed revision to the directive that is currently making its way through the EU legislative process would, if adopted in its current form, potentially pave the way for mitigating this position by excluding from the directive unexcavated soil covered by other EU legislation.

In 2005, the EC published a proposed EC Marine Strategy Directive, which would adopt an approach akin 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.

In 2006, the EC published a proposed Soil Framework Directive that, as currently drafted, would encompass all soils, not just those for agricultural uses. If adopted in its current form, the directive would require member states to develop, over time, a register of contaminated sites and to require their remediation so that they do not pose significant risks to human health or the environment. Unlike the Environmental Liability Directive, this is intended to apply to historic as well as new contamination. Member states may well need to carry out or require intrusive site investigations in order to establish whether particular sites are contaminated sites; coupled with a requirement (which will be new for some member states) for site investigations to be carried out on any sale of land that may be contaminated, this could lead to the crystallization of liabilities for BP in respect of its current or former operational and other land holdings, if any such land is found to be contaminated.

Property, plants and equipment

BP has freehold and leasehold interests in real estate in numerous countries throughout the world, but no individual property is significant to the group as a whole. See Exploration and Production on page 12 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 2006 and the group percentage of ordinary share capital (to nearest whole number) are set out in Financial statements – Note 50 on page 161. See Financial statements – Notes 29, 30 and 55 on pages 127, 128 and 185 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

	2006	2005	2004
Sales and other operating revenues from continuing operationsa	**265,906**	239,792	192,024
Profit from continuing operationsa	**22,626**	22,133	17,884
Profit for the year	**22,601**	22,317	17,262
Profit for the year attributable to BP shareholders	**22,315**	22,026	17,075
Profit attributable to BP shareholders per ordinary share cents	**111.41**	104.25	78.24
Dividends paid per ordinary share cents	**38.40**	34.85	27.70

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 5 on page 103.

Business environment

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.

Crude oil prices reached record highs in 2006 in nominal terms, driven by low surplus oil production capacity, continued demand growth and concern about vulnerability of supply. 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 but remained well above historical averages. The Henry Hub First of the 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 Global Indicator Margin (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.

The business environment in 2005 was stronger than in 2004, with higher oil and gas realizations and higher refining and olefins margins but lower retail marketing margins.

In 2005, the dated Brent price averaged $54.48 per barrel, an increase of more than $16 per barrel above the $38.27 per barrel average seen in 2004, and varied between $38.21 and $67.33 per barrel. Hurricanes Katrina and Rita severely disrupted oil and gas production in the Gulf of Mexico for an extended period but supply availability was maintained.

Natural gas prices in the US were also higher during 2005 than in 2004 in the face of rising oil prices and hurricane-induced production losses. In 2005, the Henry Hub First of the Month Index averaged $8.65 per mmBtu, up by around $2.50 per mmBtu compared with the 2004 average of $6.13 per mmBtu. High gas prices in 2005 stimulated a fall in demand, especially in the industrial sector. UK gas prices were up strongly in 2005, averaging 40.71 pence per therm at the National Balancing Point, compared with a 2004 average of 24.39 pence per therm.

Refining margins also reached record highs in 2005, with the BP GIM averaging $8.60 per barrel. This reflected further oil demand growth and the loss of refining capacity as a result of the US hurricanes. The premium for light products above fuel oils remained exceptionally high, favouring upgraded refineries over less complex sites.

Retail margins weakened in 2005 as rising product prices and price volatility made their impact felt in a competitive marketplace.

Hydrocarbon production

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.

Hydrocarbon production for subsidiaries decreased by 2.8% in 2005 compared with 2004, reflecting a decrease of 3.9% for liquids and a decrease of 1.5% for natural gas. Increases in production in our new profit centres were more than offset by the effect of hurricanes, higher planned maintenance shutdowns and anticipated decline in our existing profit centres. Hydrocarbon production for equity-accounted entities increased by 7.8%, reflecting an increase of 8.4% for liquids and an increase of 3.8% for natural gas. This increase primarily reflects increased production from TNK-BP.

Sales and other operating revenues

The increase in sales and other operating revenues (before the elimination of sales between businesses) for 2006 included approximately $39 billion from higher prices related to marketing and other sales (spot and term contracts, oil and gas realizations and other sales), partially offset by a net decrease of approximately $15 billion from lower volumes of marketing and other sales and a decrease of around $1 billion related to lower production volumes of subsidiaries.

The increase in sales and other operating revenues (before the elimination of sales between businesses) for 2005 included approximately $67 billion from higher prices related to marketing and other sales (spot and term contracts, oil and gas realizations and other sales) and $1 billion from foreign exchange movements due to sales in local currencies being translated into the US dollar. This was partially offset by a net decrease of approximately $11 billion from lower volumes of marketing and other sales and a decrease of around $1 billion related to lower production volumes of subsidiaries.

Profit attributable to BP shareholders

Profit attributable to BP shareholders for the year ended 31 December 2006 was $22,315 million, after inventory holding losses of $253 million. Inventory holding gains or 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 using the first-in first-out method. Profit attributable to BP shareholders for the year ended 31 December 2005 was $22,026 million, including inventory holding gains of $3,027 million, and profit attributable to BP shareholders for the year ended 31 December 2004 was $17,075 million, including inventory holdings gains of $1,643 million.

The profit attributable to BP shareholders for the year ended 31 December 2006 included losses from Innovene operations of $25 million, compared with a profit of $184 million and a loss of $622 million in the years ended 31 December 2005 and 31 December 2004 respectively. The loss/profit from Innovene for the years 2006 and 2005 included losses on remeasurement to fair value of $184 million and

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$591 million respectively. Financial statements Note 5 on page 103 provides further financial information for Innovene.

Profit attributable to BP shareholders for the year ended 31 December 2006:

- Included net gains of $2,114 million on the sales of assets, net fair value gains of $515 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 net impairment credit of $203 million and was after charges for legal provisions of $335 million in Exploration and Production;
- Included net disposal gains of $884 million and was after a charge of $425 million as a result of the ongoing review of fatality and personal injury compensation claims associated with 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 in Refining and Marketing;
- Included net disposal gains of $193 million and net fair value gains of $88 million on embedded derivatives and was after a charge $100 million for the impairment of a North American NGLs asset in the Gas, Power and Renewables segment; and
- Included 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 net fair value gains 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 in Other businesses and corporate.

Profit attributable to BP shareholders for the year ended 31 December 2005:

- Included net gains of $1,159 million on the sales of assets, primarily from our interest in the Ormen Lange field, 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 and a charge for impairment of $40 million relating to fields in the UK North Sea in Exploration and Production;
- Included net gains of $177 million, principally on the divestment of a number of regional retail networks in the US and was after a charge of $1,200 million in respect of fatality and personal injury compensation claims associated with 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 in Refining and Marketing;
- Included net gains of $55 million primarily on the disposal of BPs 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 in the Gas, Power and Renewables segment; and
- Included net gains on disposal of $38 million, and was after a net charge of $278 million related to new, and revisions to existing, environmental and other provisions and the reversal of environmental provisions no longer required, a charge of $134 million relating to the separation of the Olefins and Derivatives business and net fair value losses of $13 million on embedded derivatives in Other businesses and corporate.

Profit attributable to BP shareholders for the year ended 31 December 2004:

- Was after an impairment charge of $267 million in respect of fields in the deepwater Gulf of Mexico and US onshore, an impairment charge of $108 million in respect of a gas processing plant in the US and a field in the Gulf of Mexico Shelf, an impairment charge of $60 million in respect of the partner-operated Temsah platform in Egypt following a blow-out, a net loss on disposal of $65 million, a charge of $35 million in respect of Alaskan tankers that were no longer required and, in addition, following the lapse of the sale agreement for oil and gas properties in Venezuela, $31 million of the previously booked impairment was reversed in Exploration and Production;
- Was after net losses on disposal of $267 million, a charge of $206 million related to new, and revisions to existing, environmental and other provisions, a charge of $195 million for the impairment of the petrochemicals

facilities at Hull, UK, and a charge of $32 million for restructuring, integration and rationalization in Refining and Marketing;

- Included net gains on disposal of $56 million in the Gas, Power and Renewables segment; and
- Included net gains on disposal of $949 million primarily related to the sale of our interests in PetroChina and Sinopec and a credit of $66 million primarily resulting from the reversal of vacant space provisions in the UK and the US, and was after a charge of $283 million related to new, and revisions to existing, environmental and other provisions and a charge of $102 million relating to the separation of the Olefins and Derivatives business in Other businesses and corporate.

(See Environmental expenditure on page 47 for more information on environmental charges.)

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

The primary additional factors reflected in profit attributable to BP shareholders for the year ended 31 December 2005 compared with 2004 were higher liquids and gas realizations, higher refining margins and higher contributions from the operating business within the Gas, Power and Renewables segment, partially offset by lower retail marketing margins, higher costs (including the Thunder Horse incident, the Texas City refinery shutdown and planned restructuring actions) and significant volatility arising under IFRS fair value accounting.

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 97,000 at 31 December 2006, 96,200 at 31 December 2005 and 102,900 at 31 December 2004. The decrease in 2005 resulted primarily from the sale of Innovene.

Capital expenditure and acquisitions

			$ million
	2006	2005	2004
Exploration and Production	**13,075**	10,149	9,648
Refining and Marketing	**3,122**	2,757	2,862
Gas, Power and Renewables	**432**	235	530
Other businesses and corporate	**281**	797	770
Capital expenditure	**16,910**	13,938	13,810
Acquisitions and asset exchanges	**321**	211	2,841
	17,231	14,149	16,651
Disposals	**(6,254)**	(11,200)	(4,961)
Net investment	**10,977**	2,949	11,690

Capital expenditure and acquisitions in 2006, 2005 and 2004 amounted to $17,231 million, $14,149 million and $16,651 million respectively. There were no significant acquisitions in 2006 or 2005. Acquisitions during 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. Excluding acquisitions and asset exchanges, capital expenditure for 2006 was $16,910 million compared with $13,938 million in 2005 and $13,810 million in 2004. In 2006, this included $1 billion in respect of our investment in Rosneft.

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Finance costs and other finance expense

Finance costs comprises group interest less amounts capitalized. Finance costs for continuing operations in 2006 were $718 million compared with $616 million in 2005 and $440 million in 2004. These amounts included a charge of $57 million arising from early redemption of finance leases in 2005. The charge in 2006 reflected higher interest rates and costs, offset by an increase in capitalized interest compared with 2005. Compared with 2004, the charge for 2005 also reflected higher interest rates and costs offset by an increase in capitalized interest.

Other finance expense included net pension finance costs, the interest accretion on provisions and the interest accretion on the deferred consideration for the acquisition of our investment in TNK-BP. Other finance expense for continuing operations in 2006 was a credit of $202 million compared with charges of $145 million in 2005 and $340 million in 2004. The decrease in 2006 compared with 2005 primarily reflected a reduction in net pension finance costs owing to a higher return on pension assets due to the increased market value of the pension asset base. The decrease in 2005 compared with 2004 primarily reflected a reduction in net pension finance costs. This was primarily due to a higher expected return on investment driven by a higher pension fund asset value at the start of 2005 compared with the start of 2004, while the expected long-term rate of return was similar.

Taxation

The charge for corporate taxes for continuing operations in 2006 was $12,516 million, compared with $9,288 million in 2005 and $7,082 million in 2004. The effective rate was 36% in 2006, 30% in 2005 and 28% in 2004. The increase in the effective rate in 2006 compared with 2005 primarily 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. The increase in the effective rate in 2005 compared with 2004 was primarily due to a higher proportion of income in countries bearing higher tax rates, and other factors.

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Business results

Profit before interest and taxation from continuing operations, which is before finance costs, other finance expense, taxation and minority interests, was $35,658 million in 2006, $32,182 million in 2005 and $25,746 million in 2004.

Exploration and Production

			$ million
	2006	2005	2004
Sales and other operating revenues from continuing operations	**52,600**	47,210	34,700
Profit before interest and tax from continuing operationsa	**29,629**	25,502	18,085
Results include			
Exploration expense	**1,045**	684	637
Of which: Exploration expenditure written off	**624**	305	274

			$ per barrel
Key statistics			
Average BP crude oil realizationsb			
UK	**62.45**	51.22	36.11
USA	**62.03**	50.98	37.40
Rest of World	**61.11**	48.32	34.99
BP average	**61.91**	50.27	36.45
Average BP NGL realizationsb			
UK	**47.21**	37.95	31.79
USA	**36.13**	31.94	25.67
Rest of World	**36.03**	35.11	27.76
BP average	**37.17**	33.23	26.75
Average BP liquids realizationsb c			
UK	**61.67**	50.45	35.87
USA	**57.25**	47.83	35.41
Rest of World	**59.54**	47.56	34.51
BP average	**59.23**	48.51	35.39

			$ per thousand cubic feet
Average BP natural gas realizationsb			
UK	**6.33**	5.53	4.32
USA	**5.74**	6.78	5.11
Rest of World	**3.70**	3.46	2.74
BP average	**4.72**	4.90	3.86

			$ per barrel
Average West Texas Intermediate oil price	**66.02**	56.58	41.49
Alaska North Slope US West Coast	**63.57**	53.55	38.96
Average Brent oil price	**65.14**	54.48	38.27

			$/mmBtu
Average Henry Hub gas priced	**7.24**	8.65	6.13
			mb/d
Total liquids production for subsidiariesc e	**1,351**	1,423	1,480
Total liquids production for equity-accounted entitiesc e	**1,124**	1,139	1,051
			mmcf/d
Natural gas production for subsidiariese	**7,412**	7,512	7,624
Natural gas production for equity-accounted entitiese	**1,005**	912	879
			mboe/d
Total production for subsidiariese f	**2,629**	2,718	2,795
Total production for equity-accounted entitiese f	**1,297**	1,296	1,202

a Includes profit after interest and tax of equity-accounted entities.
b The Exploration and Production business 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 2006 were $53 billion, compared with $47 billion in 2005 and $35 billion in 2004. 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. The increase in 2005 primarily reflected an increase of around $13 billion related to higher liquids and gas realizations, partially offset by a decrease of around $1 billion due to slightly lower volumes of subsidiaries.

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 (these embedded derivatives are fair valued at each period end with the resulting gains or losses taken to the income statement) and a net impairment credit of $203 million (comprised of 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

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individually insignificant impairments), and was after inventory 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.

Profit before interest and tax for the year ended 31 December 2004 was $18,085 million, including inventory holding gains of $10 million, and was after an impairment charge of $267 million in respect of fields in the deepwater Gulf of Mexico and US onshore, an impairment charge of $108 million in respect of a gas processing plant in the US and a field in the Gulf of Mexico shelf, an impairment charge of $60 million in respect of the partner-operated Temsah platform in Egypt following a blow-out, a net loss on disposal of $65 million and a charge of $35 million in respect of Alaskan tankers that were no longer required. In addition, following the lapse of the sale agreement for oil and gas properties in Venezuela, $31 million of the previously booked impairment was reversed.

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 higher costs, reflecting the impacts of sector-specific inflation, increased integrity spend and revenue investments. Additionally, BPs share of the TNK-BP result was higher by around $500 million, primarily reflecting higher disposal gains.

The primary additional factors reflected in profit before interest and tax for the year ended 31 December 2005 compared with the year ended 31 December 2004 were higher liquids and gas realizations contributing around $10,100 million and around $400 million from higher volumes (in areas not affected by hurricanes), partially offset by a decrease of around $900 million due to the hurricane impact on volumes, costs associated with hurricane repairs and Thunder Horse of around $200 million and higher operating and revenue investment costs of around $1,700 million.

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.

Actual production for subsidiaries and equity-accounted entities in 2006 of 2,629mboe/d and 1,297mboe/d respectively, compared with 2,649mboe/d and 1,301mboe/d previously indicated at the time of our third-quarter results.

Total production for 2005 was 2,718mboe/d for subsidiaries and 1,296mboe/d for equity-accounted entities, compared with 2,795mboe/d and 1,202mboe/d respectively in 2004. For subsidiaries, increases in production in our new profit centres were more than offset by the effect of the hurricanes, higher planned maintenance shutdowns and anticipated decline in our existing profit centres. For equity-accounted entities, this primarily reflects growth from TNK-BP.

Refining and Marketing

			$ million
	2006	2005	2004
Sales and other operating revenues from continuing operations	**232,855**	213,326	170,639
Profit before interest and tax from continuing operationsa	**5,541**	6,426	6,506
			$/bbl

Global Indicator Refining Margin (GIM)b			
Northwest Europe	**3.92**	5.47	4.28
US Gulf Coast	**12.00**	11.40	7.15
Midwest	**9.14**	8.19	5.08
US West Coast	**14.84**	13.49	11.27
Singapore	**4.22**	5.56	4.94
BP average	**8.39**	8.60	6.31
			%
Refining availabilityc	**82.5**	92.9	95.4
			mb/d
Refinery throughputs	**2,198**	2,399	2,607

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 BPs 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 analysing 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 BPs 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 BPs 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, there was planned maintenance of a substantial part of the Texas City refinery.

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

			$ million
	2006	2005	2004
Sale of crude oil through spot and term contracts	**38,577**	36,992	21,989
Marketing, spot and term sales of refined products	**177,995**	155,098	124,458
Other sales including non-oil and to other segments	**16,283**	21,236	24,192
	232,855	213,326	170,639
			mb/d
Sale of crude oil through spot and term contracts	**2,110**	2,464	2,312
Marketing, spot and term sales of refined products	**5,801**	5,888	6,398

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. The increase in 2005 compared with 2004 was principally due to an increase of around $31 billion in marketing, spot and term sales of refined products. This reflected higher prices of $39 billion and a positive foreign exchange impact due to a weaker dollar of $1 billion, partially offset by lower volumes of $9 billion. Additionally, sales of crude oil, spot and term contracts increased by $15 billion due to higher prices of $13 billion and higher volumes of $2 billion and other sales decreased by $3 billion, primarily due to lower volumes.

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 as a result of the ongoing review of fatality and personal injury compensation claims associated with 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 in respect of fatality and personal injury compensation claims associated with the 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.

Profit before interest and tax for the year ended 31 December 2004 was $6,506 million, including inventory holding gains of $1,312 million, and is after net losses on disposal of $267 million (principally related to the closure of two manufacturing plants at Hull, UK, the disposal of our European speciality intermediate chemicals business, the disposal of our interest in the Singapore Refining Company Private Limited, the closure of the lubricants operation of the Coryton refinery in the UK and of refining operations at the ATAS refinery in Mersin, Turkey, and the sale of the Cushing and other pipeline interests in the US), a charge of $206 million related to new, and revisions to existing, environmental and other provisions, a charge of $195 million for the impairment of the petrochemicals facilities at Hull, UK, and a charge of $32 million for restructuring, integration and rationalization.

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 a positive impact from IFRS fair value accounting (compared with a negative impact in 2005), contributing around $500 million, and lower costs associated with rationalization programmes of around $320 million. In addition, refining margins, including the benefits of supply optimization, were higher by some $400 million and retail margins were higher by around $600 million, although this was partially offset by a deterioration of around $150 million in other marketing margins. These factors were offset by 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 have been offset by higher turnaround and integrity management spend.

The primary additional factors reflected in profit before interest and tax for the year ended 31 December 2005, compared with the year ended 31 December 2004, were improved refining margins, contributing approximately $2,000 million, offset by lower retail marketing margins, reducing profits by approximately $720 million, a reduction of around $870 million due to the shutdown of the Texas City refinery, along with other storm-related supply disruptions to a number of our US-based businesses, an adverse impact of around $400 million due to fair value accounting for derivatives *(see explanation below)*, a reduction of around $430 million due to rationalization and efficiency programme charges, mainly across our marketing activities in Europe.

Where derivative instruments are used to manage certain economic exposures that cannot themselves be fair valued or accounted for as hedges, timing differences in relation to the recognition of gains and losses occur. These economic exposures primarily relate to inventories held in excess of normal operating requirements that are not designated as held for trading and fair valued and forecast transactions to replenish inventory. Gains and losses on derivative commodity contracts are recognized immediately through the income statement while gains and losses on the related physical transaction are recognized when the commodity is sold.

Additionally, IFRS requires that inventory designated as held for trading is fair valued using period end spot prices while the related derivative instruments are valued using 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 quarterly timing differences.

The average refining Global Indicator Margin (GIM) in 2006 was lower than in 2005. Retail margins improved, but this improvement was partially negated by deterioration in other marketing margins.

Refining throughputs in 2006 were 2,198mb/d, 201mb/d lower than in 2005. Refining availability, excluding the Texas City refinery, was 95.7%, broadly consistent with 2005. Marketing volumes at 3,872mb/d were around 2% lower than in 2005.

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Gas, Power and Renewables

			$ million
	2006	2005	2004
Sales and other operating revenues from continuing operations	**23,708**	25,696	23,969
Profit before interest and tax from continuing operations[a]	**1,321**	1,172	1,003

[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
	2006	2005	2004
Gas marketing sales	**11,428**	15,222	13,532
Other sales (including NGLs marketing)	**12,280**	10,474	10,437
	23,708	25,696	23,969

			mmcf/d
	2006	2005	2004
Gas marketing sales volumes	**3,685**	5,096	5,244
Natural gas sales by Exploration and Production	**5,152**	4,747	3,670

Sales and other operating revenues for 2006 was $24 billion, 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. Sales and other operating revenues were $26 billion in 2005, compared with $24 billion in 2004. Gas marketing sales increased by $1.7 billion as price increases of $2.1 billion more than offset lower volumes of $0.4 billion. Other sales (including NGLs marketing) remained flat, reflecting $0.1 billion related to higher prices and $0.1 billion to lower volumes. Gas marketing sales volumes declined in 2005 and 2006 primarily due to customer portfolio changes and, in 2005, production loss caused by hurricanes in the Gulf of Mexico.

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 intra-group gas supply contract and net gains of $55 million primarily on the disposal of BPs 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.

Profit before interest and tax for the year ended 31 December 2004 was $1,003 million, including inventory holding gains of $39 million and a net gain on disposal of $56 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 $160 million partially offset by higher IFRS fair value accounting charges reducing the result by around $60 million.

The primary additional factors reflected in profit before interest and tax for the year ended 31 December 2005, compared with the equivalent period in 2004 were higher contributions from the operating businesses of around $170 million.

Other businesses and corporate

			$ million
	2006	2005	2004
Sales and other operating revenues from continuing operations	**1,009**	668	546
Profit (loss) before interest and tax from continuing operationsa	**(885)**	(1,237)	155

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

Other businesses and corporate comprises Finance, the group's aluminium asset, its investments in PetroChina and Sinopec (both divested in early 2004), interest income and costs relating to corporate activities worldwide. Following the sale of Innovene to INEOS in 2005, three equity-accounted entities (Shanghai SECCO Petrochemical Company Limited in China and Polyethylene Malaysia Sdn Bhd and Ethylene Malaysia Sdn Bhd, both in Malaysia) previously reported in Other businesses and corporate were transferred to Refining and Marketing, effective 1 January 2006.

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.

The profit before interest and tax for the year ended 31 December 2004 was $155 million, including net gains on disposals of $949 million, primarily related to the sale of our interests in PetroChina and Sinopec, and a credit of $66 million primarily resulting from the reversal of vacant space provisions in the UK and the US, and was after a charge of $283 million related to new, and revisions to existing, environmental and other provisions, and a charge of $102 million relating to the separation of the Olefins and the Derivatives business.

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Environmental expenditure

			$ million
	2006	2005	2004
Operating expenditure	**596**	494	526
Clean-ups	**59**	43	25
Capital expenditure	**806**	789	524
Additions to environmental remediation provision	**423**	565	587
Additions to decommissioning provision	**2,142**	1,023	286

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 2006 is largely related to expenditure incurred on reducing air emissions at US refineries. The increase in capital expenditure in 2005 compared with 2004 is largely related to clean fuels investment. 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 2006 includes $378 million resulting from a reassessment of existing site obligations and $45 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; and 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 which 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 on stream 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 40 on page 143. See also Environmental protection on page 35.

Liquidity and capital resources

Cash flow

The following table summarizes the group□s cash flows.

			$ million
	2006	2005	2004
Net cash provided by operating activities of continuing operations	**28,172**	25,751	24,047
Net cash provided by (used in) operating activities of Innovene operations	□	970	(669)
Net cash provided by operating activities	**28,172**	26,721	23,378
Net cash used in investing activities	**(9,518)**	(1,729)	(11,331)
Net cash used in financing activities	**(19,071)**	(23,303)	(12,835)
Currency translation differences relating to cash and cash equivalents	**47**	(88)	91
Increase (decrease) in cash and cash equivalents	**(370)**	1,601	(697)
Cash and cash equivalents at beginning of year	**2,960**	1,359	2,056
Cash and cash equivalents at end of year	**2,590**	2,960	1,359

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, 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 provided by operating activities for the year ended 31 December 2005 was $26,721 million compared with $23,378 million for the equivalent period of 2004, reflecting an increase in profit before taxation from continuing operations of $6,455 million, an increase in net cash provided by operating activities of Innovene of $1,639 million, a lower charge for provisions, less payments of $1,210 million and an increase in dividends received from jointly controlled entities and

associates of $634 million. This was partially offset by an increase in income taxes paid of $2,640 million, an increase of $1,320 million in working capital requirements, an increase in earnings from jointly controlled entities and associates of $1,263 million, a higher net credit for impairment and gain/loss on sale of businesses and fixed assets of $775 million, an increase in interest paid of $429 million and an increase in the net operating charge for pensions and other post-retirement benefits, less contributions of $351 million.

Net cash used in investing activities was $9,518 million in 2006, compared with $1,729 million and $11,331 million in 2005 and 2004. The increase in 2006 reflected a reduction in disposal proceeds of $4,946 million and an increase in capital expenditure of $2,844 million. The reduction in 2005 compared with 2004 reflected an increase in disposal proceeds of $6,239 million, primarily from the sale of Innovene, and a decrease in spending on acquisitions of $2,693 million.

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Net cash used in financing activities was $19,071 million in 2006 compared with $23,303 million in 2005 and $12,835 million in 2004. The lower outflow in 2006 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 share of $3,836 million. The higher outflow in 2005 compared with 2004 reflects an increase in the net repurchase of ordinary share capital of $4,107, higher repayments of long-term financing of $2,616 million, a net decrease of $1,433 million in short-term debt, and increases in equity dividends paid to BP shareholders of $1,318 million and to minority interest of $794 million.

The group has had significant levels of capital investment for many years. Capital investment, excluding acquisitions, was $16.9 billion in 2006, $13.9 billion in 2005 and $13.8 billion in 2004. 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 $21.7 billion at the end of 2004, $16.2 billion at the end of 2005 and was $21.4 billion at the end of 2006. The lower level of debt at the end of 2005 reflects the receipt of the Innovene disposal proceeds in December 2005.

Over the period 2004 to 2006 our cash inflows and outflows were balanced, with sources and uses both totalling $101 billion. During that period, the price of Brent has averaged $52.63/bbl. The following table summarizes the three-year sources and uses of cash.

	$ billion
Sources	
Net cash provided by operating activities	78
Divestments	22
Movement in net debt	1
	101

	$ billion
Uses	
Capital expenditure	42
Acquisitions	3
Net repurchase of shares	34
Dividends to BP shareholders	21
Dividends to Minority Interest	1
	101

Acquisitions made for cash were more than offset by divestments. Net investment over the same period has averaged $7.7 billion per year. Dividends to BP shareholders, which grew on average by 14.9% per year in dollar terms, used $21 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 last three years, $1.9 billion has been contributed to funded pension plans.

Trend information

We expect to grow cash flows underpinned by the following:

- We expect to grow production even in a $60/bbl price environment.
- We aim to control cost increases below inflation.
- We expect capital expenditure to be around $18 billion in 2007.
- We expect to continue to high-grade our portfolio consistent with our strategy.

As noted above, we expect capital expenditure, excluding acquisitions, to be around $18 billion in 2007; 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 which further our strategy; and any acquisition opportunities that may arise.

In 2006, the UK supplementary tax charge was raised to 20%, increasing the group's effective tax rate by 2%. The impact of the additional one-off deferred tax adjustment relating to this rate change was largely offset by relieving measures specifically provided in the legislation.

Total production for 2007 is expected to remain broadly the same as in 2006 after allowing for the impact on 2007 of divestments made in 2006. This estimate is based on the group's asset portfolio at 1 January 2007, expected start-ups in 2007 and Brent at $60/bbl, before any 2007 disposal effects and before any effects of prices above $60/bbl on volumes in PSAs.

The anticipated decline in production volumes from subsidiaries in our existing profit centres is partly mitigated by the development of new projects and the investment in incremental reserves in and around existing fields. We expect that this overall decline in production from subsidiaries in our existing profit centres will be more than compensated for by strong increases in production from subsidiaries in our new profit centres over the next few years. Production growth in our equity-accounted joint venture, TNK-BP, is expected to remain broadly constant to 2009.

The most important determinants of cash flows in relation to our oil and natural gas production are the prices of these commodities. In a stable price environment, cash flows from currently developed proved reserves are expected to decline in a manner consistent with anticipated production decline rates. Development activities associated with recent discoveries, as well as continued investment in these producing fields, are expected to more than offset this decline, resulting in increased operating cash flows over the next few years. Cash flows from equity-accounted entities are expected to be in the form of dividend payments.

Dividends and other distributions to shareholders and gearing

The total dividend paid in 2006 was $7,686 million, compared with $7,359 million in 2005 and $6,041 million in 2004. The dividend per share was 38.40 cents, compared with 34.85 cents per share in 2005 (an increase of 10%) and 27.70 cents per share in 2004 (an increase of 26% between 2005 and 2004). In sterling terms, the dividend paid in 2006 was also 10% higher than 2005.

Our dividend policy is to grow the dividend per share progressively. In pursuing this policy and in setting the levels of dividends we are guided by several considerations, including:

- The prevailing circumstances of the group.
- The future investment patterns and sustainability of the group.
- The trading environment.

We determine the dividend in US dollars, the economic currency of BP.

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.

We remain committed to returning the excess of net cash provided by operating activities less net cash used in investing activities to our investors where this is in excess of investment and dividend needs.

During 2006, the company repurchased 1,334 million of its own shares at a cost of $15,481 million. Of these, 358 million were purchased for cancellation and the remainder are held in treasury. The repurchased shares had a nominal value of $333 million and represented 6.5% of ordinary shares in issue, net of treasury shares, at the end of 2005. Since the inception of the share repurchase programme in 2000 until the end of 2006 we have repurchased some 3,996 million shares at a cost of $40.7 billion. We plan to continue our programme of share buybacks, subject to market conditions and constraints and to renewed authority at the April 2007 annual general meeting.

Our financial framework includes a gearing band of 20-30% which is intended to provide an efficient capital structure and the appropriate level of financial flexibility. Our aim is to maintain gearing within this range. At 31 December 2006, gearing was 20%, at the bottom of the targeted band.

The discussion above and following contains forward-looking statements with regard to future cash flows, future levels of capital expenditure and divestments, future production volumes, working capital, the renewal of borrowing facilities, shareholder distributions and share buybacks 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

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on page 9 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 groups activities

The groups 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 groups finance debt is almost entirely in US dollars and at 31 December 2006 amounted to $24,010 million (2005 $19,162 million) of which $12,924 million (2005 $8,932 million) was short term.

Net debt was $21,420 million at the end of 2006, an increase of $5,218 million compared with 2005. The ratio of net debt to net debt plus equity was 20% at the end of 2006 and 17% at the end of 2005. The ratio of 20% at 31 December 2006 takes into account seasonal impacts.

The maturity profile and fixed/floating rate characteristics of the groups debt are described in Financial statements Note 38 on page 140.

We have in place a European Debt Issuance Programme (DIP) under which the group may raise $10 billion of debt for maturities of one month or longer. At 31 December 2006, the amount drawn down against the DIP was $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 there had not been any draw-down.

Commercial paper markets in the US and Europe are a primary source of liquidity for the group. At 31 December 2006, the outstanding commercial paper amounted to $4,167 million (2005 $1,911 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 2006, the group had available undrawn committed borrowing facilities of $4,700 million ($4,500 million at 31 December 2005).

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 2006, the groups share of third-party finance debt of jointly controlled entities and associates was $4,942 million (2005 $3,266 million) and $1,143 million (2005 $970 million) respectively. These amounts are not reflected in the groups debt on the balance sheet.

The group has issued third-party guarantees under which amounts outstanding at 31 December 2006 are summarized below. Some guarantees outstanding are in respect of borrowings of jointly controlled entities and associates noted above.

							$ million
							Guarantees expiring by period
	Total	2007	2008	2009	2010	2011	2012 and thereafter
Guarantees issued in respect of							
Borrowings of jointly controlled entities and associates	1,123	91	223	118	114	116	461
Liabilities of other third parties	789	480	7	8	19	29	246

At 31 December 2006, contracts had been placed for authorized future capital expenditure estimated at $9,773 million. Such expenditure is expected to be financed largely by cash flow from operating activities.

Contractual commitments

The following table summarizes the group's principal contractual obligations at 31 December 2006. Further information on borrowings and finance leases is given in Financial statements Note 38 on page 140 and further information on operating leases is given in Financial statements Note 18 on page 118.

							$ million
							Payments due by period
Expected payments by period under contractual obligations and commercial commitments	Total	2007	2008	2009	2010	2011	2012 and thereafter
Borrowings[a]	28,680	9,164	4,403	4,663	1,022	1,106	8,322
Finance lease minimum future lease payments	1,331	82	92	93	94	97	873
Operating leases[b]	17,408	3,355	3,031	2,403	1,686	1,191	5,742
Decommissioning liabilities	12,064	337	292	255	346	273	10,561
Environmental liabilities	2,298	445	414	309	288	215	627
Pensions and other post-retirement benefits[c]	22,793	1,353	1,350	1,066	668	615	17,741
Purchase obligations[d]	139,020	86,954	16,723	7,573	4,948	4,500	18,322

a Expected payments include interest payments on borrowings totalling $5,485 million ($917 million in 2007, $750 million in 2008, $554 million in 2009, $335 million in 2010, $301 million in 2011 and $2,628 million thereafter).

b The minimum future lease payments including executory costs and after deducting related rental income from operating subleases. 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 2007 include purchase commitments existing at 31 December 2006 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 Quantitative and qualitative disclosures about market risk on page 54.

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

							$ million
							Payments due by period
Purchase obligations – payments due by period	Total	2007	2008	2009	2010	2011	2012 and thereafter
Crude oil and oil products	58,036	47,247	4,865	1,368	1,126	1,518	1,912
Natural gas	37,923	18,070	4,622	2,954	1,892	1,549	8,836
Chemicals and other refinery feedstocks	12,906	5,162	1,541	956	997	590	3,660
Power	20,148	14,464	4,407	1,270	7	–	–
Utilities	1,618	197	156	131	106	106	922
Transportation	3,704	830	530	407	369	299	1,269
Use of facilities and services	4,685	984	602	487	451	438	1,723
Total	139,020	86,954	16,723	7,573	4,948	4,500	18,322

The following table summarizes the group's capital expenditure commitments at 31 December 2006 and the proportion of that expenditure for which contracts have been placed. For jointly controlled assets, the net BP share is included in the amounts shown. The group expects its total capital expenditure excluding acquisitions to be around $18 billion in 2007.

							$ million
Capital expenditure commitments including amounts for which contracts have been placed	Total	2007	2008	2009	2010	2011	2012 and thereafter
Committed on major projects	22,273	11,175	5,607	2,812	1,659	423	597
Amounts for which contracts have been placed	9,773	5,782	2,127	1,171	435	67	191

Liquidity risk

Liquidity risk is the risk that suitable sources of funding for the group's business activities may not be available. The group has long-term debt ratings of Aa1 and AA+, assigned respectively by Moody's & Standard Poor's.

The group has access to a wide range of funding at competitive rates through the capital markets and banks. It co-ordinates relationships with banks, borrowing requirements, foreign exchange requirements and cash management centrally. The group believes it has access to sufficient funding, including through the commercial paper markets, and also has undrawn committed borrowing facilities to meet currently foreseeable borrowing requirements. At 31 December 2006, the group had substantial amounts of undrawn borrowing facilities available, including committed facilities of $4,700 million, of which $4,300 million are in place for at least five years (2005 $4,500 million expiring in 2006 and 2004 $4,500 million expiring in 2005). These facilities are with a number of international banks and borrowings under them would be at pre-agreed rates. Certain of these facilities support the group's commercial paper programme.

Critical accounting policies

The significant accounting policies of the group are summarized in Financial statements Note 1 on page 92.

Inherent in the application of many of the accounting policies used in the preparation of 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 to be 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, similar to the accounting for research and development costs.

Licence and property acquisition costs are initially capitalized within intangible assets. These costs are amortized on a straight-line basis until such time as either exploration drilling is determined to be successful or it is unsuccessful and 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.

For complicated offshore exploration discoveries, 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. If 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 sanctioned future development expenditure approved by the group.

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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:

– Proved developed reserves for producing wells.
– Total proved reserves for development costs.
– Total proved reserves for licence and property acquisition costs.
– Total proved reserves for future decommissioning costs.

The impact of changes in estimated proved reserves is dealt with prospectively by amortizing the remaining book 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 propertys book value (see discussion of recoverability of asset carrying values below).

Given the large number of producing fields in the groups 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 groups prospective charges for depreciation.

At the end of 2006, BP adopted the Securities and Exchange Commission (SEC) rules for estimating reserves for accounting and reporting purposes instead of the UK accounting rules contained in the UK SORP. These changes are explained in Financial statements Note 3 on page 102.

Oil and natural gas reserves

Commencing in 2006, BP has estimated its proved reserves on the basis of the requirements of the SEC. The 2006 year-end marker prices used to determine reserves volumes were Brent $58.93/bbl ($58.21/bbl) and Henry Hub $5.52/mmBtu ($9.52/mmbtu) . Prior to this date, BP used guidance contained in the UK SORP to estimate reserves. In estimating its reserves under UK SORP, BP used long-term planning prices.

The group 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 SECs 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 wells 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 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. Proved reserves do not include reserves that are dependent on the renewal of exploration and production licences, unless there is strong evidence to support the assumption of such renewal.

BP has an internal process to control the quality of reserves bookings that forms part of a holistic and integrated system of internal control. As discussed in the oil and natural gas accounting section and below, oil and natural gas reserves have a direct impact on certain amounts reported in the financial statements.

The 2006 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 194-195.

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. Such indicators include changes in the groups business plans, changes in commodity prices leading to unprofitable performance and, for oil and gas properties, significant downward revisions of estimated proved reserves quantities. 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 net realizable value 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 and technology improvements on operating expenses, 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 groups plans to continue to develop and produce proved and associated risk-adjusted probable and possible reserves. Expected future cash flows from the sale or production of reserves are calculated based on the groups best estimate of future oil and gas prices. For 2006, prices for oil and natural gas used for future cash flow calculations are based on market prices for the first five years and the groups long-term planning assumptions thereafter. As at 31 December 2006, the groups long-term planning assumptions were $40 per barrel for Brent and $5.50 per mmBtu for Henry Hub. Previously, prices for oil and natural gas used in future cash flow calculations were assumed to decline from the existing levels in equal steps during the following three years to the long-term planning assumptions, which were $25 per barrel and $4.0 per mmBtu for Brent and Henry Hub respectively. 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.

Charges for impairment are recognized in the groups results from time to time as a result of, among other factors, adverse changes in the recoverable reserves from oil and natural gas fields, low plant utilization or reduced profitability. If there are low oil prices or natural gas prices or refining margins or marketing margins over an extended period, the group may need to recognize significant impairment charges.

Irrespective of whether there is any indication of impairment, BP is required to test for impairment any goodwill acquired in a business combination. The group carries goodwill of approximately $10.8 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 around $4.7 billion of carry-forward tax losses in the UK and Germany, which would be available to offset against future taxable income. At the end of 2006, $216 million of deferred tax assets were recognized on these losses as this is the extent to which it is judged that suitable taxable income will arise. No material carry-forward tax losses in other taxing jurisdictions have been recognized as deferred tax assets and these are unlikely to have a significant effect on the groups tax rate in future years.

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

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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 tangible 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 to be used in discounting the cash flows. The interest rate used to determine the balance sheet obligation at the end of 2006 was 2%, unchanged from the end of 2005. 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 that can be reasonably 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).

In particular, 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 2006 was 2%, the same rate as at the previous balance sheet date.

As further described in Financial statements Note 47 on page 158 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 groups defined benefit pension and other 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 discussed and agreed with the independent actuaries 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 groups balance sheet, and pension and other post-retirement benefit expense for the following year.

The pension assumptions at 31 December 2006 and 2005 are summarized below.

						%
	UK		USA		Other	
	2006	2005	**2006**	2005	**2006**	2005
Rate of return on pension plan assets	**7.0**	7.00	**8.0**	8.00	**5.8**	5.50
Discount rate for pension plan liabilities	**5.1**	4.75	**5.7**	5.50	**4.8**	4.00
Rate of increase in salaries	**4.7**	4.25	**4.2**	4.25	**3.6**	3.25
Rate of increase for pensions in payment	**2.8**	2.50	**nil**	nil	**1.8**	1.75
Inflation	**2.8**	2.50	**2.4**	2.50	**2.2**	2.00

The assumptions used in calculating the charge for US other post-retirement benefits are consistent with those shown above for US pension plans except for the discount rate for plan liabilities which is 5.9% (2005 5.5%) .

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 groups 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 2007	(383)	383
Discount rate		
Effect on pension and other post-retirement benefit expense in 2007	(52)	75
Effect on pension and other post-retirement benefit obligation at 31 December 2006	(5,013)	6,433

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The assumed future US healthcare cost trend rate is shown below.

							%
	2007	2008	2009	2010	2011	2012	2013 and subsequent years
Beneficiaries aged under 65	8.0	7.5	7.0	6.5	6.0	5.5	5.0
Beneficiaries aged over 65	10.0	9.5	8.5	7.5	6.5	5.5	5.0

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 2007	31	(25)
Effect on US other post-retirement obligation at 31 December 2006	349	(289)

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. BPs most substantial pension liabilities are in the UK, the US and Germany, where our assumptions are as follows.

						Years
Mortality assumptions		UK		USA		Germany
	2006	2005	**2006**	2005	**2006**	2005
Life expectancy at age 60 for a male currently aged 60	**23.9**	23.0	**24.2**	21.9	**22.2**	22.1
Life expectancy at age 60 for a female currently aged 60	**26.8**	26.0	**26.0**	25.6	**26.9**	26.7
Life expectancy at age 60 for a male currently aged 40	**25.0**	23.9	**25.8**	21.9	**25.2**	25.0
Life expectancy at age 60 for a female currently aged 40	**27.8**	26.9	**26.9**	25.6	**29.6**	29.4

Adoption of International Financial Reporting Standards

For all periods up to and including the year ended 31 December 2004, BP prepared its financial statements in accordance with UK generally accepted accounting practice (UK GAAP). BP, together with all other EU companies listed on an EU stock exchange, was required to prepare consolidated financial statements in accordance with International Financial Reporting Standards (IFRS) as adopted by the EU with effect from 1 January 2005. The Annual Report and Accounts for the year ended 31 December 2005 comprised BPs first consolidated financial statements prepared under IFRS.

The general principle for first-time adoption of IFRS is that standards in force at the first reporting date (for BP, 31 December 2005) are applied retrospectively. However, IFRS 1 First-time Adoption of International Financial

Reporting Standards contains a number of exemptions that companies are permitted to apply. BP elected to take the exemption allowing comparative information on financial instruments to be prepared in accordance with UK GAAP and the group adopted IAS 32 Financial Instruments: Disclosure and Presentation (IAS 32) and IAS 39 Financial Instruments: Recognition and Measurement (IAS 39) from 1 January 2005. Had IAS 32 and IAS 39 been applied from 1 January 2003, BPs date of transition for all other IFRS in force at the first reporting date, the following are the most significant adjustments that would have been necessary in the financial statements for the year ended 31 December 2004:

- All derivatives, including embedded derivatives, would have been brought on to the balance sheet at fair value and changes in fair value would have been recognized in the income statement.
- Available-for-sale investments would have been carried at fair value rather than at cost and changes in fair value would have been recognized directly in equity.

Further information regarding the impact of adopting IAS 32 and IAS 39 is shown in Financial statements Note 49 on page 158.

US generally accepted accounting principles

The consolidated financial statements of the BP group are prepared in accordance with IFRS, which differs in certain respects from US GAAP. The principal differences between US GAAP and IFRS for BP group reporting are discussed in Financial statements Note 53 on page 169. The impact of new US accounting standards is also disclosed in that note.

Outlook

World economic growth has been sustained. US economic growth appears to have been resilient in the fourth quarter, and growth in Europe and Asia has been sustained. The near-term global outlook is for continued growth at close to current rates.

Crude oil prices averaged $59.60 per barrel (dated Brent) in the fourth quarter of 2006, $10 per barrel below the third quarter level but slightly above the same period last year. For the year, dated Brent averaged $65.14 per barrel, a record in money-of-the-day terms and more than $10 per barrel above the 2005 average. Prices in the fourth quarter drifted higher after OPEC announced production cuts in late October, but retreated in late December in face of demand weakness and rising non-OPEC supply. Crude oil prices weakened further in the early part of this year but have rebounded. Further OPEC production cuts have been announced.

US natural gas prices averaged $6.56/mmbtu (Henry Hub first of month index) in the fourth quarter, nearly identical to the third quarter average but half the very high levels seen in the fourth quarter of 2005. Gas continued to trade near parity with residual fuel oil heading into the peak winter demand months. Gas in storage at year-end was 14% above the five year average in face of unusually warm weather. Prices have found support early this year in face of cold winter weather.

UK gas prices (National Balancing Point day-ahead) in the fourth quarter averaged 29.92 pence per therm, 11% below the third quarter and less than half the level of a year ago. New infrastructure projects, high inventories and above-average temperatures contributed to the decline. These factors have eased concerns over winter supply availability and prices have fallen further so far this year.

The global average indicator refining margin fell to $6.30/bbl in the fourth quarter, down just over $2/bbl versus the third quarter and more than $1/bbl below the fourth quarter last year. Margins recovered well from mid-September lows despite a light US hurricane season and an extremely warm start to winter. So far in the first quarter, margins have averaged around $8/bbl, with the near-term outlook dependant on the weather and a relatively heavy US refinery turnaround programme.

Retail margins fell in October and November, due to the increasing cost of product, before stabilizing in December. Average retail margins

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deteriorated in the fourth quarter relative to the third. The outlook for retail margins is expected to remain uncertain.

Quantitative and qualitative disclosures about market risk

The group is exposed to a number of different market risks arising from its normal business activities. Market risk is the possibility that changes in foreign currency exchange rates, interest rates, or oil and natural gas or power prices will adversely affect the value of the groups financial assets, liabilities or expected future cash flows. The group has developed policies aimed at managing the volatility inherent in certain of these 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 which are defined in the contract. The group also trades derivatives in conjunction with its risk management activities.

All derivative activity, whether for risk management or trading, 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. Independent control functions monitor compliance with the groups policies. A Trading Risk Management Committee has oversight of the quality of internal control in the groups trading function. The control framework includes prescribed trading limits that are reviewed regularly by senior management, daily monitoring of risk exposure using value-at-risk principles, marking trading exposures to market and stress testing to assess the exposure to potentially extreme market situations. The groups operational, risk management and trading activities in oil, natural gas, power and financial markets are managed within a single integrated function that has the responsibility for ensuring high and consistent standards of control, making investments in the necessary systems and supporting infrastructure and providing professional management oversight.

In market risk management and trading, conventional exchange-traded derivatives such as futures and options are used, as well as non-exchange-traded instruments such as over-the-counter swaps, options and forward contracts.

IAS 39 Financial Instruments: Recognition and Measurement (IAS 39) prescribes strict criteria for hedge accounting, whether as a cash flow or fair value hedge, and requires that any derivative that does not meet these criteria should be classified as held for trading purposes and fair valued. BP adopted IAS 32 and IAS 39 with effect from 1 January 2005 without restating prior periods. Consequently, the groups accounting policy under UK GAAP has been used for 2004. The policy under UK GAAP and the disclosures required by UK GAAP for derivative financial instruments are shown in Financial statements Note 37 on page 139.

Where derivatives constitute a fair value hedge, the groups exposure to market risk created by the derivative is offset by the opposite exposure arising from the asset, liability or transaction being hedged. Gains and losses relating to derivatives designated as part of a cash flow hedge are taken to reserves and recycled through income or to the carrying value of assets, as appropriate as the hedged item is recognized. By contrast, where derivatives are held for trading purposes, realized and unrealized gains and losses are recognized in the period in which they occur.

The group also has embedded derivatives classified as held for trading. 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. Post the development of an active UK gas market, certain contracts were entered into or renegotiated using pricing formulae not related directly 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.

Further information about BPs use of derivatives, their characteristics and the IFRS accounting treatment thereof is given in Financial statements Note 1 and Note 36 on pages 92 and 132.

There are minor differences in the criteria for hedge accounting under IFRS and SFAS No. 133 Accounting for

Derivative Instruments and Hedging Activities. Prior to 1 January 2005, the group did not designate any of its derivative financial instruments as part of hedged transactions under SFAS 133. As a result, all changes in fair value were recognized through earnings. See Financial statements Note 53 on page 169 for further information.

Foreign currency exchange rate risk

Fluctuations in exchange rates can have significant effects on the groups 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 groups reported results.

The main underlying economic currency of the groups cash flows is the US dollar. This is because BPs major product, oil, is priced internationally in US dollars. BPs foreign 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 exchange risks centrally, by netting off naturally occurring opposite exposures wherever possible, to reduce the risks, and then dealing with any material residual foreign exchange risks. The most significant residual exposures are capital expenditure and UK and European operational requirements. In addition, most of the groups borrowings are in US dollars or are hedged with respect to the US dollar. At 31 December 2006, the total of foreign currency borrowings not swapped into US dollars amounted to $957 million. The principal elements of this are $195 million of borrowings in euros, $179 million in Australian dollars, $114 million in Chinese renminbi, $78 million in South African rand, $35 million in sterling, $224 million in Canadian dollars and $76 million in Trinidad & Tobago dollars.

The following table provides information about the groups foreign currency derivative financial instruments. These include foreign currency forward exchange agreements (forwards), cylinder option contracts (cylinders) and purchased call options that are sensitive to changes in the sterling/US dollar and euro/US dollar exchange rates. Where foreign currency denominated borrowings are swapped into US dollars using forwards or cross-currency swaps such that currency risk is completely eliminated, neither the borrowing nor the derivative is included in the table.

For forwards, the tables present the notional amounts and weighted average contractual exchange rates by contractual maturity dates and exclude forwards that have offsetting positions. Only significant forward positions are included in the tables. The notional amounts of forwards are translated into US dollars at the exchange rate included in the contract at inception. The fair value represents an estimate of the gain or loss that would be realized if the contracts were settled at the balance sheet date.

Cylinders consist of purchased call option and written put option contracts. For cylinders and purchased call options, the tables present the notional amounts of the option contracts at 31 December and the weighted average strike rates.

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The fair values for the foreign exchange contracts in the table below are based on market prices of comparable instruments (forwards) and pricing models that take into account relevant market data (options). These derivative contracts constitute a hedge; changes in the fair value or expected cash flows are offset by an opposite change in the market value or expected cash flows of the asset, liability or transaction being hedged.

$ million

Notional amount by expected maturity date	2007	2008	2009	2010	2011	Beyond 2011	Total	Fair value asset/ (liability)
At 31 December 2006								
Forwards								
Receive sterling/pay US dollars								
Contract amount	630	66	9	6	6	16	733	82
Weighted average contractual exchange rate	1.76							
Receive sterling/pay euro								
Contract amount	—	—	—	—	—	—	—	—
Weighted average contractual exchange rate								
Receive euro/pay US dollars								
Contract amount	957	136	5	3	3	9	1,113	102
Weighted average contractual exchange rate	1.24							
Cylinders								
Receive sterling/pay US dollars								
Purchased call								
Contract amount	1,685	—	—	—	—	—	1,685	14
Weighted average strike price	1.97							
Sold put								
Contract amount	1,685	—	—	—	—	—	1,685	—
Weighted average strike price	1.89							
Receive euro/pay US dollars								
Purchased call								
Contract amount	992	—	—	—	—	—	992	—
Weighted average strike price	1.35							
Sold put								
Contract amount	992	—	—	—	—	—	992	—
Weighted average strike price	1.27							

Weighted average contractual exchange rates are expressed as US dollars per non-US dollar currency unit.

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								$ million
Notional amount by expected maturity date	2006	2007	2008	2009	2010	Beyond 2010	Total	Fair value asset/ liability
At 31 December 2005								
Forwards								
Receive sterling/pay US dollars								
Contract amount	1,749	128	25	6	5	22	1,935	(66)
Weighted average contractual exchange rate	1.78							
Receive sterling/pay euro								
Contract amount	67	1	—	—	—	—	68	1
Weighted average contractual exchange rate	£0.70							
Receive euro/pay US dollars								
Contract amount	1,253	102	26	11	8	30	1,430	(13)
Weighted average contractual exchange rate	1.22							
Cylinders								
Receive sterling/pay US dollars								
Purchased call								
Contract amount	717	—	—	—	—	—	717	3
Weighted average strike price	1.84							
Sold put								
Contract amount	717	—	—	—	—	—	717	(27)
Weighted average strike price	1.77							
Receive Euro/pay US dollars								
Purchased call								
Contract amount	706	—	—	—	—	—	706	3
Weighted average strike price	1.29							
Sold put								
Contract amount	706	—	—	—	—	—	706	(23)
Weighted average strike price	1.21							
Purchased call options								
Receive sterling/pay US dollars								
Contract amount	533	—	—	—	—	—	533	0
Weighted average strike price	1.97							
Receive euro/pay US dollars								
Contract amount	207	—	—	—	—	—	207	0
Weighted average strike price	1.42							

Weighted average contractual exchange rates are expressed as US dollars per non-US dollar currency unit.

Interest rate risk

BP is exposed to interest rate risk on short- and long-term floating rate instruments and as a result of the refinancing of fixed rate finance debt. The group is exposed predominantly to US dollar LIBOR (London Inter-Bank

Offer Rate) interest rates as borrowings are mainly denominated in, or are swapped into, US dollars. To manage the balance between fixed

and floating rate debt, the group enters into interest rate and cross-currency swaps in which the group agrees to exchange, at specified intervals, the difference between fixed and variable rate interest amounts calculated by reference to an agreed notional principal amount. The proportion of floating rate debt at 31 December 2006 was 73% of total finance debt outstanding.

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The following table shows, by major currency, the group’s finance debt at 31 December 2006 and 2005 and the weighted average interest rates achieved at those dates through a combination of borrowings and other derivative instruments entered into to manage interest rate and currency exposures.

	%	years	$ million	%	$ million	$ million
			Fixed rate debt	Floating rate debt		
	Weighted average interest rate	Weighted average time for which rate is fixed	Amount	Weighted average interest rate	Amount	Total
At 31 December 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**
Total loans			**6,358**		**17,652**	**24,010**
At 31 December 2005						
US dollar	7	11	665	5	18,073	18,738
Sterling	—	—	—	6	76	76
Euro	—	—	—	3	150	150
Other currencies	9	14	157	12	41	198
Total loans			822		18,340	19,162

The group’s earnings are sensitive to changes in interest rates over the forthcoming year as a result of the floating rate instruments included in the group’s finance debt at 31 December 2006. These include the effect of interest rate and currency swaps and forwards utilized to manage interest rate risk. If the interest rates applicable to floating rate instruments were to have increased by 1% on 1 January 2007, the group’s 2007 earnings before taxes would decrease by approximately $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 2006 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 which could accompany such an increase in interest rates.

Derivatives held for trading

In conjunction with the risk management activities discussed above, the group also trades interest rate and foreign exchange rate derivatives and, in addition, undertakes trading and risk management of certain specified commodities. In order to disclose a complete picture of activities in relation to commodity derivatives, all activity (trading and risk management) is included in aggregate in Financial statements – Note 36 on page 132.

The group’s operational, risk management and trading activities in oil, natural gas, power and financial markets are managed within a single integrated function. The group’s risk management policy requires the management of only certain short-term exposures in respect of its equity share of production and certain of its refinery and marketing activities. These risks are managed in combination with the group's supply and trading activities.

To this end, the group's supply and trading function uses the full range of conventional financial and commodity derivatives available in the related commodity markets. Natural gas swaps, options and futures are used to convert specific sale and purchase contracts from fixed prices to market prices. Swaps are also used to manage exposures to gas price differentials between locations. The group's oil supply and trading activities undertake the full range of conventional derivative financial and commodity instruments and physical cargoes available in the commodity markets. 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.

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Directors, senior management and employees

Directors and senior management

The following lists the company's directors and senior management as at 20 February 2007.

Name		Initially elected or appointed
P D Sutherland	Non-Executive Chairman	Chairman since May 1997 Director since July 1995
Sir Ian Prosser	Non-Executive Deputy Chairman	Deputy chairman since February 1999 Director since May 1997
The Lord Browne of Madingley	Executive Director (Group Chief Executive)	September 1991
Dr A B Hayward	Executive Director (Group Chief Executive designate)	February 2003
Dr D C Allen	Executive Director (Group Chief of Staff)	February 2003
P B P Bevan	Group General Counsel	September 1992
S Bott	Executive Vice President, Human Resources	March 2005
I C Conn	Executive Director (Group Executive Officer, Strategic Resources)	July 2004
V Cox	Executive Vice President, Gas, Power & Renewables	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
R A Malone	Executive Vice President (Chairman and President of BP America Inc.)	July 2006
J A Manzoni	Executive Director (Chief Executive, Refining and Marketing)	February 2003
J H Bryan	Non-Executive Director	December 1998
A Burgmans	Non-Executive Director	February 2004
Sir William Castell	Non-Executive Director	July 2006
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

On 12 January 2007, BP announced that Lord Browne of Madingley would retire as group chief executive at the end of July 2007 and that Dr A B Hayward, currently head of BP's exploration and production business, would succeed him at that time.

Mr M H Wilson resigned as a director on 28 February 2006 and Mr H M P Miles retired as a director on 20 April 2006. Sir William Castell was appointed a non-executive director on 20 July 2006 and Mr A G Inglis was appointed an executive director on 1 February 2007. At the company's 2006 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 J H Bryan, 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 (54) was appointed company secretary in 2003. A solicitor, he is a director of BP Pension Trustees Limited, a director of Business in the Community and a member of the Listing Authorities Advisory Committee.

P D Sutherland, KCMG

Peter Sutherland (60) rejoined BPs 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 Investor AB and The Royal Bank of Scotland Group.

Chairman of the chairmans and nomination committees

Sir Ian Prosser

Sir Ian (63) joined BPs 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, previously Bass PLC, 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 chairmans, nomination and remuneration committees and chairman of the audit committee

The Lord Browne of Madingley, FRS, FREng

John Browne (59) joined BP in 1966 and subsequently held a variety of exploration and production and finance posts in the US, UK and Canada. He was appointed an executive director in 1991 and group chief executive in 1995. He will retire as group chief executive at the end of July 2007. He is a non-executive director of Goldman Sachs Group Inc. He was knighted in 1998 and made a life peer in 2001.

Dr A B Hayward

Tony Hayward (49) 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 1 February 2007, becoming an executive director in 2003. He has been appointed to succeed Lord Browne as group chief executive following Lord Brownes retirement in July. Dr Hayward is a non-executive director of Corus Group plc.

Dr D C Allen

David Allen (52) joined BP in 1978 and subsequently undertook a number of corporate and exploration and production roles in London and New York. He moved to BPs 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. He is a director of BP Pension Trustees Limited.

P B P Bevan

Peter Bevan (62) joined BP in 1970 after qualifying as a solicitor with a City of London firm. He worked initially in the law department of BPs 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 p.l.c. in 1998.

S Bott

Sally Bott (57) joined BP in March 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

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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.

I C Conn

Iain Conn (44) 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 BPs 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 is a non-executive director of Rolls-Royce Group plc.

V Cox

Vivienne Cox (47) 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 BP Alternative Energy. She is a non-executive director of Rio Tinto plc.

Dr B E Grote

Byron Grote (58) 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 (47) 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 BPs activities in the deepwater Gulf of Mexico. In 1999, he was appointed vice president of BPs 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 BPs exploration and production business and an executive director on 1 February 2007.

R A Malone

Bob Malone (54) 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 for BP 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 A Manzoni

John Manzoni (47) joined BP in 1983. He became group vice president for European marketing in 1999 and BP regional president for the eastern US in 2000. In 2001, he became an executive vice president and chief executive for gas and power. He was appointed chief executive of refining and marketing in 2002 and an executive director of BP in 2003. He is a non-executive director of SABMiller plc.

J H Bryan

John Bryan (70) joined BPs board in 1998, having previously been a director of Amoco. He serves on the boards of General Motors Corporation and Goldman Sachs Group Inc. He retired as the chairman of Sara Lee Corporation in 2001. He is chairman of Millennium Park Inc. in Chicago.

Member of the chairmans, audit and remuneration committees

A Burgmans

Antony Burgmans (60) joined BPs 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. He was appointed chairman of Unilever NV and Unilever PLC in 2005. He is also a member of the supervisory board of Akzo Nobel NV.

Member of the chairmans and safety, ethics and environment assurance committees

Sir William Castell, LVO

Sir William (59) joined BPs 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 and is a trustee of Londons Natural History Museum.

Member of the chairmans, audit and safety, ethics and environment assurance committees

E B Davis, Jr

Erroll B Davis, Jr (62) joined BPs 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 non-executive director of PPG Industries, Union Pacific Corporation and the US Olympic Committee.

Member of the chairmans, audit and remuneration committees

D J Flint, CBE

Douglas Flint (51) joined BPs 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 Councils 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 chairmans and audit committees

Dr D S Julius, CBE

DeAnne Julius (57) joined BPs 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 an independent 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 Lloyds TSB Group PLC, Roche Holdings SA and Serco Group plc.

Member of the chairmans and nomination committees and chairman of the remuneration committee

Sir Tom McKillop

Sir Tom (63) joined BPs 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 chairmans, remuneration and safety, ethics and environment assurance committees

Dr W E Massey

Walter Massey (68) joined BPs board in 1998, having previously been a director of Amoco. He is president of Morehouse College, a non-executive director of Bank of America and McDonalds Corporation and a member of President Bushs Council of Advisors on Science and Technology.

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

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Employees

Number of employees at 31 December	UK	Rest of Europe	USA	Rest of World	Total
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
2004					
Exploration and Production	2,900	600	5,000	7,100	15,600
Refining and Marketing	10,400	19,500	26,500	13,400	69,800
Gas, Power and Renewables	200	800	1,400	1,600	4,000
Other businesses and corporate	4,000	5,000	4,000	500	13,500
	17,500	25,900	36,900	22,600	102,900

Employee numbers decreased in 2005 compared with 2004, primarily due to the sale of Innovene. The company seeks to maintain constructive relationships with labour unions.

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Directors remuneration report

This is the boards report to shareholders on directors remuneration. It covers both executive directors and non-executive directors. The first and third parts were prepared by the remuneration committee. The second 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 Executive directors remuneration

Dear Shareholder

Executive directors remuneration for 2006 reflects a clear set of principles, set out in the pages that follow. At their heart is the importance of matching reward to performance, in a way that both reflects shareholders interests and provides fair and competitive compensation to the executives.

As described elsewhere, 2006 was a year of strong financial performance for the group. A number of strategic and operational milestones were attained. However, the year also brought serious challenges and in key operational and safety areas company performance fell short of expectations.

The remuneration committee has carefully evaluated performance against the quantitative measures set at the beginning of the year. We also made a qualitative assessment of the effect on the company and its reputation of adverse events and developments in the year. The executive team responded to these challenges with determination and a sincere commitment to implement the lessons learned. However, taking a balanced judgement on the year, the remuneration committee halved the bonuses that would have resulted directly from their quantitative assessment. This, and all other remuneration received, is shown on the following page.

We have made some changes to the style and format of the remuneration report this year in order to make it easier to read and understand. Our aim has been to set out clearly the principles and policy on which we base executive directors remuneration, as well as the figures for 2006. In addition, full details of arrangements agreed for Lord Brownes retirement later in 2007 and information on recent changes in remuneration for Dr Hayward and Mr Inglis are included in the relevant sections.

Dr D S Julius
Chairman, Remuneration Committee
23 February 2007

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2006 remuneration

All remuneration paid to executive directors in 2006 is summarized in the table below. The annual bonuses are shown in the year they were earned. The remuneration committee reviewed base salaries in 2006 and awarded increases between 5% and 10% of base salary from 1 July for each director. These increases are reflected in the numbers below and their current base salary is shown on page 64.

All executive directors are part of a final salary pension scheme, the details of which are set out later in this report. Accrued annual pension earned as of 31 December 2006 is £1,050,000 for Lord Browne, £228,000 for Dr Allen, £170,000 for Mr Conn, $675,000 for Dr Grote, £239,000 for Dr Hayward and £188,000 for Mr Manzoni. Service and transfer value detail is shown on page 67.

Summary of remuneration of executive directors in 2006[a]

	Annual remuneration								Long-term remuneration Share element of EDIP/LTPPs[b]				
									2003-2005 plan (vested in Feb 2006)		**2004-2006 plan (vested in Feb 2007)**		200 (awar Feb P ma perfo
	Salary (thousand) 2005	2006	Annual performance bonus (thousand) 2005	2006	Non-cash benefits and other emoluments (thousand) 2005	2006	Total (thousand) 2005	**2006**	Actual shares vested	Value[c] (thousand)	Actual shares vested[d]	Value[e] (thousand)	
Lord Browne	£1,451	£1,531	£1,750	£900	£90	£95	£3,291	**£2,526**	474,384	£3,067	380,668	£2,044	1,7
Dr A B Hayward	£431	£463	£460	£250	£14	£20	£905	**£733**	147,783	£955	112,941	£606	3
Dr D C Allen	£431	£463	£480	£250	£12	£13	£923	**£726**	147,783	£955	112,941	£606	3
I C Conn	£421	£463	£450	£250	£43	£42	£914	**£755**	68,250	£441	54,600	£293	3
Dr B E Grote	$923	$973	$1,100	$525	$0	$1	$2,023	**$1,499**	175,229	$1,979	127,601	$1,338	4
J A Manzoni	£431	£463	£440	£250	£47	£45	£918	**758**	£147,783	£955	112,941	£606	3

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 Long Term Performance Plans.
c Based on market price on vesting date (£6.465 per share/$67.76 per ADS).
d Gross award of shares based on a performance assessment by the remuneration committee and on the other terms of the plan. Sufficient shares are sold to pay for tax applicable. Remaining shares are held in trust for current directors until 2010, when they are released to the individual.
e Based on market price on vesting date (£5.37 per share/$62.91 per ADS).
f Maximum potential shares that could vest at the end of the three-year period depending on performance.

Annual bonus result

The 2006 annual bonus was based on performance relative to measures and targets set at the beginning of the year, as well as other factors the remuneration committee determined were relevant. Financial and operational metrics from the annual plan carried a 50% weighting and focused on earnings before interest, taxes, depreciation and amortization (EBITDA), return on average capital employed (ROACE) and safety, environment and production targets. Strategic milestones, including those relating to technology, operations and business development, accounted for 30%. Individual performance, including both leadership objectives and living the values of the group, accounted for 20%.

On the financial side, underlying EBITDA was marginally below target. There were negative effects from US operating issues and positive effects from improvements in operating performance. ROACE was marginally above target. Cash costs and capital expenditure came in around target levels. Planned divestments of non-strategic assets achieved premium prices. Targets were met for personal safety, greenhouse gas emissions, oil and gas discovered volumes and proved reserves. Average production rate was below target.

With respect to milestones, seven of nine major projects were completed as planned. However, the Thunder Horse development was delayed. Good progress was achieved to define and sanction a further 18 major projects. The alternative energy business exceeded its objectives. Good progress was made in developing and implementing a major six-point plan for improving safety and operational integrity.

In terms of individual performance, in a period of significant challenges, the executive directors demonstrated commitment, determination and unity to address issues and improve performance.

While the quantitative assessment generated a near-target score, the remuneration committee also considered broader qualitative factors. These included the findings of internal and external reports on operational and safety issues in the US business. On balance, the committee judged that bonus levels should be reduced by 50% from the level they would otherwise have been. The resulting annual bonuses are set out in the table above.

2004-2006 share element result

For the 2004-2006 share element of the Executive Directors Incentive Plan (EDIP), BPs performance was assessed in terms of shareholder return against the market (SHRAM), ROACE and earnings per share (EPS) growth. BPs three-year SHRAM was measured against the companies in the FTSE All World Oil & Gas Index. Companies within the index are weighted according to their market capitalization at the beginning of the three-year period in order to give greatest emphasis to oil majors. BPs ROACE and EPS growth were measured against ExxonMobil, Shell, Total and Chevron. Based on a performance assessment of 60 points out of 200 (0 for SHRAM, 50 for ROACE and 10 for EPS growth), the committee made awards of shares to executive directors as shown in the 2004-2006 columns in the table above.

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Remuneration policy

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

- The remuneration structure will support BPs aim to maximize 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.
- 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.
- There will be a quantitative and qualitative assessment of performance, with the remuneration committee making an informed judgement within a framework approved by shareholders.
- Pay and employment conditions elsewhere in the group will be taken into account, especially in setting annual salary increases.
- Executives will develop a significant personal shareholding in order to align their interests with those of shareholders.
- 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.
- Remuneration policy and practice will be as transparent as possible.

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. In 2006, well over three-quarters of executive directors total potential remuneration was performance-related, in line with the target. The same will be true for potential remuneration in 2007.

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 committees 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 2007 is 120% of base salary. In normal circumstances, the maximum payment for substantially exceeding performance targets will continue to be 150% of base salary.

Annual bonus awards for 2007 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 weightings on annual bonus targets are:

- 50% Financial metrics from the annual plan, principally EBITDA, cash costs and capital expenditure.
- 30% Non-financial measures focusing on health, safety and the environment; growth; and reputation.
- 20% Individual performance against leadership objectives and against living the values of the group (incorporating BPs code of conduct).

The remuneration committee will also review carefully the underlying performance of the group in the light of the five-year business plan 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 in the best interests 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.

Group chief executive

As for previous years, the target level for 2007 for Lord Browne is 130% of base salary, with a maximum payment for substantially exceeding performance targets of 165% of base salary. Lord Browne will retire on 31 July 2007. His annual bonus award for 2007 will be pro-rated to reflect his service during the financial year up to his retirement in July.

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 2006 and would only do so in 2007 in exceptional circumstances. This section describes the share element. 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

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 (7.5 times base salary in the case of the group chief executive).

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.

Where shares vest under awards made in 2007 and future years, 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 should hold shares equivalent in value to five times his or her base salary within five years of appointment as an executive director. This policy is reflected in the terms of the EDIP, as shares awarded will only be released at the end of the three-year retention period, described below, if these minimum shareholding guidelines are met.

Performance conditions

For performance share awards in 2007, the performance conditions will continue to relate to BP's total shareholder return (TSR) compared with other oil majors – ExxonMobil, Shell, Total and Chevron – over a three-year period. 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

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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 BPs 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 BPs business. This would be judged by reference to a range of measures including ROACE, growth in EPS, reserves replacement and cash flow. 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.

Group chief executive

As noted above, as group chief executive, Lord Browne is eligible for performance share awards of up to 7.5 times his base salary. While the largest part of this is related to TSR, the committee has decided that up to two times base salary should be based on long-term leadership measures. These focus on sustaining BPs financial, strategic and organizational health. They include, among other measures, maintenance of BPs performance culture and the continued development of BPs business strategy, executive talent and internal organization. As with the TSR element, this element will be assessed over a three-year performance period.

The remuneration committee has agreed that Lord Browne will be granted a share award under the 2007-2009 plan on the above basis. The performance targets for this award (and those granted to him on the same basis in 2005 and 2006) will be assessed by the remuneration committee at the end of the three-year performance period that applies to each award. The actual number of shares received will depend on the extent to which relevant performance conditions are satisfied.

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 dependants benefit of two-thirds of the members pension. The scheme pension is not integrated with state pension benefits.

The rules of the BP Pension Scheme have recently been amended such that the normal retirement age is 65. Scheme members can 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.

In April 2006, the UK government made important changes to the operation and taxation of pensions. The remuneration committee decided to deliver pension benefits in excess of the new lifetime allowance of £1.5 million set by the legislation via an unapproved, unfunded pension arrangement paid by the company direct.

US directors

Dr Grote participates in the US BP Retirement Accumulation Plan (US plan), which features a cash balance formula. The US plan took its current form on 1 July 2000. 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 2006, shown in the table on page 67, 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.

Service contracts

Director[a]	Contract date	Salary as at 31 Dec 2006
Lord Browne	11 Nov 1993	£1,575,000
Dr A B Hayward	29 Jan 2003	£485,000
Dr D C Allen	29 Jan 2003	£485,000
I C Conn	22 Jul 2004	£485,000
Dr B E Grote	7 Aug 2000	$1,000,000
J A Manzoni	29 Jan 2003	£485,000

a Subsequent to 31 December 2006, Dr Hayward's salary was increased to £750,000 and Mr Inglis' salary, on appointment to the board, to £425,000.

When Lord Browne retires on 31 July 2007, he will become entitled to a payment equal to the aggregate of 12 months' base salary at that date, his target annual bonus level (130% of base salary) and £90,000 in respect of fringe benefits. In accordance with the committee's policy, the payment will be made in four quarterly instalments (the first payable in November 2007) and each instalment will be reduced by an amount equal to any of Lord Browne's replacement earnings for the quarter in question, to the extent that such earnings exceed one-third of the relevant quarterly instalment.

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 Dr Allen, Mr Conn, Dr Hayward and Mr Manzoni 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 had an unexpired term of one year on 31 December 2006. 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 have included 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.

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Part 2 Non-executive directors remuneration

Policy

The board sets the level of remuneration for all non-executive directors within the limit approved from time to time by shareholders. The remuneration of the chairman is set by the board rather than the remuneration committee, in line with BPs governance policies, as we believe the performance of the chairman is a matter for the board as a whole rather than any one committee. The boards policy is that non-executive remuneration should be consistent with recognized best-practice standards. Non-executive directors are encouraged to establish a holding in BP shares broadly related to one years base fee.

Annual fee structure

Non-executive directors remuneration consists of the following elements:

- Cash fees, paid monthly, with increments for positions of additional responsibility, reflecting workload and potential liability.
- A fixed allowance, currently £5,000, for transatlantic or equivalent inter-continental travel to attend a board or board committee meeting (excluding the chairman).
- Reasonable travel and related business expenses.

No share or share option awards are made to any non-executive director in respect of service on the board.

The fees were reviewed in 2005 by an ad hoc board committee and were increased with effect from 1 January 2005 to reflect the change in workload and global market rates for independent or non-executive directors since the previous review in 2002. There was no increase in 2006.

Current fee structure

	£ thousand
Chairman[a]	500
Deputy chairman[b]	100
Board member	75
Committee chairmanship fee	20
Transatlantic attendance allowance[c]	5

a The chairman is not eligible for committee chairmanship fees or transatlantic attendance allowance but has the use of a fully maintained office for company business, a chauffeured car and security advice.

b The deputy chairman receives a £25,000 increment on top of the standard board fee. In addition, he is eligible for committee chairmanship fees and the transatlantic attendance allowance. The deputy chairman is currently chairman of the audit committee.

c This allowance is payable to non-executive directors undertaking transatlantic or equivalent intercontinental travel for the purpose of attending a board meeting or board committee meeting.

Superannuation gratuities

In accordance with the companys long-standing practice, non-executive directors who retired from the board after at least six years service are, at the time of their retirement, eligible for consideration for a superannuation gratuity. The board is authorized to make such payments under the companys Articles of Association. The amount of the payment is determined at the boards discretion (having regard to the directors period of service as a director and other relevant factors).

In 2002, the board revised its policy with respect to superannuation gratuities so that: (i) non-executive directors appointed to the board after 1 July 2002 would not be eligible for consideration for such a payment; and (ii) 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 superannuation gratuity payments during the year to the following former directors: Mr Miles £46,000 (who retired in April 2006) and Mr Wilson £21,000 (who resigned from the board in February 2006). These payments were in line with the policy arrangements agreed in 2002 (outlined above).

Remuneration of non-executive directors in 2006[a]

		£ thousand
Current directors	2006	2005
J H Bryan	110	110
A Burgmans	85	90
Sir William Castell[b]	38.5	n/a
E B Davis, Jr	100	110
D J Flint	100	90
Dr D S Julius	105	107
Sir Tom McKillop	85	90
Dr W E Massey	130	130
Sir Ian Prosser	130	135
P D Sutherland	500	500
Directors leaving the board in 2006		
H M P Miles[c d]	30	90
M H Wilson[e]	22.5	105

a This information has been subject to audit.
b Appointed on 20 July 2006.
c Also received a superannuation gratuity of £46,000.
d Also received £37,500 for serving as a director and non-executive chairman of BP Pension Trustees Limited.
e Also received a superannuation gratuity of £21,000.

Based on the current fee structure, the table above shows the 2006 remuneration of each non-executive director.

Non-executive directors have letters of appointment that 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.

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 2006 and 31 Dec 2006[a]	Date on which director reaches age 70 [b]
J H Bryan	5,546	5 Oct 2006
E B Davis, Jr	4,490	5 Aug 2014
Dr W E Massey	3,346	5 Apr 2008
Director leaving the board in 2006		
M H Wilson[c]	3,170	4 Nov 2007

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 Wilson resigned from the board on 28 February 2006. Mr Wilson had received awards of Amoco shares under the plan between 1 November 1993 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 11 May 2006 and the shares vested on that date (when the BP ADS market price was $76.07) without payment by him.

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Part 3 Additional statutory and other disclosures

Remuneration committee

All the members of the committee are independent non-executive directors. Throughout this year, Dr Julius (chairman), Mr Bryan, Mr Davis, Sir Tom McKillop and Sir Ian Prosser were members. Lord Browne 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 committees 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 companys pension scheme of which the executive directors are members.
- To nominate, on behalf of the board, any trustees (or directors of corporate trustees) of the scheme.
- To monitor the policies being applied by the group chief executive in remunerating senior executives who are not executive directors.

Constitution and operation

Each member of the remuneration committee (named on page *73*) is subject to annual re-election as a director of the company. The board considers all committee members to be independent (*see page 70*). They have no personal financial interest, other than as shareholders, in the committees decisions.

The committee met five times in the period under review. There was a full attendance record except for Mr Davis, who was unable to attend one meeting. 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.

Advice

Advice is provided to the committee by the company secretarys office, which is independent of executive management and reports to the chairman of the board. Mr Aronson, an independent consultant, is the committees 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 2006, 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. The committee continued to engage Kepler Associates to advise on performance measurement. Kepler Associates also provided performance data and limited ad hoc advice on performance measurement to the group.

Freshfields Bruckhaus Derringer 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 62, to ensure they met an independent, objective standard. They also provided audit, audit-related and taxation services for the group.

Historical TSR performance[a]

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 and to the FTSE All World Oil & Gas Index. BP is a constituent of both indices, which are the most relevant broad equity market indices for this purpose.

a This information has been subject to audit.

Past directors

Until 30 September 2006, Mr Olver acted as a consultant to BP in relation to its activities in Russia and served as a BP-nominated director of TNK-BP Limited, a joint venture company owned 50% by BP. Under the consultancy agreement, he received £225,000 in fees in 2006 as well as reimbursement of costs and support for his role. He was also entitled to retain fees paid to him by TNK-BP up to a maximum of $120,000 a year for his role as a director, deputy chairman and chairman of the audit committee of TNK-BP Limited.

Mr Miles (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. This position is for a term of three years and he receives £150,000 per annum.

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Pensions[a]

thousand

	Service at 31 Dec 2006	Accrued pension entitlement at 31 Dec 2006	Additional pension earned during the year ended 31 Dec 2006[b]	Transfer value of accrued benefit[c] at 31 Dec 2005 (A)	Transfer value of accrued benefit[c] at 31 Dec 2006 (B)	Amount of B-A less contributions made by the director in 2006
Lord Browne (UK)	40 years	£1,050	£59	£19,979	£21,700	1,721
Dr A B Hayward (UK)	25 years	£239	£31	£3,408	£4,017	£609
Dr D C Allen (UK)	28 years	£228	£28	£3,433	£4,006	£573
I C Conn (UK)	21 years	£170	£23	£2,124	£2,510	£386
Dr B E Grote (US)	27 years	$675	$105	$6,681	$7,591	$910
J A Manzoni (UK)	23 years	£188	£24	£2,518	£2,961	£443

a This information has been subject to audit.
b Additional pension earned during the year includes an inflation increase of 2.2% for UK directors and 3.3% for US directors.
c Transfer values have been calculated in accordance with version 8.1 of guidance note GN11 issued by the actuarial profession.

Group chief executive

As stated in previous years’ reports, Lord Browne is eligible for consideration for an ex-gratia lump sum superannuation payment equivalent to one year’s base salary. This is in line with the company’s past practice for directors retiring on or after age 55 having accrued at least 30 years’ service. The remuneration committee has approved the payment of this sum to Lord Browne immediately following his retirement. This payment will be in addition to his pension entitlements under the scheme described above. No other executive director is eligible for consideration for an ex-gratia payment on retirement because in 1996 the remuneration committee decided that appointees to the board after that time should cease to be eligible.

Share element of EDIP and LTPPs[a]

				Share element/LTPP interests			Interests vested in 2006		
			Market price	Potential maximum performance shares[b]					
	Performance period	Date of award of performance shares	of each share at date of award of performance shares £	At 1 Jan 2006	Awarded 2006	At 31 Dec 2006	Number of ordinary shares vested[c]	Vesting date	Market price of each share at vesting date £
Lord Browne	2003-2005	17 Feb 2003	3.96	1,265,024	–	–	474,384	13 Feb 2006	6.47
	2004-2006	**25 Feb 2004**	**4.25**	**1,268,894**	–	**1,268,894**	**380,668**	**15 Feb 2007**	**5.37**
	2005-2007	28 April 2005	5.33	2,006,767	–	2,006,767	–	–	–
	2006-2008	16 Feb 2006	6.54	–	1,761,249	1,761,249	–	–	–
Dr A B Hayward	2003-2005	17 Feb 2003	3.96	394,088	–	–	147,783	13 Feb 2006	6.47

	2004-2006	**25 Feb 2004**	**4.25**	**376,470**	—	**376,470**	**112,941**	**15 Feb 2007**	**5.37**
	2005-2007	28 Apr 2005	5.33	436,623	—	436,623	—	—	—
	2006-2008	16 Feb 2006	6.54	—	383,200	383,200	—	—	—
Dr D C Allen	2003-2005	17 Feb 2003	3.96	394,088	—	—	147,783	13 Feb 2006	6.47
	2004-2006	**25 Feb 2004**	**4.25**	**376,470**	—	**376,470**	**112,941**	**15 Feb 2007**	**5.37**
	2005-2007	28 Apr 2005	5.33	436,623	—	436,623	—	—	—
	2006-2008	16 Feb 2006	6.54	—	383,200	383,200	—	—	—
I C Conn	2003-2005	17 Feb 2003	3.96	182,000	—	—	68,250	13 Feb 2006	6.47
	2004-2006	**25 Feb 2004**	**4.25**	**182,000**	—	**182,000**	**54,600**	**15 Feb 2007**	**5.37**
	2005-2007	28 Apr 2005	5.33	415,832	—	415,832	—	—	—
	2006-2008	16 Feb 2006	6.54	—	383,200	383,200	—	—	—
Dr B E Grote	2003-2005	17 Feb 2003	3.96	467,276	—	—	175,229	13 Feb 2006	6.47
	2004-2006	**25 Feb 2004**	**4.25**	**425,338**	—	**425,338**	**127,601**	**15 Feb 2007**	**5.37**
	2005-2007	28 Apr 2005	5.33	501,782	—	501,782	—	—	—
	2006-2008	16 Feb 2006	6.54	—	470,432	470,432	—	—	—
J A Manzoni	2003-2005	17 Feb 2003	3.96	394,088	—	—	147,783	13 Feb 2006	6.47
	2004-2006	**25 Feb 2004**	**4.25**	**376,470**	—	**376,470**	**112,941**	**15 Feb 2007**	**5.37**
	2005-2007	28 Apr 2005	5.33	436,623	—	436,623	—	—	—
	2006-2008	16 Feb 2006	6.54	—	383,200	383,200	—	—	—

a This information has been subject to audit.

b BP's performance is measured against the oil sector. For the periods 2003-2005 and 2004-2006, the performance measure is SHRAM, which is measured against the FTSE All World Oil & Gas Index, and ROACE and EPS growth, which are measured against ExxonMobil, Shell, Total and Chevron. For periods 2005-2007 onward, the performance condition is TSR measured against ExxonMobil, Shell, Total and Chevron. 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.

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Share options[a]

	Option type	At 1 Jan 2006	Granted	Exercised	At 31 Dec 2006	Option price	Market price at date of exercise	Date from which first exercisable	Expiry date
Lord Browne	SAYE	4,550			4,550	£3.50		1 Sep 2008	28 Feb 2009
	EDIP	408,522			408,522	£5.99		15 May 2001	15 May 2007
	EDIP	1,269,843		1,269,843		£5.67	£6.67	19 Feb 2002	19 Feb 2008
	EDIP	1,348,032			1,348,032	£5.72		18 Feb 2003	18 Feb 2009
	EDIP	1,348,032		1,348,032		£3.88	£6.67	17 Feb 2004	17 Feb 2010
	EDIP	1,500,000			1,500,000	£4.22		25 Feb 2005	25 Feb 2011
Dr A B Hayward	SAYE	3,302			3,302	£5.11		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	160,000	—	160,000	—	£3.88	£6.55	17 Feb 2006	17 Feb 2013
	EXEC	126,000	—	—	126,000	£4.22		25 Feb 2007	25 Feb 2014
Dr B E Grote[b]	SAR	35,200	—	35,200	—	$25.27	$66.96	6 Mar 1999	6 Mar 2006
	SAR	40,000	—	—	40,000	$33.34		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
J A Manzoni	SAYE	878	—	—	878	£4.52		1 Sep 2007	28 Feb 2008
	SAYE	2,548	—	—	2,548	£3.50		1 Sep 2008	28 Feb 2009
	SAYE	847	—	—	847	£3.86		1 Sep 2009	28 Feb 2010
	EXEC	34,000	—	—	34,000	£5.99		15 May 2003	15 May 2010
	EXEC	72,250	—	—	72,250	£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

The closing market prices of an ordinary share and of an ADS on 31 December 2006 were £5.68 and $67.10 respectively.

During 2006, the highest market prices were £7.12 and $76.47 respectively and the lowest market prices were £5.64 and $63.72 respectively.

EDIP = Executive Directors’ Incentive Plan adopted by shareholders in April 2005 as described on page 63.
BPA = BP Amoco share option plan, which applied to US executive directors prior to the adoption of the EDIP.
SAR = Stock Appreciation Rights under BP America Inc. Share Appreciation Plan.
SAYE = Save As You Earn employee share scheme.
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.

a This information has been subject to audit.
b Numbers shown are ADSs under option. One ADS is equivalent to six ordinary shares.

This directors’ remuneration report was approved by the board and signed on its behalf by David J Jackson, company secretary, on 23 February 2007.

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Governance: board performance report

Governance and the role of our board

Governance is the system by which the company's owners and their representatives on the board ensure that the company pursues its defined purpose and only allocates resources to that purpose. It is neither a process of compliance nor an additional level of management. The board's activity is focused on this task as the representative of BP's owners and it discharges this through actions that promote long-term shareholder interest.

BP's approach to governance is based on the connection between good governance and maximizing shareholder value. We believe that good governance involves both clarity of roles and distinct skills and processes. The BP board governs the company on behalf of shareholders, while management is delegated to the group chief executive through the board governance policies. These policies use a coherent, principles-based approach that ensures our board and management operate within a clear and efficient governance framework that places long-term shareholder interest at the centre of everything the company does.

In maximizing long-term shareholder interest, the board exercises judgement when carrying out its work in policy-making, monitoring executive action and active consideration of group strategy. While being responsible to shareholders, the board also recognizes the need to be responsive to the interests of those with whom the company interacts.

Shareholders

Accountability

The board, principally through the AGM, is accountable to shareholders for the performance and activities of the entire BP group. The board takes steps to understand shareholder preferences and to evaluate systematically the financial, social, environmental and ethical matters that may influence or affect the interests of our shareholders.

Dialogue

Throughout the year, the chairman has regular meetings with institutional shareholders to discuss issues of governance and high-level strategy. Shareholder dialogue is also undertaken by the group chief executive and other directors, the company secretary's office, investor relations and other teams within BP on wider issues relating to the operation and financial performance of the company. Presentations given by the company to the investment community are available on the 'Investor' section of *www.bp.com.*

Reporting

BP uses a number of different reporting channels to provide feedback and accountability on the company's performance to shareholders. These include the Annual Report and Accounts (which now includes a business review), Annual Review, Annual Report on Form 20-F and announcements made through stock exchanges on which BP shares are listed, as well as the AGM. BP seeks to promote the use of electronic communications within its reporting methods, so all these documents are available via our website at *www.bp.com.*

AGM and voting

Shareholders are encouraged to attend the AGM and use the opportunity to ask questions and hear the resulting discussion about BPs performance. However, given the size and geographical diversity of the companys shareholder base, we recognize that this may not always be practical and shareholders who are unable to attend 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. The company has introduced a vote withheld option on the proxy form in order to comply with the revised UK Combined Code. A vote withheld is not a vote in law and will not be counted in the calculation of the proportion of votes for and against a resolution.

After the event, copies of speeches and presentations given at the AGM are available to download via www.bp.com, together with the outcome of voting on the resolutions.

The chairman and the board committee chairmen were present during the 2006 AGM. Board members also met shareholders informally after the main business of the AGM. In 2006, voting levels at the AGM increased to 64%, up from 62% in 2005.

Election of directors

All directors stand for re-election 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 an outline of the skills and experience that the company feels are relevant in proposing them for the office of director.

Voting levels from the 2006 AGM demonstrated continued support for all our directors.

How the board governs the company

The boards governance policies describe its relationship with shareholders, the conduct of board affairs and the boards relationship with the group chief executive. The policies recognize the boards separate and unique role as the link in the chain of authority between the shareholders and the group chief executive. It is this unique task that gives the board its central role in governance.

The board governance policies address the dual role played by the group chief executive and executive directors as both members of the board and leaders of executive management. The policies require a majority of the board to be composed of independent non-executive directors. To assure the integrity of the governance process, the relationship between the board and the group chief executive is governed by the non-executive directors, particularly through the work of the board committees they populate.

The board focuses on those tasks that are unique to it as a board, reserving to itself the making of broad policy decisions. It delegates detailed consideration to either board committees and officers (for board processes) or to the group chief executive (in the case of management of the companys business activities). The board governs BP through setting general policy for the conduct of business (and, critically, by clearly articulating its goals) and by monitoring its implementation by the group chief executive.

To discharge its governance function effectively, the board has laid down rules for its own activities in a governance process policy. Responsibility for implementing this policy is placed on the chairman. This policy covers:

- The conduct of members at meetings.
- The cycle of board activities and the setting of agendas.
- The provision of timely information to the board.
- Board officers and their roles.
- Board committees, their tasks and composition.
- Qualifications for board membership and the process of the nomination committee.
- The evaluation and assessment of board performance.
- The remuneration of non-executive directors.
- The process for directors to obtain independent advice.

- The appointment and role of the company secretary.

The delegation of authority from the board to the group chief executive and the expectations and limitations on that authority are set out in three separate board governance policies, which enables the board to shape BPs values and standards:

1. Board-executive linkage policy, which outlines how the board delegates authority to the group chief executive and the extent of that authority.
   It also sets out how the performance of the group chief executive will be monitored.
2. Board goals policy, which clarifies what the board expects the group chief executive to deliver.

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3. Executive limitations policy, which defines the boundaries on how the group chief executive can achieve these results and requires that any executive action taken in the course of business considers internal controls, risk preferences, financing, ethical behaviour, health, safety, the environment, treatment of employees and political considerations.

Accountability in our business

The group chief executive describes to the board how the expected outcome and goals are intended to be delivered through regular business plans, which also encompass an assessment of the group's risks. During the year, the board receives updates on progress towards these outcomes through actual and forecasted results.

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. This key dialogue specifically includes any materially under-performing business activities, actions that breach the executive limitations policy and material matters of a social responsibility, environmental or ethical nature.

The board-executive linkage policy also sets out how the group chief executive's performance will be monitored and recognizes that, in the multitude of changing circumstances, judgement will always be involved. The systems set out in the board-executive linkage policy are designed to manage, rather than to eliminate, the risk of failure to achieve the goals or observe the executive limitations policy. They provide reasonable, rather than absolute, assurance against material misstatement or loss.

The board: structure and skills

The board is composed of the chairman, nine non-executive and seven executive directors. In total, four nationalities are represented on the board. The names and biographical details of the directors are provided on pages 58-59.

The board is actively engaged in orderly succession planning for both executive and non-executive roles, to enable the board's composition to be renewed without compromising its continued effectiveness.

Lord Browne will retire as group chief executive and from the board on 31 July 2007. Dr Tony Hayward will become group chief executive on 1 August 2007. Mr Michael Wilson stepped down from the board at the end of February 2006 and Mr Michael Miles retired in April 2006. Sir William Castell joined the board in July 2006. Mr Andy Inglis joined the board on 1 February 2007 as chief executive of the exploration and production segment in succession to Dr Hayward. At the 2007 AGM, Mr John Bryan will retire from the board.

The efficiency and effectiveness of the board are of paramount importance. Our board is large but this is necessary to allow both sufficient executive director representation to cover the breadth and depth of the group's business activities and sufficient non-executive representation to reflect the scale and complexity of the company and to staff our board committees. A board of this size also allows systematic succession planning for key roles.

We believe that our non-executive directors bring a broad range of relevant skills and experience to the work of the board and its committees. Not only do they contribute international and operational experience, but they also provide an understanding of the economies and world capital markets in which the group operates and an appreciation of the health, safety and environmental and sustainability issues the group faces. Our executive directors bring a further perspective to the work of the board through their deep comprehension of the company's business.

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, the non-executive directors fulfil this requirement and the board has determined that those who served during 2006 were independent. All non-executive directors are now subject to annual election and to date have received overwhelming endorsement at successive AGMs.

Sir Ian Prosser joined the board in 1997. It is the view of the board that, despite having served for more than nine years, he remains independent. His experience and long-term perspective on BP's business have provided a valuable contribution to the board, given the long-term nature of our business. The board has specifically requested that he remain chairman of the audit committee for the time being through the retirement of Dr Byron Grote.

Those directors who joined the BP board in 1998 after service on the board of Amoco Corporation (Messrs Bryan, Massey and Davis) are considered independent since the most senior executive management of BP comprises individuals who were not previously Amoco employees. While Amoco businesses and assets are a key part of the group, the scope and scale of BP since its acquisition of the ARCO, Burmah Castrol and Veba businesses are fundamentally different from those of the former Amoco Corporation.

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, our board ensures appropriate processes are in place to manage any possible conflict of interest.

Board directors: terms of appointment

The chairman and directors of BP stand for re-election each year and, subject to BP's Articles of Association, 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 reviewed in the directors' remuneration report on pages 61-68.

BP's policy on directors' retirement is as follows: 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. It is the board's policy that non-executive directors are not generally expected to hold office for more than 10 years.

In accordance with BP's Articles of Association, directors are granted an indemnity from the company in respect of liabilities incurred as a result of their office, to the extent permitted by law. In respect of those liabilities for which directors may not be indemnified, the company maintained a directors' and officers' liability insurance policy throughout 2006. This policy has been renewed for 2007. 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.

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 14 directors attended), the board met nine times during 2006: six times in the UK, twice in the US and once in Turkey. Two of these meetings were two-day strategy discussions. A number of board committee meetings were held during the year; for details of these and their attendance by board members please see the following table.

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Directors’ attendance

	Board meetings		Audit committee meetings		SEEAC meetings		Chairman’s committee meetings		Remuneration committee meetings		Nomination committee meetings	
	Attended	Possible	Attended	Possible	Attended	Possible	Attended	Possible	Attended	Possible	Attended	Poss
P D Sutherland	9	9	–	–	–	–	4	4	5	5	6	
J H Bryan	9	9	10	12	–	–	4	4	5	5	–	
A Burgmans	9	9	–	–	6	7	4	4	–	–	–	
Sir William Castell	3	3	1	2	2	2	1	1	–	–	–	
E B Davis, Jr	7	9	11	12	–	–	3	4	4	5	–	
D J Flint	9	9	11	12	–	–	4	4	–	–	–	
Dr D S Julius	8	9	–	–	–	–	3	4	5	5	6	
Sir Tom McKillop	9	9	–	–	4	4	4	4	5	5	–	
Dr W E Massey	9	9	–	–	7	7	4	4	–	–	6	
H M P Miles	4	4	3	4	1	3	0	1	–	–	–	
Sir Ian Prosser	9	9	11	12	–	–	4	4	5	5	6	
M H Wilson	2	2	3	3	2	2	1	1	–	–	–	
Lord Browne	9	9	–	–	–	–	–	–	–	–	–	
Dr A B Hayward	9	9	–	–	–	–	–	–	–	–	–	
Dr D C Allen	9	9	–	–	–	–	–	–	–	–	–	
I C Conn	9	9	–	–	–	–	–	–	–	–	–	
Dr B E Grote	9	9	–	–	–	–	–	–	–	–	–	
J A Manzoni	9	9	–	–	–	–	–	–	–	–	–	

Serving as a director: induction, training and evaluation

Induction

Following their appointment to the board, new directors undertake an induction programme that is tailored to their specific needs. This programme covers matters such as the operation and activities of the group (including key financial, business, social and environmental risks to the group’s activities), the role of the board and the matters reserved for its decision, the tasks and membership of the principal board committees, the powers delegated to those committees, the board’s governance policies and practices and the latest financial information about the group. The chairman is accountable for the induction of new board members and is assisted by the company secretary’s office in this role.

Training

On appointment, our 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 policies. In addition, non-executive directors also receive ongoing training specific to the tasks of the particular board committees on which they serve in order to update their skills and knowledge and enhance their effectiveness during their tenure.

Our directors are updated on BP’s business, the environment in which it operates and other matters throughout their period in office.

Outside appointments

As part of their ongoing development, our executive directors are permitted to take up an external board appointment, subject to the agreement of the BP board. Generally, outside appointments for executive directors are limited to a single company board only, although our current group chief executive, by exception, serves on two outside company boards. Our board is satisfied that these appointments do not conflict with his duties and commitments to BP. Executive directors retain any fees received in respect of such external appointments.

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 the extent of directors other interests under review to ensure that the efficacy of our board is not compromised.

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 questionnaire aimed at building on the outcome of the previous years evaluation and endeavouring to assess the manner in which the board had responded to the issues that occurred during 2006. The board is considering the output from the evaluation.

Separate evaluations of the audit and the safety, ethics and environment assurance committees took place during the year and are reported in the committee reports on pages 72-73. The remuneration committee will be reviewing its 2006 performance in the first half of 2007. The potential use of external providers in the context of board evaluation is being kept under review.

The chairman and the senior independent director

BPs board governance policies require that neither the chairman nor the deputy chairman is employed as an executive of the group. During 2006, the posts were held by Mr Sutherland and Sir Ian Prosser, respectively. Sir Ian also acts as our 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 and individual director 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 board/executive relationship. 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 chairmans committee *(reported on page 74)*. The performance of the chairman is evaluated each year, with the evaluation discussion taking place when the chairman is not present.

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Board committees

The governance process policy allocates 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 committees for 2006 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 demonstrably independent of the executive management of the group.

Audit committee report

Membership and meeting schedule

The audit committee consists solely of independent non-executive directors. Its membership is selected to provide a broad set of financial, international and commercial expertise appropriate to fulfil the committee's duties.

Members of the audit committee include Sir Ian Prosser (chairman), Mr D J Flint, Mr E B Davis, Jr and Mr J H Bryan. During 2006, Mr M H Wilson and Mr H M P Miles retired from the committee and Sir William Castell joined as a new member. The company secretary's office ensures new committee members receive briefings on the committee's tasks and process before taking up their roles.

The board has determined that Mr Flint possesses the financial and audit committee experience as defined by the Combined Code guidance and the US Securities and Exchange Commission and has nominated him as the audit committee's financial expert.

At the request of the audit committee chairman, each meeting is attended by the lead partner of the external auditors (Ernst & Young), the BP general auditor (head of internal audit), the group chief financial officer, the chief accounting officer and the group controller.

The audit committee met 12 times during 2006.

Role of audit committee

The tasks of the audit committee include gaining assurance on the financial processes of the group and the integrity of its reports and accounts. On behalf of the board, it monitors observance of the executive limitations policy relating to financial matters. The committee reviews the management of financial risks and the internal controls designed to address them.

The committee believes that it meets each of the tasks that are outlined in the Combined Code as falling within the remit of an audit committee.

Agenda and information

Central to the operation of the audit committee is the meeting agenda. Forward agendas are set at the start of each year to determine a high-level work programme for the committee. Agendas are constructed from regular items, including those that are required by regulation, and items reflecting the board's desire to review group risks. Between committee meetings, the chairman reviews any issues that arise with the group chief financial officer, the external auditors and the BP general auditor and items may be added to the next committee meeting agenda as appropriate.

The committee receives information on agenda items from both internal and external sources, including the chief financial officer, the internal auditor and BP's external auditors. Presentations are made by a wide cross-section of the group's business and financial control management. Where relevant to a particular business or functional review, additional Ernst & Young audit staff attend and contribute. In addition, the committee meets both the external auditors and BP general auditor in private sessions where the executive management are not present.

In common with other BP board committees, the audit committee can access independent advice and counsel if it requires, on an unrestricted basis. Further support is provided to the committee by the company secretary's office and, during 2006, external specialist legal and regulatory advice was provided to the committee by Sullivan & Cromwell LLP.

The activities of the audit committee and any issues that have arisen are reported back to the main board by the audit committee chairman following each meeting.

Committee activities in 2006

Financial reports

During the year, the committee reviewed all annual and quarterly financial reports before recommending their publication to the board. The committee also examined the application of new financial standards, critical accounting policies and judgements.

Internal controls and risk management

In the course of 2006, the audit committee reviewed reports on risks, control and assurance for all the BP business segments (exploration and production, refining and marketing and gas, power and renewables), together with BPs trading function. Reviews were also carried out on BPs long-term contractual commitments and the manner in which the risks and control systems for these contracts were being managed.

Key regulatory issues are discussed throughout the year by the committee as part of its standing agenda items. These include a quarterly review of the companys evaluation of its internal controls systems as part of the requirement of Section 404 of the Sarbanes-Oxley Act. The committee also examines the effectiveness of BPs enterprise level controls through the annual assessment undertaken by the companys internal audit function.

In addition to the recurring items on the agenda, the audit committee considered a range of other specific topics during the year, including a review of tax planning and provisions, an evaluation of the companys pension and post-retirement benefit assumptions and an assessment of BPs oil and gas reserves methodology.

Relationship with external auditors

As outlined above, 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 also invited to attend meetings to participate in discussions relating to their areas of expertise, for example, during business segment reviews.

During the year, the committee held two private meetings with the external auditors without the presence of executive management, in order to discuss any issues or concerns on the part of both the committee and the auditors.

The performance of the external auditors is evaluated by the audit committee each year. Central to this evaluation is scrutiny of the external auditors independence, objectivity and viability. To maintain the independence of the external auditors, the provision of non-audit services is limited to tax and audit-related work that fall within specific categories. This work is pre-approved by the audit committee and all non-audit services are monitored quarterly. Fees paid to the external auditors during the year for audit and other services were $73 million, of which 16% was for non-audit work *(see Financial statements Note 20 on page 119)*. Non-audit services provided by Ernst & Young have been significantly reduced over recent years but, reflecting regulatory and reporting developments in the UK and US, audit fees have increased substantially.

In addition to the restrictions on non-audit work, the objectivity and independence of the external auditors are augmented by the rotation of audit staff on a regular basis. A new lead audit partner is appointed every five years and other senior audit staff are moved every seven years. It is the policy of the company that no partners or senior staff connected with the BP audit may transfer to BP.

After considering both the proposed fee structure and the audit engagement terms for 2007, the audit committee has recommended to the board that the reappointment of the auditors be proposed to shareholders at the 2007 AGM.

Internal audit

BPs internal audit function advises the committee on the companys identification and control of risk. The general auditor contributes widely to the committees discussion of the companys framework of internal controls and the effectiveness of their application. The audit committee agreed the work programme to be undertaken by internal audit during the

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year and obtained satisfaction that the proposed work plan appropriately responded to the key risks facing the company and that internal audit had adequate staff and resources to complete its work.

In addition to regular observations and updates at each committee meeting, internal audit made two written reports of its findings to the committee in 2006. These reports contributed to the committees view on how effective the companys system of internal controls had been and formed the basis of its recommendations to the board.

During the year, the committee met privately with the head of internal audit (the BP general auditor), without the presence of executive management. It also evaluated the performance of the internal audit function.

Fraud reporting and employee concerns/whistleblowing

The committee received a quarterly report from internal audit on instances of actual or potential fraud or concerns relating to the financial accounting of the company. In addition, the group compliance and ethics function reported on issues raised via the employee concerns programme, OpenTalk, together with other topics arising from the companys annual certification process.

Performance evaluation

The audit committee conducts a yearly evaluation of its performance. The review for 2006 involved a survey of committee members and other individuals who had regularly attended the committee. The results of the review were fed back to the committee in November. No significant process changes were identified but the committee did determine to take additional time in private session at the end of each meeting and to hold a joint meeting with the safety, ethics and environment assurance committee each year to review the general auditors internal controls and risk management report. These adjustments were incorporated in the forward agenda and work plan for 2007.

The audit committee plans to meet 12 times during 2007.

Safety, ethics and environment assurance committee report

Membership and meeting schedule

The committees members consist solely of independent non-executive directors and include Dr W E Massey (chairman) and Mr A Burgmans. During 2006, Mr M H Wilson and Mr H M P Miles retired from the committee and Sir William Castell and Sir Tom McKillop joined as new members. The company secretarys office ensures new committee members receive briefings on the committees tasks and process before taking up their roles.

In addition to the members above, each meeting is attended by the lead partner of the external auditors (Ernst & Young) and the BP general auditor (head of internal audit) at the invitation of the committee chairman.

Reports and presentation to the committee are led by the executive director with functional accountability for safety and the environment (Mr Iain Conn) and the committees dialogue includes meeting with the relevant senior managers and functional experts for each of its agenda topics. In 2006, the group chief executive attended one meeting.

The safety, ethics and environment assurance committee, created in 1997, has increased the frequency of its meetings in recent years from four per year in 2003 to seven in 2006. This has reflected both the increased breadth of the companys business (for example, expansion into new geographies such as Russia) and the committees additional work in monitoring the executive managements response to incidents (including the Texas City fire and explosion and the oil spills in Alaska).

Role of the committee

On behalf of the board, the committee monitors observance of the executive limitations policy that relates to the environmental, health and safety, security and ethical performance and compliance of the company.

During 2006, the committees name was amended. Having reviewed its agendas over the past few years, it was considered by the board that the addition of safety to ethics and environment assurance provided a better reflection of the committees work.

Agenda and information

The tasks of the safety, ethics and environment assurance committee are particularly broad as they cover all non-financial risks. In constructing its

forward agenda at the beginning of each year, the committee pays particular attention to the review of group risks conducted by the general auditor and risks identified in the companys business plans.

Forward agendas also include regular or standing agenda items. Standing agenda items are those that enable the committee to monitor and assess how the executive limitations policy is being observed (for example, compliance and ethics and health, safety and environment reports) and review the specific non-financial risks that are identified in the company’s annual plan (for example, in performing regional risk reviews). The chairman of the committee will also review the forward agenda against any emerging issues or developments that may arise during the year and amend as necessary.

The committee receives information relating to agenda items from both internal and external sources, including internal audit, BP’s external auditors, the group compliance and ethics function and external market and reputation research. In common with other BP board committees, the safety, ethics and environment assurance committee can access independent advice and counsel if it requires, on an unrestricted basis.

The activities of the safety, ethics and environment assurance committee and any issues that have arisen are reported back to the main board by the committee chairman following each meeting.

Committee activities in 2006

HSE performance

The committee received reports on both the company’s overall HSE performance, including an examination of key metrics, and on individual topics such as human resources capability, employee health and HSE in TNK-BP. Progress in safety and operations management since the incident at the Texas City refinery has been reviewed regularly.

Regional risk reviews

While most of the board-level monitoring is undertaken through business segments or functions, risks that require management at a country or regional level are also scrutinized by the committee. During the year, risk reviews were carried out for North America, Russia and the Caspian.

Compliance and ethics

The group compliance and ethics function reports to the committee on a quarterly basis. During 2006, the compliance and ethics reports covered the results of the 2005 certification process, progress on the implementation of the company’s code of conduct and the operation of OpenTalk.

Performance evaluation

The committee conducts an annual review of its process and performance. This year’s review was discussed at the committee’s November meeting and has led to enhancements in the committee process going forward, including the incorporation of reports from the new group operations risk committee and an increase in time allotted to agenda items to enable further in-depth discussion.

The safety, ethics and environment assurance committee plans to meet seven times during 2007.

Remuneration committee report

Membership and meeting schedule

The remuneration committee consists solely of non-executive directors, who are considered by the board to be independent. Committee members include Dr D S Julius (chairman), Mr J H Bryan, Mr E B Davis, Jr, Sir Tom McKillop and Sir Ian Prosser. The chairman of the board also attends meetings of the committee.

The committee met five times during 2006 and is independently advised.

Role of remuneration committee

The committee’s main task is to determine the terms of engagement and remuneration of the executive directors.

Further details of the committee’s role, authority and activities during the year are set out in the directors’ remuneration report on pages 61-68, which is the subject of a vote by shareholders at the 2007 AGM.

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Chairmans committee report

Membership and meeting schedule

The chairmans committee comprises all the non-executive directors and is chaired by the board chairman.

The committee met four times during the year.

Role of chairmans committee

The task of the committee is to consider broad issues of governance, including the performance of the chairman and the group chief executive, succession planning, the organization of the group and any matters referred to it for an opinion from another board committee.

Committee activities in 2006

The main focus of the committee was on the task of ensuring an orderly succession plan for the group chief executive role. In that respect, the committee formed a working group comprised of the chairmen of each of the boards standing committees, which has taken forward the detailed work necessary to ensure a best-practice process to identify a new group chief executive. The working group met six times during the year.

The committee took external advice as appropriate and benchmarked all the candidates against the external market.

The committee concluded its work by making a unanimous recommendation to the board that Dr A B Hayward be appointed as the next group chief executive.

Nomination committee report

Membership and meeting schedule

The nomination committee consists of non-executive directors. Its members include Dr D S Julius, Sir Ian Prosser and Dr W E Massey and the committee is chaired by the board chairman, Mr P D Sutherland. All members of the nomination committee are considered by the board to be independent.

The committee met six times during the year.

Role of nomination committee

The task of the nomination committee is to identify and evaluate candidates for appointment and reappointment as director or company secretary of BP.

Committee activities in 2006

As a result of the committees processes, Sir William Castell joined the board in 2006.

The committee continues to keep under review the skills and background that the board requires to perform its various tasks. The committee recognizes that, with the forthcoming retirements of directors, at least one new non-executive director will need to be appointed to the board each year for the next three years. The committee is currently evaluating candidates with a North American background.

Directors interests

Current directors	At 31 Dec 2006	At 1 Jan 2006	Change from 31 Dec 2006 to 20 Feb 2007
Dr D C Allen	530,933a	443,742	66,635
Lord Browne	2,525,313b	2,242,954	224,594
J H Bryan	158,760c	158,760	
A Burgmans	10,000	10,000	
I C Conn	209,449d	156,349	32,348
E B Davis, Jr	68,992c	67,610	
D J Flint	15,000	15,000	
Dr B E Grote	1,105,825e	988,812	75,288

Dr A B Hayward	407,021	305,543	70,071
A G Inglis	193,022f		30,090
Dr D S Julius	15,000	15,000	
Sir Tom McKillop	20,000	20,000	
J A Manzoni	376,213	275,743	66,769
Dr W E Massey	49,722c	49,722	
Sir Ian Prosser	16,301	16,301	
P D Sutherland	30,079	30,079	
Sir W M Castell			

Directors leaving the board in 2006	At retirement	At 1 Jan 2006
H M P Miles	22,145	22,145
M H Wilson	60,000c	60,000

a Includes 25,368 shares held as ADSs.
b Includes 61,186 shares held as ADSs.
c Held as ADSs.
d Includes 40,155 shares held as ADSs.
e Held as ADSs, except for 94 that are held as ordinary shares.
f Interest as at 1 February 2007 on appointment as a director.

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 Companies Act 1985 as at the applicable dates. In making these disclosures, the directors did not distinguish their beneficial and non-beneficial interests.

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 20 February 2007, 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	819,823a
The Lord Browne of Madingley	2,749,907	3,768,016a
I C Conn	241,797	799,032a
Dr B E Grote	1,181,113	972,212a
Dr A B Hayward	477,092	819,823a
A G Inglis	223,112	—
J A Manzoni	442,982	819,823a
J H Bryan	158,760	—
A Burgmans	10,000	—
Sir William Castell	—	—
E B Davis, Jr	68,992	—
D J Flint	15,000	—
Dr D S Julius	15,000	—
Dr W E Massey	49,722	—
Sir Tom McKillop	20,000	—
Sir Ian Prosser	16,301	—
P D Sutherland	30,079	—

As at 20 February 2007, 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
The Lord Browne of Madingley	3,261,104
I C Conn	332,390
Dr B E Grote	1,427,190b
Dr A B Hayward	769,620
A G Inglis	415,300
J A Manzoni	780,523

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 In addition to the above, Dr Grote holds 40,000 Stock Appreciation Rights (equivalent to 240,000 ordinary shares).

There are no directors or members of senior management who own more than 1% of the ordinary shares outstanding. At 20 February 2007, all directors and senior management as a group held interests in 15,488,669 ordinary shares or their calculated equivalent and 8,584,526 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 68.

Employee share plans

The following table shows employee share options granted.

			options thousands
	2006	2005	2004
Employee share options granted during the year[a]	**53,978**	54,482	80,395

a For the options outstanding at 31 December 2006, the exercise price ranges and weighted average remaining contractual lives are shown in Financial statements Note 44 on page 153.

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 44 on page 153) and the granting of share options as elements of remuneration for executive directors and senior employees.

Savings and matching plans

BP ShareSave Plan

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 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. Until 2003, a three-year savings plan was also run in a small number of other countries. Options will remain outstanding in respect of these countries until the end of June 2007. 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

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 over 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. However in certain countries 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 Options/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 to the employee at the date of exercise. There are no performance conditions; however, participants must continue in employment with BP for the first three calendar years of the plan for the options/SARs to vest. Special arrangements may apply for qualifying leavers. The options/SARs are exercisable between the third and 10th anniversaries of the grant date.

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. Until such time as the companys 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 43 on page 150*. Assets and liabilities of the ESOPs are recognized as assets and liabilities of the group.)

At 31 December 2006, the ESOPs held 12,795,887 shares (2005 14,560,003 shares and 2004 8,621,219 shares) for potential future awards, which had a market value of $142 million (2005 $156 million and 2004 $84 million).

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Pursuant to the various BP group share option schemes, the following options for ordinary shares of the company were outstanding at 20 February 2007:

Options outstanding (shares)	Expiry dates of options	Exercise price per share
422,119,465	2007-2016	$5.0967-$11.921

Major shareholders and related party transactions

Register of members holding BP ordinary shares as at 31 December 2006

Range of holdings	Number of shareholders	Percentage of total shareholders	Percentage of total share capital
1-200	61,108	18.50	0.01
201-1,000	126,141	38.20	0.30
1,001-10,000	128,717	38.98	1.81
10,001-100,000	12,366	3.74	1.18
100,001-1,000,000	1,087	0.33	1.83
Over 1,000,000[a]	822	0.25	94.87
Totals	330,241	100.00	100.00

a Includes JP Morgan Chase Bank, holding 26.46% of the total share capital 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 2006[a]

Range of holdings	Number of ADS holders	Percentage of total ADS holders	Percentage of total ADS holders
1-200	37,265	24.99	0.05
201-1,000	36,140	24.24	0.34
1,001-10,000	58,388	39.16	3.63
10,001-100,000	16,708	11.20	7.60
100,001-1,000,000	600	0.40	1.91
Over 1,000,000[b]	12	0.01	86.47
Totals	149,113	100.00	100.00

a One ADS represents six 25 cent ordinary shares.
b One of the holders of ADSs represents some 751,000 underlying shareholders.

As at 31 December 2006, there were also 1,534 preference shareholders.

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 5,673,615,543 ordinary shares (29.08% of the company's ordinary share capital). Legal & General Group plc hold interests in 730,844,705 ordinary shares (3.75% of the company's ordinary share capital).

At the date of this report the company has also been notified of the following interests in preference shares. Co-operative Insurance Society Limited holds interests in 1,572,538 8% cumulative first preference

shares (21.74% of that class) and 1,789,796 9% cumulative second preference shares (32.70% of that class). The National Farmers Union Mutual Insurance Society Ltd holds 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). Prudential plc 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 685,000 9% preference shares (12.51% of that class).

The total preference shares in issue comprise only 0.39% of the company's total issued nominal share capital, the rest being ordinary shares.

Related party transactions

The group had no material transactions with jointly controlled entities and associates during the period commencing 1 January 2006 to the date of this report. Transactions between the group and its significant jointly controlled entities and associates are summarized in Financial statements – Note 29 on page 127 and Financial statements – Note 30 on page 128.

In the ordinary course of its business, the group has transactions with various organizations with which certain of its directors are associated but, except as described in this report, no material transactions responsive to this item have been entered into in the period commencing 1 January 2006 to 20 February 2007.

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. Until their shares have been exchanged for BP ADSs, Amoco and Atlantic Richfield shareholders do not have the right to receive dividends.

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 before the 'refund' and deduction of withholding taxes as described in Taxation on page 80. Refund means an amount equal to the tax credit available to individual shareholders resident in the UK in respect of such dividend, less a withholding tax equal to 15% (but limited to the amount of the tax credit) of the aggregate of such tax credit and such dividend.

For dividends paid after 30 April 2004, there is no refund available to shareholders resident in the US. See Taxation on page 80 for more information.

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		March	June	September	December	Total
Dividends per American depositary share						
2002	UK pence	24.3	24.3	23.3	23.4	95.3
	US cents	34.5	34.5	36.0	36.0	141.0
	Can. cents	54.9	54.1	56.7	56.1	221.8
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
	Can. 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
	Can. 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
	Can. 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**	**230.4**
	Can. cents	**64.5**	**64.1**	**67.4**	**66.5**	**262.5**

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 40.

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. The CFTC is seeking permanent injunctive relief, disgorgement, restitution and payment of civil monetary penalties. On 28 June 2006, the US Department of Justice filed a criminal charge against a former BP Products propane trader, who entered a guilty plea. Proceedings in the CFTC’s civil enforcement action have been stayed by the District Court pending the further investigation of these matters by the Department of Justice. BP Products believes that it has co-operated fully with the CFTC in its investigation of this matter and is assisting the Department of Justice in its ongoing investigation. 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.

The CFTC is currently investigating various aspects of BP Products’ crude oil trading and storage activities in the US since 2003 and has made various formal and informal requests for information. BP has provided, and continues to provide, responsive data and other information to these requests. The CFTC is also conducting an investigation into BP Products’ trading of unleaded gasoline futures contracts on 31 October 2002. The CFTC staff notified BP on 21 November 2006 that they intend to recommend to the CFTC that a civil enforcement action be brought against BP Corporation North America Inc. alleging violations of Sections 6(c), 6(d) and 9(a)(2) of the Commodity Exchange Act in connection with its trading of unleaded gasoline futures contracts on 31 October 2002. BP has provided, and continues to provide, responsive documents and witness testimony. The US Attorney for the Northern District of Illinois is also conducting an investigation into BP Products’ trading of unleaded gasoline futures contracts on 31 October 2002.

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 1,000 settlements in respect of all the fatalities and many of the personal injury claims arising from the incident. Trials have been scheduled for a number of unresolved claims in mid-2007, although to date all claims scheduled for trial have been resolved in advance of trial. The US Occupational Safety and Health Administration (OSHA), the US Chemical Safety and Hazard Investigation Board (CSB), the US Environmental Protection Agency and the Texas Commission on Environmental Quality, 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. OSHA referred the matter to the US Department of Justice for criminal investigation, and the Department of Justice has opened an investigation. 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 25 for a discussion of the Baker Panel’s report, which was published on 16 January 2007. Other government legal actions related to this matter are pending.

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.

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 which

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it has incurred. If any claims are asserted by Exxon that affect Alyeska and its owners, BP will defend the claims vigorously.

Since 1987, Atlantic Richfield Company, 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 as 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 37.

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 re-establish equilibrium. Dealings in ordinary shares may also take place between an investor and a market-maker, via a member firm, outside the electronic order book.

In the US 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, Pacific and Toronto Stock Exchanges. ADSs are evidenced by American depositary receipts, or 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 composite tape.

	Pence	Dollars
	Ordinary shares	American depositary shares[a]

		High	Low	High	Low
Year ended 31 December					
2002		625.00	387.00	53.98	36.25
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
Year ended 31 December					
2005:	First quarter	579.50	499.00	66.65	56.60
	Second quarter	600.00	516.00	64.94	57.95
	Third quarter	686.00	580.50	72.75	62.84
	Fourth quarter	679.00	599.00	71.25	63.26
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 (through 20 February)	**574.50**	**527.50**	**64.03**	**61.29**
Month of					
September 2006		**605.50**	**560.00**	**68.60**	**63.81**
October 2006		**619.00**	**558.50**	**69.49**	**63.52**
November 2006		**606.50**	**566.00**	**69.11**	**65.75**
December 2006		**587.50**	**563.00**	**66.88**	**66.20**
January 2007		**574.50**	**527.50**	**62.27**	**61.29**
February 2007 (through 20 February)		**544.00**	**527.50**	**64.03**	**61.90**

a An ADS is equivalent to six 25 cent ordinary shares.

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Market prices for the ordinary shares on the LSE and in after-hours trading off the LSE, in each case while the New York Stock Exchange is open, and the market prices for ADSs on the New York Stock Exchange 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 20 February 2007, 945,592,180 ADSs (equivalent to 5,673,553,084 ordinary shares or some 29.08% of the total) were outstanding and were held by approximately 148,268 ADR holders. Of these, about 146,556 had registered addresses in the US at that date. One of the registered holders of ADSs represents some 759,659 underlying holders.

On 20 February 2007, there were approximately 332,034 holders of record of ordinary shares. Of these holders, around 1,471 had registered addresses in the US and held a total of some 4,201,229 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.

Memorandum and articles of association

The following summarizes certain provisions of BPs Memorandum and Articles of Association and applicable English law. This summary is qualified in its entirety by reference to the UK Companies Act and BPs 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 82.

On 24 April 2003, the shareholders of BP voted at the AGM to adopt new Articles of Association to consolidate amendments which 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.

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 BPs 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 which 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 directors 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 companys intention to change its current policy of paying dividends in US dollars.

Apart from shareholders rights to share in BPs 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 BP 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.

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Record holders of BP ADSs also are 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 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.

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 upon 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 BPs Memorandum or Articles of Association on the right of non-residents or foreign persons to hold or vote the companys 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 BP'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.

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.

This section is further based in part upon 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.

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.

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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 United Kingdom 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 United Kingdom 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.

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 income or, in the case of certain US holders, financial services income (or, for tax years beginning after 31 December 2006, general category income), which is treated separately from other types of income 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. 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 companys 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 holders 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) which 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 holders 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 holders 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.

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 individuals death or on transfer during the individuals 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 Depositarys nominee will give rise to further stamp duty at the rate of £1.50 per £100 (or part) or stamp duty reserve tax at the rate of 1.5% of the value of the ordinary shares at the time of the transfer.

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.

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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 Depositarys 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 (i.e., cash dividend plus the Refund if any) 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

BPs Annual Report and Accounts is available online at *www.bp.com*. Shareholders have the ability to receive a hard copy of BPs 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 BPs 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 and 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 SECs public reference room located at 100 F Street NE, Washington, DC 20549, US. Please call the SEC at 1-800-SEC-0330 or log on to *www.sec.gov.* In addition, BPs SEC filings are available to the public at the SECs 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.

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 companys 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

As disclosed in the 2005 20-F, the company changed its accounting treatment for certain over-the-counter forward contracts to account for those contracts on a net basis and implemented improvements in the company's disclosure controls and procedures and internal controls over financial reporting to ensure the correct accounting for these contracts. During 2006, further improvements were made in the design and operation of the company's disclosure controls and procedures and internal control over financial reporting following the identification of additional transactions which should have been presented net. These improvements included the training of staff regarding the application of the policy change, implementing additional preventative and detective controls in the internal reporting systems, adding further verification steps and increasing management oversight of compliance therewith.

Aside from these improvements, 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, and the required reconciliation to US GAAP.

As of the end of the 2006 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 2006 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 the required reconciliation to US GAAP, 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.

Management's assessment of the effectiveness of BP's internal control over financial reporting as of 31 December 2006 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report appearing on page 86.

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.

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.

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Code of ethics

The company has adopted a code of ethics for its group chief executive, deputy group chief executive, chief financial officer, general auditor, group chief accounting officer and 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 accountant 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 BPs 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); and provision of Ernst & Young publications. 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 20 and 54 on pages 119 and 184 for details of audit fees.)

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][c]	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[b]
2006				
January	**70,000,000**	**11.67**	**70,000,000**	
February	**139,785,200**	**11.41**	**139,785,200**	
March	**139,294,200**	**11.41**	**139,294,200**	
April	**107,608,638**	**12.22**	**107,608,638**	
May	**149,312,153**	**12.33**	**149,312,153**	
June	**118,823,000**	**11.31**	**118,823,000**	
July	**159,261,259**	**11.82**	**159,261,259**	
August	**91,904,300**	**11.87**	**91,904,300**	
September	**47,989,000**	**10.95**	**47,989,000**	
October	**171,740,000**	**11.15**	**171,740,000**	
November	**113,255,000**	**11.28**	**113,255,000**	
December	**25,390,000**	**11.42**	**25,390,000**	
2007				
January	**73,361,264**	**10.80**	**73,361,264**	
February (through 20 February)	**61,797,871**	**10.55**	**61,797,871**	

a All share purchases were open market transactions.
b At the AGM on 20 April 2006, authorization was given to repurchase up to 2 billion ordinary shares in the period to the next AGM or 19 July 2007, the latest date by which an AGM must be held. This authorization is renewed annually at the AGM.
c Made up of 493,533,135 shares repurchased for cancellation and 975,988,750 shares held in treasury.

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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]
2006				
January	**41,068**	**11.24**		
February	**1,638,669**	**11.33**		
March	**6,198,758**	**11.47**		
April				
May	**13,829**	**12.11**		
June	**10,001,371**	**10.70**		
July				
August				
September	**13,606**	**11.15**		
October	**10,231**	**11.00**		
November				
December				
2007				
January	**71,643**	**10.93**		
February (through 20 February)	**1,700,000**	**11.46**		

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.

Annual general meeting

The 2007 annual general meeting will be held on Thursday 12 April 2007 at 11.30 a.m. at ExCeL London, One Western Gateway, Royal Victoria Dock, London E16 1XL. A separate notice convening the meeting is sent to shareholders with this Report, together with an explanation of the items of special 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 2007.

By order of the board
David J Jackson
Secretary
23 February 2007

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**
Exhibit 4.3	Medium Term Performance Plan***
Exhibit 4.4	Deferred Annual Bonus 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 companys Annual Report on Form 20-F for the year ended 31 December 2003.
** Incorporated by reference to the companys Annual Report on Form 20-F for the year ended 31 December 2004.
*** Incorporated by reference to the companys Annual Report on Form 20-F for the year ended 31 December 2005.
\# 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, please contact the Registrar or ADS Depositary.

To elect to receive the Directors Report and Annual Accounts in place of summary financial statements for all future financial years, please write to the Registrar.

To elect to receive your company documents (such as the Annual Report and Accounts, Annual Review and Notice of Meeting) electronically, please register at *www.bp.com/edelivery*.

UK Registrars Office
The BP Registrar, Lloyds TSB Registrars
The Causeway, Worthing, West Sussex BN99 6DA
Telephone: +44 (0)121 415 7005; Freephone in UK: 0800 701107
Textphone: 0870 600 3950; Fax: +44 (0)1903 833371

US ADS Administration
JPMorgan Chase Bank
PO Box 3408, South Hackensack, NJ 07606-3408
Telephone: +1 201 680 6630
Toll-free in US and Canada: +1 877 638 5672

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Report of independent registered public accounting firm

To: The Board of Directors
BP p.l.c.

We have audited the accompanying group balance sheets of BP p.l.c. as of 31 December 2006, and 2005, 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 2006. 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 2006 and 2005, and the group results of operations and cash flows for each of the three years in the period ended 31 December 2006, in accordance with International Financial Reporting Standards as adopted by the European Union which differ in certain respects from United States generally accepted accounting principles (see Note 53 of Notes to Financial Statements).

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 2006, 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 23 February 2007 expressed an unqualified opinion thereon.

As discussed in Note 36 to the Financial Statements, the group changed its method of accounting for derivative instruments in 2005.

/s/ ERNST & YOUNG LLP
Ernst & Young LLP

London, England
23 February 2007

Report of independent registered public accounting firm

To: The Board of Directors
BP p.l.c.

We have audited management's assessment, included in the accompanying Management's report on internal control over financial reporting on page 82, that BP p.l.c. maintained effective internal control over financial reporting as of 31 December 2006, 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). 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. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, 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, management's assessment that BP p.l.c. maintained effective internal control over financial reporting as of 31 December 2006 is fairly stated, in all material respects, based on the Turnbull criteria. Also, in our opinion, BP p.l.c. maintained, in all material respects, effective internal control over financial reporting as of 31 December 2006, 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 2006, and 2005, 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 2006, and our report dated 23 February 2007 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP
Ernst & Young LLP

London, England
23 February 2007

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Consent of independent registered public accounting firm

We consent to the incorporation by reference of our report dated 23 February 2007 with respect to the group financial statements of BP p.l.c., managements assessment of internal control, and the effectiveness of the companys internal control over financial reporting, included in this Annual Report (Form 20-F) for the year ended 31 December 2006 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 and 333-131583) of BP p.l.c.

/s/ ERNST & YOUNG LLP
Ernst & Young LLP

London, England
6 March 2007

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Group income statement

For the year ended 31 December $ million

	Note	**2006**	2005	2004
Sales and other operating revenues	7	**265,906**	239,792	192,024
Earnings from jointly controlled entities after interest and tax	8	**3,553**	3,083	1,818
Earnings from associates after interest and tax	8	**442**	460	462
Interest and other revenues	9	**701**	613	615
Total revenues		**270,602**	243,948	194,919
Gains on sale of businesses and fixed assets	10	**3,714**	1,538	1,685
Total revenues and other income		**274,316**	245,486	196,604
Purchases		**187,183**	163,026	128,055
Production and manufacturing expenses		**23,293**	21,592	17,330
Production and similar taxes	11	**3,621**	3,010	2,149
Depreciation, depletion and amortization	12	**9,128**	8,771	8,529
Impairment and losses on sale of businesses and fixed assets	13	**549**	468	1,390
Exploration expense	19	**1,045**	684	637
Distribution and administration expenses	15	**14,447**	13,706	12,768
Fair value (gain) loss on embedded derivatives	36	**(608)**	2,047	
Profit before interest and taxation from continuing operations		**35,658**	32,182	25,746
Finance costs	21	**718**	616	440
Other finance (income) expense	22	**(202)**	145	340
Profit before taxation from continuing operations		**35,142**	31,421	24,966
Taxation	23	**12,516**	9,288	7,082
Profit from continuing operations		**22,626**	22,133	17,884
Profit (loss) from Innovene operations	5	**(25)**	184	(622)
Profit for the year		**22,601**	22,317	17,262
Attributable to				
BP shareholders		**22,315**	22,026	17,075
Minority interest		**286**	291	187
		22,601	22,317	17,262
Earnings per share cents				
Profit for the year attributable to BP shareholders				
Basic	25	**111.41**	104.25	78.24
Diluted	25	**110.56**	103.05	76.87

Profit from continuing operations attributable to BP shareholders

Basic	**111.54**	103.38	81.09
Diluted	**110.68**	102.19	79.66

The notes on pages 92-193 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	**2006**	2005
Non-current assets			
Property, plant and equipment	26	**90,999**	85,947
Goodwill	27	**10,780**	10,371
Intangible assets	28	**5,246**	4,772
Investments in jointly controlled entities	29	**15,074**	13,556
Investments in associates	30	**5,975**	6,217
Other investments	31	**1,697**	967
Fixed assets		**129,771**	121,830
Loans		**817**	821
Other receivables	33	**862**	770
Derivative financial instruments	36	**3,025**	3,909
Prepayments and accrued income		**1,034**	1,012
Defined benefit pension plan surplus	41	**6,753**	3,282
		142,262	131,624
Current assets			
Loans		**141**	132
Inventories	32	**18,915**	19,760
Trade and other receivables	33	**38,692**	40,902
Derivative financial instruments	36	**10,373**	10,056
Prepayments and accrued income		**3,006**	1,268
Current tax receivable		**544**	212
Cash and cash equivalents	34	**2,590**	2,960
		74,261	75,290
Assets classified as held for sale	5	**1,078**	—
		75,339	75,290
Total assets		**217,601**	206,914
Current liabilities			
Trade and other payables	35	**42,236**	42,136
Derivative financial instruments	36	**9,424**	10,036
Accruals and deferred income		**6,147**	5,017
Finance debt	38	**12,924**	8,932
Current tax payable		**2,635**	4,274
Provisions	40	**1,932**	1,602
		75,298	71,997

Liabilities directly associated with the assets classified as held for sale	5	**54**	
		75,352	71,997
Non-current liabilities			
Other payables	35	**1,430**	1,935
Derivative financial instruments	36	**4,203**	5,871
Accruals and deferred income		**961**	989
Finance debt	38	**11,086**	10,230
Deferred tax liabilities	23	**18,116**	16,258
Provisions	40	**11,712**	9,954
Defined benefit pension plan and other post-retirement benefit plan deficits	41	**9,276**	9,230
		56,784	54,467
Total liabilities		**132,136**	126,464
Net assets		**85,465**	80,450
Equity			
Share capital	42	**5,385**	5,185
Reserves		**79,239**	74,476
BP shareholders equity	43	**84,624**	79,661
Minority interest	43	**841**	789
Total equity	43	**85,465**	80,450

Peter Sutherland Chairman
The Lord Browne of Madingley Group Chief Executive

The notes on pages 92-193 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	**2006**	2005	2004
Operating activities				
Profit before taxation from continuing operations		**35,142**	31,421	24,966
Adjustments to reconcile profit before taxation to net cash provided by operating activities				
Exploration expenditure written off	19	**624**	305	274
Depreciation, depletion and amortization	12	**9,128**	8,771	8,529
Impairment and (gain) loss on sale of businesses and fixed assets	10, 13	**(3,165)**	(1,070)	(295)
Earnings from jointly controlled entities and associates	8	**(3,995)**	(3,543)	(2,280)
Dividends received from jointly controlled entities and associates		**4,495**	2,833	2,199
Interest receivable		**(473)**	(479)	(284)
Interest received		**500**	401	331
Finance costs	21	**718**	616	440
Interest paid		**(1,242)**	(1,127)	(698)
Other finance (income) expense	22	**(202)**	145	340
Share-based payments		**416**	278	224
Net operating charge for pensions and other post-retirement benefits, less contributions		**(261)**	(435)	(84)
Net charge for provisions, less payments		**(160)**	1,100	(110)
(Increase) decrease in inventories		**995**	(6,638)	(3,182)
(Increase) decrease in other current and non-current assets		**3,596**	(16,427)	(10,225)
Increase (decrease) in other current and non-current liabilities		**(4,211)**	18,628	10,290
Income taxes paid		**(13,733)**	(9,028)	(6,388)
Net cash provided by operating activities of continuing operations		**28,172**	25,751	24,047
Net cash provided by (used in) operating activities of Innovene operations	5	**–**	970	(669)
Net cash provided by operating activities		**28,172**	26,721	23,378
Investing activities				
Capital expenditures		**(15,125)**	(12,281)	(12,286)
Acquisitions, net of cash acquired		**(229)**	(60)	(1,503)
Investment in jointly controlled entities		**(37)**	(185)	(1,648)
Investment in associates		**(570)**	(619)	(942)
Proceeds from disposal of fixed assets	6	**5,963**	2,803	4,236
Proceeds from disposal of businesses	6	**291**	8,397	725
Proceeds from loan repayments		**189**	123	87
Other		**–**	93	–
Net cash used in investing activities		**(9,518)**	(1,729)	(11,331)
Financing activities				
Net repurchase of shares		**(15,151)**	(11,315)	(7,208)

Proceeds from long-term financing		**3,831**	2,475	2,675
Repayments of long-term financing		**(3,655)**	(4,820)	(2,204)
Net increase (decrease) in short-term debt		**3,873**	(1,457)	(24)
Dividends paid				
BP shareholders	24	**(7,686)**	(7,359)	(6,041)
Minority interest		**(283)**	(827)	(33)
Net cash used in financing activities		**(19,071)**	(23,303)	(12,835)
Currency translation differences relating to cash and cash equivalents		**47**	(88)	91
Increase (decrease) in cash and cash equivalents		**(370)**	1,601	(697)
Cash and cash equivalents at beginning of year		**2,960**	1,359	2,056
Cash and cash equivalents at end of year		**2,590**	2,960	1,359

The notes on pages 92-193 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	**2006**	2005	2004
Currency translation differences		**2,025**	(2,502)	2,283
Exchange gain on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets			(315)	(78)
Actuarial gain relating to pensions and other post-retirement benefits		**2,615**	975	107
Available-for-sale investments marked to market		**561**	322	
Available-for-sale investments recycled to the income statement		**(695)**	(60)	
Cash flow hedges marked to market		**413**	(212)	
Cash flow hedges recycled to the income statement		**(93)**	36	
Cash flow hedges recycled to the balance sheet		**(6)**		
Unrealized gain on acquisition of further investment in equity-accounted investments				94
Tax on currency translation differences		**(201)**	11	(208)
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		**(820)**	(356)	96
Tax on available-for-sale investments		**108**	(72)	
Tax on cash flow hedges		**(47)**	63	
Tax on share-based payments		**26**		39
Net income (expense) recognized directly in equity		**3,886**	(2,015)	2,333
Profit for the year		**22,601**	22,317	17,262
Total recognized income and expense for the year		**26,487**	20,302	19,595
Attributable to				
BP shareholders		**26,152**	20,011	19,408
Minority interest		**335**	291	187
		26,487	20,302	19,595
Effect of change in accounting policy adoption of IAS 32 and IAS 39 on 1 January 2005				
BP shareholders			(243)	
Minority interest				
	49		(243)	

The notes on pages 92-193 are an integral part of these consolidated financial statements of the BP group.

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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 2006 were authorized for issue by the board of directors on 23 February 2007 and the balance sheet was signed on the board's behalf by Peter Sutherland and The Lord Browne of Madingley. 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 adopted by the European Union (EU). IFRS as adopted by the EU differs in certain respects from IFRS as issued by the International Accounting Standards Board (IASB). However, the consolidated financial statements for the years presented would be no different had the group applied IFRS as issued by the IASB. 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 2006, or issued and early adopted.

In preparing the consolidated financial statements for the current year, the group has adopted the following amendments to IFRS and IFRIC interpretations:

- Amendment to IAS 21 'The Effects of Changes in Foreign Exchange Rates' – 'Net Investment in a Foreign Operation'.
- Amendment to IAS 39 'Financial Instruments: Recognition and Measurement' – 'The Fair Value Option'.
- Amendments to IAS 39 'Financial Instruments: Recognition and Measurement' and IFRS 4 'Insurance Contracts' – 'Financial Guarantee Contracts'.
- IFRIC 5 'Rights to Interests Arising from Decommissioning, Restoration and Environmental Rehabilitation Funds'.
- IFRIC 6 'Liabilities Arising from Participating in a Specific Market – Waste Electrical and Electronic Equipment'.
- IFRIC 7 'Applying IAS 29 for the First Time'.
- IFRIC 8 'Scope of IFRS 2 – Share-based payment'.
- IFRIC 9 'Reassessment of embedded derivatives'.

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: Disclosure and Presentation' (IAS 32) and IAS 39 'Financial Instruments: Recognition and Measurement' (IAS 39) which have been applied with effect from 1 January 2005. For the year ended 31 December 2004 financial instruments have been accounted for in accordance with the group's previous accounting policies under UK generally accepted accounting practice (UK GAAP). For further information see Note 49.

The consolidated financial statements are presented in US dollars and all values are rounded to the nearest million dollars ($ million), except where otherwise indicated.

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 and is presented separately within equity in the consolidated balance sheet.

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. 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 at each balance sheet date whether an investment in a jointly controlled entity is impaired. If there is objective evidence that an impairment loss has been incurred, the carrying amount of the investment is compared with its recoverable amount, being the higher of its fair value less costs to sell and value in use. Where the carrying amount exceeds the recoverable amount, the investment is written down to its recoverable amount.

The group ceases to use the equity method of accounting on the date from which it no longer has joint control 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.

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1 Significant accounting policies *continued*

Interests in associates

An associate is an entity over which the group is in a position to exercise significant influence through participation in the financial and operating policy decisions of the investee, but which is not a subsidiary or a jointly controlled entity.

The results, assets and liabilities of an associate are incorporated in these financial statements using the equity method of accounting as described above for jointly controlled entities.

Foreign currency translation

Functional currency is the currency of the primary economic environment in which a company operates and is normally the currency in which the company 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 translated 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 in terms of historical cost 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 acquisition 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 are allocated against the interests of the parent.

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.

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. 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 UK GAAP carrying amount.

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 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.

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.

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1 Significant accounting policies *continued*

Licence and property acquisition costs

Exploration and property leasehold 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.

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 the fair value of the asset given up unless the exchange transaction lacks commercial substance or the fair value of neither the asset received nor the asset given up is reliably measurable.

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 and is now written off is replaced and it is probable that future economic benefits associated with the item will flow to the group, the expenditure is capitalized. 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, decommissioning and field development 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 sanctioned future development expenditure.

Other property, plant and equipment is depreciated on a straight-line basis over its expected useful life.

The useful lives of the groups other property, plant and equipment are as follows:

Land improvements	15 to 25 years
Buildings	20 to 40 years

Refineries	20 to 30 years
Petrochemicals plants	20 to 30 years
Pipelines	10 to 50 years
Service stations	15 years
Office equipment	3 to 7 years
Fixtures and fittings	5 to 15 years

The expected useful lives of property, plant and equipment are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

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. 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. If any such indication of impairment exists, the group makes an estimate of its recoverable amount. 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.

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1 Significant accounting policies *continued*

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. When financial assets are recognized initially, they are measured at fair value, normally being the transaction price plus, in the case financial assets not at fair value through profit or loss, directly attributable transaction costs. As explained in Note 49, the group has not restated comparative amounts on first applying IAS 32 and IAS 39, as permitted in IFRS 1 'First-time Adoption of International Financial Reporting Standards'.

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.

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 being 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. These include using recent arm's-length market transactions; reference to the current market value of another instrument which is substantially the same; discounted cash flow analysis; and pricing models. 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 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.

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 administration costs.

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.

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, or on a derivative asset that is linked to and must be settled by delivery of such an unquoted equity instrument, 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.

Trade and other receivables

Trade and other receivables are carried at the original invoice amount, less allowances made for doubtful receivables. Where the time value of money is material, receivables are carried at amortized cost. Provision is made when there is objective evidence that the group will be unable to recover balances in full. Balances are written off when the probability of recovery is assessed as being remote.

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1 Significant accounting policies *continued*

Cash and cash equivalents

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.

For the purpose of the group cash flow statement, cash and cash equivalents consist of cash and cash equivalents as defined above, net of outstanding bank overdrafts.

Trade and other payables

Trade and other payables are carried at payment or settlement amounts. Where the time value of money is material, payables are carried at amortized cost.

Interest-bearing loans and borrowings

All loans and borrowings are initially recognized at fair value, being the fair value of the proceeds received net of issue costs associated with the borrowing.

After initial recognition, interest-bearing loans and borrowings 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 other finance expense.

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 inception of the lease at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Lease payments are apportioned between the finance charges and reduction of the lease liability so as to achieve a constant rate of interest on the remaining balance of the liability. Finance charges 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

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. From 1 January 2005, 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.

For those derivatives designated as hedges and for which hedge accounting is desired, the hedging relationship is documented at its inception. This documentation identifies the hedging instrument, the hedged item or transaction, the nature of the risk being hedged and how effectiveness will be measured throughout its duration. Such hedges are expected at inception to be highly effective.

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, including intragroup transactions.
- Hedges of the net investment in a foreign entity.

Any gains or losses arising from changes in the fair value of all other derivatives, which are classified as held for trading, are taken to the income statement. These may arise from derivatives for which hedge accounting is not applied because they are either not designated or not effective as hedging instruments or from derivatives that are acquired for trading purposes.

The treatment of gains and losses arising from revaluing derivatives designated as hedging instruments depends on the nature of the hedging relationship, as follows:

Fair value hedges

For fair value hedges, the carrying amount of the hedged item is adjusted for gains and losses attributable to the risk being hedged; the derivative is remeasured at fair value and gains and losses from both are taken to profit or loss. For hedged items carried at amortized cost, the adjustment is amortized through the income statement such that it is fully amortized by maturity. When an unrecognized firm commitment is designated as a hedged item, this gives rise to an asset or liability in the balance sheet, representing the cumulative change in the fair value of the firm commitment attributable to the hedged risk.

The group discontinues fair value hedge accounting if the hedging instrument expires or is sold, terminated or exercised, the hedge no longer meets the criteria for hedge accounting or the group revokes the designation.

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. Where the hedged item is the cost of a non-financial asset or liability, 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.

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1 Significant accounting policies *continued*

Hedges of the net investment in a foreign entity

For hedges of the net investment in a foreign entity, 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 entity is sold.

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 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 and, where appropriate, the risks specific to the liability. Where discounting is used, the increase in the provision due to the passage of time is recognized as other finance expense. Any change in the amount recognized for environmental and litigation and other provisions arising through changes in discount rates is included within 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 reasonably estimated. Generally, the timing 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 reasonable estimate of that liability can be made. Where an obligation exists for a new facility, such as oil and natural gas production or transportation facilities, this will be on construction or installation. An obligation for decommissioning may also crystallize during the period of operation of a facility through a change in legislation or through a decision to terminate operations. The amount recognized is the present value of the estimated future expenditure determined in accordance with local conditions and requirements.

A corresponding item of property, plant and equipment of an amount equivalent to the provision is also created. This is subsequently depreciated as part of the capital costs of the facility or item of plant.

Any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding 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 they 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.

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1 Significant accounting policies *continued*

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 for 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) and is based on actuarial advice. 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.

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 groups liability for current tax is calculated using tax rates that have been enacted or substantively enacted by the balance sheet date.

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

Deferred tax liabilities are recognized for all taxable temporary differences:

Except where the deferred tax liability arises on goodwill that is not tax deductible or the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss.

In respect of taxable temporary differences associated with investments in subsidiaries, jointly controlled entities and associates, except where the 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.

Deferred tax assets are recognized for all deductible temporary differences, carry-forward of unused tax assets and unused tax losses, to the extentthat 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 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 groups 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 revenue reserves. 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.

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1 Significant accounting policies *continued*

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 method that is the rate that exactly discounts estimated future cash receipts through the expected life of the financial instrument) to the net carrying amount of the financial asset.

Dividend income from investments is recognized when the shareholders' right to receive the payment is established.

Research

Research costs are expensed as incurred.

Finance costs

Finance costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use.

All other finance costs are recognized in the income statement in the period in which they are incurred.

Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities as well as the disclosure of contingent assets and liabilities at the balance sheet date and the reported amounts of revenues and expenses during the reporting period. Actual outcomes could differ from those estimates.

Impact of new International Financial Reporting Standards

Adopted for 2006

The following amendments to IFRS and IFRIC interpretations have been adopted by the group with effect from 1 January 2006.

Amendment to IAS 21 'The Effects of Changes in Foreign Exchange Rates' – 'Net Investment in a Foreign Operation' was issued in December 2005. The amendment clarifies the requirements of IAS 21 regarding an entity's investment in foreign operations. This amendment was adopted by the EU in May 2006. There was no material impact on the group's reported income or net assets as a result of adoption of this amendment.

The IASB issued an amendment to the fair value option in IAS 39 in June 2005. The option to irrevocably designate, on initial recognition, any financial instruments as ones to be measured at fair value with gains and losses recognized in profit and loss has now been restricted to those financial instruments meeting certain criteria. The criteria are where such designation eliminates or significantly reduces an accounting mismatch, when a group of financial assets, financial liabilities or both are managed and their performance is evaluated on a fair value basis in accordance with a documented risk management or investment strategy, and when an instrument contains an embedded derivative that meets particular conditions. The group has not designated any financial instruments as being at-fair-value-through-profit-and-loss, thus there was no effect on the group's reported income or net assets as a result of adoption of this amendment.

In August 2005, the IASB issued amendments to IAS 39 and IFRS 4 'Insurance Contracts' regarding financial guarantee contracts. These amendments require the issuer of financial guarantee contracts to account for them under IAS 39 as opposed to IFRS 4 unless an issuer has previously asserted explicitly that it regards such contracts as insurance contracts and has used accounting applicable to insurance contracts. In these instances the issuer may elect to apply either IAS 39 or IFRS 4. Under the amended IAS 39, a financial guarantee contract is initially recognized at fair value and is subsequently measured at the higher of (a) the amount determined in accordance with IAS 37 Provisions, Contingent Liabilities and Contingent Assets and (b) the amount initially recognized, less, when appropriate, cumulative amortization recognized in accordance with IAS 18 Revenue. This standard impacts guarantees given by group companies in respect of equity-accounted entities as well as in respect of other third parties; these are recorded in the groups financial statements at initial fair value less cumulative amortization. The effect on the groups reported income and net assets as a result of adoption of this amendment was not material.

In addition, in 2006 BP has adopted IFRIC 5 Rights to Interests Arising from Decommissioning, Restoration and Environmental Rehabilitation Funds and IFRIC 6 Liabilities Arising from Participating in a Specific Market Waste Electrical and Electronic Equipment and has decided to early adopt IFRIC 7 Applying IAS 29 for the First Time, IFRIC 8 Scope of IFRS 2 Share-based payment and IFRIC 9 Reassessment of embedded derivatives. There were no changes in accounting policy 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.

In August 2005, the IASB issued IFRS 7 Financial Instruments Disclosures which is effective for annual periods beginning on or after 1 January 2007. Upon adoption, the group will disclose additional information about its financial instruments, their significance and the nature and extent of risks to which they give rise. More specifically, the group will be required to make specified minimum disclosures about credit risk, liquidity risk and market risk. There will be no effect on reported income or net assets.

Also in August 2005, IAS 1 Amendment Presentation of Financial Statements: Capital Disclosures was issued by the IASB, which requires disclosures of an entitys 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. This is effective for annual periods beginning on or after 1 January 2007. There will be no effect on the groups reported income or net assets.

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1 Significant accounting policies *continued*

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 not yet been adopted by the EU.

Three further IFRIC interpretations, issued in late 2006, are not yet effective and have not yet been adopted by the EU.

IFRIC 10 ‘Interim Financial Reporting and Impairment’ prohibits the reversal of an impairment loss relating to goodwill or certain financial assets made in an earlier interim period in the same annual period.

IFRIC 11 ‘IFRS 2 – Group and Treasury Share Transactions’ deals with share-based payment arrangements within a group and share-based payment arrangements satisfied by using treasury shares.

The directors do not anticipate that the adoption of these interpretations will have a material effect on the reported income or net assets of the group.

IFRIC 12 ‘Service Concession Arrangements’ gives guidance on the accounting by operators for public-to-private service concession arrangements.

BP has not yet completed its evaluation of the impact of adopting this interpretation.

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2 Resegmentation

With effect from 1 January 2006 the following changes to the business segment boundaries have been implemented:

(a) Following the sale of Innovene to INEOS in December 2005, the transfer of three equity-accounted entities (Shanghai SECCO Petrochemical Company Limited in China and Polyethylene Malaysia Sdn Bhd and Ethylene Malaysia Sdn Bhd, both in Malaysia), previously reported in Other businesses and corporate, to Refining and Marketing.

(b) The formation of BP Alternative Energy in November 2005 has resulted in the transfer of certain mid-stream assets and activities to Gas, Power and Renewables:

- South Houston Green Power co-generation facility (in the Texas City refinery) from Refining and Marketing.
- Watson Cogeneration (in the Carson refinery) from Refining and Marketing.
- Phu My Phase 3 CCGT plant in Vietnam from Exploration and Production.

(c) The transfer of Hydrogen for Transport activities from Gas, Power and Renewables to Refining and Marketing. The impact of the changes described above is shown in the tables below.

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									200
By business — as reported	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	Tota continuin operation
Sales and other operating revenues									
Segment sales and other operating revenues	47,210	213,465	25,557	21,295	(55,359)	252,168	(20,627)	8,251	239,79
Less: sales between businesses	(32,606)	(11,407)	(3,095)	(8,251)	55,359	—	8,251	(8,251)	
Third party sales	14,604	202,058	22,462	13,044	—	252,168	(12,376)	—	239,79
Segment results									
Profit (loss) before interest and tax	25,508	6,442	1,104	(523)	(208)	32,323	(668)	527	32,18
Assets and liabilities									
Net assets (liabilities)	73,092	45,125	5,095	(2,602)	(40,260)	80,450			

By business as restated									
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	239,79
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)		239,79
Segment results									
Profit (loss) before interest and tax	25,502	6,426	1,172	(569)	(208)	32,323	(668)	527	32,18
Assets and liabilities									
Net assets (liabilities)	73,060	45,234	5,587	(3,171)	(40,260)	80,450			

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By business as reported	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	Tota continuin operation
Sales and other operating revenues									
Segment sales and other operating revenues	34,700	170,749	23,859	17,994	(43,999)	203,303	(17,448)	6,169	192,02
Less: sales between businesses	(24,756)	(10,632)	(2,442)	(6,169)	43,999		6,169	(6,169)	
Third party sales	9,944	160,117	21,417	11,825		203,303	(11,279)		192,02

Segment results									
Profit (loss) before interest and tax	18,087	6,544	954	(362)	(191)	25,032	526	188	25,746
By business — as restated									
Sales and other operating revenues									
Segment sales and other operating revenues	34,700	170,639	23,969	17,994	(43,999)	203,303	(17,448)	6,169	192,024
Less: sales between businesses	(24,756)	(10,632)	(2,442)	(6,169)	43,999	—	6,169	(6,169)	
Third party sales	9,944	160,007	21,527	11,825	—	203,303	(11,279)	—	192,024
Segment results									
Profit (loss) before interest and tax	18,085	6,506	1,003	(371)	(191)	25,032	526	188	25,746

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3 Oil and natural gas reserves estimates

At the end of 2006, BP adopted the US Securities and Exchange Commission (SEC) rules for estimating oil and natural gas reserves for all accounting and reporting purposes 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). The main differences 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 represents a simplification of the groups reserves reporting, as in the future only one set of reserves estimates will be disclosed. In addition, the use of SEC reserves for accounting purposes will bring our IFRS and US GAAP reporting into closer alignment, as well as making our results more comparable with those of our major competitors.

This change in accounting estimate has 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 is applied prospectively, with no restatement of prior periods results. The groups actual DD&A charge for the year is $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 which was used to calculate DD&A for the last three months of the year. Over the life of a field this change would have no overall effect on DD&A but the estimated effect for 2007 is expected to be an increase of approximately $400 million to $500 million for the group.

4 Acquisitions

Acquisitions in 2006

BP made a number of minor acquisitions in 2006 for a total consideration of $256 million. All these business combinations were in the Gas, Power and Renewables segment and were accounted for using the acquisition method of accounting. 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 minor acquisitions in 2005 for a total consideration of $84 million. All these business combinations were accounted for using the acquisition method of accounting. No significant fair value adjustments were made to the acquired assets and liabilities. Goodwill of $27 million arose on these acquisitions. There was also additional goodwill on the Solvay acquisition of $59 million (see below).

Acquisitions in 2004

On 2 November 2004, Solvay exercised its option to sell its interests in BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America to BP. Solvay held 50% of BP Solvay Polyethylene Europe and 51% of BP Solvay Polyethylene North America. On completion, the two entities, which manufacture and market high-density polyethylene, became wholly owned subsidiaries of BP. The total consideration for the acquisition was $1,391 million, subject to final closing adjustments. There were closing adjustments and selling costs in 2005 amounting to $59 million. These created additional goodwill of $59 million, which was written off. Other minor acquisitions were made for a total consideration of $14 million. All business combinations have been accounted for using the acquisition method of accounting. The fair value of the property, plant and equipment was estimated by determining the net present value of future cash flows. No significant adjustments were made to the other assets and liabilities acquired. The assets and liabilities acquired as part of the 2004 acquisitions are shown in aggregate in the table below.

			$ million
			2004
	Book value on acquisition	Fair value adjustments	Fair value

Property, plant and equipment	703	760	1,463
Intangible assets	15	—	15
Current assets (excluding cash)	721	—	721
Cash and cash equivalents	36	—	36
Trade and other payables	(329)	—	(329)
Deferred tax liabilities	—	(185)	(185)
Defined benefit pension plan deficits	(3)	—	(3)
Net investment in equity-accounted entities transferred to full consolidation	(547)	(94)	(641)
Net assets acquired	596	481	1,077
Goodwill			328
Consideration			1,405

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5 Non-current assets held for sale and discontinued operations

Non-current assets held for sale

On 27 June 2006, BP announced its intention to sell the Coryton refinery in the UK, following a review of its European refinery portfolio which concluded that the group would optimise 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 is 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 Coryton disposal group, reported within the Refining and Marketing segment, classified as held for sale at 31 December 2006 are set out below.

	$ million
Assets	
Property, plant and equipment	564
Goodwill	60
Inventories	454
Assets classified as held for sale	1,078
Liabilities	
Current liabilities	54
Liabilities directly associated with assets classified as held for sale	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 are recycled to the income statement.

On 1 February 2007, it was agreed to sell the Coryton disposal group, subject to required regulatory approval, to Petroplus Holdings AG, an independent refiner and wholesaler of petroleum products headquartered in Zug, Switzerland, for a sale price of $1.4 billion, plus hydrocarbons to be valued at closing.

Discontinued operations

The sale of Innovene, BPs 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 has been 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
	2006	2005	2004

Total revenues and other income		12,441	11,327
Expenses		11,709	12,041
Profit (loss) before interest and taxation		732	(714)
Other finance income (expense)		3	(17)
Profit (loss) before taxation and loss recognized on remeasurement to fair value less costs to sell and on disposal		735	(731)
Loss recognized on the remeasurement to fair value less costs to sell and on disposal	**(184)**	(591)	
Profit (loss) before taxation from Innovene operations	**(184)**	144	(731)
Tax (charge) credit			
on profit (loss) before loss recognized on remeasurement to fair value less costs to sell and on disposal	**166**	(306)	109
on loss recognized on the remeasurement to fair value less costs to sell and on disposal	**(7)**	346	
Profit (loss) from Innovene operations	**(25)**	184	(622)
Earnings (loss) per share from Innovene operations cents			
Basic	**(0.13)**	0.87	(2.85)
Diluted	**(0.12)**	0.86	(2.79)
The cash flows of Innovene operations are presented below			
Net cash provided by (used in) operating activities		970	(669)
Net cash used in investing activities		(524)	(1,731)
Net cash provided by (used in) financing activities		(446)	2,400

Further information is contained in Note 6.

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6 Disposals

			$ million
	2006	2005	2004
Proceeds from the sale of Innovene operations	**(34)**	8,304	
Proceeds from the sale of other businesses	**325**	93	725
Proceeds from the sale of businesses	**291**	8,397	725
Proceeds from disposal of fixed assets	**5,963**	2,803	4,236
	6,254	11,200	4,961
By business			
Exploration and Production	**4,005**	1,416	914
Refining and Marketing	**1,789**	888	1,007
Gas, Power and Renewables	**297**	540	144
Other businesses and corporate	**163**	8,356	2,896
	6,254	11,200	4,961

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.

Cash received during the year from disposals amounted to $6.3 billion (2005 $11.2 billion and 2004 $5.0 billion). 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 major transactions in 2004 that generated over $2.3 billion of proceeds were the sale of the group's investments in PetroChina and Sinopec. 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 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. In 2004, in the US, we sold 45% of our interest in King's Peak in the deepwater Gulf of Mexico to Marubeni Oil & Gas, divested our interest in Swordfish, and additionally sold various properties, including our interest in the South Pass 60 property in the Gulf of Mexico Shelf. In Canada, BP sold various assets in Alberta to Fairborne Energy. In Indonesia, we disposed of our interest in the Kangean Production Sharing Contract and our participating interest in the Muriah Production Sharing Contract.

Refining and Marketing

The churn of retail assets represents a significant element of the total in all three years. In addition, in 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. During 2004, major transactions included the sale of the Singapore refinery, the divestment of the European speciality intermediate chemicals business and the Cushing and other pipeline interests in the US.

Gas, Power and Renewables

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. During 2004, the group sold its interest in two Canadian natural gas liquids plants.

Other businesses and corporate

During 2006, the group disposed of miscellaneous non-core businesses and assets. 2005 includes the proceeds from the sale of Innovene. The disposal of the group's investments in PetroChina and Sinopec were the major transactions in 2004. In addition, the group sold its US speciality intermediate chemicals and fabrics and fibres businesses.

Summarized financial information for the sale of businesses is shown below.

			$ million
	2006	2005	2004
The disposals comprise the following			
Non-current assets	**143**	6,452	1,046
Other current assets	**169**	4,779	477
Non-current liabilities	**(10)**	(364)	(44)
Current liabilities	**(70)**	(2,488)	(59)
	232	8,379	1,420
Profit (loss) on sale of businesses	**167**	18	(695)
Total consideration	**399**	8,397	725
Consideration not yet received	**(74)**	–	–
Closing adjustments associated with the sale of Innovene	**(34)**	–	–
Proceeds from the sale of businesses[a]	**291**	8,397	725

a Includes cash and cash equivalents disposed of $2 million (2005 $15 million and 2004 $10 million).

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7 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 the group's internal financial reporting systems.

BP has 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 and field development and production, together with pipeline transportation and natural gas processing. The activities of Refining and Marketing include oil supply and trading as well as refining and petrochemicals manufacturing and marketing. Gas, Power and Renewables activities include marketing and trading of gas and power, marketing of liquefied natural gas, natural gas liquids and low-carbon power generation through the Alternative Energy business. The group is managed on an integrated basis.

Other businesses and corporate comprises Finance, the group's aluminum asset, interest income and costs relating to corporate activities worldwide.

The accounting policies of operating segments are the same as those described in Note 1.

Sales between segments are made at prices that approximate market prices, taking into account the volumes involved. Segment revenue and segment result include transactions between business segments. These transactions and any unrealized profits and losses are eliminated on consolidation.

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 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.

By business	Exploration and Production	Refining and Marketing	Gas, Power and Renewables	Other businessess and corporate	Consolidation adjustment and eliminations	Total group	Innovene operations	Cons ac eli
Sales and other operating revenues								
Segment sales and other operating revenues	**52,600**	**232,855**	**23,708**	**1,009**	**(44,266)**	**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**	–	
Equity-accounted earnings	**3,517**	**341**	**138**	**(1)**	–	**3,995**	–	
Segment revenues	**19,946**	**229,120**	**19,827**	**1,008**	–	**269,901**	–	
Interest and other revenues	–	–	–	–	**701**	**701**	–	
Total revenues	**19,946**	**229,120**	**19,827**	**1,008**	**701**	**270,602**	–	

Segment results							
Profit (loss) before interest and tax	**29,629**	**5,541**	**1,321**	**(1,069)**	**52**	**35,474**	**184**
Finance costs and other finance expense	—	—	—	—	**(516)**	**(516)**	—
Profit (loss) before taxation	**29,629**	**5,541**	**1,321**	**(1,069)**	**(464)**	**34,958**	**184**
Taxation	—	—	—	—	**(12,357)**	**(12,357)**	**(159)**
Profit (loss) for the year	**29,629**	**5,541**	**1,321**	**(1,069)**	**(12,821)**	**22,601**	**25**
Assets and liabilities							
Segment assets	**99,310**	**80,964**	**27,398**	**14,184**	**(4,799)**	**217,057**	
Tax receivable	—	—	—	—	**544**	**544**	
Total assets	**99,310**	**80,964**	**27,398**	**14,184**	**(4,255)**	**217,601**	
Includes							
Equity-accounted investments	**15,510**	**4,675**	**853**	**11**	—	**21,049**	
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							
Intangible assets	**1,614**	**253**	**192**	**43**	—	**2,102**	
Property, plant and equipment	**10,227**	**2,733**	**337**	**232**	—	**13,529**	
Other	**1,277**	**158**	**159**	**6**	—	**1,600**	
Total	**13,118**	**3,144**	**688**	**281**	—	**17,231**	
Depreciation, depletion and amortization	**6,533**	**2,244**	**192**	**159**	—	**9,128**	—
Impairment losses	**137**	**155**	**100**	**69**	—	**461**	—

Impairment reversals	**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**	—
Gains on sale of businesses and fixed assets	**2,309**	**1,112**	**193**	**100**	—	**3,714**	—

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7 Segmental analysis *continued*

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]
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
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)	–
Equity-accounted earnings	3,232	249	62	(14)	–	3,529	14	–
Segment revenues	17,836	202,168	22,663	13,030	–	255,697	(12,362)	–
Interest and other revenues	–	–	–	–	689	689	(76)	–
Total revenues	17,836	202,168	22,663	13,030	689	256,386	(12,438)	–
Segment results								
Profit (loss) before interest and tax	25,502	6,426	1,172	(569)	(208)	32,323	(668)	527
Finance costs and other finance expense	–	–	–	–	(758)	(758)	(3)	–
Profit (loss) before taxation	25,502	6,426	1,172	(569)	(966)	31,565	(671)	527
Taxation	–	–	–	–	(9,248)	(9,248)	133	(173)
Profit (loss) for the year	25,502	6,426	1,172	(569)	(10,214)	22,317	(538)	354
Assets and liabilities								
Segment assets	93,447	77,485	28,952	12,144	(5,326)	206,702		
Tax receivable	–	–	–	–	212	212		

Total assets	93,447	77,485	28,952	12,144	(5,114)	206,914		
Includes								
Equity-accounted investments	14,657	4,336	771	9	—	19,773		
Segment liabilities	(20,387)	(32,251)	(23,365)	(15,315)	4,548	(86,770)		
Current tax payable	—	—	—	—	(4,274)	(4,274)		
Finance debt	—	—	—	—	(19,162)	(19,162)		
Deferred tax liabilities	—	—	—	—	(16,258)	(16,258)		
Total liabilities	(20,387)	(32,251)	(23,365)	(15,315)	(35,146)	(126,464)		
Other segment information								
Capital expenditure and acquisitions								
Intangible assets	989	451	31	10	—	1,481		
Property, plant and equipment	8,751	2,036	199	779	—	11,765		
Other	497	373	5	28	—	903		
Total	10,237	2,860	235	817	—	14,149		
Depreciation, depletion and amortization	6,033	2,382	235	533	—	9,183	(412)	—
Impairment losses	266	93	—	59	—	418	(59)	—
Loss on remeasurement to fair value less costs to sell and on disposal of Innovene operations	—	—	—	591	—	591	(591)	—
Losses on sale of businesses and fixed assets	39	64	—	6	—	109	—	—
Gains on sale of businesses and fixed assets	1,198	241	55	47	—	1,541	(3)	—

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7 Segmental analysis *continued*

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]
Sales and other operating revenues								
Segment sales and other operating revenues	34,700	170,639	23,969	17,994	(43,999)	203,303	(17,448)	6,169
Less: sales between businesses	(24,756)	(10,632)	(2,442)	(6,169)	43,999	—	6,169	(6,169)
Third party sales	9,944	160,007	21,527	11,825	—	203,303	(11,279)	—
Equity-accounted earnings	1,983	262	35	(12)	—	2,268	12	—
Segment revenues	11,927	160,269	21,562	11,813	—	205,571	(11,267)	—
Interest and other revenues	—	—	—	—	673	673	(58)	—
Total revenues	11,927	160,269	21,562	11,813	673	206,244	(11,325)	—
Segment results								
Profit (loss) before interest and tax	18,085	6,506	1,003	(371)	(191)	25,032	526	188
Finance costs and other finance expense	—	—	—	—	(797)	(797)	17	—
Profit (loss) before taxation	18,085	6,506	1,003	(371)	(988)	24,235	543	188
Taxation	—	—	—	—	(6,973)	(6,973)	(53)	(56)
Profit (loss) for the year	18,085	6,506	1,003	(371)	(7,961)	17,262	490	132
Other segment information								
Depreciation, depletion and amortization	5,583	2,532	218	679	—	9,012	(483)	—
	435	195	—	891	—	1,521	(879)	—

Impairment losses								
Impairment reversals	31	—	—	—	—	31	—	—
Losses on sale of businesses and fixed assets	227	371	—	416	—	1,014	(235)	—
Gains on sale of businesses and fixed assets	162	104	56	1,365	—	1,687	(2)	—

[a] 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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7 Segmental analysis *continued*

$ million

						2006
By geographical area	UK	Rest of Europe	USA	Rest of World	Consolidation adjustment and eliminations	Total
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
Segment revenues	54,581	61,960	95,030	58,330		269,901
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 (expense) income	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
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						
Intangible assets	**421**	**53**	**905**	**723**	—	**2,102**
Property, plant and equipment	**1,120**	**916**	**5,531**	**5,962**	—	**13,529**
Other	**46**	**22**	**156**	**1,376**	—	**1,600**
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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7 Segmental analysis *continued*

$ million

						2005
By geographical area	UK	Rest of Europe	USA	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
Segment revenues	49,077	54,670	93,097	46,491	—	243,335
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
Assets and liabilities						
Segment assets	44,007	26,560	79,838	64,129	(7,832)	206,702
Tax receivable	2	158	6	46	—	212
Total assets	44,009	26,718	79,844	64,175	(7,832)	206,914
Includes						
Equity-accounted investments	74	1,496	1,420	16,783	—	19,773
Segment liabilities	(25,079)	(16,824)	(34,146)	(18,553)	7,832	(86,770)

Current tax payable	(798)	(1,057)	(678)	(1,741)	—	(4,274)
Finance debt	(9,706)	(433)	(6,159)	(2,864)	—	(19,162)
Deferred tax liabilities	(2,223)	(936)	(9,400)	(3,699)	—	(16,258)
Total liabilities	(37,806)	(19,250)	(50,383)	(26,857)	7,832	(126,464)
Other segment information						
Capital expenditure and acquisitions						
Intangible assets	205	43	579	654	—	1,481
Property, plant and equipment	1,340	919	4,804	4,702	—	11,765
Other	53	18	86	746	—	903
Total	1,598	980	5,469	6,102	—	14,149
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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7 Segmental analysis *continued*

$ million

2004

By geographical area	UK	Rest of Europe	USA	Rest of World	Total
Sales and other operating revenues					
Segment sales and other operating revenues	59,615	52,540	86,358	48,534	247,047
Less: sales attributable to Innovene operations	(2,365)	(7,682)	(4,109)	(672)	(14,828)
Segment revenues from continuing operations	57,250	44,858	82,249	47,862	232,219
Less: sales between areas	(18,846)	(1,396)	(1,539)	(10,188)	(31,969)
Less: sales by continuing operations to Innovene	(5,263)	(896)	(2,064)	(3)	(8,226)
Third party sales of continuing operations	33,141	42,566	78,646	37,671	192,024
Equity-accounted income	9	17	92	2,162	2,280
Segment revenues	33,150	42,583	78,738	39,833	194,304
Segment results					
Profit before interest and tax from continuing operations	2,875	3,121	9,725	10,025	25,746
Finance costs and other finance (expense) income	155	(261)	(513)	(161)	(780)
Profit before taxation from continuing operations	3,030	2,860	9,212	9,864	24,966
Taxation	(1,745)	(779)	(2,596)	(1,962)	(7,082)
Profit for the year from continuing operations	1,285	2,081	6,616	7,902	17,884
Loss from Innovene operations	(327)	(110)	(96)	(89)	(622)
Profit for the year	958	1,971	6,520	7,813	17,262
Other segment information					
Depreciation, depletion and amortization	2,030	930	3,906	1,663	8,529
Exploration expense	26	25	361	225	637
Impairment losses	—	—	570	41	611
Impairment reversals	—	—	—	31	31
Losses on sale of businesses and fixed assets	282	—	177	320	779
Gains on sale of businesses and fixed assets	—	—	133	1,552	1,685

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8 Earnings from jointly controlled entities and associates

$ million

By business	**Profit (loss) before interest and tax**	**Interest**	**Tax**	**Minority interest**	**Profit (loss) for the year**
					2006
Exploration and Production[a]	**5,838**	**324**	**1,804**	**193**	**3,517**
Refining and Marketing	**487**	**79**	**67**	–	**341**
Gas, Power and Renewables	**179**	**21**	**20**	–	**138**
Other businesses and corporate	**(1)**	–	–	–	**(1)**
	6,503	**424**	**1,891**	**193**	**3,995**
Earnings from jointly controlled entities	**5,834**	**361**	**1,727**	**193**	**3,553**
Earnings from associates	**669**	**63**	**164**	–	**442**
	6,503	**424**	**1,891**	**193**	**3,995**

a Includes a net gain of $892 million on the disposal of fixed assets.

$ million

By business	Profit (loss) before interest and tax	Interest	Tax	Minority interest	Profit (loss) for the year
					2005
Exploration and Production[b]	4,813	227	1,250	104	3,232
Refining and Marketing	385	55	81	–	249
Gas, Power and Renewables	77	7	8	–	62
Other businesses and corporate	(14)	–	–	–	(14)
	5,261	289	1,339	104	3,529
Innovene operations	14	–	–	–	14
Continuing operations	5,275	289	1,339	104	3,543
Earnings from jointly controlled entities	4,615	232	1,196	104	3,083
Earnings from associates	660	57	143	–	460
	5,275	289	1,339	104	3,543

b Includes a net gain of $270 million on the disposal of fixed assets.

					$ million
					2004
By business	Profit (loss) before interest and tax	Interest	Tax	Minority interest	Profit (loss) for the year
Exploration and Production	3,244	189	1,029	43	1,983
Refining and Marketing	360	19	79	—	262
Gas, Power and Renewables	44	7	2	—	35
Other businesses and corporate	(9)	3	—	—	(12)
	3,639	218	1,110	43	2,268
Innovene operations	9	(3)	—	—	12
Continuing operations	3,648	215	1,110	43	2,280
Earnings from jointly controlled entities	3,017	167	989	43	1,818
Earnings from associates	631	48	121	—	462
	3,648	215	1,110	43	2,280

9 Interest and other revenues

			$ million
	2006	2005	2004
Dividends	**5**	52	37
Interest from loans and other investments	**154**	73	34
Other interest	**314**	324	244
Miscellaneous income	**228**	240	358
	701	689	673
Innovene operations	—	(76)	(58)
Continuing operations	**701**	613	615

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10 Gains on sale of businesses and fixed assets

			$ million
	2006	2005	2004
Gains on sale of businesses			
Refining and Marketing	**104**	18	
Other businesses and corporate	**63**		
	167	18	
Gains on sale of fixed assets			
Exploration and Production	**2,309**	1,198	162
Refining and Marketing	**1,008**	223	104
Gas, Power and Renewables	**193**	55	56
Other businesses and corporate	**37**	47	1,365
	3,547	1,523	1,687
	3,714	1,541	1,687
Innovene operations		(3)	(2)
Continuing operations	**3,714**	1,538	1,685

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 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. For 2004, divestments included interests in oil and natural gas properties in Australia, Canada and the Gulf of Mexico.

Refining and Marketing

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. For 2004, divestments included the sale of the Cushing and other pipeline interests in the US and the churn of retail assets.

Gas, Power and Renewables

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. During 2004, the group divested its interest in two natural gas liquids plants in Canada.

Other businesses and corporate

In 2006, the group disposed of its ethylene oxide business. For 2004, the major disposals were the divestment of the group's investments in PetroChina and Sinopec.

Additional information on the sale of businesses and fixed assets is given in Note 6.

11 Production and similar taxes

			$ million
	2006	2005	2004
UK	**260**	495	335
Overseas	**3,361**	2,515	1,814
	3,621	3,010	2,149

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12 Depreciation, depletion and amortization

			$ million
By business	**2006**	2005	2004
Exploration and Production			
UK	**1,720**	1,663	1,642
Rest of Europe	**223**	228	184
USA	**2,236**	2,426	2,407
Rest of World	**2,354**	1,716	1,350
	6,533	6,033	5,583
Refining and Marketing			
UK[a]	**303**	316	318
Rest of Europe	**603**	687	645
USA	**1,048**	1,082	1,238
Rest of World	**290**	297	331
	2,244	2,382	2,532
Gas, Power and Renewables			
UK	**18**	47	37
Rest of Europe	**13**	20	24
USA	**117**	109	88
Rest of World	**44**	59	69
	192	235	218
Other businesses and corporate			
UK	**98**	203	251
Rest of Europe	**1**	130	204
USA	**58**	187	199
Rest of World	**2**	13	25
	159	533	679
By geographical area			
UK[a]	**2,139**	2,229	2,248
Rest of Europe	**840**	1,065	1,057
USA	**3,459**	3,804	3,932
Rest of World	**2,690**	2,085	1,775
	9,128	9,183	9,012
Innovene operations	–	(412)	(483)
Continuing operations	**9,128**	8,771	8,529

a UK area includes the UK-based international activities of Refining and Marketing.

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13 Impairment and losses on sale of businesses and fixed assets

			$ million
	2006	2005	2004
Impairment losses			
Exploration and Production	**137**	266	435
Refining and Marketing	**155**	93	195
Gas, Power and Renewables	**100**	–	–
Other businesses and corporate	**69**	59	891
	461	418	1,521
Impairment reversals			
Exploration and Production	**(340)**	–	(31)
	(340)	–	(31)
Loss on sale of businesses or termination of operations			
Refining and Marketing	–	–	279
Other businesses and corporate	–	–	416
	–	–	695
Loss on sale of fixed assets			
Exploration and Production	**195**	39	227
Refining and Marketing	**228**	64	92
Other businesses and corporate	**5**	6	–
	428	109	319
Loss on remeasurement to fair value less costs to sell and on disposal of Innovene operations	**184**	591	–
	733	1,118	2,504
Innovene operations	**(184)**	(650)	(1,114)
Continuing operations	**549**	468	1,390

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 10% (2005 10% and 2004 9%). This discount rate is derived from the group's post-tax weighted average cost of capital. A different pre-tax discount rate is used where the tax rate applicable to the asset is significantly different from the average corporate tax rate applicable to the group as a whole.

Exploration and Production

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 recognised. 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 managements 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. During 2004, as a result of impairment triggers, reviews were conducted which resulted in impairment charges of $83 million in respect of Kings Peak in the Gulf of Mexico, $20 million in respect of two fields in the Gulf of Mexico Shelf Matagorda Island area and $184 million in respect of various US onshore fields. A charge of $88 million was reflected in respect of a gas processing plant in the US and a charge of $60 million following the blow-out of the Temsah platform in Egypt. In addition, following the lapse of the sale agreement for oil and gas properties in Venezuela, $31 million of the previously booked impairment charge was released.

Refining and Marketing

During 2006, certain assets in our Retail and Aromatics and 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. With the formation of Olefins and Derivatives at the end of 2004 certain agreements and assets were restructured to reflect the armskength relationship that would exist in the future. This resulted in an impairment of the petrochemical facilities at Hull, UK.

Gas, Power and Renewables

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 on-going operational costs.

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13 Impairment and losses on sale of businesses and fixed assets *continued*

Other businesses and corporate

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. In 2004, in connection with the Solvay transactions, the group recognized impairment charges of $325 million for goodwill and $270 million for property, plant and equipment in BP Solvay Polyethylene Europe. As part of a restructuring of the North American Olefins and Derivatives businesses, decisions were taken to exit certain businesses and facilities, resulting in impairments and write-downs of $294 million.

Loss on sale of businesses or termination of operations

The principal transactions that give rise to the losses for each business segment are described below.

Refining and Marketing

In 2004, activities included the closure of two manufacturing plants at Hull, UK, which produced acids; the sale of the European speciality intermediate chemicals business; the closure of the lubricants operation of the Coryton refinery in the UK and of refining operations at the ATAS refinery in Mersin, Turkey.

Other businesses and corporate

For 2004, activities included the sale of the US speciality intermediate chemicals business; the sale of the fabrics and fibres business; and the closure of the linear alpha-olefins production facility at Pasadena, Texas.

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 includes increases in decommissioning liability estimates associated with the hurricane-damaged fields which were divested during the year. For 2004, this included interests in oil and natural gas properties in Indonesia and the Gulf of Mexico.

Refining and Marketing

For 2006, the principal transactions contributing to the loss were retail churn. For 2004, the principal transactions contributing to the loss were divestment of the Singapore refinery and retail churn.

14 Impairment of goodwill

		$ million
Goodwill at 31 December	**2006**	2005
Exploration and Production	**4,282**	4,371
Refining and Marketing	**6,390**	5,955
Gas, Power and Renewables	**108**	45
	10,780	10,371

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 strategic performance units (SPUs), namely Refining, Retail, Lubricants, Aromatics and Acetyls and Business Marketing.

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 10% (2005 10%). This discount rate is derived from the group□s post-tax weighted average cost of capital. A different pre-tax discount rate is used where the tax rate applicable to the region is significantly different from the average corporate tax rate applicable to the group as a whole.

The four or five year business segment plans, which are approved on an annual basis by senior management, are the source for 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 to 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 $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 (2005 $55 per barrel in 2005 decreasing in equal annual steps over the following three years to $25 per barrel in 2009 and beyond). Similarly, the group□s assumption for Henry Hub natural gas prices is an 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 (2005 $8.65 per mmBtu in 2005 decreasing in equal annual steps over the following three years to $4.00 per mmBtu in 2009 and beyond). These prices are adjusted to arrive at appropriate consistent price assumptions for different qualities of oil and gas.

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14 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 BPs 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 2006 using data which was appropriate at that time. As permitted by IAS 36, the detailed calculation made in 2005 was used for the 2006 impairment test on the goodwill allocated to the Rest of World as the criteria of IAS 36 were considered to be satisfied in respect of this region: the excess of the recoverable amount over the carrying amount was substantial in 2005; 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. Therefore, the detailed impairment test for goodwill was reperformed only on the carrying amounts in the UK and the US.

The following table shows the carrying value of the goodwill allocated to each of the regions of the Exploration and Production segment and 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.

					$ million
					2006
	UK	**Rest of Europe**	**USA**	**Rest of World**	**Total**
Goodwill	**341**		**3,426**	**515**	**4,282**
Excess of recoverable amount over carrying amount	**7,886**	**n/a**	**28,856**	**n/a**	

					$ million
					2005
	UK	Rest of Europe	USA	Rest of World	Total
Goodwill	341		3,515	515	4,371
Excess of recoverable amount over carrying amount	3,205	n/a	6,421	n/a	

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 shown above (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.

On the basis of the rules of thumb using estimated 2007 production profiles and an assumed average 15-year production life, it is estimated that the long-term price of Brent that would cause the total recoverable amount to be equal to the total carrying amount of the 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. No reasonably possible change in oil or gas prices would cause the headroom in the Rest of the World to be reduced to zero.

Estimated production volumes are based on detailed data for the fields and take into account development plans for the fields agreed by management as part of the long-term planning process. 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 which would reduce the groups headroom to zero.

Refining and Marketing

For all cash generating units, the cash flows for the next four years are derived from the four-year business segment plan. The cost inflation rate is assumed to be 2.5% (2005 assumption was 2.5%) throughout the period. For determining the value in use for each of the SPUs, cash flows for a period of 10 years have been discounted and aggregated with its terminal value.

Refining

Cash flows beyond the four-year period are extrapolated using a 2% growth rate (2005 assumption was 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 value assigned to the gross margin is based on a $7.25 per barrel global indicator margin (GIM), which is then adjusted for specific refinery configurations. In 2005 the value assigned to the gross margin was based on a $5.25 per barrel GIM, except in the first year of the plan period when a GIM of $7.25 was used, reflecting market conditions expected in the near term. The value assigned to the production volume is 850mmbbl a year (2005 900mmbbl) and remains constant over the plan period. The value assigned to the terminal value assumption is 6 times earnings (2005 5 times), which is indicative of similar assets in the current market. These key assumptions reflect past experience and are consistent with external sources.

Management believes that no reasonably possible change in the key assumptions would lead to the Refining value in use being equal to its carrying amount.

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14 Impairment of goodwill *continued*

Retail

Cash flows beyond the four-year period are extrapolated using a 1.3% growth rate (2005 assumption was no growth) 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, branded marketing volumes, the terminal value and discount rate. The value assigned to the unit gross margin varies between markets. For the purpose of planning, each market develops a gross margin based upon a market-specific reference price adjusted for the different income streams within the market and other market specific factors. The weighted average Retail reference margin used in the plan was 5.0 cents per litre (2005 5.4 cents per litre). The value assigned to the branded marketing volume assumption is 100 billion litres a year (2005 101 billion litres a year). The unit gross margin assumptions decline on average by 5% a year over the plan period and marketing volume assumptions grow by an average of 5% a year over the plan period. The value assigned to the terminal value assumption is 6.5 times earnings (2005 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 $2.1 billion. Based on sensitivity analysis, it is estimated that if there is an adverse change in the unit gross 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 billion and, if there is an adverse change in Retail volumes of 11 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 $0.7 billion and, if the multiple of earnings falls to 3 times 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 $0.7 billion and, if the discount rate increases to 13%, the value in use of the Retail unit would equal its carrying amount.

Lubricants

Cash flows beyond the four-year period are extrapolated using a 3% margin growth rate (2005 assumption was 3%), which is lower than the long-term average growth rate for the first four 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 margins and sales volumes over the plan period are 53 cents per litre (2005 56 cents per litre) and 3.5 billion litres a year (2005 3.5 billion litres) respectively. These key assumptions reflect past experience.

The Lubricants unit’s recoverable amount exceeds its carrying amount by $2.0 billion. Based on sensitivity analysis, it is estimated that if there is an adverse change in the operating gross margin of 5 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 $1.1 billion and, if there is an adverse change in Lubricants sales volumes of 300 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 $0.6 billion and, if the discount rate increases to 14% the value in use of the Lubricants unit would equal its carrying amount.

					$ 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**	—

	$ million
	2005

	Refining	Retail	Lubricants	Other	Total
Goodwill	1,388	832	3,612	123	5,955
Excess of recoverable amount over carrying amount	n/a	1,511	3,953	n/a	

15 Distribution and administration expenses

$ million

	2006	2005	2004
Distribution	**13,174**	13,187	12,325
Administration	**1,273**	1,325	1,284
	14,447	14,512	13,609
Innovene operations		(806)	(841)
Continuing operations	**14,447**	13,706	12,768

16 Currency exchange gains and losses

$ million

	2006	2005	2004
Currency exchange losses charged to income	**222**	94	55
Innovene operations		(80)	(13)
Continuing operations	**222**	14	42

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17 Research

	2006	2005	2004
			$ million
Expenditure on research	**395**	502	439
Innovene operations	–	(128)	(139)
Continuing operations	**395**	374	300

18 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 minimum future lease payments are excluded from the information given below.

	2006	2005	2004
			$ million
Minimum lease payments	**3,660**	2,737	2,442
Sub-lease rentals	**(131)**	(114)	(115)
	3,529	2,623	2,327
Innovene operations	–	(49)	(89)
Continuing operations	**3,529**	2,574	2,238

The minimum future lease payments at 31 December (before deducting related rental income from operating sub-leases, for 2006 of $626 million, 2005 $718 million) were as follows:

Minimum future lease payments	**2006**	2005	2004
			$ million
Payable within			
1 year	**3,428**	2,610	2,061
2 to 5 years	**8,440**	6,584	4,357
Thereafter	**5,684**	4,619	3,341
	17,552	13,813	9,759

The following additional disclosures represent the net operating lease expense and net minimum future lease payments, after deducting amounts reimbursed, or to 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. For 2006, $895 million of the cost for the year has been capitalized.

Where BP is not the operator of a jointly controlled asset, operating lease costs and minimum future lease payments are excluded from the information given below.

			$ million
	2006	2005	2004
Minimum lease payments	**2,937**	1,841	1,840
Sub-lease rentals	**(131)**	(110)	(109)
	2,806	1,731	1,731
Innovene operations	—	(49)	(89)
Continuing operations	**2,806**	1,682	1,642

			$ million
Minimum future lease payments	**2006**	2005	2004
Payable within			
1 year	**2,732**	1,643	1,534
2 to 5 years	**7,290**	4,666	3,778
Thereafter	**5,221**	4,579	3,275
	15,243	10,888	8,587

The group has entered into operating leases on ships, plant and machinery, commercial vehicles, land and buildings, including service station sites and office accommodation. The ship leases represent approximately 36% (2005 52%) of the minimum future lease payments. The 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

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18 Operating leases *continued*

Principal details of the leases are:

Ships: the group has entered into a number of structured operating leases for vessels, but which generally have no renewal or extension options. In most cases rentals vary with interest rates, but the amounts of these 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.

Plant and machinery: this principally comprises leases for drilling rigs. Generally these leases have no renewal options. There are no financial restrictions placed upon the lessee by entering into these leases.

Commercial vehicles: primarily railcar leases. Generally these leases have no renewal options. There are no financial restrictions placed upon the lessee by entering into these leases.

Land and buildings: the majority of these leases have no renewal options. There are no financial restrictions placed upon the lessee by entering into these leases.

The minimum future lease payments including executory costs associated with the leases of $482 million (after deducting related rental income from operating sub-leases of $626 million) were as follows:

	$ million
	2006
2007	**3,355**
2008	**3,031**
2009	**2,403**
2010	**1,686**
2011	**1,191**
Thereafter	**5,742**
	17,408

19 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
	2006	2005	2004
Exploration and evaluation costs			
Exploration expenditure written off	**624**	305	274
Other exploration costs	**421**	379	363
Exploration expense for the year	**1,045**	684	637
Intangible assets	**4,110**	4,008	3,761
Net assets	**4,110**	4,008	3,761
Capital expenditure	**1,537**	950	754

Net cash used in operating activities	**421**	379	363
Net cash used in investing activities	**1,498**	950	754

20 Auditors remuneration

$ million

Fees Ernst & Young	**2006**	2005	2004
Fees payable to the company s auditors for the audit of the company s accounts[a]	**15**	19	13
Fees payable to the company s auditors and its associates for other services			
Audit of the company s subsidiaries pursuant to legislation	**31**	34	30
Other services pursuant to legislation	**15**	6	7
	61	59	50
Tax services	**1**	10	14
Services relating to corporate finance transactions	**2**	3	7
All other services	**9**	23	9
Audit fees in respect of the BP pension plans		1	1
	73	96	81
Innovene operations		(9)	(3)
Continuing operations	**73**	87	78

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 2006 include $5 million of additional fees for 2005 (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 and employee tax services.

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20 Auditors remuneration *continued*

The audit committee has established pre-approval policies and procedures for the engagement of Ernst & Young to render audit and certain assurance and tax services. The audit fees payable to Ernst & Young are reviewed by the audit committee in the context of other global companies for cost-effectiveness. Ernst & Young performed further assurance and tax services that were not prohibited by regulatory or other professional requirements and were pre-approved by the committee. Ernst & Young is engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit nature. Tax services were awarded either through a full competitive tender process or following an assessment of the expertise of Ernst & Young compared to that of other potential service providers. These services are for a fixed term.

Fees paid to major firms of accountants other than Ernst & Young for other services amounted to $52 million (2005 $151 million and 2004 $82 million).

21 Finance costs

$ million

	2006	2005	2004
Bank loans and overdrafts	**130**	44	34
Other loans	**1,020**	828	573
Finance leases	**46**	38	37
Interest payable	**1,196**	910	644
Capitalized at 5.25% (2005 4.25% and 2004 3%)[a]	**(478)**	(351)	(204)
Early redemption of borrowings and finance leases		57	
	718	616	440

a Tax relief on capitalized interest is $182 million (2005 $123 million and 2004 $73 million).

22 Other finance income and expense

$ million

	2006	2005	2004
Interest on pension and other post-retirement benefit plan liabilities	**1,940**	2,022	2,012
Expected return on pension and other post-retirement benefit plan assets	**(2,410)**	(2,138)	(1,983)
Interest net of expected return on plan assets	**(470)**	(116)	29
Unwinding of discount on provisions	**245**	201	196
Unwinding of discount on deferred consideration for acquisition of investment in TNK-BP	**23**	57	91
Change in discount rate for provisions[a]			41
	(202)	142	357
Innovene operations		3	(17)
Continuing operations	**(202)**	145	340

a Revaluation of environmental and litigation and other provisions at a different discount rate.

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23 Taxation

$ million

Tax on profit	2006	2005	2004
Current tax			
Charge for the year	**11,199**	10,511	7,217
Adjustment in respect of prior years	**442**	(977)	(308)
	11,641	9,534	6,909
Innovene operations	**159**	(910)	(48)
Continuing operations	**11,800**	8,624	6,861
Deferred tax			
Origination and reversal of temporary differences in the current year	**1,956**	164	138
Adjustment in respect of prior years	**(1,240)**	(450)	(74)
	716	(286)	64
Innovene operations	**—**	950	157
Continuing operations	**716**	664	221
Tax on profit from continuing operations	**12,516**	9,288	7,082
Tax on profit from continuing operations may be analysed as follows:			
Current tax charge			
UK	**2,657**	880	1,839
Overseas	**9,143**	7,744	5,022
	11,800	8,624	6,861
Deferred tax charge			
UK	**500**	(489)	(218)
Overseas	**216**	1,153	439
	716	664	221
Total			
UK	**3,157**	391	1,621
Overseas	**9,359**	8,897	5,461
	12,516	9,288	7,082

$ million

Tax included in statement of recognized income and expense	2006	2005	2004
Current tax			
Current year tax charge	**(51)**	45	23
	(51)	45	23
Deferred tax			
Origination and reversal of temporary differences in the current year	**985**	309	50
Adjustment in respect of prior years	—	(95)	—
	985	214	50
Tax included in statement of recognized income and expense	**934**	259	73
This comprises:			
Currency translation differences	**201**	(11)	208
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	**820**	356	(96)
Share-based payments	**(26)**	—	(39)
Net (gain) loss on revaluation of cash flow hedges	**47**	(63)	—
Unrealized (gain) loss on available-for-sale financial assets	**(108)**	72	—
Tax included in statement of recognized income and expense	**934**	259	73

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23 Taxation *continued*

Reconciliation of the effective tax rate

The following table provides a reconciliation of the UK statutory corporation tax rate to the effective tax rate of the group on profit before taxation from continuing operations.

			$ million
	2006	2005	2004
Profit before taxation from continuing operations	**35,142**	31,421	24,966
Tax on profit from continuing operations	**12,516**	9,288	7,082
Effective tax rate	**36%**	30%	28%

	% of profit before tax from continuing operations		
UK statutory corporation tax rate	30	30	30
Increase (decrease) resulting from			
UK supplementary and overseas taxes at higher rates	11	9	8
Tax reported in equity-accounted entities	(3)	(3)	(3)
Adjustments in respect of prior years	(2)	(3)	(1)
Restructuring benefits	—	(1)	(2)
Current year losses unrelieved (prior year losses utilized)	(1)	(3)	(3)
Other	1	1	(1)
Effective tax rate	36	30	28

Deferred tax

					$ million
	Income statement			Balance sheet	
	2006	2005	2004	**2006**	2005
Deferred tax liability					
Depreciation	**1,484**	(778)	492	**21,463**	18,529
Pension plan surplus	**173**	170	10	**1,733**	957
Other taxable temporary differences	**417**	887	(113)	**4,439**	3,864
	2,074	279	389	**27,635**	23,350
Deferred tax asset					
Petroleum revenue tax	**4**	121	77	**(457)**	(407)
Pension plan and other post-retirement benefit plan deficits	**71**	220	92	**(1,824)**	(1,822)
	(615)	(329)	106	**(2,960)**	(2,218)

Decommissioning, environmental and other provisions					
Derivative financial instruments	**(115)**	(629)		**(974)**	(807)
Tax credit and loss carry forward	**220**	(245)	6	**(662)**	(253)
Other deductible temporary differences	**(923)**	297	(606)	**(2,642)**	(1,585)
	(1,358)	(565)	(325)	**(9,519)**	(7,092)
Net deferred tax liability	**716**	(286)	64	**18,116**	16,258

			$ million
	2006	2005	2004
Analysis of movements during the year			
At 1 January	**16,258**	16,701	16,051
Adoption of IAS 32 and 39		(112)	
Restated	**16,258**	16,589	16,051
Exchange adjustments	**175**	(178)	358
Charge for the year on ordinary activities	**716**	(286)	64
Charge for the year in the statement of recognized income and expense	**985**	214	50
Other movements	**(18)**	(81)	178
At 31 December	**18,116**	16,258	16,701

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 UK statutory rate. 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 current high oil price environment continues to create conditions that encourage host governments to review their fiscal regimes.

In 2006 the UK supplementary charge was raised to 20% increasing the group's effective tax rate by 2%. The impact of the additional one-off deferred tax adjustment relating to this rate change ($460 million) was largely offset by utilization of relieving measures specifically provided in the legislation.

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 2006 has been to reduce the reported effective tax rate by around 3%. This effect is expected to continue for the foreseeable future assuming similar income levels from the entities.

Going forward, the effective tax rate is expected to be around 37%.

At 31 December 2006, 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.

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23 Taxation *continued*

At 31 December 2006, 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 $4.7 billion (2005 $5.1 billion and 2004 $7.7 billion) of carry-forward tax losses in the UK and Germany, which would be available to offset against future taxable income. These tax losses do not time expire. At the end of 2006, $216 million of deferred tax assets were recognized on these losses (2005 $176 million of assets and 2004 no tax assets were recognized). Tax assets are recognized only to the extent that it is considered more likely than not that suitable taxable income will arise. The group has not recognized any significant deferred tax assets in relation to carry forwards of losses in other taxing jurisdictions and this is not expected to have a material effect on the group's tax rate in future years.

At the end of 2006, the group had around $2.0 billion (2005 $1.5 billion) of unused tax credits in the UK and the US, in respect of which no deferred tax assets have been recognized. In 2006, $828 million of tax credits were utilized (2005 $774 million).

The major components of temporary differences in the current year are tax depreciation, US inventory holding gains (classified under other taxable temporary differences) and provisions.

24 Dividends

	pence per share			cents per share			$ million		
	2006	2005	2004	**2006**	2005	2004	**2006**	2005	2004
Dividends announced and paid									
Preference shares							**2**	2	2
Ordinary shares									
March	**5.288**	4.522	3.674	**9.375**	8.500	6.750	**1,922**	1,823	1,492
June	**5.251**	4.450	3.807	**9.375**	8.500	6.750	**1,893**	1,808	1,477
September	**5.324**	5.119	3.860	**9.825**	8.925	7.100	**1,943**	1,871	1,536
December	**5.241**	5.061	3.910	**9.825**	8.925	7.100	**1,926**	1,855	1,534
	21.104	19.152	15.251	**38.400**	34.850	27.700	**7,686**	7,359	6,041
Dividend announced per ordinary share, payable in March 2007	**5.258**	—	—	**10.325**	—	—	**1,999**	—	—

The group does not account for dividends until they have been paid. The accounts for the year ended 31 December 2006 do not reflect the dividend announced on 6 February 2007 and payable in March 2007; this will be treated as an appropriation of profit in the year ended 31 December 2007.

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25 Earnings per ordinary share

			cents per share
	2006	2005	2004
Basic earnings per share	**111.41**	104.25	78.24
Diluted earnings per share	**110.56**	103.05	76.87

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 profit attributable to ordinary shareholders is adjusted for the unwinding of the discount on the deferred consideration for the acquisition of our interest in TNK-BP. The weighted average number of shares outstanding during the year is adjusted for the number of shares to be issued for the deferred consideration for the acquisition of our interest in TNK-BP and the number of shares that would be issued on conversion of outstanding share options into ordinary shares using the treasury stock method.

			$ million
	2006	2005	2004
Profit from continuing operations attributable to BP shareholders	**22,340**	21,842	17,697
Less dividend requirements on preference shares	**2**	2	2
Profit from continuing operations attributable to BP ordinary shareholders	**22,338**	21,840	17,695
Profit (loss) from discontinued operations	**(25)**	184	(622)
	22,313	22,024	17,073
Unwinding of discount on deferred consideration for acquisition of investment in TNK-BP (net of tax)	**16**	40	64
Diluted profit for the year attributable to BP ordinary shareholders	**22,329**	22,064	17,137

			shares thousand
	2006	2005	2004
Basic weighted average number of ordinary shares	**20,027,527**	21,125,902	21,820,535
Potential dilutive effect of ordinary shares issuable under employee share schemes	**109,813**	87,743	56,985
Potential dilutive effect of ordinary shares issuable as consideration for BPs interest in the TNK-BP joint venture	**58,118**	197,802	415,016
	20,195,458	21,411,447	22,292,536

The number of ordinary shares outstanding at 31 December 2006, excluding treasury shares, was 19,510,496,490. Between the reporting date and the date of completion of these financial statements there has been a net decrease of 128,708,405 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 options was 111,029,592 at 31 December 2006. There has been a decrease of 25,627,050 in the number of potential ordinary shares between the reporting date and the completion of the financial statements.

Earnings (loss) per share for the discontinued operations is derived from the net profit (loss) attributable to ordinary shareholders from discontinued operations of $25 million loss (2005 $184 million profit and 2004 $622 million loss), divided by the weighted average number of ordinary shares for both basic and diluted amounts as shown above.

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26 Property, plant and equipment

$ m

	Land and land improvements	Buildings	Oil and gas properties	Plant, machinery and equipment	Fixtures, fittings and office equipment	Transport-ation	Oil depots, storage tanks and service stations	Total	Of w a u constru
Cost									
At 1 January 2006	**4,576**	**2,835**	**113,474**	**28,780**	**2,247**	**13,266**	**11,235**	**176,413**	**16,**
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**	**11,**
Transfers[a]	–	–	**(628)**	–	**(1)**	–	–	**(629)**	**(9,**
Reclassified as assets held for sale	**(15)**	**(1)**	–	**(842)**	–	**(1)**	**(47)**	**(906)**	
Deletions	**(455)**	**(325)**	**(5,628)**	**(486)**	**(219)**	**(1,314)**	**(1,412)**	**(9,839)**	**(**
At 31 December 2006	**4,442**	**3,129**	**118,554**	**30,642**	**3,006**	**12,000**	**11,211**	**182,984**	**17,**
Depreciation									
At 1 January 2006	**709**	**1,437**	**61,253**	**13,417**	**1,450**	**7,104**	**5,096**	**90,466**	
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)**	**(5,048)**	**(173)**	**(212)**	**(471)**	**(708)**	**(7,067)**	
At 31 December 2006	**675**	**1,470**	**61,250**	**14,628**	**1,762**	**6,946**	**5,254**	**91,985**	
Net book amount at 31 December 2006	**3,767**	**1,659**	**57,304**	**16,014**	**1,244**	**5,054**	**5,957**	**90,999**	**17,**
Cost									

At 1 January 2005	5,471	2,846	107,066	42,302	2,827	13,588	12,421	186,521	15
Exchange adjustments	(387)	(136)	(15)	(2,364)	(180)	(4)	(1,117)	(4,203)	
Acquisitions	19	3	—	—	1	—	—	23	
Additions	41	191	8,773	2,451	383	133	816	12,788	10
Transfers	—	—	325	—	—	—	—	325	(8
Deletions	(568)	(69)	(2,675)	(13,609)	(784)	(451)	(885)	(19,041)	(
At 31 December 2005	4,576	2,835	113,474	28,780	2,247	13,266	11,235	176,413	16
Depreciation									
At 1 January 2005	863	1,419	57,111	19,556	1,859	7,141	5,480	93,429	
Exchange adjustments	(17)	(60)	(7)	(916)	(67)	(76)	(496)	(1,639)	
Charge for the year	79	143	5,696	1,691	399	309	704	9,021	
Impairment losses	—	—	266	590	—	—	42	898	
Transfers	—	—	6	—	—	—	—	6	
Deletions	(216)	(65)	(1,819)	(7,504)	(741)	(270)	(634)	(11,249)	
At 31 December 2005	709	1,437	61,253	13,417	1,450	7,104	5,096	90,466	
Net book amount at 31 December 2005	3,867	1,398	52,221	15,363	797	6,162	6,139	85,947	16
Assets held under finance leases at net book amount included above									
At 31 December 2006	**5**	**18**	**42**	**341**	**1**	**9**	**29**	**445**	
At 31 December 2005	8	24	46	315	2	9	35	439	

Decommissioning asset at net book amount included above

	Cost	Depreciation	Net
At 31 December 2006	**6,391**	**2,558**	**3,833**
At 31 December 2005	5,398	2,342	3,056

a Includes $1,087 million transferred to equity-accounted investments.
b Includes $890 million transferred to equity-accounted investments.

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27 Goodwill

		$ million
	2006	2005
Cost		
At 1 January	**10,371**	11,182
Exchange adjustments	**524**	(488)
Acquisitions	**64**	86
Reclassified as assets held for sale	**(60)**	—
Deletions	**(119)**	(409)
At 31 December	**10,780**	10,371
Impairment losses		
At 1 January	—	325
Impairment in the year	—	59
Deletions	—	(384)
At 31 December	—	—
Net book amount at 31 December	**10,780**	10,371

28 Intangible assets

						$ million
			2006			2005
	Exploration expenditure	**Other intangibles**	**Total**	**Exploration expenditure**	Other intangibles	Total
Cost						
At 1 January	**4,661**	**1,740**	**6,401**	4,311	1,377	5,688
Exchange adjustments	**2**	**50**	**52**	(66)	(44)	(110)
Acquisitions	—	**187**	**187**	—	—	—
Additions	**1,537**	**378**	**1,915**	950	531	1,481
Transfers[a]	**(698)**	—	**(698)**	(325)	—	(325)
Deletions	**(912)**	**(227)**	**(1,139)**	(209)	(124)	(333)
At 31 December	**4,590**	**2,128**	**6,718**	4,661	1,740	6,401
Amortization						
At 1 January	**653**	**976**	**1,629**	550	933	1,483
Exchange adjustments	—	**20**	**20**	(8)	(32)	(40)
Charge for the year	**624**	**217**	**841**	305	161	466
Transfers	**(2)**	—	**(2)**	(6)	—	(6)
Impairment losses	**109**	—	**109**	—	—	—

Deletions	**(904)**	**(221)**	**(1,125)**	(188)	(86)	(274)
At 31 December	**480**	**992**	**1,472**	653	976	1,629
Net book amount at 31 December	**4,110**	**1,136**	**5,246**	4,008	764	4,772

a Included in transfers of exploration expenditure is $240 million transferred to equity-accounted investments.

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29 Investments in jointly controlled entities

The significant jointly controlled entities of the BP group at 31 December 2006 are shown in Note 50. 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

			2006			2005			2004
	TNK-BP	**Other**	**Total**	TNK-BP	Other	Total	TNK-BP	Other	Total
Sales and other operating revenues	**17,863**	**6,119**	**23,982**	15,122	4,255	19,377	7,839	2,225	10,064
Profit before interest and taxation	**4,616**	**1,218**	**5,834**	3,817	779	4,596	2,421	586	3,007
Finance costs and other finance expense	**192**	**169**	**361**	128	104	232	101	69	170
Profit before taxation	**4,424**	**1,049**	**5,473**	3,689	675	4,364	2,320	517	2,837
Taxation	**1,467**	**260**	**1,727**	976	220	1,196	675	314	989
Minority interest	**193**	**–**	**193**	104	–	104	43	–	43
Profit for the yeara	**2,764**	**789**	**3,553**	2,609	455	3,064	1,602	203	1,805
Innovene operations	**–**	**–**	**–**	–	19	19	–	13	13
Continuing operations	**2,764**	**789**	**3,553**	2,609	474	3,083	1,602	216	1,818
Non-current assets	**11,243**	**7,612**	**18,855**	11,564	6,310	17,874			
Current assets	**5,403**	**2,184**	**7,587**	4,278	1,682	5,960			
Total assets	**16,646**	**9,796**	**26,442**	15,842	7,992	23,834			
Current liabilities	**3,594**	**1,272**	**4,866**	3,617	914	4,531			
Non-current liabilities	**4,226**	**3,370**	**7,596**	3,553	2,550	6,103			
Total liabilities	**7,820**	**4,642**	**12,462**	7,170	3,464	10,634			
Minority interest	**473**	**–**	**473**	583	–	583			
	8,353	**5,154**	**13,507**	8,089	4,528	12,617			
Group investment in jointly controlled entities									
Group share of net assets (as above)b	**8,353**	**5,154**	**13,507**	8,089	4,528	12,617			
Loans made by group companies to jointly controlled entities	**–**	**1,567**	**1,567**	–	939	939			

8,353	**6,721**	**15,074**	8,089	5,467	13,556

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.

b Total includes BP's share of retained earnings of $2,752 million (2005 $2,242 million).

In 2004, BP agreed with the Alfa Group and Access-Renova (AAR), its partner in the TNK-BP joint venture, to incorporate AAR's 50% interest in Slavneft into TNK-BP in return for $1,418 million in cash (which was subsequently reduced by receipt of pre-acquisition dividends of $64 million to $1,354 million).

BP Solvay Polyethylene Europe became a subsidiary with effect from 2 November 2004. See Note 4 for further information. In 2005, it was sold as part of the Innovene operations.

During 2004, BP China and Sinopec announced the establishment of the BP-Sinopec (Zhejiang) Petroleum Co. Ltd, a retail joint venture between BP and Sinopec. Based on the existing service station network of Sinopec, the joint venture will build, operate and manage a network of 500 service stations in Hangzhou, Ningbo and Shaoxing. Also during 2004, BP China and PetroChina announced the establishment of BP-PetroChina Petroleum Company Ltd. Located in Guangdong, one of the most developed provinces in China, the joint venture will acquire, build, operate and manage 500 service stations in the province. The initial investment in both joint ventures amounted to $106 million.

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 2006.

Sales to jointly controlled entities

$ million

		2006		2005		2004	
	Product	**Sales**	**Amount receivable at 31 December**	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
Atlantic 4 Holdings	LNG	**227**	**35**	—	—	—	—
Atlantic LNG 2/3 Company of Trinidad and Tobago	LNG	**1,123**	**99**	1,157	—	532	—
BP Solvay Polyethylene Europe[a]	Chemicals feedstocks	—	—	—	—	230	—
Pan American Energy	Crude oil	**389**	—	75	2	118	4
Ruhr Oel	Employee services	**330**	**597**	169	527	192	780
TNK-BP	Employee services	**189**	**99**	125	14	49	—

a The 2004 sales to BP Solvay Polyethylene Europe shown above relate to the period to 2 November 2004.

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29 Investments in jointly controlled entities *continued*

Purchases from jointly controlled entities

$ million

		2006		2005		2004	
	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	**254**		190		120	
Pan American Energy	Crude oil	**4**	**2**	661	81	481	43
Ruhr Oel	Refinery operating costs	**758**	**32**	384	134	477	249
TNK-BP	Crude oil and oil products	**2,662**	**85**	908	17	1,809	80

30 Investments in associates

The significant associates of the group are shown in Note 50. Summarized financial information for the groups share of associates is set out below.

$ million

	2006	2005	2004
Sales and other operating revenues	**8,792**	6,879	5,509
Profit before interest and taxation	**669**	665	632
Finance costs and other finance expense	**63**	57	48
Profit before taxation	**606**	608	584
Taxation	**164**	143	121
Profit for the year	**442**	465	463
Innovene operations		(5)	(1)
Continuing operations	**442**	460	462
Non-current assets	**6,573**	5,514	
Current assets	**2,294**	2,248	
Total assets	**8,867**	7,762	
Current liabilities	**2,029**	1,755	
Non-current liabilities	**2,600**	2,037	

Total liabilities	**4,629**	3,792
Net assets	**4,238**	3,970
Group investment in associates		
Group share of net assets (as above)[a]	**4,238**	3,970
Loans made by group companies to associates	**1,737**	2,247
	5,975	6,217

a Includes BP's share of retained earnings of $480 million (2005 $696 million).

BP Solvay Polyethylene North America became a subsidiary with effect from 2 November 2004. See Note 4 for further information. In 2005, it was sold as part of the Innovene operations.

Transactions between the significant associates and the group are summarized below.

Sales to associates $ million

		2006		2005		2004	
	Product	**Sales**	**Amount receivable at 31 December**	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
Atlantic LNG Company of Trinidad and Tobago	LNG	**635**	**62**	579	—	414	—
The Baku-Tbilisi-Ceyhan Pipeline Co	Crude oil/employee services	**112**	**4**	99	3	46	3
BP Solvay Polyethylene North America[a]	Chemicals feedstocks	—	—	—	—	217	—

Purchases from associates $ million

		2006		2005		2004	
	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	**866**	**91**	1,355	164	866	91
Abu Dhabi Petroleum Co.	Crude oil	**1,547**	**145**	2,260	214	1,547	145
The Baku-Tbilisi-Ceyhan Pipeline Co	Crude oil	**155**	—	—	—	—	—
BP Solvay Polyethylene North America[a]	Chemicals feedstocks	—	—	—	—	9	—

a The 2004 BP Solvay Polyethylene North America sales and purchases shown above relate to the period to 2 November 2004.

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31 Other investments

		$ million
	2006	2005
Listed	**1,516**	830
Unlisted	**181**	137
	1,697	967

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 table below shows other investments stated at cost.

		$ million
	2006	2005
At cost		
Listed	**1,056**	250
Unlisted	**219**	173
	1,275	423

During 2006, the group sold its interests in Zhenhai Refining and Chemicals Company, Eiffage, the French-based construction company, and Enagas, the Spanish gas transport grid operator, for aggregate proceeds of $0.8 billion, recognizing gains of $0.5 billion. Also in 2006, the group acquired a stake in Rosneft for $1 billion. In 2004, the group disposed of its interests in PetroChina and Sinopec for aggregate proceeds of $2.4 billion and recognized gains of $1.3 billion.

32 Inventories

		$ million
	2006	2005
Crude oil	**5,357**	5,457
Natural gas	**127**	164
Refined petroleum and petrochemical products	**10,817**	10,700
	16,301	16,321
Supplies	**1,222**	919
	17,523	17,240
Trading inventories	**1,392**	2,520
	18,915	19,760

Cost of inventories expensed in the income statement	**187,183**	163,026

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33 Trade and other receivables

$ million

	2006		2005	
	Current	**Non-current**	Current	Non-current
Trade	**32,656**		33,565	
Jointly controlled entities	**635**		1,345	
Associates	**267**		186	
Other	**5,134**	**862**	5,806	770
	38,692	**862**	40,902	770

$ million

	2006					2005				
	Currency of denomination					Currency of denomination				
	US dollar	**Sterling**	**Euro**	**Other currencies**	**Total**	US dollar	Sterling	Euro	Other currencies	Total
Functional currency										
US dollar		**1,217**	**123**	**5,286**	**6,626**		1,111	354	6,045	7,510
Sterling	**376**		**1,652**	**39**	**2,067**	404		453	15	872
Euro	**692**	**7**		**1**	**700**	1,496	1		948	2,445
Other currencies	**248**	**1**	**1**		**250**	458	1	1		460
	1,316	**1,225**	**1,776**	**5,326**	**9,643**	2,358	1,113	808	7,008	11,287

Trade and other receivables of the group at 31 December have the maturities shown below.

$ million

	2006	2005
Within one year	**38,692**	40,902
1 to 2 years	**187**	129
2 to 3 years	**86**	82
3 to 4 years	**82**	56
4 to 5 years	**76**	51
Over 5 years	**431**	452
	39,554	41,672

The movement in the valuation allowance for trade receivables is set out below.

	$ million	
	2006	2005
At 1 January	**374**	526
Exchange adjustments	**32**	(30)
Charge for the year	**158**	67
Utilization	**(143)**	(189)
At 31 December	**421**	374

The carrying amounts of Trade and other receivables approximate their fair value. Trade and other receivables are predominantly non-interest bearing.

34 Cash and cash equivalents

	$ million	
	2006	2005
Cash at bank and in hand	**2,052**	1,594
Cash equivalents		
Listed	**29**	73
Unlisted	**509**	1,293
Carrying amount at 31 December	**2,590**	2,960

Cash equivalents are classified as available-for-sale financial assets and as such are recorded at fair value. Cash and cash equivalents at 31 December 2006 includes $773 million which is restricted. This relates principally to amounts on deposit to cover trading positions on trading exchanges.

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35 Trade and other payables

	2006		2005	
	Current	**Non-current**	Current	Non-current
Trade	**28,319**	**—**	28,614	—
Jointly controlled entities	**87**	**—**	251	—
Associates	**305**	**—**	627	—
Production and similar taxes	**852**	**899**	763	1,281
Social security	**59**	**—**	78	—
Other	**12,614**	**531**	11,803	654
	42,236	**1,430**	42,136	1,935

$ million

	2006					2005				
	Currency of denomination					Currency of denomination				
	US dollar	**Sterling**	**Euro**	**Other currencies**	**Total**	US dollar	Sterling	Euro	Other currencies	Total
Functional currency										
US dollar	**—**	**1,476**	**165**	**5,818**	**7,459**	—	1,802	157	6,640	8,599
Sterling	**396**	**—**	**507**	**—**	**903**	133	—	306	—	439
Euro	**185**	**2**	**—**	**1**	**188**	611	4	—	17	632
Other currencies	**322**	**4**	**8**	**—**	**334**	339	12	38	—	389
	903	**1,482**	**680**	**5,819**	**8,884**	1,083	1,818	501	6,657	10,059

$ million

Trade and other payables of the group at 31 December 2006 have the maturities shown below.

	2006	2005
Within one year	**42,236**	42,136
1 to 2 years	**269**	276
2 to 3 years	**215**	211
3 to 4 years	**153**	182
4 to 5 years	**184**	179
Over 5 years	**609**	1,087
	43,666	44,071

$ million

The carrying amounts of Trade and other payables approximate their fair value. Included within Other payables for 2005 was the deferred consideration for the acquisition of our interest in TNK-BP, which was discounted on initial recognition. The remaining Trade and other payables are predominantly interest free.

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36 Derivative financial instruments

An outline of the group’s financial risks and the policies and objectives pursued in relation to those risks is set out in the quantitative and qualitative disclosures about market risk section on pages 54-57.

This note contains the disclosures required by IAS 32 for derivative financial instruments. IAS 39 prescribes strict criteria for hedge accounting, whether as a cash flow or fair value hedge, and requires that any derivative that does not meet these criteria should be classified as held for trading and fair valued. BP adopted IAS 32 and IAS 39 with effect from 1 January 2005 without restating prior periods’ financial information. Consequently, the group’s accounting policy under UK GAAP has been used for 2004. The policy under UK GAAP and the disclosures required by UK GAAP for derivative financial instruments are shown in Note 37.

In the normal course of business the group is a party to 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 trading activity that is undertaken in conjunction with each of these activities using a similar range of contracts.

The fair value of derivative financial instruments at 31 December are set out below.

$ million

				2006				2005
	Fair value asset	**Contractual or notional amounts**	**Fair value or liability**	**Contractual notional amounts**	Fair value asset	Contractual or notional amounts	Fair value liability	Contractual or notional amounts
Derivatives held for trading								
Currency derivatives	**137**	**6,820**	**(32)**	**3,923**	41	634	(18)	1,687
Oil derivatives	**2,664**	**57,600**	**(2,368)**	**59,524**	2,765	56,394	(2,826)	52,524
Natural gas derivatives	**6,558**	**139,961**	**(5,703)**	**107,145**	6,836	148,794	(6,307)	128,330
Power derivatives	**3,232**	**22,250**	**(3,190)**	**25,859**	3,341	25,793	(3,158)	26,618
Other derivatives	**113**	**499**	–	–	–	–	–	–
	12,704	**227,130**	**(11,293)**	**196,451**	12,983	231,615	(12,309)	209,159
Embedded derivatives								
Natural gas and LNG contracts	**107**	**219**	**(2,171)**	**11,810**	587	4,620	(3,098)	8,563
Interest rate contracts	–	–	**(26)**	**150**	–	–	(30)	150
	107	**219**	**(2,197)**	**11,960**	587	4,620	(3,128)	8,713
Cash flow hedges								
Currency forwards, futures and swaps	**205**	**2,223**	**(33)**	**1,274**	34	666	(94)	3,100
Currency options	**14**	**2,677**	–	–	–	693	(35)	1,470
Commodity futures	–	–	–	–	57	274	–	–
	219	**4,900**	**(33)**	**1,274**	91	1,633	(129)	4,570
Fair value hedges								
Currency forwards, futures and swaps	**228**	**3,865**	**(13)**	**598**	222	2,566	(124)	1,967

Interest rate swaps	**33**	**1,688**	**(91)**	**4,397**	19	324	(217)	7,521
	261	**5,553**	**(104)**	**4,995**	241	2,890	(341)	9,488
Hedges of net investments in foreign entities	**107**	**394**	—	—	63	346	—	—
	13,398	**238,196**	**(13,627)**	**214,680**	13,965	241,104	(15,907)	231,930
Of which — current	**10,373**		**(9,424)**		10,056		(10,036)	
— non-current	**3,025**		**(4,203)**		3,909		(5,871)	

The fair values of embedded derivatives are included within non-current and current derivative financial instruments on the group balance sheet as this is believed to be the most appropriate presentation. Previously, these balances were reported within non-current and current prepayments and accrued income and accruals and deferred income. The comparative figures have been restated to conform with the 2006 presentation.

Derivatives held for trading

The group maintains active trading positions in a variety of derivatives. This activity is undertaken in conjunction with risk management activities. Derivatives held for trading purposes are recognized at fair value and 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 described in the section on market risk exposure.

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36 Derivative financial instruments *continued*

The following tables show 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 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**	–	–	–
Other 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**

$ million

	Currency	Oil price	Natural gas price	Power price	Other
Fair value of contracts at 1 January 2005	(54)	(171)	558	177	–
Contracts realized or settled in the year	23	175	(735)	76	–
Fair value of options at inception	–	(73)	(65)	(9)	–
Fair value of other new contracts entered into during the year	–	–	24	10	–
Other changes in fair values relating to price	54	8	747	(71)	–
Fair value of contracts at 31 December 2005	23	(61)	529	183	–

If at inception of a contract the valuation cannot be supported by observable market data, any gain or loss determined by the valuation methodology is not recognized in the income statement but is deferred on the balance sheet and commonly known as ‘day one profit’. When all of the remaining contracts can be valued using observable market data this gain or loss is recognized in income. Changes in valuation from this initial valuation are recognized immediately through income.

The following table shows the change in the associated fair value of assets and liabilities.

$ million

	2006		2005	
	Natural gas price	**Power price**	Natural gas price	Power price

Fair value of contracts not recognized through the income statement at 1 January	**(39)**	**(10)**	(15)	—
Fair value of new contracts at inception not recognized in the income statement	**(2)**	**(1)**	(24)	(10)
Fair value recycled into the income statement	**5**	**11**	—	—
Fair value of contracts not recognized through profit at 31 December	**(36)**	—	(39)	(10)

Derivative assets held for trading have the following fair values, contractual or notional values and maturities.

							$ million
							2006
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives							
Fair value	**117**	—	**12**	**3**	**2**	**3**	**137**
Notional value	**6,338**	**75**	**241**	**89**	**54**	**23**	**6,820**
Oil price derivatives							
Fair value	**2,520**	**116**	**20**	**7**	**1**	—	**2,664**
Notional value	**52,591**	**4,736**	**210**	**62**	**1**	—	**57,600**
Natural gas price derivatives							
Fair value	**4,532**	**919**	**374**	**166**	**114**	**453**	**6,558**
Notional value	**81,102**	**33,499**	**9,837**	**5,186**	**3,396**	**6,941**	**139,961**
Power price derivatives							
Fair value	**2,845**	**274**	**86**	**27**	—	—	**3,232**
Notional value	**16,063**	**4,999**	**1,171**	**17**	—	—	**22,250**
Other derivatives							
Fair value	**64**	**26**	**23**	—	—	—	**113**
Notional value	**213**	**149**	**137**	—	—	—	**499**
Total derivative assets held for trading							
Fair value	**10,078**	**1,335**	**515**	**203**	**117**	**456**	**12,704**
Notional value	**156,307**	**43,458**	**11,596**	**5,354**	**3,451**	**6,964**	**227,130**

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36 Derivative financial instruments *continued*

$ million

	2005						
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives							
Fair value	28	6	1	1	1	4	41
Notional value	358	73	51	28	32	92	634
Oil price derivatives							
Fair value	2,476	225	37	19	8	—	2,765
Notional value	52,260	3,378	676	45	35	—	56,394
Natural gas price derivatives							
Fair value	4,509	1,194	528	292	125	188	6,836
Notional value	113,897	17,562	8,560	4,021	2,068	2,686	148,794
Power price derivatives							
Fair value	2,474	594	119	143	11	—	3,341
Notional value	19,156	5,049	857	535	196	—	25,793
Total derivative assets held for trading							
Fair value	9,487	2,019	685	455	145	192	12,983
Notional value	185,671	26,062	10,144	4,629	2,331	2,778	231,615

Derivative liabilities held for trading have the following fair values, contractual or notional values and maturities.

$ million

	2006						
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives							
Fair value	**(8)**	**(7)**	**(12)**	**(2)**	**(2)**	**(1)**	**(32)**
Notional value	**3,183**	**204**	**214**	**92**	**56**	**174**	**3,923**
Oil price derivatives							
Fair value	**(2,230)**	**(89)**	**(29)**	**(19)**	**(1)**	**—**	**(2,368)**
Notional value	**55,488**	**3,541**	**363**	**111**	**21**	**—**	**59,524**
Natural gas price derivatives							
Fair value	**(3,931)**	**(875)**	**(273)**	**(109)**	**(86)**	**(429)**	**(5,703)**
Notional value	**63,593**	**25,962**	**7,710**	**3,059**	**1,591**	**5,230**	**107,145**
Power price derivatives							
Fair value	**(2,777)**	**(289)**	**(98)**	**(26)**	**—**	**—**	**(3,190)**
Notional value	**20,086**	**4,457**	**1,299**	**17**	**—**	**—**	**25,859**
Total derivative liabilities held for trading							
Fair value	**(8,946)**	**(1,260)**	**(412)**	**(156)**	**(89)**	**(430)**	**(11,293)**
Notional value	**142,350**	**34,164**	**9,586**	**3,279**	**1,668**	**5,404**	**196,451**

							$ million
							2005
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives							
Fair value	(12)	(4)	(1)	(1)	—	—	(18)
Notional value	1,013	177	119	170	67	141	1,687
Oil price derivatives							
Fair value	(2,486)	(275)	(26)	(20)	(19)	—	(2,826)
Notional value	49,732	2,276	446	35	35	—	52,524
Natural gas price derivatives							
Fair value	(3,967)	(1,319)	(591)	(187)	(89)	(154)	(6,307)
Notional value	90,916	25,269	6,457	2,903	1,577	1,208	128,330
Power price derivatives							
Fair value	(2,459)	(557)	(59)	(70)	(13)	—	(3,158)
Notional value	20,030	4,990	778	625	195	—	26,618
Total derivative liabilities held for trading							
Fair value	(8,924)	(2,155)	(677)	(278)	(121)	(154)	(12,309)
Notional value	161,691	32,712	7,800	3,733	1,874	1,349	209,159

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36 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
							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**

							$ million
							2005
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Prices actively quoted	(100	(86)	46	42	33	(8)	(73)
Prices sourced from observable data or market corroboration	660	(48)	(41)	60	(11)	–	620
Prices based on models and other valuation methods	3	(2)	3	75	2	46	127
	563	(136)	8	177	24	38	674

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 $117 million (2005 $130 million gain).

Credit risk

Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due. The primary activities of the group are oil and natural gas exploration and production, gas and power marketing and trading, oil refining and marketing and the manufacture and marketing of petrochemicals. The group's principal customers, suppliers and financial institutions with which it conducts business are located throughout the world.

The group has a credit policy that governs the management of credit risk, including the establishment of counterparty credit limits and specific transaction approvals. The group limits credit risk by assessing creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness after transactions have been initiated. Creditworthiness is assessed using Moody's Investors

Service, Standard & Poors and qualitative and quantitative data. The group attempts to mitigate credit risk by entering into contracts that permit netting and allow for termination of the contract upon the occurrence of certain events of default. Depending upon the creditworthiness of the counterparty, the group may require collateral in the form of cash deposits or letters of credit and parent company guarantees.

The maximum exposure of the group to credit risk is represented by the balance sheet carrying amount for all financial instruments within the scope of IAS 32, principally derivative financial instruments, trade and other receivables and financial guarantees. Financial guarantees in respect of equity-accounted entities were $1,123 million and financial guarantees in respect of third parties were $789 million at 31 December 2006. The maximum exposure to credit risk does not take account of collateral of $689 million.

Trade and other derivative assets and liabilities are presented on a net basis where netting arrangements are in place with counterparties are unconditional and where there is an intent to settle amounts due on a net basis.

Market risk

The group measures its market risk exposure, i.e. potential gain or loss in fair values, on its held-for-trading activity 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 values 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 group calculates value at risk for the bulk of instruments and exposures in the held-for-trading category, other than the UK North Sea natural gas embedded derivatives, for which a sensitivity analysis is calculated.

The potential movement in fair values is expressed to 1.65 standard deviations which is equivalent to a 95% confidence level. This means that, in broad terms, one would expect to see an increase or a decrease in fair values greater than the value at risk on one occasion per month if the portfolio were left unchanged.

The 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 futures, swap agreements and options. Additionally, where physical commodities 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.

The following table shows values at risk for the held-for-trading activities described above.

Value at risk on 1.65 standard deviations — $ million

	2006				2005			
	High	**Low**	**Average**	**Year end**	High	Low	Average	Year end
Interest rate trading	**1**		**1**		1			
Currency trading	**5**		**2**		5	1	2	1
Oil price trading	**56**	**16**	**29**	**22**	80	17	33	31
Natural gas price trading	**29**	**10**	**19**	**15**	39	6	15	17
Power price trading	**11**	**2**	**6**	**3**	16	2	7	9

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36 Derivative financial instruments *continued*

Gains and losses relating to derivative contracts are included within sales and other operating revenues in the income statement. The contract types treated in this way include futures, options, swaps and certain forward sales and purchase contracts where delivery is routinely obviated by the purchase or sale of offsetting contracts. Also included within sales and other operating revenues are gains and losses on inventory held for trading purposes and the change in fair value of derivative contracts which have been determined to be not for trading purposes but are required to be fair valued. The total amount relating to these items was a gain of $2,842 million (2005 $838 million gain and 2004 $1,216 million gain).

Derivative assets held for trading denominated in currencies other than the functional currency of individual operating units are summarized below.

$ million

					2006					2005
					Currency of denomination					Currency of denomination
	US dollar	**Sterling**	**Euro**	**Other currencies**	**Total**	US dollar	Sterling	Euro	Other currencies	Total
Functional currency										
US dollar	—	**55**	—	**244**	**299**	—	137	—	4	141
Sterling	**198**	—	**2,227**	**1**	**2,426**	—	—	1,504	—	1,504
	198	**55**	**2,227**	**245**	**2,725**	—	137	1,504	4	1,645

Derivative liabilities held for trading denominated in currencies other than the functional currency of individual operating units are summarized below.

$ million

					2006					2005
					Currency of denomination					Currency of denomination
	US dollar	**Sterling**	**Euro**	**Other currencies**	**Total**	US dollar	Sterling	Euro	Other currencies	Total
Functional currency										
US dollar	—	**(59)**	—	**(276)**	**(335)**	—	(110)	—	—	(110)
Sterling	**(18)**	—	**(2,383)**	—	**(2,401)**	—	—	(1,523)	—	(1,523)
	(18)	**(59)**	**(2,383)**	**(276)**	**(2,736)**	—	(110)	(1,523)	—	(1,633)

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 price curves for each of the different products that are built up from active market pricing data and extrapolated to 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.

The following table shows the changes during the year in the net fair value of embedded derivatives.

				$ million
		2006		2005
	Natural gas and LNG price	**Interest rate**	Natural gas and LNG price	Interest rate
Fair value of contracts at 1 January	**(2,511)**	**(30)**	(659)	(17)
Contracts realized or settled in the year	**762**	**—**	138	—
Other changes in fair values relating to price	**21**	**4**	(2,287)	(13)
Exchange adjustments	**(336)**	**—**	297	—
Fair value of contracts at 31 December	**(2,064)**	**(26)**	(2,511)	(30)

Embedded derivative assets have the following fair values, contractual or notional values and maturities.

							$ 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							
Fair value	**49**	**58**	**—**	**—**	**—**	**—**	**107**
Notional value	**119**	**100**	**—**	**—**	**—**	**—**	**219**

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36 Derivative financial instruments *continued*

							$ million
							2005
	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							
Fair value	330	176	76	5	—	—	587
Notional value	425	484	465	450	429	2,367	4,620

Embedded derivative liabilities have the following fair values, contractual or notional values and maturities.

							$ 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							
Fair value	**(444)**	**(433)**	**(320)**	**(218)**	**(186)**	**(570)**	**(2,171)**
Notional value	**1,352**	**1,229**	**1,279**	**1,278**	**1,249**	**5,423**	**11,810**
Interest rate embedded derivatives							
Fair value	—	**(26)**	—	—	—	—	**(26)**
Notional value	—	**150**	—	—	—	—	**150**

							$ million
							2005
	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							
Fair value	(953)	(703)	(472)	(237)	(180)	(553)	(3,098)
Notional value	740	870	1,097	832	767	4,257	8,563
Interest rate embedded derivatives							
Fair value	—	—	(30)	—	—	—	(30)
Notional value	—	—	150	—	—	—	150

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

							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)**

$ million

							2005
	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	51	28	—	—	—	—	79
Prices based on models and other valuation methods	(674)	(542)	(426)	(231)	(182)	(565)	(2,620)
	(623)	(514)	(426)	(231)	(182)	(565)	(2,541)

The net change in fair value of contracts based on models and other valuation methods during the year is a gain of $423 million (2005 loss of $1,773 million).

Sensitivity analysis

Detailed below for the natural gas embedded derivatives is a sensitivity of the fair value to immediate 10% favourable and adverse changes in the key assumptions.

	At 31 December 2006	At 31 December 2005
Remaining contract terms	**2 to 12 years**	3 to 13 years
Contractual / notional amount	**4,968 million therms**	8,220 million therms
Discount rate — nominal risk free	**4.5%**	4.5%
Fair value asset (liability)	**$(2,171) million**	$(2,590) million

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36 Derivative financial instruments *continued*

The reduction in notional contract gas volumes compared to 2005 was in part due to deliveries during the year but additionally due to the termination of a contract to supply 1,822 million therms from 2008-2018.

$ million

	2006				2005			
	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	**332**	**7**	**45**	**31**	408	30	(63)	34
Unfavourable 10% change	**(341)**	**(7)**	**(41)**	**(32)**	(427)	(45)	58	(34)

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. Also, 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.

The fair value gain (loss) on embedded derivatives is shown below.

$ million

	2006	2005
Natural gas and LNG embedded derivatives	**604**	(2,034)
Interest rate embedded derivatives	**4**	(13)
Fair value gain (loss)	**608**	(2,047)

The fair value gain (loss) in the above table includes $179 million of exchange losses (2005 $115 million of exchange gains) arising on transactions which are denominated in a currency other than the functional currency of an individual operating unit.

Embedded derivative liabilities denominated in currencies other than the functional currency of individual operating units are summarized below.

$ million

	2006					2005				
	Currency of denomination					Currency of denomination				
	US dollar	**Sterling**	**Euro**	**Other currencies**	**Total**	US dollar	Sterling	Euro	Other currencies	Total
Functional currency										
US dollar		**(1,003)**			**(1,003)**					

Cash flow hedges

At 31 December, the group held forward currency contracts, cylinders and options which were being used to hedge the foreign currency risk of highly probable transactions. The effective portion of the change in fair value of the hedging instrument is recognized directly in equity, whilst the ineffective portion is recognized in profit or loss. 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 previously recognized in equity is transferred to profit or loss. The hedges were assessed to be highly effective.

An analysis of the changes in net fair value is shown below.

		$ million
	2006	2005
Fair value of cash flow hedges at 1 January	**(38)**	198
Change in fair value during the year	**398**	(191)
Fair value recognized in income statement during the year	**(168)**	(8)
Fair value on capital expenditure hedging recycled into carrying value of assets during the year	**(6)**	(37)
Fair value of cash flow hedges at 31 December	**186**	(38)

The forward currency contracts and cylinders primarily cover the purchase of sterling and euros for US dollars, with 85% of such contracts due to mature within the next year.

Fair value hedges

At 31 December, 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. These hedges were assessed to be highly effective.

The interest rate and currency swaps have an average maturity of 2 to 3 years, and are used to convert sterling, euro, Swiss franc and Australian dollar denominated borrowings into US dollar floating rate debt.

Hedges of net investments in foreign entities

At 31 December, the group held currency swap contracts as a hedge of a long-term investment in a UK subsidiary. The hedge was assessed to be highly effective. At 31 December 2006, the hedge had a fair value of $107 million (2005 $63 million) and the gain on the hedge recognized in equity was $105 million (2005 $58 million). US dollars have been sold forward for sterling purchased, with a maturity of 2 to 3 years.

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37 Derivative financial instruments (UK GAAP)

The following information for 2004 shows certain disclosures required by UK GAAP (FRS 13 Derivatives and other Financial Instruments: Disclosures).

The group uses derivative financial instruments (derivatives) to manage certain exposures to fluctuations in foreign currency exchange rates and interest rates and to manage some of its margin exposure from changes in oil, natural gas and power prices. Derivatives are also traded in conjunction with these risk management activities.

The purpose for which a derivative contract is used is identified at inception. To qualify as a derivative for risk management, the contract must be in accordance with established guidelines that ensure it is effective in achieving its objective. All contracts not identified at inception as being for the purpose of risk management are designated as being held for trading purposes and accounted for using the fair value method, as are all oil price derivatives.

The group accounts for derivatives using the following methods:

Fair value method

Derivatives are carried on the balance sheet at fair value (marked-to-market), with changes in that value recognized in earnings of the period. This method is used for all derivatives that are held for trading purposes. Interest rate contracts traded by the group include futures, swaps, options and swaptions. Foreign exchange contracts traded include forwards and options. Oil, natural gas and power price contracts traded include swaps, options and futures.

Accrual method

Amounts payable or receivable in respect of derivatives are recognized ratably in earnings over the period of the contracts. This method is used for derivatives held to manage interest rate risk. These are principally swap agreements used to manage the balance between fixed and floating interest rates on long-term finance debt. Other derivatives held for this purpose may include swaptions and futures contracts. Amounts payable or receivable in respect of these derivatives are recognized as adjustments to interest expense over the period of the contracts. Changes in the derivative's fair value are not recognized.

Deferral method

Gains and losses from derivatives are deferred and recognized in earnings or as adjustments to carrying amounts, as appropriate, when the underlying debt matures or the hedged transaction occurs. This method is used for derivatives used to convert non-US dollar borrowings into US dollars, to hedge significant non-US dollar firm commitments or anticipated transactions, and to manage some of the group's exposure to natural gas and power price fluctuations. Derivatives used to convert non-US dollar borrowings into US dollars include foreign currency swap agreements and forward contracts. Gains and losses on these derivatives are deferred and recognized on maturity of the underlying debt, together with the matching loss or gain on the debt. Derivatives used to hedge significant non-US dollar transactions include foreign currency forward contracts and options and to hedge natural gas and power price exposures include swaps, futures and options. Gains and losses on these contracts and option premiums paid are also deferred and recognized in the income statement or as adjustments to carrying amounts, as appropriate, when the hedged transaction occurs.

Where derivatives used to manage interest rate risk or to convert non-US dollar debt or to hedge other anticipated cash flows are terminated before the underlying debt matures or the hedged transaction occurs, the resulting gain or loss is recognized on a basis that matches the timing and accounting treatment of the underlying debt or hedged transaction. When an anticipated transaction is no longer likely to occur or finance debt is terminated before maturity, any deferred gain or loss that has arisen on the related derivative is recognized in the income statement, together with any gain or loss on the terminated item.

Risk management

Gains and losses on derivatives used for risk management purposes are deferred and recognized in earnings or as adjustments to carrying amounts, as appropriate, when the underlying debt matures or the hedged transaction occurs. When an anticipated transaction is no longer likely to occur or finance debt is terminated before maturity, any deferred gain or loss that has arisen on the related derivative is recognized in the income statement, together with any gain or loss on the terminated item. Where such derivatives used for hedging purposes are terminated before the underlying debt matures or the hedged transaction occurs, the resulting gain or loss is recognized on a basis that matches the timing and accounting treatment of the underlying hedged item. The unrecognized and carried-forward gains and losses on derivatives used for hedging, and the movements therein, are shown in the following table.

$ million

	Unrecognized			Carried forward in the balance sheet		
	Gains	Losses	Total	Gains	Losses	Total
Gains and losses at 1 January 2004	331	(130)	201	1,003	(425)	578
of which accounted for in income in 2004	98	(28)	70	438	(75)	363
Gains and losses at 31 December 2004	487	(408)	79	1,063	(364)	699
of which expected to be recognized in income in 2005	259	(267)	(8)	265	(77)	188

Trading activities

The group maintains active trading positions in a variety of derivatives. This activity is undertaken in conjunction with risk management activities. Derivatives held for trading purposes are marked-to-market and any gain or loss recognized in the income statement. For traded derivatives, many positions have been neutralized, with trading initiatives being concluded by taking opposite positions to fix a gain or loss, thereby achieving a zero net market risk.

The group measures its market risk exposure, i.e. potential gain or loss in fair values, on its trading activity 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 values 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 over the previous 12 months, together with the correlation of these price movements. The potential movement in fair values is expressed to three standard deviations, which is equivalent to a 99.7% confidence level. This means that, in broad terms, one would expect to see an increase or a decrease in fair values greater than the value at risk on only one occasion per year if the portfolio were left unchanged.

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37 Derivative financial instruments (UK GAAP) *continued*

The group calculates value at risk on all instruments that are held for trading purposes and that therefore give an exposure to market risk. The value-at-risk model takes account of derivative financial instruments 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 futures, swap agreements and options. Financial assets and liabilities and physical crude oil and refined products that are treated as trading positions are also included in these calculations. The value-at-risk calculation for oil, natural gas and power price exposure also includes cash-settled commodity contracts such as forward contracts.

The following table shows values at risk for trading activities.

				$ million
				2004
	High	Low	Average	Year end
Interest rate trading	1			
Foreign exchange trading	4	1	1	1
Oil price trading	55	18	29	45
Natural gas price trading	42	11	23	18
Power price trading	18	2	8	7

The presentation of trading results shown in the table below includes certain activities of BPs trading units that involve the use of derivative financial instruments in conjunction with physical and paper trading of oil, natural gas and power. It is considered that a more comprehensive representation of the groups oil, natural gas and power price trading activities is given by aggregating the gain or loss on such derivatives together with the gain or loss arising from the physical and paper trades to which they relate, representing the net result of the trading portfolio.

	$ million
	2004
	Net gain (loss)
Interest rate trading	4
Foreign exchange trading	136
Oil price trading	1,371
Natural gas price trading	461
Power price trading	160
	2,132

38 Finance debt

						$ million
			2006			2005
	Within 1 yeara	**After 1 year**	**Total**	Within 1 yeara	After 1 year	Total

Bank loans	**543**	**806**	**1,349**	155	547	702
Other loans	**12,321**	**9,525**	**21,846**	8,717	8,962	17,679
Total borrowings	**12,864**	**10,331**	**23,195**	8,872	9,509	18,381
Net obligations under finance leases	**60**	**755**	**815**	60	721	781
	12,924	**11,086**	**24,010**	8,932	10,230	19,162

a Amounts due within one year include current maturities of long-term debt.

Included within Other loans repayable within one year above are US Industrial Revenue/Municipal Bonds of $2,744 million (2005 $2,462 million) with maturity periods ranging from 1 to 34 years. They are classified as repayable within one year as the bondholders typically have the option to tender these bonds for repayment on interest reset dates. 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 assessing the maturity profile of its finance debt and they are reflected as such in the borrowings repayment schedule below. Similar treatment is applied for loans associated with long-term gas supply contracts totalling $1,976 million (2005 $992 million) that mature over 10 years.

At 31 December 2006, the group had substantial amounts of undrawn borrowing facilities available, including committed facilities of $4,700 million, of which $4,300 million are in place for at least 5 years (2005 $4,500 million all expiring in 2006). These facilities are with a number of international banks and borrowings under them would be at pre-agreed rates. Certain of these facilities support the group's commercial paper programme.

At 31 December 2006, the group's share of third-party finance debt of jointly controlled entities and associates was $4,942 million (2005 $3,266 million) and $1,143 million (2005 $970 million) respectively. These amounts are not reflected in the group's debt on the balance sheet.

We have in place a European Debt Issuance Programme (DIP) under which the group may raise $10 billion of debt for maturities of one month or longer. At 31 December 2006 the amount drawn down against the DIP was $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 2006 there had not been any draw-down.

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38 Finance debt *continued*

Analysis of borrowings by year of expected repayment $ million

			2006			2005
	Bank loans	**Other loans**	**Total**	Bank loans	Other loans	Total
Due after 10 years	**153**	**3,202**	**3,355**		2,842	2,842
Due within 10 years	**90**	**62**	**152**	18	203	221
9 years	**97**	**329**	**426**	21	182	203
8 years	**90**	**301**	**391**	24	188	212
7 years	**82**	**318**	**400**	26	558	584
6 years	**74**	**896**	**970**	34	446	480
5 years	**131**	**674**	**805**	35	537	572
4 years	**34**	**653**	**687**	35	2,223	2,258
3 years	**28**	**4,081**	**4,109**	98	2,219	2,317
2 years	**27**	**3,626**	**3,653**	256	3,018	3,274
	806	**14,142**	**14,948**	547	12,416	12,963
1 year	**543**	**7,704**	**8,247**	155	5,263	5,418
	1,349	**21,846**	**23,195**	702	17,679	18,381

Interest rates

The weighted average interest rate on finance debt is 5%.

The proportion of floating rate debt at 31 December 2006 was 73% of total finance debt outstanding. Aside from debt issued in the US municipal bond markets, interest rates on floating rate debt denominated in US dollars are linked principally to the London Inter-Bank Offer Rate (LIBOR), while rates on debt in other currencies are based on local market equivalents. The group monitors interest rate risk using a process of sensitivity analysis. Assuming no changes to the finance debt and related hedge balances, it is estimated that a change of 1% in the general level of interest rates on 1 January 2007 would change 2007 profit before tax by approximately $180 million.

			Fixed rate		**Floating rate**	
	Weighted average interest rate %	**Weighted average time for which rate is fixed Years**	**Amount $ million**	**Weighted average interest rate %**	**Amount $ million**	**Total $ million**
						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**

						2005
US dollar	7	11	665	5	18,073	18,738
Sterling				6	76	76
Euro				3	150	150
Other currencies	9	14	157	12	41	198
			822		18,340	19,162

A further analysis of interest rates on total borrowings, excluding finance lease obligations, at 31 December, is given below.

	Weighted average interest rate %		$ million	
	2006	2005	**2006**	2005
Bank and other loans long term				
US dollar	**6**	5	**9,888**	9,178
Sterling	**5**	7	**35**	29
Euros	**4**	5	**177**	144
Other currencies	**7**	9	**231**	158
			10,331	9,509
Bank and other loans short term				
Current maturities of long-term debt			**3,078**	3,007
Commercial paper	**5**	4	**4,167**	1,911
US Industrial Revenue/Municipal bonds	**4**	4	**2,744**	2,462
Bank loans and other borrowings	**6**	7	**2,875**	1,492
			12,864	8,872
			23,195	18,381

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38 Finance debt *continued*

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
	2006	2005
Minimum future lease payments payable within		
1 year	**82**	78
2 to 5 years	**376**	320
Thereafter	**873**	838
	1,331	1,236
Less finance charges	**516**	455
Net obligations	**815**	781
Of which payable within 1 year	**60**	60
payable within 2 to 5 years	**164**	133
payable thereafter	**591**	588

Fair values

For 2006, 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 2006, whereas in the balance sheet the amount would be reported under current liabilities. Long-term borrowings also include US Industrial Revenue/Municipal Bonds and loans associated with long-term gas supply contracts classified on the balance sheet as current liabilities.

The carrying value of the groups short-term borrowings, comprising mainly commercial paper, bank loans and overdrafts, approximates their fair value. The fair value of the groups 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 groups current incremental borrowing rates for similar types and maturities of borrowing.

				$ million
		2006		2005
	Fair value	**Carrying amount**	Fair value	Carrying amount
Short-term borrowings	**7,040**	**7,040**	3,297	3,297
Long-term borrowings	**16,201**	**16,155**	15,313	15,084
Net obligations under finance leases	**832**	**815**	803	781
Total finance debt	**24,073**	**24,010**	19,413	19,162

39 Analysis of changes in net debt

Net debt is current and non-current finance debt less cash and cash equivalents. The net debt ratio is the ratio of net debt to net debt plus total equity. The net debt ratio at 31 December 2006 was 20% (2005 17%).

$ million

			2006			2005
Movement in net debt	**Finance debt**	**Cash and cash equivalents**	**Net debt**	Finance debt	Cash and cash equivalents	Net debt
At 1 January	**(19,162)**	**2,960**	**(16,202)**	(23,091)	1,359	(21,732)
Adoption of IAS 39	—	—	—	(147)	—	(147)
Restated	**(19,162)**	**2,960**	**(16,202)**	(23,238)	1,359	(21,879)
Exchange adjustments	**(172)**	**47**	**(125)**	(44)	(88)	(132)
Debt acquired	**(13)**	—	**(13)**	—	—	—
Net cash flow	**(4,049)**	**(417)**	**(4,466)**	3,803	1,689	5,492
Fair value hedge adjustment	**(581)**	—	**(581)**	171	—	171
Other movements	**(33)**	—	**(33)**	146	—	146
At 31 December	**(24,010)**	**2,590**	**(21,420)**	(19,162)	2,960	(16,202)
Equity			**85,465**			80,450

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40 Provisions

$ 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**

$ million

	Decommissioning	Environmental	Litigation and other	Total
At 1 January 2006	5,572	2,457	1,570	9,599
Exchange adjustments	(38)	(32)	(35)	(105)
New or increased provisions	1,023	565	1,964	3,552
Write-back of unused provisions	–	(335)	(86)	(421)
Unwinding of discount	122	47	32	201
Utilization	(128)	(366)	(650)	(1,144)
Deletions	(101)	(25)	–	(126)
At 31 December 2006	6,450	2,311	2,795	11,556
Of which – expected to be incurred within 1 year	162	489	951	1,602
– expected to be incurred in more than 1 year	6,288	1,822	1,844	9,954

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% (2005 2.0%) . These costs are 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 reasonably 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% (2005 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 liability.

The group also holds provisions for litigation, expected rental shortfalls on surplus properties, and sundry other liabilities. Included within the new or increased provisions made for 2006 is an amount of $425 million (2005 $1,200 million) in respect of the Texas City incident of which a total of $1,355 million has been disbursed to claimants ($863 million in 2006 and $492 million in 2005).

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% (2005 4.5%) or a real discount rate of 2.0% (2005 2.0%), as appropriate.

41 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, in the UK the primary pension arrangement is a funded final salary pension plan which 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.

Contributions to funded defined benefit plans are based on advice from independent actuaries using actuarial methods, the objective of which is to provide adequate funds to meet pension obligations as they fall due. During 2006, contributions of $438 million (2005 $340 million and 2004 $249 million) and $181 million (2005 $279 million and 2004 $30 million) were made to the UK plans and US plans respectively. In addition, contributions of $136 million (2005 $140 million and 2004 $116 million) were made to other funded defined benefit plans. The aggregate level of contributions in 2007 is expected to be approximately $750 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 cost of providing pensions and other post-retirement benefits is assessed annually by independent actuaries using the projected unit credit method. The date of the most recent actuarial review was 31 December 2006.

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41 Pensions and other post-retirement benefits *continued*

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 2006 are used to determine the pension liabilities at that date and the pension cost for 2007.

%

Financial assumptions		UK			USA			Other	
	2006	2005	2004	**2006**	2005	2004	**2006**	2005	2004
Discount rate for pension plan liabilities	**5.1**	4.75	5.25	**5.7**	5.50	5.75	**4.8**	4.00	5.00
Discount rate for post-retirement benefit plans	**n/a**	n/a	n/a	**5.9**	5.50	5.75	**n/a**	n/a	n/a
Rate of increase in salaries	**4.7**	4.25	4.00	**4.2**	4.25	4.00	**3.6**	3.25	4.00
Rate of increase for pensions in payment	**2.8**	2.50	2.50	**nil**	nil	nil	**1.8**	1.75	2.50
Rate of increase in deferred pensions	**2.8**	2.50	2.50	**nil**	nil	nil	**1.1**	1.00	2.50
Inflation	**2.8**	2.50	2.50	**2.4**	2.50	2.50	**2.2**	2.00	2.50

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. BPs most substantial pension liabilities are in the UK, the US and Germany, where our assumptions are as follows:

Years

Mortality assumptions		UK			USA			Germany	
	2006	2005	2004	**2006**	2005	2004	**2006**	2005	2004
Life expectancy at age 60 for a male currently aged 60	**23.9**	23.0	23.0	**24.2**	21.9	21.9	**22.2**	22.1	20.3
Life expectancy at age 60 for a female currently aged 60	**26.8**	26.0	26.0	**26.0**	25.6	25.6	**26.9**	26.7	25.4
Life expectancy at age 60 for a male currently aged 40	**25.0**	23.9	23.9	**25.8**	21.9	21.9	**25.2**	25.0	20.3
Life expectancy at age 60 for a female currently aged 40	**27.8**	26.9	26.9	**26.9**	25.6	25.6	**29.6**	29.4	25.4

The assumed future US healthcare cost trend rate is as follows:

%

Assumed future US healthcare cost trend rate	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013 and subsequent years**
Beneficiaries aged under 65	**8.0**	**7.5**	**7.0**	**6.5**	**6.0**	**5.5**	**5.0**

Beneficiaries aged over 65	**10.0**	**9.5**	**8.5**	**7.5**	**6.5**	**5.5**	**5.0**

BP’s post-retirement medical plans in the US provide amongst other things prescription drug coverage for Medicare-eligible retirees. The group’s obligation for other post-retirement benefits reflects the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The provisions of the Act provide for a federal subsidy for plans that provide prescription drug benefits and meet certain qualifications, and alternatively would allow prescription drug plan sponsors to co-ordinate with the Medicare benefit. BP reflects the impact of the legislation by reducing its actuarially determined obligation for post-retirement benefits and reducing the net cost for post-retirement benefits. For the year ended 31 December 2006 the reduction in net cost was $40 million (2005 $41 million).

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.

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 to manage their asset mix and 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.

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41 Pensions and other post-retirement benefits *continued*

The expected long-term rates of return and market values of the various categories of asset held by the significant defined benefit plans at 31 December are set out below.

	2006		2005		2004	
	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	**7.5**	**23,631**	7.50	18,465	7.50	17,329
Bonds	**4.7**	**3,881**	4.25	2,719	4.50	2,859
Property	**6.5**	**1,370**	6.50	1,097	6.50	1,660
Cash	**3.8**	**379**	3.50	1,001	4.00	459
	7.0	**29,261**	7.00	23,282	7.00	22,307
US pension plans						
Equities	**8.5**	**6,528**	8.50	5,961	8.50	6,043
Bonds	**5.0**	**1,371**	4.75	1,079	4.75	1,057
Property	**8.0**	**15**	8.00	21	8.00	28
Cash	**3.2**	**41**	3.00	256	3.00	55
	8.0	**7,955**	8.00	7,317	8.00	7,183
US other post-retirement benefit plans						
Equities	**8.5**	**19**	8.50	20	8.50	21
Bonds	**5.0**	**7**	4.75	8	4.75	9
	7.5	**26**	7.25	28	7.25	30
Other plans						
Equities	**7.6**	**1,158**	7.50	991	8.00	933
Bonds	**4.6**	**1,199**	4.00	943	4.25	857
Property	**4.7**	**120**	5.75	130	5.25	114
Cash	**3.0**	**191**	1.50	216	3.50	288
	5.8	**2,668**	5.50	2,280	6.00	2,192

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 2007	(383)	383
Discount rate		
Effect on pension and other post-retirement benefit expense in 2007	(52)	75
Effect on pension and other post-retirement benefit obligation at 31 December 2006	(5,013)	6,433

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 2007	31	(25)
Effect on US other post-retirement obligation at 31 December 2006	349	(289)

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41 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	**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 a	**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 b	**46**	**–**	**–**	**227**	**273**
Contributions by plan participants	**38**	**–**	**–**	**5**	**43**
Benefit payments (funded plans)	**(981)**	**(615)**	**(4)**	**(149)**	**(1,749)**

Benefit payments (unfunded plans)	—	**(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 c	**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)	**(981)**	**(615)**	**(4)**	**(149)**	**(1,749)**
Acquisitions	—	—	—	—	—
Disposals	**143**	**(13)**	—	—	**130**
Actuarial gain on plan assets c	**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 Included within production and manufacturing expenses and distribution and administration expenses.
b The charge for special termination benefits represents the increased liability arising as a result of early retirements occuring as part of a restructuring programme in the UK and Europe.
c 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 2006 reimbursement balances due from or to other companies in respect of pensions amounted to $479 million reimbursement assets (2005 $465 million) and $71 million reimbursement liabilities (2005 $71 million). These balances are not included as part of the pension liability, but are reflected elsewhere in the group balance sheet.

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41 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	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 a	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
Movements in benefit obligation during the year					
Benefit obligation at 1 January	20,399	7,826	3,676	8,044	39,945
Exchange adjustments	(2,194)	—	—	(928)	(3,122)
Current service cost	379	216	50	140	785
Past service cost	5	(10)	(5)	51	41
Interest cost	1,003	444	207	368	2,022
Special termination benefits	37	—	—	10	47

Contributions by plan participants	37	—	—	5	42
Benefit payments (funded plans)	(922)	(570)	(4)	(116)	(1,612)
Benefit payments (unfunded plans)	(1)	(30)	(204)	(314)	(549)
Acquisitions	—	20	16	3	39
Disposals	(578)	(252)	(39)	(303)	(1,172)
Actuarial (gain) loss on obligation	1,898	256	(219)	454	2,389
Benefit obligation at 31 December	20,063	7,900	3,478	7,414	38,855
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	22,307	7,183	30	2,192	31,712
Exchange adjustments	(2,469)	—	—	(195)	(2,664)
Expected return on plan assets b	1,456	557	2	123	2,138
Contributions by plan participants	37	—	—	5	42
Contributions by employers (funded plans)	340	279	—	140	759
Benefit payments (funded plans)	(922)	(570)	(4)	(116)	(1,612)
Acquisitions	—	8	—	—	8
Disposals	(578)	(236)	—	(26)	(840)
Actuarial gain on plan assets b	3,111	96	—	157	3,364
Fair value of plan assets at 31 December	23,282	7,317	28	2,280	32,907
Surplus (deficit) at 31 December	3,219	(583)	(3,450)	(5,134)	(5,948)
Represented by					
Asset recognized	3,240	—	—	42	3,282
Liability recognized	(21)	(583)	(3,450)	(5,176)	(9,230)
	3,219	(583)	(3,450)	(5,134)	(5,948)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	3,240	(226)	(32)	(476)	2,506
Unfunded	(21)	(357)	(3,418)	(4,658)	(8,454)
	3,219	(583)	(3,450)	(5,134)	(5,948)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(20,042)	(7,543)	(60)	(2,756)	(30,401)
Unfunded	(21)	(357)	(3,418)	(4,658)	(8,454)
	(20,063)	(7,900)	(3,478)	(7,414)	(38,855)

a Included within production and manufacturing expenses and distribution and administration expenses.
b 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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41 Pensions and other post-retirement benefits *continued*

$ million

					2004
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	363	215	61	118	757
Past service cost	5	—	(4)	38	39
Settlement, curtailment and special termination benefits	37	—	—	27	64
Payments to defined contribution plans	—	150	—	12	162
Total operating charge	405	365	57	195	1,022
Innovene operations	(35)	(25)	(3)	(22)	(85)
Continuing operations a	370	340	54	173	937
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	1,351	526	2	104	1,983
Interest on plan liabilities	(981)	(445)	(240)	(346)	(2,012)
Other finance income (expense)	370	81	(238)	(242)	(29)
Innovene operations	(6)	(3)	14	12	17
Continuing operations	364	78	(224)	(230)	(12)
Analysis of the amount recognized in the statement of recognized income and expense					
Actual return less expected return on pension plan assets	818	379	—	152	1,349
Change in assumptions underlying the present value of the plan liabilities	(795)	(108)	495	(366)	(774)
Experience gains and losses arising on the plan liabilities	83	(22)	33	(562)	(468)
Actuarial gain (loss) recognized in statement of recognized income and expense	106	249	528	(776)	107

a Included within production and manufacturing expenses and distribution and administration expenses.

$ million

History of surplus (deficit) and of experience gains and losses	**2006**	2005	2004	2003
Benefit obligation at 31 December	**42,433**	38,855	39,945	35,995

Fair value of plan assets at 31 December	**39,910**	32,907	31,712	27,853
Surplus (deficit)	**(2,523)**	(5,948)	(8,233)	(8,142)
Experience gains and losses on plan liabilities	**(124)**	(212)	(468)	873
Actual return less expected return on pension plan assets	**1,967**	3,364	1,349	2,392
Actual return on plan assets	**4,377**	5,502	3,332	3,892
Actuarial gain recognized in statement of recognized income and expense	**2,615**	975	107	76
Cumulative amount recognized in statement of recognized income and expense	**3,773**	1,158	183	76

Estimated future benefit payments

The expected benefit payments, which reflect expected future service, as appropriate, but excluding fund expenses, up until 2016 are as follows:

$ million

	UK pension plans	**US pension plans**	**US other post-retirement benefit plans**	**Other plans**	**Total**
2007	**1,013**	**619**	**212**	**509**	**2,353**
2008	**1,053**	**650**	**213**	**519**	**2,435**
2009	**1,070**	**673**	**219**	**513**	**2,475**
2010	**1,146**	**695**	**224**	**506**	**2,571**
2011	**1,165**	**714**	**229**	**496**	**2,604**
2012-2016	**6,432**	**3,621**	**1,156**	**2,271**	**13,480**

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42 Called up share capital

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

	2006		2005		2004	
Issued	**Shares (thousand)**	**$ million**	Shares (thousand)	$ million	Shares (thousand)	$ million
8% cumulative first preference shares of £1 each	**7,233**	**12**	7,233	12	7,233	12
9% cumulative second preference shares of £1 each	**5,473**	**9**	5,473	9	5,473	9
		21		21		21
Ordinary shares of 25 cents each						
1 January	**20,657,045**	**5,164**	21,525,978	5,382	22,122,610	5,531
Issue of new shares for employee share schemes	**64,854**	**16**	82,144	20	91,512	23
Issue of ordinary share capital for TNK-BP	**111,151**	**28**	108,629	27	139,096	35
Repurchase of ordinary share capital	**(358,374)**	**(90)**	(1,059,706)	(265)	(827,240)	(207)
Other [a]	**982,625**	**246**	–	–	–	–
31 December	**21,457,301**	**5,364**	20,657,045	5,164	21,525,978	5,382
		5,385		5,185		5,403
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 1,334,362,750 ordinary shares (2005 1,059,706,481 and 2004 827,240,360 ordinary shares) for a total consideration of $15,481 million (2005 $11,597 million and 2004 $7,548 million), of which 358,374,000 were for cancellation and 975,988,750 were retained in treasury. At 31 December 2006, 1,946,804,533 shares of nominal value $487 million were held in treasury (2005 982,624,971 shares of nominal value of $246 million). Transaction costs of share repurchases amounted to $83 million (2005 $63 million and 2004 $43 million).

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43 Capital and reserves

	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 pensions 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 c	**246**	—	—	—
At 31 December 2006	**5,385**	**9,074**	**839**	**27,201**

a For the year ended 31 December 2006, purchases of shares by ESOP trusts amounted to $205 million (2005 $251 million and 2004 $147 million).
b At 31 December 2006, the foreign currency translation reserve includes $122 million relating to non-current assets held for sale, which will be recycled to the income statement upon disposal of such assets.
c Reclassification in respect of share repurchases in 2005.

	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 pensions 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

	Share capital	Share premium account	Capital redemption reserve	Merger reserve
At 1 January 2004	5,552	3,957	523	27,077
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 pensions and other post-retirement benefits (net of tax)	—	—	—	—
Unrealized gain on acquisition of further investment in equity-accounted investments	—	—	—	—
Issue of ordinary share capital for TNK-BP	35	1,215	—	—
Repurchase of ordinary share capital	(207)	—	207	—
Share-based payments (net of tax)	23	464	—	85
Profit for the year	—	—	—	—
Dividends	—	—	—	—
At 31 December 2004	5,403	5,636	730	27,162

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$ mill

Other reserve	Own shares[a]	Treasury shares	Foreign currency translation reserve[b]	Available-for-sale investments	Cash flow hedges	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Minority interest	To equ
16	**(140)**	**(10,598)**	**2,943**	**385**	**(234)**	**643**	**46,151**	**79,661**	**789**	**80,4**
–	**(19)**	–	**1,742**	**27**	**6**	–	–	**1,756**	**49**	**1,8**
–	–	–	–	–	–	–	**1,795**	**1,795**	–	**1,7**
–	–	–	–	–	–	–	–	**1,250**	–	**1,2**
–	–	–	–	**478**	–	–	–	**478**	–	**4**
–	–	–	–	**(504)**	–	–	–	**(504)**	–	**(5**
–	–	**(11,472)**	–	–	–	–	**(4,009)**	**(15,481)**	–	**(15,4**
(11)	**5**	**134**	–	–	–	**216**	**(79)**	**773**	–	**7**
–	–	–	–	–	**313**	–	–	**313**	–	**3**
–	–	–	–	–	**(46)**	–	–	**(46)**	–	**(**
–	–	–	–	–	–	–	**22,315**	**22,315**	**286**	**22,6**
–	–	–	–	–	–	–	**(7,686)**	**(7,686)**	**(283)**	**(7,9**
–	–	**(246)**	–	–	–	–	–	–	–	
5	**(154)**	**(22,182)**	**4,685**	**386**	**39**	**859**	**58,487**	**84,624**	**841**	**85,4**

$ 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

$ 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
129	(96)	—	3,619	—	—	212	28,166	69,139	1,125	70,264
—	(7)	—	2,075	—	—	—	—	2,068	64	2,132
—	—	—	(78)	—	—	—	—	(78)	—	(78)
—	—	—	—	—	—	—	203	203	—	203
—	—	—	—	—	—	—	94	94	—	94
—	—	—	—	—	—	—	—	1,250	—	1,250
—	—	—	—	—	—	—	(7,548)	(7,548)	—	(7,548)
(85)	21	—	—	—	—	231	(9)	730	—	730
—	—	—	—	—	—	—	17,075	17,075	187	17,262
—	—	—	—	—	—	—	(6,041)	(6,041)	(33)	(6,074)
44	(82)	—	5,616	—	—	443	31,940	76,892	1,343	78,235

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43 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.

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44 Share-based payments

Effect of share-based payment transactions on the group's result and financial position	2006	2005	2004
			$ million
Total expense recognized for equity-settled share-based payment transactions	**405**	348	289
Total expense recognized for cash-settled share-based payment transactions	**14**	20	36
Total expense recognized for share-based payment transactions	**419**	368	325
Closing balance of liability for cash-settled share-based payment transactions	**38**	48	59
Total intrinsic value for vested cash-settled share-based payments	**23**	41	53

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 which vest (net of tax) are then subject to a three-year retention period. The director's remuneration report on pages 61-68 includes full details of this plan.

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 61-68 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.

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 BPs 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 BPs 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 restriction 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, then 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 recipients 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 BPs 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.

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44 Share-based payments *continued*

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 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 3½ 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.

Savings and matching plans
BP ShareSave Plan
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 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. Until 2003, a three-year savings plan was also run in a small number of other countries. Options will remain outstanding in respect of these countries until the end of June 2007. 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
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 over 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. However in certain countries 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 Options / 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 to the employee at the date of exercise. There are no performance conditions; however, participants must continue in employment with BP for the first three calendar years of the plan for the options/SARs to vest. Special arrangements may apply for qualifying leavers. The options/SARs are exercisable between the third and 10th anniversaries of the grant date.

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 in employees, the amount paid for those shares is deducted in arriving at shareholders' equity. See Note 43. Assets and liabilities of the ESOPs are recognized as assets and liabilities of the group.

At 31 December 2006, the ESOPs held 12,795,887 shares (2005 14,560,003 shares and 2004 8,621,219 shares) for potential future awards, which had a market value of $142 million (2005 $156 million and 2004 $84 million).

Share option transactions		**2006**		2005		2004
	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	**450,453,502**	**7.64**	470,263,808	7.16	461,885,881	6.76
Granted during the year	**53,977,639**	**11.18**	54,482,053	10.24	80,394,760	7.93
Forfeited during the year	**(7,169,710)**	**8.69**	(4,844,827)	8.30	(7,043,911)	6.77
Exercised during the year	**(70,658,480)**	**6.52**	(68,687,976)	6.40	(62,625,182)	5.18
Expired during the year	**(131,489)**	**7.99**	(759,556)	6.75	(2,347,740)	7.55
Outstanding at end of the year	**426,471,462**	**8.25**	450,453,502	7.64	470,263,808	7.16
Exercisable at the end of the year	**236,726,966**	**7.41**	222,729,398	7.54	224,627,758	7.00
Available for grant at 31 December	**699,535,945**		955,924,506		966,076,636	

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44 Share-based payments *continued*

As share options are exercised continuously throughout the year, the weighted average share price during the year of $11.85 (2005 $10.77 and 2004 $8.95) is representative of the weighted average share price at the date of exercise. For the options outstanding at 31 December 2006, 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	**100,854,491**	**3.92**	**6.02**	**87,474,704**	**6.06**
$6.80 – $8.50	**196,009,067**	**4.93**	**8.01**	**122,344,799**	**8.08**
$8.51 – $10.21	**55,376,829**	**5.79**	**9.30**	**26,907,463**	**8.76**
$10.22 – $11.92	**74,231,075**	**8.81**	**11.14**	–	–
	426,471,462	**5.48**	**8.25**	**236,726,966**	**7.41**

Fair values and associated details for options and shares granted

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

Options granted in 2004	EDIP Options	BPSOP	ShareSave 3 year	ShareSave 5 year
Option pricing model used	Binomial	Binomial	Binomial	Binomial
Weighted average fair value	$1.34	$1.55	$1.94	$2.13
Weighted average share price	$8.09	$8.12	$8.75	$8.75
Weighted average exercise price	$8.09	$8.09	$7.00	$7.00
Expected volatility	22%	22%	22%	22%
Option life	7 years	10 years	3.5 years	5.5 years
Expected dividends	3.75%	3.75%	3.75%	3.75%
Risk free interest rate	3.50%	4.00%	3.00%	3.75%
Expected exercise behaviour	5% years 2-6, 75% year 7	5% years 4-9, 70% year 10	100% year 4	100% year 6

The group uses a third party estimate of expected volatility of US ADSs for the quarter within which the grant date of the relevant plan falls. This estimate takes into account the volatility implied by options in the market.

Shares granted in 2006	**MTPP-TSR**	**MTPP-FCF**	**EDIP-TSR**	**EDIP-LTL**	**RSP**
Number of equity instruments granted (million)	**8.7**	**7.8**	**3.3**	**0.5**	**0.5**
Weighted average fair value	**$7.28**	**$11.23**	**$4.87**	**$11.23**	**$11.07**
Fair value measurement basis	**Monte Carlo**	**Market value**	**Monte Carlo**	**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

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44 Share-based payments *continued*

The group used a Monte Carlo simulation to fair value the TSR element of the 2006 and 2005 MTPP and EDIP plans. In accordance with the rules of the plans the model simulates BPs 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.

Shares granted in 2004	LTPP-SHRAM	LTPP-EPS/ROACE	EDIP-SHRAM	EDIP-EPS/ROACE	RSP
Number of equity instruments granted (million)	6.8	4.1	0.9	0.5	0.1
Weighted average fair value	$4.06	$7.21	$4.06	$7.21	$8.12
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 SHRAM element of the 2004 LTPP and EDIP plan. In accordance with the rules of the plan, the model simulates BPs SHRAM and compares it with the comparator companies (all companies in the FTSE All World Oil & Gas Index) over the three-year period of the plan. The SHRAMs of the comparator companies have been determined from market data over the preceding three-year period. The model takes into account the historic dividend yields, 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 SHRAM 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.

45 Employee costs and numbers

$ million

Employee costs	**2006**	2005	2004
Wages and salaries	**8,411**	8,695	7,922
Social security costs	**751**	754	667
Share-based payments	**419**	368	325
Pension and other post-retirement benefit costs	**770**	929	1,051
	10,351	10,746	9,965
Innovene operations		(892)	(898)
Continuing operations	**10,351**	9,854	9,067

Number of employees at 31 December	**2006**	2005	2004
Exploration and Production	**19,000**	17,000	15,600
Refining and Marketing[a]	**69,500**	70,800	69,800
Gas, Power and Renewables	**4,500**	4,100	4,000
Other businesses and corporate	**4,000**	4,300	13,500

	97,000	96,200	102,900
By geographical area			
UK	**16,900**	16,500	17,500
Rest of Europe	**20,200**	21,300	25,900
USA	**33,700**	34,400	36,900
Rest of World	**26,200**	24,000	22,600
	97,000	96,200	102,900

a Includes 26,100 (2005 27,800 and 2004 27,900) service station staff.

			2006					2005		
Average number of employees	**UK**	**Rest of Europe**	**USA**	**Rest of World**	**Total**	UK	Rest of Europe	USA	Rest of World	Total
Exploration and Production	**3,300**	**700**	**6,100**	**8,100**	**18,200**	3,000	600	5,300	7,300	16,200
Refining and Marketing	**11,300**	**19,300**	**24,900**	**15,000**	**70,500**	11,100	19,700	26,200	14,000	71,000
Gas, Power and Renewables	**300**	**700**	**1,600**	**1,700**	**4,300**	200	800	1,500	1,400	3,900
Other businesses and corporate	**1,900**	**200**	**1,900**	**100**	**4,100**	3,800	3,900	3,600	300	11,600
	16,800	**20,900**	**34,500**	**24,900**	**97,100**	18,100	25,000	36,600	23,000	102,700

					2004
Average number of employees	UK	Rest of Europe	USA	Rest of World	Total
Exploration and Production	2,900	700	4,900	6,900	15,400
Refining and Marketing	10,300	19,200	27,200	12,900	69,600
Gas, Power and Renewables	200	800	1,400	1,600	4,000
Other businesses and corporate	3,700	4,800	5,700	1,000	15,200
	17,100	25,500	39,200	22,400	104,200

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46 Remuneration of directors and key management

Remuneration of directors $ million

	2006	2005	2004
Total for all directors			
Emoluments	**14**	18	19
Gains made on the exercise of share options	**12**	—	3
Amounts awarded under incentive schemes	**14**	8	6

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.

Pension contributions

Five executive directors participated in a non-contributory pension scheme established for UK staff by a separate trust fund to which contributions are made by BP based on actuarial advice. One US executive director participated in the US BP Retirement Accumulation Plan during 2006.

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 61-68.

Remuneration of key management $ million

	2006	2005	2004
Total for all key management			
Short-term employee benefits	**30**	25	24
Post-retirement benefits	**4**	4	3
Share-based payments	**26**	27	20

Key management, in addition to executive and non-executive directors, includes other senior managers who attend the Group Chief Executive’s Meeting.

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.

Post-retirement benefits

The amounts represent the estimated cost to the group of providing defined benefit pensions and other post-retirement benefits to key 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 key 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 key management have participated are the Executive Directors' Incentive Plan (EDIP), the Medium Term Performance Plan (MTPP) and the Long Term Performance Plan (LTPP). For details of these plans refer to Note 44.

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47 Contingent liabilities

There were contingent liabilities at 31 December 2006 in respect of guarantees and indemnities entered into as part of the ordinary course of the groups business. No material losses are likely to arise from such contingent liabilities. Group companies have issued guarantees under which amounts outstanding at 31 December 2006 were $1,123 million (2005 $1,228 million) in respect of borrowings of jointly controlled entities and associates and $789 million (2005 $736 million) in respect of liabilities of other third parties.

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 BPs 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.

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 groups 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 groups business. While the outcome of such legal proceedings cannot be readily foreseen, BP believes that they will be resolved without material effect on the groups results of operations, financial position or liquidity.

The group is subject to numerous national and local environmental laws and regulations concerning its products, operations and other activities. These laws and regulations may require the group to take future action to remediate the effects on the environment of prior disposal or release of chemicals or petroleum substances by the group or other parties. Such contingencies may exist for various sites including refineries, chemical plants, oil fields, service stations, terminals and waste disposal sites. In addition, the group may have obligations relating to prior asset sales or closed facilities. The ultimate requirement for remediation and its cost are inherently difficult to estimate. However, the estimated cost of known environmental obligations has been provided in these accounts in accordance with the groups accounting policies. While the amounts of future costs could be significant and could be material to the groups results of operations in the period in which they are recognized, BP does not expect these costs to have a material effect on the groups 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.

48 Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been placed at 31 December 2006 amounted to $9,773 million (2005 $7,596 million). Capital commitments of jointly controlled entities amounted to $1,217 million (2005 $576 million).

49 First-time adoption of International Financial Reporting Standards

For all periods up to and including the year ended 31 December 2004, BP prepared its financial statements in accordance with UK generally accepted accounting practice (UK GAAP). BP, together with all other European Union (EU) companies listed on an EU stock exchange, was required to prepare consolidated financial statements in accordance with International Financial Reporting Standards (IFRS) as adopted by the EU with effect from 1 January 2005. The Annual Report and Accounts for the year ended 31 December 2005 comprised BP's first consolidated financial statements prepared under IFRS.

The general principle for first-time adoption of IFRS is that standards in force at the first reporting date (for BP, 31 December 2005) are applied retrospectively. However, IFRS 1 'First-time Adoption of International Financial Reporting Standards' contains a number of exemptions that companies are permitted to apply. BP elected to take advantage of the exemption allowing comparative information on financial instruments to be prepared in accordance with UK GAAP and the group adopted IAS 32 'Financial Instruments: Disclosure and Presentation' (IAS 32) and IAS 39 'Financial Instruments: Recognition and Measurement' (IAS 39) from 1 January 2005.

Had IAS 32 and IAS 39 been applied from 1 January 2003, BP's date of transition for all other IFRS in force at the first reporting date, the following are the most significant adjustments that would have been necessary in the financial statements for the year ended 31 December 2004:

- All derivatives, including embedded derivatives, would have been brought on to the balance sheet at fair value, and changes in fair value would have been recognized in the income statement.
- Available-for-sale investments would have been carried at fair value rather than at cost and changes in fair value would have been recognized directly in equity.

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49 First-time adoption of International Financial Reporting Standards *continued*

The reconciliation set out below shows the adjustments to the group balance sheet at 1 January 2005 on the adoption of IAS 32 and IAS 39.

Group balance sheet reconcilation

	IFRS at 31 December 2004	Fair value hedges	Cash flow hedges	Non-qualifying hedge derivatives	Other non-financial contracts at fair value	Other non-financial contracts no longer at fair value	Available-for-sale financial assets	Embedded derivatives	Elimination of deferred gains/ losses	Total IAS 39 adjustments
Non-current assets										
Property, plant and equipment	93,092	—	—	—	—	—	—	—	—	—
Goodwill	10,857	—	—	—	—	—	—	—	—	—
Intangible assets	4,205	—	—	—	—	—	—	—	—	—
Investments in jointly controlled entities	14,556	—	—	—	—	—	—	—	—	—
Investments in associates	5,486	—	—	—	—	—	—	—	—	—
Other investments	394	—	—	—	—	—	344	—	—	344
Fixed assets	128,590	—	—	—	—	—	344	—	—	344
Loans	811	—	—	—	—	—	—	—	—	—
Other receivables	429	—	—	—	—	—	—	—	—	—
Derivative financial instruments	898	112	79	8	110	(34)	—	599	(147)	727
Prepayments and accrued income	354	—	—	—	—	—	—	—	—	—
Defined benefit pension plan surplus	2,105	—	—	—	—	—	—	—	—	—
	133,187	112	79	8	110	(34)	344	599	(147)	1,071
Current assets										
Loans	193	—	—	—	—	—	—	—	—	—
Inventories	15,645	—	—	—	—	—	—	—	—	—
Trade and other	37,099	—	(2)	—	—	—	—	—	—	(2)

receivables										
Derivative financial instruments	5,317	—	141	178	34	47	—	278	—	678
Prepayments and accrued income	1,671	—	—	—	—	—	—	—	—	—
Current tax receivable	159	—	—	—	—	—	—	—	—	—
Cash and cash equivalents	1,359	—	—	—	—	—	—	—	—	—
	61,443	—	139	178	34	47	—	278	—	676
Total assets	194,630	112	218	186	144	13	344	877	(147)	1,747
Current liabilities										
Trade and other payables	38,540	—	—	—	—	—	—	—	—	—
Derivative financial instruments	5,074	—	16	210	14	—	—	402	—	642
Accruals and deferred income	4,482	—	—	—	—	—	—	—	—	—
Finance debt	10,184	—	—	—	—	—	—	—	—	—
Current tax payable	4,131	—	—	—	—	—	—	—	—	—
Provisions	715	—	—	—	—	—	—	—	—	—
	63,126	—	16	210	14	—	—	402	—	642
Non-current liabilities										
Other payables	3,581	—	—	—	—	—	—	—	—	—
Derivative financial instruments	158	129	4	17	12	—	—	1,151	—	1,313
Accruals and deferred income	699	—	—	—	—	—	—	—	—	—
Finance debt	12,907	(17)	—	—	—	—	—	—	164	147
Deferred tax liabilities	16,701	—	60	(13)	44	5	114	(267)	(55)	(112)
Provisions	8,884	—	—	—	—	—	—	—	—	—
Defined benefit pension plan and other post-retirement benefit plan deficits	10,339	—	—	—	—	—	—	—	—	—
	53,269	112	64	4	56	5	114	884	109	1,348

Total liabilities	116,395	112	80	214	70	5	114	1,286	109	1,990
Net assets	78,235	—	138	(28)	74	8	230	(409)	(256)	(243)
BP shareholders' equity	76,892	—	138	(28)	74	8	230	(409)	(256)	(243)
Minority interest	1,343	—	—	—	—	—	—	—	—	—
Total equity	78,235	—	138	(28)	74	8	230	(409)	(256)	(243)

The fair values of embedded derivatives are included within non-current and current derivative financial instruments on the group balance sheet as this is believed to be the most appropriate presentation. Previously, these balances were reported within non-current and current prepayments and accrued income and accruals and deferred income.

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49 First-time adoption of International Financial Reporting Standards *continued*

Adjustments required to the balance sheet as at 1 January 2005 for the adoption of IAS 32 and IAS 39

Under UK GAAP, all derivatives used for trading purposes were recognized on the balance sheet at fair value. However, derivative financial instruments used for hedging purposes were recognized by applying either the accrual method or the deferral method. Under the accrual method, which was used for derivatives, principally swaps, used to manage interest rate risk, amounts payable or receivable in respect of derivatives are recognized ratably in earnings over the period of the contracts. Changes in the derivatives fair value are not recognized. Under the deferral method, gains and losses from derivatives were deferred and recognized in earnings or as adjustments to carrying amounts as the underlying hedged transaction matured or occurred. This method was applied for derivatives used to convert non-US dollar borrowings into US dollars, to hedge significant non-US dollar firm commitments or anticipated transactions, and to manage some of the groups exposure to natural gas and power price fluctuations.

For IFRS, all financial assets and financial liabilities are recognized initially at fair value. In subsequent periods the measurement of these financial instruments depends on their classification into one of the following measurement categories: i) financial assets or financial liabilities at-fair-value-through-profit-and-loss (such as those used for trading purposes and all derivatives which do not qualify for hedge accounting); ii) loans and receivables; and iii) available-for-sale financial assets (including certain investments held for the long term).

Fair value hedges

Where fair value hedge accounting was applied to transactions that hedge the groups exposure to the changes in the fair value of a firm commitment or a recognized asset or liability that are attributable to a specific risk the derivatives designated as hedging instruments are recorded at their fair value in the groups balance sheet and changes in their fair value are recognized in the income statement. Any gain or loss on the hedged item attributable to the hedged risk is adjusted against the carrying amount of the hedged item and recognized in the income statement.

The pay floating interest rate swaps and currency swaps hedging the debt book in place on 1 January 2005 were highly effective and consequently qualify as fair value hedges for hedge accounting. The full fair value of the swaps was recognized on the balance sheet and the carrying value of debt was adjusted.

Cash flow hedges

The group uses currency derivatives to hedge its exposure to variability in cash flows arising either from a recognized asset or liability or a forecast transaction. The hedged instrument is recognized at fair value on the balance sheet. At maturity of the hedged item, the element deferred in equity is treated in accordance with the nature of the hedged exposure, for example, capitalized into the cost of an item of property, plant and equipment, or expensed in the case of a hedge of a tax payment.

Non-qualifying hedge derivatives

Under IAS 39, there are strict criteria that need to be met in order for hedge accounting to be applied. This adjustment records the impact of those derivatives, or elements thereof, held by the group that do not qualify for hedge accounting, or hedges for which hedge accounting has not been claimed under IAS 39. From 1 January 2005, these positions will be fair valued (marked to market) and the change in fair value taken to income.

Other non-financial contracts at fair value

Certain net-settled non-financial contracts are deemed to meet the definition of financial instruments under IAS 39 and, as such, need to be recorded on the balance sheet at fair value.

Other non-financial contracts no longer at fair value

Certain non-financial contracts held for trading purposes were marked to market under UK GAAP. However, under IFRS they could no longer be recorded at fair value as they did not meet the definition of financial assets or financial liabilities. These contracts are accounted for on an accruals basis.

Available-for-sale financial assets

Under UK GAAP, the groups investments other than subsidiaries, jointly controlled entities and associates were stated at cost less accumulated impairment losses.

For IFRS, these investments are classified as available-for-sale financial assets, and are recorded at fair value with the gain or loss arising as a result of the change in fair value being recorded directly in equity.

The transition adjustment relates to the fair value of listed investments held by the group. In accordance with IAS 39, all future fair value adjustments will be booked directly in equity until disposal of the investment, when the cumulative associated gains or losses are recycled through the income statement. At this point, the gain or loss on disposal under IFRS will be identical to that which would result using historical cost accounting.

Embedded derivatives

Embedded derivatives are required to be separated from their host contracts and separately recorded at fair value, with any resulting change in gain or loss in the period being recognized in the income statement.

Certain contracts have been determined to contain embedded derivatives. These embedded derivatives will be fair valued at each period end with the resulting gains or losses taken to the income statement.

Elimination of currently deferred gains and losses from derivatives

Under UK GAAP, gains and losses from derivatives are deferred and recognized in earnings or as adjustments to carrying amounts, as appropriate, when the underlying debt matures or the hedged transaction occurs. Where derivatives that are used to manage interest rate risk, to convert non-US dollar debtor to hedge other anticipated cash flows are terminated before the underlying debt matures or the hedged transaction occurs, the resulting gain or loss is recognized on a basis that matches the timing and accounting treatment of the underlying debt or hedged transaction.

On transition to IFRS, only assets and liabilities that qualify as such can continue to be recognized. Consequently, all gains and losses that were generated by derivatives used for hedging purposes and deferred in the balance sheet as if they were assets or liabilities must be eliminated from the transitional balance sheet. This is achieved by transferring gains and losses arising from cash flow hedges to equity, pending recycling to income at a later date, and by transferring gains and losses arising from fair value hedges to adjust the carrying value of the hedged item, in this case, finance debt.

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50 Subsidiaries, jointly controlled entities and associates

The more important subsidiaries, jointly controlled entities and associates of the group at 31 December 2006 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 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
France			
BP France	100	France	Refining and marketing and petrochemicals
Germany			
Deutsche BP	100	Germany	Refining and marketing and petrochemicals

Britoil	100	Scotland	Exploration and production
Jupiter Insurance	100	Guernsey	Insurance
US			
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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50 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
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 thus 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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51 Oil and natural gas exploration and production activities[a]

$ million

									2006
	UK	Rest of Europe	USA	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 groups share of jointly controlled entities and associates net capitalized costs at 31 December 2006 was $10,870 million.

	UK	Rest of Europe	USA	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 costsb	**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 groups share of jointly controlled entities and associates costs incurred in 2006 was $1,688 million: in Russia $1,109 milion, Rest of Americas $424 million, Asia Pacific $16 million and other $139 million.

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Results of operations for the year ended 31 December									
Sales and other operating revenuesc									
Third parties	**5,378**	**628**	**1,381**	**2,196**	**1,159**	**1,647**	****	**768**	**13,157**
	2,329	**1,024**	**14,572**	**3,229**	**807**	**2,875**	****	**7,640**	**32,476**

Sales between businesses									
	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)d	**(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 taxatione,f	**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 groups share of jointly controlled entities and associates results of operations 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. Mid-stream activities of natural gas gathering and distribution and the operation of the main pipelines and tankers are excluded. The main mid-stream activities are the Alaskan transportation facilities, the Forties Pipeline system and the Central Area Transmission System. The groups 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 Sales and other operating revenues represents proceeds from the sale of production and other crude oil and gas, including royalty oil sold on behalf of others where royalty payable in cash.

d 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.

e 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.

f 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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51 Oil and natural gas exploration and production activities[a] *continued*

$ million

2005

	UK	Rest of Europe	USA	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	USA	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	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Results of operations for the year ended 31 December									
Sales and other operating revenues[c]									
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)[d]	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[e f]	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 groups share of jointly controlled entities and associates results of operations 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. Mid-stream activities of natural gas gathering and distribution and the operation of the main pipelines and tankers are excluded. The main mid-stream activities are the Alaskan transportation facilities, the Forties Pipeline system and the Central Area Transmission System. The groups 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 Sales and other operating revenues represents proceeds from the sale of production and other crude oil and gas, including royalty oil sold on behalf of others where royalty is payable in cash.
d 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 groups self-insurance programme.
e 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.
f 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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51 Oil and natural gas exploration and production activities[a] continued

$ million

									2004
	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Capitalized costs at 31 December									
Gross capitalized costs									
Proved properties	30,639	4,691	43,011	10,450	2,892	10,401	—	3,834	105,918
Unproved properties	300	170	1,395	456	1,240	526	119	105	4,311
	30,939	4,861	44,406	10,906	4,132	10,927	119	3,939	110,229
Accumulated depreciation	20,780	2,794	19,713	5,546	1,350	5,573	—	1,014	56,770
Net capitalized costs	10,159	2,067	24,693	5,360	2,782	5,354	119	2,925	53,459

The group’s share of jointly controlled entities’ and associates’ net capitalized costs at 31 December 2004 was $11,013 million.

Costs incurred for the year ended 31 December									
Acquisition of properties									
Proved	—	—	—	—	—	—	—	—	—
Unproved	2	—	58	5	—	13	—	—	78
	2	—	58	5	—	13	—	—	78
Exploration and appraisal costs[b]	51	17	423	199	85	142	113	9	1,039
Development costs	679	262	3,247	527	88	1,460	—	1,007	7,270
Total costs	732	279	3,728	731	173	1,615	113	1,016	8,387

The group’s share of jointly controlled entities’ and associates’ costs incurred in 2004 was $1,102 million: in Russia $773 million and Rest of Americas $329 million.

Results of operations for the year ended 31 December									
Sales and other operating revenues[c]									
Third parties	3,458	626	1,735	1,776	977	492	5	403	9,472
Sales between businesses	2,424	609	11,794	2,556	530	1,439	—	2,912	22,264
	5,882	1,235	13,529	4,332	1,507	1,931	5	3,315	31,736

Exploration expenditure	26	25	361	141	14	45	17	8	637
Production costs	901	117	1,428	535	142	323	—	131	3,577
Production taxes	273	30	477	239	45	—	—	1,023	2,087
Other costs (income)d	(211)	38	1,884	458	96	122	(3)	1,380	3,764
Depreciation, depletion and amortization	1,524	172	2,268	611	174	287	—	121	5,157
Impairments and (gains) losses on sale of businesses and fixed assets	21	1	344	(55)	113	48	—	(3)	469
	2,534	383	6,762	1,929	584	825	14	2,660	15,691
Profit before taxatione f	3,348	852	6,767	2,403	923	1,106	(9)	655	16,045
Allocable taxes	1,242	534	2,103	859	(4)	441	2	150	5,327
Results of operations	2,106	318	4,664	1,544	927	665	(11)	505	10,718

The group's share of jointly controlled entities' and associates' results of operations in 2004 was a profit of $1,814 million after deducting interest of $189 million, taxation of $969 million and minority interest of $43 million.

a This note contains information relating to oil and natural gas exploration and production activities. Mid-stream activities of natural gas gathering and distribution and the operation of the main pipelines and tankers are excluded. The main mid-stream 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 Sales and other operating revenues represents proceeds from the sale of production and other crude oil and gas, including royalty oil sold on behalf of others where royalty is payable in cash.

d Includes the value of royalty oil sold on behalf of others where royalty is payable in cash, property taxes and other government take.

e Excludes accretion expense attributable to exploration and production activities amounting to $120 million. Under IFRS, accretion expense is included in other finance expense in the group income statement.

f The Exploration and Production profit before interest and tax is set out below.

									$ million
									2004
Exploration and production activities									
Group (as above)	3,348	852	6,767	2,403	923	1,106	(9)	655	16,045
Jointly controlled entities and associates	—	—	—	113	36	—	1,665	—	1,814
Mid-stream activities	105	(15)	40	123	(50)	(19)	—	42	226
Total profit before interest and tax	3,453	837	6,807	2,639	909	1,087	1,656	697	18,085

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Additional information for US reporting

52 Suspended exploration well costs

Included within the total exploration expenditure of $4,110 million (2005 $4,008 million and 2004 $3,761 million) shown as part of intangible assets (see Note 28) is an amount of $1,863 million (2005 $1,931 million and 2004 $1,680 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 a 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: (a) that exploration drilling is still under way or firmly planned, or (b) that it either has been determined, or work is underway 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
	2006	2005	2004
Capitalized exploration well costs			
At 1 January	**1,931**	1,680	1,698
Additions pending determination of proved reserves	**590**	565	391
Exploration well costs written off in the year	**(168)**	(81)	(84)
Costs of exploration wells divested in the year	**(36)**	(72)	(34)
Reclassified to tangible assets following determination of proved reserves	**(251)**	(161)	(291)
Reclassified to investment in jointly controlled entity	**(203)**	–	–
At 31 December	**1,863**	1,931	1,680

The following table provides an ageing profile of suspended exploration wells.

At 31 December		**2006**		2005		2004
	Cost $ million	**Wells gross**	Cost $ million	Wells gross	Cost $ million	Wells gross
Age						
Less than 1 year	**611**	**45**	593	46	411	26
1 to 5 years	**736**	**64**	823	69	787	81
6 to 10 years	**267**	**37**	309	42	292	29
More than 10 years	**249**	**26**	206	20	190	18
Total	**1,863**	**172**	1,931	177	1,680	154

The following table provides an analysis of the amount of costs directly associated with exploration wells.

			2006			2005			2004
	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	**188**	**17**	**12**	451	31	14	290	15	12
Other projects with recent or planned drilling activity	**894**	**86**	**21**	718	65	20	400	36	13
Projects with completed exploration activity	**781**	**69**	**27**	762	81	28	990	103	41
At 31 December	**1,863**	**172**	**60**	1,931	177	62	1,680	154	66

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 48 projects which have exploration well costs which have been capitalized for more than twelve months as at 31 December 2006. Of these, there are 21 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 $781 million at 31 December 2006. Details of the activities being undertaken to progress these projects towards development are shown below.

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52 Suspended exploration well costs *continued*

Country	Project	Cost $ million	**2006 wells gross**	Years wells drilled	Anticipated year of development project sanction	Comment
Angola	Chumbo	26	**2**	2003-2005	2008-2009	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	2007	Assessment of hydrocarbon quantities as potentially commercial completed; development option using FPSO identified and under evaluation.
		77	**7**			
Colombia	Volcanera	43	**1**	1993	2009	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project in progress; development options identified and under evaluation; planned phased development linked to neighbouring field using existing infrastructure; seismic survey in process.
		43	**1**			
Egypt	Ras El Bar Seth	3	**1**	1995	2009-2012	Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; development planned through tieback to existing infrastructure; gas sale agreement in place.
	Western Mediterranean Block B	14	**3**	2002-2004	2008-2017	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.
		17	**4**			
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 which is currently under development.
		51	**9**			
Norway	Skarv/Snadd	72	**8**	1998-2002	2007	Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; planned development with floating production system and export infrastructure agreed with partners.
		72	**8**			
Trinidad	Chachalaca	48	**1**	2005	2007	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project in progress; development option selected.
	Coconut	47	**1**	2005	2010+	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project in progress; development options identified and under evaluation; planned subsea tieback to existing infrastructure.

Corallita/Lantana	24	**2**	1996	2007-2008	Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; planned subsea tieback to existing infrastructure fields dedicated to LNG gas contract delivery; dependent upon capacity in existing infrastruture.
Manakin	21	**1**	2000	2010+	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project in progress; development options identified and under evaluation; planned subsea tieback to existing production facilities and LNG train; inter-governmental discussions on unitization continue.
	140	**5**			

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52 Suspended exploration well costs *continued*

Country	Project	Cost $ million	**2006 wells gross**	Years wells drilled	Anticipated year of development project sanction	Comment
UK	Andrew	14	**1**	1998	2007	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	2007	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project in progress; development options identified and under evaluation; development expected in conjunction with Harding Gas Project nearby.
	Puffin	29	**9**	1982-1991	2008-2010	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.
	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 tieback to existing production vessel; awaiting capacity in existing infrastructure.
		153	**16**			

US	Entrada	24	**2**	2000	2007	Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; expected development as subsea tieback to facilities installed in 2005; negotiations with infrastructure owners for product handling agreement are under way.
	Liberty	20	**1**	1997	2008	Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; planned tieback via extended reach drilling from existing infrastructure; Memorandums of Understanding with two key permitting agencies have been secured.
	Mad Dog Deep	49	**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	33	**3**	2005	2008	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.
		126	**7**			
Vietnam	Hai Thach	65	**3**	1995-2002	2008-2009	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project in place; development options identified and under evaluation; licence extension under negotiation.
	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 2007.
	78	**4**	
Miscellaneous smaller projects	24	**8**	
	781	**69**	

Certain projects which were classified as projects with completed exploration drilling activity at 31 December 2005 are not classified as such at 31 December 2006:

- The following projects were sanctioned for development in 2006: Florena/Pauto in Colombia; Ras El Bar/Taurt in Egypt; Cashima and Red Mango in Trinidad; and Dorado in the US.
- In Egypt, further exploratory drilling was undertaken in 2006 on the Temsah project, and $8 million relating to part of the project was sanctioned in 2006.
- In Angola, the Bavuca/Kakocha/Mavacola/Mbulumbumba/Vicango project was regrouped into two separate projects, with one project planning further exploratory drilling in 2007 and an appraisal well having been drilled on the other in 2006.
- In the US, the Point Thompson/Sourdough project was written off resulting in an expense of $27 million in respect of the well costs.

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53 US GAAP reconciliation

The consolidated financial statements of the BP group are prepared in accordance with International Financial Reporting Standards (IFRS) as adopted for use by the EU, which differ in certain respects from US generally accepted accounting principles (US GAAP). IFRS as adopted by the EU differs in certain respects from IFRS as issued by the International Accounting Standards Board (IASB). However, the consolidated financial statements for the years presented would be no different had the group applied IFRS as issued by the IASB.

The following is a summary of the adjustments to profit for the year attributable to BP shareholders and to BP shareholders equity that would be required if US GAAP had been applied instead of IFRS.

Profit for the year — $ million except per share amounts

For the year ended 31 December	**2006**	2005	2004
Profit as reported to accord with IFRS	**22,315**	22,026	17,075
Adjustments			
Deferred taxation/business combinations (a)	**(224)**	(496)	(517)
Provisions (b)	**177**	9	(80)
Oil and natural gas reserves differences (c)	**(243)**	11	30
Goodwill and intangible assets (d)	**13**		(61)
Derivative financial instruments (e)	**142**	87	(337)
Inventory valuation (f)	**162**	(232)	162
Gain arising on asset exchange (g)	**(10)**	(12)	(107)
Pensions and other post-retirement benefits (h)	**(873)**	(486)	(47)
Impairments (i)	**(332)**	(378)	677
Equity-accounted investments (j)	**(104)**	(255)	147
Consolidation of variable interest entities (l)	**(5)**		
Major maintenance expenditure (m)			217
Share-based payments (n)	**92**	6	24
Other	**6**	156	(93)
Profit for the year before cumulative effect of accounting change as adjusted to accord with US GAAP	**21,116**	20,436	17,090
Cumulative effect of accounting change			
Major maintenance expenditure (m)		(794)	
Profit for the year as adjusted to accord with US GAAP	**21,116**	19,642	17,090
Dividend requirements on preference shares	**2**	2	2
Profit for the year attributable to ordinary shares as adjusted to accord with US GAAP	**21,114**	19,640	17,088
Per ordinary share cents			
Basic before cumulative effect of accounting change	**105.42**	96.72	78.31
Cumulative effect of accounting change		(3.76)	
	105.42	92.96	78.31
Diluted before cumulative effect of accounting change	**104.63**	95.62	76.88
Cumulative effect of accounting change		(3.71)	

	104.63	91.91	76.88
Per American depositary share centsa			
Basic before cumulative effect of accounting change	**632.52**	580.32	469.86
Cumulative effect of accounting change		(22.56)	
	632.52	557.76	469.86
Diluted before cumulative effect of accounting chane	**627.78**	573.72	461.28
Cumulative effect of accounting change		(22.26)	
	627.78	551.46	461.28

a One American depositary share is equivalent to six ordinary shares.

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53 US GAAP reconciliation *continued*

BP shareholders equity

At 31 December	2006	2005
		$ million
BP shareholders equity as reported to accord with IFRS	**84,624**	79,661
Adjustments		
Deferred taxation/business combinations (a)	**1,801**	2,025
Provisions (b)	**63**	(112)
Oil and natural gas reserves differences (c)	**(202)**	41
Goodwill and intangible assets (d)	**248**	171
Derivative financial instruments (e)	**202**	225
Inventory valuation (f)	**(5)**	(167)
Gain arising on asset exchange (g)	**229**	239
Pensions and other post-retirement benefits (h)		3,146
Impairments (i)	**2**	327
Equity-accounted investments (j)	**(160)**	(43)
Consolidation of variable interest entities (l)	**(5)**	
Share-based payments (n)	**(254)**	(334)
Other	**(26)**	(32)
BP shareholders equity as adjusted to accord with US GAAP	**86,517**	85,147

Comprehensive income

The components of comprehensive income, net of related tax, are as follows:

For the year ended 31 December	2006	2005	2004
			$ million
Profit for the year as adjusted to accord with US GAAP	**21,116**	19,642	17,090
Currency translation differences net of tax benefit (expense) of $(203) million (2005 $328 million and 2004 $(208) million)	**1,824**	(2,865)	2,143
Investments			
Unrealized gains net of tax benefit (expense) of $(83) million (2005 $(110) million and 2004 $(71) million)	**480**	291	141
Unrealized losses net of tax benefit (expense) of $nil (2005 $16 million and 2004 $nil)	**(2)**	(42)	
Less: reclassification adjustment for gains included in net income net of tax benefit (expense) of $191 million (2005 $22 million and 2004 $627 million)	**(504)**	(59)	(1,165)
Currency translation differences net of tax benefit (expense) of $nil (2005 $nil and 2004 $nil)	**27**	(32)	
Unrealized gains (losses) on cash flow hedges net of tax benefit (expense) of $(3) million (2005 $63 million and	**102**	(131)	

2004 $nil)			
Minimum pension liability adjustment net of tax benefit (expense) of $44 million (2005 $(94) million and 2004 $130 million)	**82**	249	(838)
Comprehensive income	**23,125**	17,053	17,371

Accumulated other comprehensive income

		$ million
At 31 December	**2006**	2005
Currency translation differences	**3,320**	1,496
Net unrealized gains on investments	**386**	385
Unrealized losses on cash flow hedges	**(29)**	(131)
Minimum pension liability adjustment		(866)
Funded status of defined benefit pension and other post-retirement benefit plans[b c]	**(1,383)**	
Accumulated other comprehensive income	**2,294**	884

b The amount reported for the funded status of defined benefit pension and other post-retirement benefit plans at 31 December 2006 includes $(599) million resulting from the adoption of FASB Statement of Financial Accounting Standards (SFAS) No. 158 Employers Accounting for Defined Benefit Pension and Other Post-retirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R). Further information on the effects of adoption of SFAS 158 is provided in note (h) Pensions and other post-retirement benefits.

c Includes $(13) million relating to equity-accounted entities.

Consolidated statement of cash flows

The groups financial statements include a consolidated cash flow statement in accordance with IAS 7 Cash Flow Statements. The statement prepared under IAS 7 presents substantially the same information as that required under FASB SFAS No. 95 Statement of Cash Flows; however, as permitted under IAS 7, the group includes payments in respect of capitalized interest in operating activities. Under SFAS 95, these payments are treated as cash outflows for investing activities.

The adjustments to the groups cash flow statement for the year to accord with US GAAP are summarized below.

Increase (decrease) in caption heading			$ million
For the year ended 31 December	**2006**	2005	2004
Net cash provided by operating activities	**478**	351	204
Net cash provided by (used in) investing activities	**(478)**	(351)	(204)
Increase (decrease) in cash and cash equivalents			

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53 US GAAP reconciliation *continued*

The principal differences between IFRS and US GAAP for BP group reporting relate to the following:

(a) Deferred taxation/business combinations

Under IFRS, deferred tax assets and liabilities are recognized for the difference between the assigned values and the tax bases of the assets and liabilities recognized in a purchase business combination. IFRS 3 Business Combinations typically requires the offset to the recognition of such deferred tax assets and liabilities to be adjusted against goodwill. However, under the exemptions contained in IFRS 1 First-time Adoption of International Financial Reporting Standards, business combinations prior to the groups date of transition to IFRS were not restated in accordance with IFRS 3 and the offset was taken as an adjustment to shareholders equity at the date of transition to IFRS.

Under US GAAP, deferred tax assets or liabilities are also recognized for the difference between the assigned values and the tax bases of the assets and liabilities recognized in a purchase business combination. SFAS No. 141 Business Combinations, requires that the offset be recognized against goodwill. As such, the treatment adopted under IFRS 1 as compared with SFAS 141 creates a difference related to business combinations accounted for under the purchase method that occurred prior to the groups date of transition to IFRS.

The adjustments to profit for the year and to BP shareholders equity to accord with US GAAP are summarized below.

Increase (decrease) in caption heading		$ million	
	2006	2005	2004
Depreciation, depletion and amortization	**397**	254	2,048
Taxation	**(173)**	242	(1,531)
Profit for the year	**(224)**	(496)	(517)

	$ million	
	2006	2005
Property, plant and equipment	**3,062**	3,459
Deferred tax liabilities	**1,261**	1,434
BP shareholders equity	**1,801**	2,025

The major components of deferred tax liabilities and assets on a US GAAP basis at 31 December were as follows.

	$ million	
	2006	2005
Deferred tax liability		
Depreciation	**22,295**	20,782
Pension plan surplus	**1,733**	1,371
Other taxable temporary differences	**4,687**	4,214
	28,715	26,367
Deferred tax asset		
Petroleum revenue tax	**(457)**	(407)
Pension plan and other post-retirement benefit plan deficits	**(2,012)**	(1,154)

Decommissioning, environmental and other provisions	**(2,942)**	(2,292)
Derivative financial instruments	**(928)**	(770)
Tax credit and loss carry forward	**(3,920)**	(3,533)
Other deductible temporary differences	**(2,623)**	(1,591)
Gross deferred tax asset	**(12,882)**	(9,747)
Valuation allowance	**3,830**	3,222
Net deferred tax asset	**(9,052)**	(6,525)
Net deferred tax liability	**19,663**	19,842

(b) Provisions

Under IFRS, provisions for decommissioning and environmental liabilities are measured on a discounted basis if the effect of the time value of money is material. In accordance with IAS 37 Provisions, Contingent Liabilities and Contingent Assets, the provisions for decommissioning and environmental liabilities are estimated using costs based on current prices and discounted using rates that take into consideration the time value of money and risks inherent in the liability. The periodic unwinding of the discount is included in other finance expense. Similarly, the effect of a change in the discount rate is included in other finance expense in connection with all provisions other than decommissioning liabilities.

Upon initial recognition of a decommissioning provision, a corresponding amount is also recognized as an item of property, plant and equipment and is subsequently depreciated as part of the capital cost of the facilities. Adjustments to the decommissioning liabilities, associated with changes to the future cash flow assumptions or changes in the discount rate, are reflected as increases or decreases to the corresponding item of property, plant and equipment and depreciated prospectively over the assets remaining economic useful life.

Under US GAAP, decommissioning liabilities are recognized in accordance with SFAS No. 143 Accounting for Asset Retirement Obligations. SFAS 143 is similar to IAS 37 and requires that when an asset retirement liability is recognized, a corresponding amount is capitalized and depreciated as an additional cost of the related asset. The liability is measured based on the risk-adjusted future cash outflows discounted using a credit-adjusted risk-free rate. The unwinding of the discount is included in operating profit for the period. Unlike IFRS, subsequent changes to the discount rate do not impact the carrying value of the asset or liability. Subsequent changes to the estimates of the timing or amount of future cash flows, resulting in an increase to the asset and liability, are remeasured using updated assumptions related to the credit-adjusted risk-free rate.

In addition, the use of different oil and natural gas reserves volumes between US GAAP and IFRS until 1 October 2006 (see note (c) Oil and natural gas reserves differences) resulted in different field lives and hence differences in the manner in which the subsequent unwinding of the discount and the depreciation of the corresponding assets associated with decommissioning provisions were recognized.

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53 US GAAP reconciliation *continued*

Under US GAAP, environmental liabilities are discounted only where the timing and amounts of payments are fixed and reliably determinable.

Under IFRS, an expected loss is recognized immediately as a provision for an executory contract if the unavoidable costs of meeting the obligations under the contract exceed the economic benefits expected to be received under it. Under US GAAP, an expected loss can only be recognized if the contract is within the scope of authoritative literature that specifically provides for such accruals. The group has recognized losses under IFRS on certain sales contracts with fixed-price ceilings which do not meet loss recognition criteria under US GAAP.

The adjustments to profit for the year and to BP shareholders equity to accord with US GAAP are summarized below.

Increase (decrease) in caption heading — $ million

	2006	2005	2004
Production and manufacturing expenses and depreciation, depletion and amortization	**56**	201	254
Distribution and administration expenses	**(108)**		
Other finance (income) expense	**(245)**	(201)	(196)
Taxation	**120**	(9)	22
Profit for the year	**177**	9	(80)

$ million

	2006	2005
Property, plant and equipment	**(2,065)**	(1,842)
Provisions	**(2,184)**	(1,666)
Deferred tax liabilities	**56**	(64)
BP shareholders equity	**63**	(112)

The following data summarizes the movements in the asset retirement obligations, as adjusted to accord with US GAAP.

$ million

	2006	2005
At 1 January	**4,429**	3,898
Exchange adjustments	**9**	4
New provisions/adjustment to provisions	**1,679**	554
Unwinding of discount	**280**	237
Utilized/deleted	**(360)**	(264)
At 31 December	**6,037**	4,429

(c) Oil and natural gas reserves differences

The groups past practice was to use the UK accounting rules contained in the Statement of Recommended Practice Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities (SORP) for estimating oil and natural gas reserves for accounting and reporting purposes. These rules are different in certain respects from the corresponding SEC rules. In particular, the SEC requires the use of year-end prices, whereas under SORP the group used long-term planning prices. The consequential difference in reserves volumes resulted in different charges for depreciation, depletion and amortization (DD&A) between IFRS and US GAAP.

At the end of 2006, the group adopted the SEC rules for estimating oil and natural gas reserves for IFRS accounting and reporting purposes and the charge for DD&A was calculated on this basis for the last three months of the year. This is a change in accounting estimate and the impact of the change is applied prospectively. Differences in charges for DD&A between IFRS and US GAAP will continue due to the difference in net book values of the underlying oil and natural gas properties.

The adjustments to profit for the year and to BP shareholders equity to accord with US GAAP are summarized below.

Increase (decrease) in caption heading		$ million	
	2006	2005	2004
Gain on sale of businesses and fixed assets	**(198)**		
Depreciation, depletion and amortization	**201**	(20)	(48)
Taxation	**(156)**	9	18
Profit for the year	**(243)**	11	30

		$ million
	2006	2005
Property, plant and equipment	**(331)**	68
Deferred tax liabilities	**(129)**	27
BP shareholders equity	**(202)**	41

US GAAP requires the unit-of-production depreciation calculation to be based on development expenditure incurred to date and proved developed reserves. Where production commences before all development wells are drilled, a portion of the development costs incurred to date is excluded from the calculation. For the groups portfolio of fields there is no material difference between the groups charge for unit-of-production depreciation determined on an IFRS basis and on a US GAAP basis.

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53 US GAAP reconciliation *continued*

(d) Goodwill and intangible assets

For the purposes of US GAAP, the group accounts for goodwill according to SFAS No. 141 Business Combinations, and SFAS No. 142 Goodwill and Other Intangible Assets. For the purposes of IFRS, the group accounts for goodwill under the provisions of IFRS 3 Business Combinations and IAS 38 Intangible Assets. As a result of the transition rules available under IFRS 1, the group did not restate its past business combinations in accordance with IFRS 3 and assumed its UK GAAP carrying amount for goodwill as its IFRS carrying amount upon transition to IFRS, at 1 January 2003.

Under US GAAP, goodwill and other indefinite lived intangible assets have not been amortized since 31 December 2001. Such assets are subject to periodic impairment testing. The group has goodwill, but does not have any other intangible assets with indefinite lives. Under IFRS, goodwill amortization ceased from 1 January 2003.

The movement in the goodwill difference during 2006 is the result of movements in foreign exchange rates and a difference in the amount of goodwill allocated to the Gulf of Mexico Shelf assets sold.

During the fourth quarter of 2006 the group completed a goodwill impairment review using the two-step process prescribed in US GAAP. The first step includes a comparison of the fair value of a reporting unit to its carrying value, including goodwill. When the carrying value exceeds the fair value, the goodwill of the reporting unit is potentially impaired and the second step is then completed in order to measure the impairment loss, if any. No impairment charge resulted from this review.

The adjustments to profit for the year and to BP shareholders equity to accord with US GAAP are summarized below.

Increase (decrease) in caption heading			$ million
	2006	2005	2004
Gain on sale of businesses and fixed assets	**13**		
Depreciation, depletion and amortization	****		61
Profit for the year	**13**		(61)

		$ million
	2006	2005
Goodwill	**248**	171
BP shareholders equity	**248**	171

In accordance with group accounting practice, exploration licence acquisition costs are capitalized initially as an intangible asset and are amortized over the estimated period of exploration. Where proved reserves of oil or natural gas are determined and development is sanctioned, the unamortized cost is transferred to property, plant and equipment. Where exploration is unsuccessful, the unamortized cost is charged against income. At 31 December 2006 and 31 December 2005, exploration licence acquisition costs included in the groups property, plant and equipment and intangible assets, net of accumulated amortization were as follows.

		$ million
	2006	2005
Exploration licence acquisition cost included in non-current assets (net of accumulated amortization)		
Property, plant and equipment	**1,076**	1,201
Intangible assets	**639**	597

Changes to the net book amount of exploration expenditure, goodwill and other intangible assets, as adjusted to accord with US GAAP, during the years ended 31 December 2006 and 2005 are shown below.

					$ million
	Exploration expenditure	Goodwill	Additional minimum pension liability (h)	Other intangibles	Total
Net book amount					
At 1 January 2005	3,761	11,535	39	443	15,778
Amortization expense	(305)	—	—	(161)	(466)
Other movements	552	(862)	(12)	482	160
At 1 January 2006	**4,008**	**10,673**	**27**	**764**	**15,472**
Amortization expense	**(732)**	**—**	**—**	**(217)**	**(949)**
Other movements	**834**	**476**	**(27)**	**589**	**1,872**
At 31 December 2006	**4,110**	**11,149**	**—**	**1,136**	**16,395**

Amortization expense relating to other intangibles is expected to be in the range of $200-250 million in each of the succeeding five years.

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53 US GAAP reconciliation *continued*

(e) Derivative financial instruments

Under IFRS, the group accounts for its derivative financial instruments under IAS 39 Financial Instruments: Recognition and Measurement. IAS 39 requires that derivative financial instruments be measured at fair value and changes in fair value are either recognized in the income statement or directly in equity (other comprehensive income) depending on the classification of the instrument. Changes in the fair value of derivatives held for trading purposes or those not designated or effective as hedges are recognized in the income statement.

Changes in the fair value of derivatives designated and effective as cash flow hedges are recognized directly in equity (other comprehensive income). Amounts recorded in equity are transferred to the income statement when the hedged transaction affects profit or loss. Where the hedged item is the cost of a non-financial asset or liability, the amounts taken to equity are transferred to the initial carrying amount of the non-financial asset or liability.

Changes in the fair value of derivatives designated and effective as fair value hedges are recognized in the income statement. The carrying amount of the hedged item is adjusted for gains and losses attributable to the risk being hedged with the corresponding gains and losses recognized in the income statement.

On adoption of IAS 39 on 1 January 2005, all cash flow and fair value hedges that previously qualified for hedge accounting under UK GAAP were recorded on the balance sheet at fair value with the offset recorded through equity.

Under US GAAP all derivative financial instruments are accounted for under SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities and recorded on the balance sheet at their fair value. Similar to IAS 39, SFAS 133 requires that changes in the fair value of derivatives are recorded each period in the income statement or other comprehensive income, depending on whether the instrument is designated as part of a hedge transaction.

Prior to 1 January 2005, the group did not designate any of its derivative financial instruments as part of hedged transactions under SFAS 133. As a result, all changes in fair value were recognized in the income statement. A difference therefore exists between the treatment applied under SFAS 133 and that upon initial adoption of IAS 39 associated with those specific derivative instruments. This difference will remain until these individual derivative transactions mature.

Additionally, under IFRS, hedge accounting can be applied to certain centrally-hedged foreign currency exposures. Under US GAAP, hedge accounting can be applied only where the companies between the central treasury and the entity having the foreign currency exposure have the same functional currency.

The adjustments to profit for the year and to BP shareholders equity to accord with US GAAP are summarized below.

Increase (decrease) in caption heading		$ million	
	2006	2005	2004
Production and manufacturing expenses	**(169)**		481
Finance costs	**(17)**	(15)	
Taxation	**44**	(72)	(144)
Profit for the year	**142**	87	(337)

	$ million	
	2006	2005
Goodwill	**131**	131
Finance debt	**(117)**	(140)
Deferred tax liabilities	**46**	46
BP shareholders equity	**202**	225

(f) Inventory valuation

Under IFRS, inventory held for trading purposes is remeasured to fair value with the changes in fair value recognized in the income statement. Under US GAAP, all balances recorded in inventory are measured at the lower of cost and net realizable value.

The adjustments to profit for the year and to BP shareholders equity to accord with US GAAP are summarized below.

Increase (decrease) in caption heading			$ million
	2006	2005	2004
Purchases	**(250)**	357	(250)
Taxation	**88**	(125)	88
Profit for the year	**162**	(232)	162

		$ million
	2006	2005
Inventories	**(7)**	(257)
Deferred tax liabilities	**(2)**	(90)
BP shareholders equity	**(5)**	(167)

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53 US GAAP reconciliation *continued*

(g) Gain arising on asset exchange

Under IFRS, exchanges of non-monetary assets are generally accounted for at fair value at the date of the transaction, with any gain or loss recognized in profit or loss. Under US GAAP prior to 1 January 2005, exchanges of non-monetary assets were accounted for at book value. From 1 January 2005 exchanges of non-monetary assets are generally accounted for at fair value under both IFRS and US GAAP.

The adjustments to profit for the year and to BP shareholders equity to accord with US GAAP are summarized below.

Increase (decrease) in caption heading $ million

	2006	2005	2004
Depreciation, depletion and amortization	**15**	19	117
Taxation	**(5)**	(7)	(10)
Profit for the year	**(10)**	(12)	(107)

$ million

	2006	2005
Property, plant and equipment	**352**	367
Deferred tax liabilities	**123**	128
BP shareholders equity	**229**	239

(h) Pensions and other post-retirement benefits

Under IFRS, the group accounts for its pension and other post-retirement benefit plans according to IAS 19 Employee Benefits. Surpluses and deficits of pension and other post-retirement benefit plans are included in the group balance sheet at their fair values and all movements in these balances are reflected in the income statement, except for those relating to actuarial gains and losses which are reflected in the statement of recognized income and expense. In the past, this treatment has differed from the groups US GAAP treatment under SFAS No. 87 Employers Accounting for Pensions and SFAS No. 106 Employers Accounting for Post-retirement Benefits Other Than Pensions, where actuarial gains and losses were not recognized in the income statement as they occurred but were recognized within income in full only when they exceeded certain thresholds, and otherwise were amortized. This difference in recognition rules for actuarial gains and losses gave rise to differences in periodic pension and other post-retirement benefit expense as measured under IAS 19 compared to SFAS 87 and SFAS 106.

In addition, when a pension plan had an accumulated benefit obligation which exceeded the fair value of the plan assets, SFAS 87 required the unfunded amount to be recognized as a minimum liability in the balance sheet. The offset to this liability was recorded as an intangible asset up to the amount of any unrecognized prior service cost or transitional liability, and thereafter directly in other comprehensive income. IAS 19 does not have a similar concept. As a result, this created a difference in shareholders equity as measured under IFRS and US GAAP.

In September 2006, the FASB issued SFAS No. 158 Employers Accounting for Defined Benefit Pension and Other Post-retirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R). SFAS 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit post-retirement plan (other than a multi-employer plan) as an asset or liability in the balance sheet and to recognize changes in that funded status in other comprehensive income in the year in which the changes occur. Because the funded status of benefit plans is fully recognized in the balance sheet, a minimum liability will no longer be recognized. Retrospective application of SFAS 158 is not permitted. Upon adoption of SFAS 158, the recognition of the overfunded or underfunded status of the groups defined benefit pension and other post-retirement plans generally accords with the groups IFRS accounting. Differences in recognition rules for actuarial gains and losses will continue to give rise to differences in periodic pension and other post-retirement benefit expense as measured under IFRS and US GAAP. The group has adopted SFAS 158 with effect from 31 December 2006, resulting in a $599 million decrease in BP shareholders equity, as adjusted to accord with US GAAP. Of this total effect, $586 million relates to group entities and $13 million relates to equity-accounted entities. The effect on equity-accounted entities is included in note (j) Equity-accounted investments. Further information on the effects of adoption of SFAS 158 is given below.

The adjustments to profit for the year and to BP shareholders equity to accord with US GAAP are summarized below.

Increase (decrease) in caption heading			$ million
	2006	2005	2004
Production and manufacturing expenses	**801**	583	330
Other finance (income) expense	**470**	116	(29)
Taxation	**(398)**	(213)	(254)
Profit for the year	**(873)**	(486)	(47)

		$ million
	2006	2005
Intangible assets		27
Other receivables		6,667
Defined benefit pension plan surplus		(3,282)
Current liabilities	**603**	
Provisions		7,884
Defined benefit pension plan and other post-retirement benefit plan deficits	**(603)**	(9,230)
Deferred tax liabilities		1,612
BP shareholders equity		3,146

The incremental effects of adopting the provisions of SFAS 158 on the groups balance sheet at 31 December 2006, as adjusted to accord with US GAAP, are presented in the following table. The adoption of SFAS 158 had no effect on the groups consolidated income statement, as adjusted to accord with US GAAP, and will not affect the groups US GAAP profit in future periods. Had the group not been required to adopt SFAS 158 at 31 December 2006, the group would have recognized an additional minimum pension liability. The effect of recognizing the additional minimum pension liability is included in the table below in the column headed Prior to adoption.

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53 US GAAP reconciliation *continued*

$ million

	Prior to adoption	Effect of adoption	As reported
Intangible assets	**12**	**(12)**	**—**
Other receivables	**7,022**	**(7,022)**	**—**
Defined benefit pension plan surplus	**—**	**6,753**	**6,753**
Current liabilities	**—**	**603**	**603**
Provisions	**8,622**	**(8,622)**	**—**
Defined benefit pension plan and other post-retirement benefit plan deficits	**—**	**8,673**	**8,673**
Deferred tax liabilities	**573**	**(349)**	**224**
BP shareholders' equity	**(2,161)**	**(586)**	**(2,747)**
Accumulated other comprehensive income	**1,022**	**935**	**1,957**
Taxation	**238**	**349**	**587**
Accumulated other comprehensive income (net of deferred tax)	**784**	**586**	**1,370**

Further information in respect of the group's defined benefit pension and other post-retirement plans required under US GAAP is set out below.

Analysis of the pension and other post-retirement benefits expense

$ million

	2006	2005	2004
Defined benefit plans			
Service cost – benefits earned during year	**829**	785	757
Interest cost on projected benefit obligation	**1,940**	2,022	2,012
Expected return on plan assets	**(2,140)**	(2,115)	(2,161)
Amortization of transition asset	**11**	10	9
Recognized net actuarial (gain) loss	**934**	656	445
Recognized prior service cost	**55**	79	64
Curtailment and settlement (gains) losses	**(43)**	(38)	(4)
Special termination benefits	**278**	49	60
	1,864	1,448	1,182
Defined contribution plans	**177**	172	162
	2,041	1,620	1,344
Innovene operations	**—**	(83)	(102)
Total pension and other post-retirement benefits expense for continuing operations	**2,041**	1,537	1,242

The table below shows the amounts included in accumulated other comprehensive income at 31 December 2006 that have not yet been recognized as components of the pension and other post-retirement benefits expense in the income statement, as adjusted to accord with US GAAP.

$ million

	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
Net actuarial (gain) loss	**(1,805)**	**2,099**	**514**	**1,055**	**1,863**
Prior service cost (credit)	**398**	**101**	**(431)**	**19**	**87**
Transition obligation (asset)	**—**	**—**	**—**	**7**	**7**
	(1,407)	**2,200**	**83**	**1,081**	**1,957**

The amounts included in accumulated other comprehensive income at 31 December 2006 which are expected to be recognized as components of the pension and other post-retirement benefits expense for the year ended 31 December 2007 in the income statement, as adjusted to accord with US GAAP are shown below.

$ million

	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
Net actuarial (gain) loss	**243**	**222**	**47**	**120**	**632**
Prior service cost (credit)	**76**	**11**	**(54)**	**3**	**36**
Transition obligation (asset)	**—**	**—**	**—**	**—**	**—**
	319	**233**	**(7)**	**123**	**668**

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53 US GAAP reconciliation *continued*

The table below shows, at 31 December 2006, the aggregate projected benefit obligation and the aggregate fair value of plan assets for those pension plans where the projected benefit obligation exceeds the fair value of the plan assets.

$ million

	UK pension plans	**US pension plans**	**Other plans**	**Total**
Projected benefit obligation	**117**	**411**	**7,082**	**7,610**
Fair value of plan assets	—	**54**	**1,554**	**1,608**
Excess of projected benefit obligation over plan assets	**117**	**357**	**5,528**	**6,002**

The table below shows, at 31 December 2006, the aggregate accumulated benefit obligation and the aggregate fair value of plan assets for those pension plans where the accumulated benefit obligation exceeds the fair value of the plan assets.

$ million

	UK pension plans	**US pension plans**	**Other plans**	**Total**
Accumulated benefit obligation	**92**	**386**	**5,770**	**6,248**
Fair value of plan assets	—	**54**	**660**	**714**
Excess of accumulated benefit obligation over plan assets	**92**	**332**	**5,110**	**5,534**

A summary of benefit obligations and amounts recognized under US GAAP in the balance sheet at 31 December 2005 is shown below.

$ million

	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
Benefit obligation at 31 December	20,063	7,900	3,478	7,414	38,855
Fair value of plan assets at 31 December	23,282	7,317	28	2,280	32,907
Funded status	3,219	(583)	(3,450)	(5,134)	(5,948)
Unrecognized transition (asset) obligation	—	—	—	17	17
Unrecognized net actuarial (gain) loss	222	3,249	793	1,454	5,718
Unrecognized prior service cost	490	70	(485)	8	83
Net amount recognized	3,931	2,736	(3,142)	(3,655)	(130)

Prepaid benefit cost (accrued benefit liability)	3,910	2,535	(3,154)	(4,508)	(1,217)
Intangible asset	—	12	—	15	27
Accumulated other comprehensive income[a]	21	189	12	838	1,060
	3,931	2,736	(3,142)	(3,655)	(130)

[a] Total $866 million net of deferred tax.

(i) Impairments

Under IFRS, in determining the amount of any impairment loss, the carrying value of property, plant and equipment and goodwill is compared with the discounted value of the future cash flows. Under US GAAP, SFAS No. 144 “Accounting for the Impairment or Disposal of Long-lived Assets” requires that the carrying value is compared with the undiscounted future cash flows to determine if an impairment is present, and only if the carrying value is less than the undiscounted cash flows is an impairment loss recognized. The impairment is measured using the discounted value of the future cash flows. Due to this difference, some impairment charges recognized under IFRS, adjusted for the impacts of depreciation, have not been recognized for US GAAP.

Additionally, under IFRS, in certain situations and subject to certain limitations, a previously-recognized impairment loss is reversed. Under US GAAP, the reversal of a previously-recognized impairment loss for an asset to be held and used is not permitted.

The decrease to gain on sale of businesses and fixed assets for the year ended 31 December 2006 represents the impact of a 2005 impairment charge recognized under IFRS but not for US GAAP on certain Gulf of Mexico Shelf assets that were subsequently sold in 2006.

The adjustments to profit for the year and to BP shareholders’ equity to accord with US GAAP are summarized below.

Increase (decrease) in caption heading		$ million	
	2006	2005	2004
Gain on sale of businesses and fixed assets	**(208)**	—	—
Depreciation, depletion and amortization	**6**	28	—
Impairment and losses on sale of businesses and fixed assets	**340**	477	(986)
Taxation	**(222)**	(127)	309
Profit for the year	**(332)**	(378)	677

		$ million
	2006	2005
Property, plant and equipment	**(40)**	504
Deferred tax liabilities	**(42)**	177
BP shareholders’ equity	**2**	327

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53 US GAAP reconciliation *continued*

(j) Equity-accounted investments

Under IFRS the group's accounting policies are applied in arriving at the amounts to be included in the financial statements in relation to equity-accounted investments. The major difference between IFRS and US GAAP in this respect relates to deferred tax (see note (a) Deferred taxation/business combinations).

The adjustments to profit for the year and to BP shareholders' equity to accord with US GAAP are summarized below.

Increase (decrease) in caption heading			$ million
	2006	2005	2004
Earnings from jointly controlled entities	**(104)**	(255)	147
Profit for the year	**(104)**	(255)	147

		$ million
	2006	2005
Investments in jointly controlled entities	**(160)**	(43)
BP shareholders' equity	**(160)**	(43)

(k) Assets classified as held for sale

Recognition and measurement of assets classified as held for sale (and liabilities directly associated with assets classified as held for sale) under IFRS is substantially equivalent to US GAAP. However, the amounts presented for IFRS reporting differ from those under US GAAP due to differences in the underlying carrying values of the assets and liabilities classified as held for sale.

The adjustments to BP shareholders' equity to accord with US GAAP are summarized below.

Increase (decrease) in caption heading		$ million
	2006	2005
Goodwill	**(10)**	–
Assets classified as held for sale	**10**	–
BP shareholders' equity	**–**	–

(l) Consolidation of variable interest entities

In December 2003, the FASB issued FASB Interpretation No. 46 (Revised) 'Consolidation of Variable Interest Entities'. Interpretation 46 clarifies the application of existing consolidation requirements to entities where a controlling financial interest is achieved through arrangements that do not involve voting interests. Under Interpretation 46, a variable interest entity is consolidated if a company is subject to a majority of the risk of loss from the variable interest entity's activities or entitled to receive a majority of the entity's residual returns.

The group currently has several ships under construction or in service which are accounted for under IFRS as operating leases. Under Interpretation 46 certain of the arrangements represent variable interest entities that would be consolidated by the group. The maximum exposure to loss as a result of the group's involvement with these entities is limited to the debt of the entity, less the fair value of the ships at the end of the lease term.

During 2006, a number of the existing leasing arrangements that were being consolidated for US GAAP reporting were modified. Under the revised arrangements, the group is not the primary beneficiary. As such, the arrangements are no longer consolidated under US GAAP.

The adjustments to profit for the year and to BP shareholders' equity to accord with US GAAP are summarized below.

Increase (decrease) in caption heading		$ million	
	2006	2005	2004
Production and manufacturing expenses	**(18)**	(32)	(15)
Depreciation, depletion and amortization	**21**	23	10
Finance costs	**6**	9	5
Taxation	**(4)**	—	—
Profit for the year	**(5)**	—	—

	$ million	
	2006	2005
Property, plant and equipment	**497**	807
Trade and other payables	**(45)**	(31)
Finance debt	**551**	838
Deferred tax liabilities	**(4)**	—
BP shareholders' equity	**(5)**	—

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53 US GAAP reconciliation *continued*

(m) Major maintenance expenditure

For the purposes of US GAAP reporting, prior to 1 January 2005, the group capitalized expenditures on maintenance, refits or repairs where it enhanced or restored the performance of an asset, or replaced an asset or part of an asset that was separately depreciated. This included other elements of expenditure incurred during major plant maintenance shutdowns, such as overhaul costs.

With effect from 1 January 2005, the group changed its US GAAP accounting policy to expense the part of major maintenance that represents overhaul costs and similar major maintenance expenditure as incurred. The effect of this accounting change for US GAAP reporting is reflected as a cumulative effect of an accounting change for the year ended 31 December 2005 of $794 million (net of tax benefits of $354 million). This adjustment is equal to the net book value of capitalized overhaul costs as of 1 January 2005 as reported under US GAAP. This new accounting policy reflects the policy applied under IFRS for all periods presented. As a result, a difference between IFRS and US GAAP exists for periods prior to 1 January 2005 which reflects the capitalization of overhaul costs net of the related depreciation charge as calculated under US GAAP.

The adjustments to profit for the year to accord with US GAAP are summarized below.

Increase (decrease) in caption heading		$ million	
	2006	2005	2004
Production and manufacturing expenses	—	—	(586)
Depreciation, depletion and amortization	—	—	296
Taxation	—	—	73
Profit for the year before cumulative effect of accounting change	—	—	217
Cumulative effect of accounting change	—	(794)	—
Profit for the year	—	(794)	217

The following pro forma information summarizes the profit for the year assuming the change in accounting for major maintenance expenditure was applied retrospectively with effect from 1 January 2004.

		$ million
	2005[a]	2004
Profit for the year attributable to ordinary shares as adjusted to accord with US GAAP		
As reported	19,640	17,088
Pro forma	20,434	16,871
Per ordinary share — cents		
Basic — as reported	92.96	78.31
Basic — pro forma	96.72	77.32
Diluted — as reported	91.90	76.88
Diluted — pro forma	95.61	75.97
Per American depositary share — cents		
Basic — as reported	557.76	469.86
Basic — pro forma	580.32	463.92
Diluted — as reported	551.40	461.28
Diluted — pro forma	573.66	455.82

a Pro forma data for the year ended 31 December 2005 excludes the cumulative effect of adoption.

(n) Share-based payments

The group adopted SFAS No. 123 (revised 2004), "Share-Based Payment" with effect from 1 January 2005 using the modified prospective transition method. Under SFAS 123(R), share-based payments to employees are required to be measured based on their grant date fair value (with limited exceptions) and recognized over the related service period. For periods prior to 1 January 2005, the group accounted for share-based payments under Accounting Principles Board Opinion No. 25 using the intrinsic value method.

With effect from 1 January 2005, as part of the adoption of IFRS, the group adopted IFRS 2 ‘Share-based Payment’. IFRS 2 requires the recognition of expense when goods or services are received from employees or others in consideration for equity instruments. In adopting IFRS 2, the group elected to restate prior years to recognize an expense associated with share-based payments that were not fully vested at 1 January 2003, BP’s date of transition to IFRS, and the liability relating to cash-settled share-based payments at 1 January 2003.

As a result of the transition requirements of SFAS 123(R) and IFRS 2, certain differences between US GAAP and IFRS have arisen. For periods prior to 1 January 2005, the group has recognized share-based payments under IFRS using a fair value method which is substantially different from the intrinsic value method used under US GAAP. From 1 January 2005, the group has used the fair value method to measure share-based payment expense under both IFRS and US GAAP. A difference in expense exists however because the group uses a different valuation model under US GAAP for issued options outstanding and not yet vested at 31 December 2004 as required under the transition rules of SFAS 123(R).

In addition, deferred taxes on share-based compensation are recognized differently under US GAAP than under IFRS. Under US GAAP, deferred taxes are recorded on share-based payment expense recognized during the period in accordance with SFAS 109. Under IFRS, deferred taxes are only recorded on the difference between the tax base of the underlying shares and the carrying value of the employee services as determined at each balance sheet date in accordance with IAS 12.

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53 US GAAP reconciliation *continued*

The adjustments to profit for the year and to BP shareholders equity to accord with US GAAP are summarized below.

Increase (decrease) in caption heading

			$ million
	2006	2005	2004
Production and manufacturing expenses	**5**	4	(28)
Distribution and administration expenses	**9**	9	(58)
Taxation	**(106)**	(19)	62
Profit for the year	**92**	6	24

		$ million
	2006	2005
Deferred tax liabilities	**254**	334
BP shareholders equity	**(254)**	(334)

(o) Discontinued operations

Under IFRS, a component of an entity held for sale as part of a single plan to dispose of a separate major line of business is classified as a discontinued operation in the income statement.

Under US GAAP (EITF Issue No. 03-13 Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations), a disposed component of an enterprise is classified as a discontinued operation only where the ongoing entity has no significant continuing direct cash flows and does not retain an interest, contract or other arrangement sufficient to enable the entity to exert significant influence over the disposed components operating and financial policies after disposal.

In connection with the sale of Innovene the group has a number of commercial arrangements with Innovene for the supply of refining and petrochemical feedstocks, and the purchase and sale of refined products.

Because of continuing direct cash flows that will result from activities with Innovene subsequent to divestment, under US GAAP the operations of Innovene would not be classified as a discontinued operation but would be included in the groups continuing operations. Under IFRS, the operations of Innovene are classified as discontinued operations.

The following summarizes the income statement reclassifications that would be made if the operations of Innovene were shown in continuing operations.

			$ million
			2006
	As reported	**Reclassification**	**As adjusted**
Sales and other operating revenues	**265,906**		**265,906**
Profit before interest and taxation from continuing operations	**35,658**	**(184)**	**35,474**
Finance costs	**718**		**718**
Other finance (income) expense	**(202)**		**(202)**
Profit before taxation from continuing operations	**35,142**	**(184)**	**34,958**

Taxation	**12,516**	**(159)**	**12,357**
Profit from continuing operations	**22,626**	**(25)**	**22,601**
Loss from Innovene operations	**(25)**	**25**	—
Profit for the year	**22,601**	—	**22,601**

			$ million
			2005
	As reported	Reclassification	As adjusted
Sales and other operating revenues	239,792	12,376	252,168
Profit before interest and taxation from continuing operations	32,182	141	32,323
Finance costs	616	—	616
Other finance (income) expense	145	(3)	142
Profit before taxation from continuing operations	31,421	144	31,565
Taxation	9,288	(40)	9,248
Profit from continuing operations	22,133	184	22,317
Profit from Innovene operations	184	(184)	—
Profit for the year	22,317	—	22,317

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53 US GAAP reconciliation *continued*

			$ million
			2004
	As reported	Reclassification	As adjusted
Sales and other operating revenues	192,024	11,279	203,303
Profit before interest and taxation from continuing operations	25,746	(714)	25,032
Finance costs	440		440
Other finance expense	340	17	357
Profit before taxation from continuing operations	24,966	(731)	24,235
Taxation	7,082	(109)	6,973
Profit from continuing operations	17,884	(622)	17,262
Loss from Innovene operations	(622)	622	
Profit for the year	17,262		17,262

(p) Energy trading contracts

The disclosure requirements of EITF 02-03 Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities, in respect of energy trading contracts are set out below. For the group, energy trading contracts in oil, natural gas, NGLs and power comprise exchange-traded derivative instruments such as futures and options and non-exchange-traded instruments such as swaps, over-the-counter options and forward contracts.

The following tables show the net fair value of contracts held for trading purposes at 31 December analysed by maturity period and by methodology of fair value estimation.

					$ million
					2006
	Less than 1 year	**1-3 years**	**4-5 years**	**Over 5 years**	**Total**
Prices actively quoted					
Prices sourced from observable data or market corroboration	**654**	**83**	**55**	**4**	**796**
Prices based on models and other valuation methods	**12**	**(26)**	**(14)**	**20**	**(8)**
	666	**57**	**41**	**24**	**788**

	$ million
	2005

	Less than 1 year	1-3 years	4-5 years	Over 5 years	Total
Prices actively quoted	(179)	(146)	(4)	(12)	(341)
Prices sourced from observable data or market corroboration	660	(89)	49	—	620
Prices based on models and other valuation methods	12	1	77	46	136
	493	(234)	122	34	415

The following tables show the changes during the year in the net fair value of instruments held for trading purposes for the years 2006, 2005 and 2004.

$ million

	Oil price	**Natural gas price**	**Power price**
Fair value of contracts at 1 January 2006	**(34)**	**270**	**179**
Contracts realized or settled in the year	**83**	**(259)**	**(33)**
Unrealized gains (losses) recognized at inception of contract	**36**	**249**	**(69)**
Unrealized gains (losses) recognized as a result of changes in valuation techniques and assumptions	**1**	—	—
Other unrealized gains (losses) recognized during the year	**(68)**	**469**	**(36)**
Fair value of contracts at 31 December 2006	**18**	**729**	**41**

$ million

	Oil price	Natural gas price	Power price
Fair value of contracts at 1 January 2005	(140)	414	177
Contracts realized or settled in the year	144	(681)	76
Unrealized gains (losses) recognized at inception of contract	(73)	(41)	1
Unrealized gains (losses) recognized as a result of changes in valuation techniques and assumptions	—	—	—
Other unrealized gains (losses) recognized during the year	35	578	(75)
Fair value of contracts at 31 December 2005	(34)	270	179

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53 US GAAP reconciliation *continued*

			$ million
	Oil price	Natural gas price	Power price
Fair value of contracts at 1 January 2004	(154)	191	134
Contracts realized or settled in the year	154	259	54
Unrealized gains (losses) recognized at inception of contract	(33)	73	(3)
Unrealized gains (losses) recognized as a result of changes in valuation techniques and assumptions	–	–	–
Other unrealized gains (losses) recognized during the year	(107)	(109)	(8)
Fair value of contracts at 31 December 2004	(140)	414	177

In addition to the risk management activities related to equity crude disposal, refinery supply and marketing, BP's supply and trading function undertakes trading in the full range of conventional derivative financial and commodity instruments and physical cargoes available in the energy markets. The group controls the scale of the trading exposures by using a value-at-risk model with a maximum value-at-risk limit authorized by the board.

The group measures its market risk exposure, i.e. potential gain or loss in fair values, on its trading activity 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 values 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 potential movement in fair values is expressed to 1.65 standard deviations which is equivalent to a 95% confidence level. This means that, in broad terms, one would expect to see an increase or a decrease in fair values greater than the value at risk on approximately one occasion per month if the portfolio were left unchanged.

The group calculates value at risk on all instruments that are held for trading purposes and therefore give an exposure to market risk. The value-at-risk models take account of derivative financial instruments such as oil, natural gas and power price futures and swap agreements. Financial assets and liabilities and physical crude oil and refined products that are treated as held for trading positions are also included in these calculations. For options, a linear approximation is included in the value-at-risk models. The value-at-risk calculation for oil, natural gas, NGLs and power price exposure also includes derivative commodity instruments (commodity contracts that permit settlement either by delivery of the underlying commodity or in cash), such as forward contracts.

The following table shows values at risk for energy trading activities.

				$ million
	High	Low	Average	Year end
2006				
Oil price trading	**56**	**16**	**29**	**22**
Natural gas and NGL price trading	**29**	**10**	**19**	**15**
Power price trading	**11**	**2**	**6**	**3**
2005				
Oil price trading	80	17	33	31
Natural gas and NGL price trading	39	6	15	17
Power price trading	16	2	7	9
2004				
Oil price trading	30	10	16	25
Natural gas and NGL price trading	23	6	13	10

Power price trading	10	1	4	4

Impact of new US accounting standards

Adopted for 2006

Accounting changes and error corrections

In May 2005, the FASB issued SFAS No. 154 "Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3". SFAS 154 applies to all voluntary changes in accounting principle and changes the requirements for the accounting for and reporting of a change in accounting principle. SFAS 154 requires retrospective application to prior period financial statements of a voluntary change in accounting principle unless it is impracticable. Previously, most voluntary changes in accounting principle were recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. SFAS 154 also requires that a change in the method of depreciation, amortization or depletion for long-lived non-financial assets be accounted for as a change in accounting estimate that is affected by a change in accounting principle. Previously, such changes were reported as a change in accounting principle. SFAS 154 is effective for accounting changes and corrections of errors made in accounting periods beginning after 15 December 2005. The group adopted SFAS 154 with effect from 1 January 2006. The adoption of SFAS 154 did not have a significant effect on the group's profit as adjusted to accord with US GAAP, or on BP shareholders' equity as adjusted to accord with US GAAP.

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53 US GAAP reconciliation *continued*

Revenue

In September 2005, the FASB ratified the consensus reached by the EITF regarding Issue No. 04-13 "Accounting for Purchases and Sales of Inventory with the Same Counterparty". EITF 04-13 addresses accounting issues that arise when a company both sells inventory to and buys inventory from another entity in the same line of business. The purchase and sale transactions may be pursuant to a single contractual arrangement or separate contractual arrangements and the inventory purchased or sold may be in the form of raw material, work-in-process or finished goods. At issue is whether the revenue, inventory cost and cost of sales should be recorded at fair value or whether the transactions should be classified as non-monetary transactions. EITF 04-13 requires purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another be combined and recorded as exchanges measured at the book value of the item sold. EITF 04-13 is effective for new arrangements entered into and modifications or renewals of existing arrangements in accounting periods beginning after 15 March 2006. The group adopted EITF 04-13 with effect from 1 January 2006. The adoption of EITF 04-13 did not have a significant effect on the group's profit as adjusted to accord with US GAAP, or on BP shareholders' equity as adjusted to accord with US GAAP.

Share-based payments

In February 2006, the FASB issued Staff Position No. FAS 123(R)-4 "Classification of Options and Similar Instruments Issued as Employee Compensation That Allow for Cash Settlement upon the Occurrence of a Contingent Event". FSP 123(R)-4 clarifies the classification of options and similar instruments issued as employee compensation that allow for cash settlement upon the occurrence of a contingent event. Under FSP 123(R)-4, an option or similar instrument with a contingent cash settlement provision is classified as an equity award provided that the contingent event that permits or requires cash settlement is not considered probable of occurring, the contingent event is not within the control of the employee and the award includes no other features that would require liability classification. For entities that adopted SFAS 123(R) prior to the issuance of FSP 123(R)-4, FSP 123(R)-4 is effective for accounting periods beginning after 3 February 2006. The group adopted FSP 123(R)-4 with effect from 1 January 2006. The adoption of FSP 123(R)-4 did not have a significant effect on the group's profit as adjusted to accord with US GAAP, or on BP shareholders' equity as adjusted to accord with US GAAP.

Consolidation of variable interest entities

In April 2006, the FASB issued Staff Position No. FIN 46(R)-6, "Determining the Variability to Be Considered in Applying FASB Interpretation No. 46(R)". FSP 46(R)-6 clarifies how variability should be considered in applying FIN 46(R). Variability is used in applying FIN 46(R) to determine whether an entity is a variable interest entity, which interests are variable interests in the entity, and who is the primary beneficiary of the variable interest entity. Under FSP 46(R)-6, the variability to be considered in applying FIN 46(R)-6 is based on the design of the entity, the nature and risks of the entity and the purpose for which entity was created. FSP 46(R)-6 is effective for accounting periods beginning after 15 June 2006. The group adopted FSP 46(R)-6 with effect from 1 July 2006. The adoption of FSP 46(R)-6 did not have a significant effect on the group's profit as adjusted to accord with US GAAP, or on BP shareholders' equity as adjusted to accord with US GAAP.

Pensions and other post-retirement benefits

In September 2006, the FASB issued SFAS No. 158 "Employers' Accounting for Defined Benefit Pension and Other Post-retirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)". SFAS 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit post-retirement plan (other than a multi-employer plan) as an asset or liability in the balance sheet and to recognize changes in that funded status in other comprehensive income in the year in which the changes occur. The group adopted SFAS 158 with effect from 31 December 2006, resulting in a $599 million decrease in BP shareholders' equity, as adjusted to accord with US GAAP. Of this total effect, $586 million relates to group entities and $13 million relates to equity-accounted entities. Further information on the effects of adoption of SFAS 158 is provided in note (h) Pensions and other post-retirement benefits.

Financial statement misstatements

In September 2006, the staff of the SEC issued Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements". SAB 108 was issued to address the diversity in practice in quantifying misstatements from prior years and assessing their effect on current year financial statements. SAB 108 is effective for fiscal years ending after 15 November 2006. The adoption of SAB 108 did not have a significant effect on the group's profit as adjusted to accord with US GAAP, or on BP shareholders' equity as adjusted to accord with US GAAP.

Not yet adopted

Financial instruments

In February 2006, the FASB issued SFAS No. 155, Accounting for Certain Hybrid Financial Instruments an amendment of FASB Statements No. 133 and 140. SFAS 155 simplifies the accounting for certain hybrid financial instruments under SFAS 133 by permitting fair value remeasurement for financial instruments containing an embedded derivative that otherwise would require separation of the derivative from the financial instrument. SFAS 155 is effective for all financial instruments acquired, issued or subject to a remeasurement event occurring in fiscal years beginning after 15 September 2006. The adoption of SFAS 155 is not expected to have a significant effect on the groups profit as adjusted to accord with US GAAP, or on BP shareholders equity as adjusted to accord with US GAAP.

Taxes collected from customers

In June 2006, the FASB ratified the consensus reached by the EITF regarding Issue No. 06-3 How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation). Under EITF 06-3, taxes collected from customers and remitted to governmental authorities can be presented either gross within revenue and cost of sales, or net. Where such taxes are significant, EITF 06-3 requires disclosure of the accounting policy for presenting taxes and the amount of any such taxes that are recognized on a gross basis. EITF 06-3 is effective for accounting periods beginning after 15 December 2006. The group has not yet adopted EITF 06-3. The groups accounting policy with regard to taxes collected from customers and remitted to governmental authorities is to present such taxes net in the income statement, and as a result the adoption of EITF 06-3 will not have any impact.

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53 US GAAP reconciliation continued

Income taxes

In June 2006, the FASB issued FASB Interpretation No. 48 "Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109". Interpretation 48 clarifies the accounting for uncertainty with regard to income taxes recognized in an entity's financial statements in accordance with SFAS 109 and prescribes a recognition threshold and measurement attribute for the recognition and measurement of a tax position taken or expected to be taken in a tax return. Interpretation 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The group will adopt Interpretation 48 with effect from 1 January 2007. Adoption of Interpretation 48 is not expected to have a significant effect on the group's profit as adjusted to accord with US GAAP, or on BP shareholders' equity as adjusted to accord with US GAAP.

Fair value measurements

In September 2006, the FASB issued SFAS No. 157 "Fair Value Measurements". SFAS 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS 157 applies under other accounting pronouncements that require or permit fair value measurements. SFAS 157 is effective for accounting periods beginning after 15 November 2007. The group has not yet completed its evaluation of the impact of adopting SFAS 157 on the group's profit as adjusted to accord with US GAAP, or on BP shareholders' equity as adjusted to accord with US GAAP.

Fair value option

In February 2007, the FASB issued SFAS No. 159 "The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115". SFAS 159 permits an entity, at specified election dates, to choose to measure certain financial instruments and other items at fair value. The objective of SFAS 159 is to provide entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently, without having to apply complex hedge accounting provisions. SFAS 159 is effective for accounting periods beginning after 15 November 2007. The group has not yet completed its evaluation of the impact of adopting SFAS 159 on the group's profit as adjusted to accord with US GAAP, or on BP shareholders' equity as adjusted to accord with US GAAP.

54 Auditors' remuneration for US reporting

$ million

		2006		2005		2004
Audit fees – Ernst & Young	**UK**	**Total**	UK	Total	UK	Total
Group audit	**18**	**36**	15	31	13	27
Audit-related regulatory reporting	**7**	**9**	3	6	4	7
Statutory audit of subsidiaries	**6**	**19**	7	23	4	16
	31	**64**	25	60	21	50
Innovene operations	**–**	**–**	(8)	(8)	(2)	(2)
Continuing operations	**31**	**64**	17	52	19	48
Fees for other services – Ernst & Young						
Further assurance services						
Acquisition and disposal due diligence	**2**	**3**	2	2	6	7
Pension plan audits	**–**	**–**	–	1	–	1
Other further assurance services	**3**	**5**	16	23	6	9

Tax services						
Compliance services	—	**1**	5	10	3	13
Advisory services	—	—	—	—	—	1
	5	**9**	23	36	15	31
Innovene operations	—	—	—	(1)	—	(1)
Continuing operations	**5**	**9**	23	35	15	30

Audit fees for 2006 include $5 million of additional fees for 2005 (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 $nil (2005 $4 million and 2004 $3 million) in respect of advice on accounting, auditing and financial reporting matters; $nil (2005 $16 million and 2004 $1 million) in respect of internal accounting and risk management control reviews; $5 million (2005 $3 million and 2004 $3 million) in respect of non-statutory audits and $nil (2005 $nil and 2004 $2 million) in respect of project assurance and advice on business and accounting process improvement.

The tax compliance services relate to income tax and indirect tax compliance and employee tax 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 to that of other potential service providers. These services are for a fixed term.

Fees paid to major firms of accountants other than Ernst & Young for other services amount to $52 million (2005 $151 million and 2004 $82 million).

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55 Summarized financial information on jointly controlled entities and associates

A summarized statement of income and assets and liabilities based on latest information available, with respect to the group's equity-accounted jointly controlled entities and associates, is set out below. These figures represent 100% of the income statements and balance sheets of the equity-accounted entities, not BP's ownership interest.

			$ million
	2006	2005	2004
Sales and other operating revenues	**77,464**	61,698	38,842
Gross profit	**17,745**	14,451	9,063
Profit for the year	**9,113**	8,043	5,466

		$ million
At 31 December	**2006**	2005
Non-current assets	**58,086**	52,401
Current assets	**24,153**	19,808
	82,239	72,209
Current liabilities	**(17,804)**	(15,403)
Non-current liabilities	**(23,973)**	(20,328)
Net assets	**40,462**	36,478

56 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
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
2004					
Fixed assets Investments[b]	209	12	4	(57)	168
Doubtful debts[b]	441	254	6	(175)	526

a Principally currency transactions.
b Deducted in the balance sheet from the assets to which they apply.

57 Computation of ratio of earnings to fixed charges (unaudited)

$ million, except ratios

For the year ended 31 December	**2006**	2005	2004	2003	2002
Profit before taxation[a]	**35,142**	31,421	24,966	17,731	
Groups share of income in excess of dividends from equity-accounted entities[a]		(710)	(81)	(666)	
Capitalized interest, net of amortization[a]	**(341)**	(193)	(133)	(123)	
	34,801	30,518	24,752	16,942	
Fixed charges					
Interest expense[a]	**718**	559	440	482	
Rental expense representative of interest[a]	**946**	605	619	460	
Capitalized interest[a]	**478**	351	204	190	
	2,142	1,515	1,263	1,132	
Total adjusted earnings available for payment of fixed charges[a]	**36,943**	32,033	26,015	18,074	
Ratio of earnings to fixed charges	**17.2**	21.1	20.6	16.0	
Fixed charges, as adjusted to accord with US GAAP	**2,142**	1,525	1,263	1,132	1,476
Total adjusted earnings available for payment of fixed charges, after taking account of adjustments to profit before taxation to accord with US GAAP	**34,856**	30,550	23,905	16,760	13,583
Ratio of earnings to fixed charges with adjustments to accord with US GAAP	**16.3**	20.0	18.9	14.8	9.2

a Data for 2006, 2005, 2004 and 2003 has been prepared on the basis of IFRS as adopted for use in the EU. Data for 2002 has not been restated to an IFRS basis.

58 Condensed consolidating information on certain US subsidiaries

BP p.l.c. fully and unconditionally guarantees the payment obligations of its 100%-owned subsidiary BP Exploration (Alaska) Inc. under the BP Prudhoe Bay Royalty Trust. The following financial information for BP p.l.c., BP Exploration (Alaska) Inc. and all other subsidiaries on a condensed consolidating basis is intended to provide investors with meaningful and comparable financial information about BP p.l.c. and its subsidiary issuers of registered securities and is provided pursuant to Rule 3-10 of Regulation S-X in lieu of the separate financial statements of each subsidiary issuer of public debt securities. Investments include the investments in subsidiaries recorded under the equity method for the purposes of the condensed consolidating financial information. Equity income of subsidiaries is the groups 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 Australia Capital Markets Limited, 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.

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58 Condensed consolidating information on certain US subsidiaries *continued*

Income statement $ 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**

The following is a summary of the adjustments to the profit for the year attributable to BP shareholders which would be required if US GAAP had been applied instead of IFRS.

					$ million
					2006
	Issuer	**Guarantor**			
	BP Exploration (Alaska) Inc.	**BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Profit as reported	**2,193**	**22,420**	**21,496**	**(23,794)**	**22,315**
Adjustments					
Deferred taxation/business combinations	**(33)**	**(224)**	**(191)**	**224**	**(224)**
Provisions	**10**	**177**	**168**	**(178)**	**177**
Oil and natural gas reserves differences	—	**(243)**	**(243)**	**243**	**(243)**
Goodwill and intangible assets	—	**13**	**13**	**(13)**	**13**
Derivative financial instruments	—	**142**	**142**	**(142)**	**142**
Inventory valuation	**(5)**	**162**	**162**	**(157)**	**162**
Gain arising on asset exchange	**(10)**	**(10)**	—	**10**	**(10)**
Pensions and other post-retirement benefits	—	**(873)**	**(389)**	**389**	**(873)**
Impairments	—	**(332)**	**(332)**	**332**	**(332)**
Equity-accounted investments	—	**(104)**	**(104)**	**104**	**(104)**
Consolidation of varaible interest entities	—	**(5)**	**(5)**	**5**	**(5)**
Share-based payments	—	**92**	—	—	**92**
Other	**(8)**	**6**	**14**	**(6)**	**6**
Profit for the year as adjusted to accord with US GAAP	**2,147**	**21,221**	**20,731**	**(22,983)**	**21,116**

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58 Condensed consolidating information on certain US subsidiaries *continued*

Income statement (continued) $ 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			3,083		3,083
Earnings from associates after interest and tax			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

The following is a summary of the adjustments to the profit for the year attributable to BP shareholders which would be required if US GAAP had been applied instead of IFRS.

					$ million
					2005
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Profit as reported	2,680	22,026	20,151	(22,831)	22,026
Adjustments					
Deferred taxation/business combinations	(41)	(496)	(455)	496	(496)
Provisions	5	9	4	(9)	9
Oil and natural gas reserves differences	—	11	11	(11)	11
Derivative financial instruments	—	87	87	(87)	87
Inventory valuation	(13)	(232)	(232)	245	(232)
Gain arising on asset exchange	(12)	(12)	—	12	(12)
Pensions and other post-retirement benefits	—	(486)	(650)	650	(486)
Impairments	—	(378)	(378)	378	(378)
Equity-accounted investments	—	(255)	(255)	255	(255)
Share-based payments	—	6	—	—	6
Other	—	156	156	(156)	156
Profit for the year before cumulative effect of accounting change as adjusted to accord with US GAAP	2,619	20,436	18,439	(21,058)	20,436
Cumulative effect of accounting change					
Major maintenance expenditure	—	(794)	(794)	794	(794)
Profit for the year as adjusted to accord with US GAAP	2,619	19,642	17,645	(20,264)	19,642

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58 Condensed consolidating information on certain US subsidiaries *continued*

Income statement (continued)					$ million
For the year ended 31 December					2004
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	3,811	—	192,024	(3,811)	192,024
Earnings from jointly controlled entities — after interest and tax	—	—	1,818	—	1,818
Earnings from associates — after interest and tax	—	—	462	—	462
Equity-accounted income of subsidiaries — after interest and tax	256	16,951	—	(17,207)	—
Interest and other revenues	34	1,466	515	(1,400)	615
Total revenues	4,101	18,417	194,819	(22,418)	194,919
Gains on sale of businesses and fixed assets	—	—	1,685	—	1,685
Total revenues and other income	4,101	18,417	196,504	(22,418)	196,604
Purchases	506	—	131,360	(3,811)	128,055
Production and manufacturing expenses	421	—	16,909	—	17,330
Production and similar taxes	267	—	1,882	—	2,149
Depreciation, depletion and amortization	483	—	8,046	—	8,529
Impairment and losses on sale of businesses and fixed assets	—	—	1,390	—	1,390
Exploration expense	4	—	633	—	637
Distribution and administration expenses	3	1,472	11,452	(159)	12,768
Profit before interest and taxation from continuing operations	2,417	16,945	24,832	(18,448)	25,746
Finance costs	—	274	1,407	(1,241)	440
Other finance expense (income)	15	(358)	683	—	340
Profit before taxation from continuing operations	2,402	17,029	22,742	(17,207)	24,966
Taxation	552	(46)	6,576	—	7,082
Profit from continuing operations	1,850	17,075	16,166	(17,207)	17,884
Profit (loss) from Innovene operations	—	—	(622)	—	(622)
Profit for the year	1,850	17,075	15,544	(17,207)	17,262
Attributable to					
BP shareholders	1,850	17,075	15,357	(17,207)	17,075

Minority interest			187		187
	1,850	17,075	15,544	(17,207)	17,262

The following is a summary of the adjustments to the profit for the year attributable to BP shareholders which would be required if US GAAP had been applied instead of IFRS.

					$ million
					2004
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Profit as reported	1,850	17,075	15,357	(17,207)	17,075
Adjustments					
Deferred taxation/business combinations	(10)	(517)	(626)	636	(517)
Provisions	(1)	(80)	(78)	79	(80)
Oil and natural gas reserves differences		30	30	(30)	30
Goodwill		(61)	(61)	61	(61)
Derivative financial instruments		(337)	(337)	337	(337)
Inventory valuation		162	162	(162)	162
Gain arising on asset exchange	(19)	(107)	(88)	107	(107)
Pensions and other post-retirement benefits		(47)	(98)	98	(47)
Impairments		677	677	(677)	677
Equity-accounted investments		147	147	(147)	147
Major maintenance expenditure		217	217	(217)	217
Share-based payments		24			24
Other		(93)	(93)	93	(93)
Profit for the year as adjusted to accord with US GAAP	1,820	17,090	15,209	(17,029)	17,090

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58 Condensed consolidating information on certain US subsidiaries *continued*

Balance sheet $ million

At 31 December	Issuer	Guarantor			2006
	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 and accrued income			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 and accrued income	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 and deferred income	—	**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 and deferred income	—	**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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58 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**
Capital and reserves					
Capital shares	**3,353**	**5,385**	—	**(3,353)**	**5,385**
Paid-in surplus	**3,145**	**9,913**	—	**(3,145)**	**9,913**
Merger reserve	—	**26,504**	**697**	—	**27,201**
Other reserves	—	**5**	—	—	**5**
Shares held by ESOP trusts	—	**(154)**	—	—	**(154)**
Available-for-sale investments	—	—	**386**	—	**386**
Cash flow hedges	—	—	**39**	—	**39**
Foreign currency translation reserve	—	—	**4,685**	—	**4,685**
Treasury shares	—	**(22,182)**	—	—	**(22,182)**
Shared-based payments	—	**859**	—	—	**859**
Retained earnings	**10,507**	**90,542**	**61,243**	**(103,805)**	**58,487**
	17,005	**110,872**	**67,050**	**(110,303)**	**84,624**

The following is a summary of the adjustments to BP shareholders’ equity which would be required if US GAAP had been applied instead of IFRS.

$ million

At 31 December					2006
	Issuer	**Guarantor**			
	BP Exploration (Alaska) Inc.	**BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
BP shareholders’ equity as reported	**17,005**	**110,872**	**67,050**	**(110,303)**	**84,624**
Adjustments					
Deferred taxation/business combinations	**182**	**1,801**	**1,619**	**(1,801)**	**1,801**
Provisions	**41**	**63**	**25**	**(66)**	**63**
Oil and natural gas reserves differences	—	**(202)**	**(202)**	**202**	**(202)**
Goodwill and intangible assets	—	**248**	**248**	**(248)**	**248**
Derivative financial instruments	—	**202**	**202**	**(202)**	**202**

Inventory valuation	**(81)**	**(5)**	**(5)**	**86**	**(5)**
Gain arising on asset exchange	**229**	**229**	—	**(229)**	**229**
Impairments	—	**2**	**2**	**(2)**	**2**
Equity-accounted investments	—	**(160)**	**(160)**	**160**	**(160)**
Consolidation of variable interest entities	—	**(5)**	**(5)**	**5**	**(5)**
Share-based payments	—	**(254)**	—	—	**(254)**
Other	**(8)**	**(26)**	**(18)**	**26**	**(26)**
BP shareholders' equity as adjusted to accord with US GAAP	**17,368**	**112,765**	**68,756**	**(112,372)**	**86,517**

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58 Condensed consolidating information on certain US subsidiaries *continued*

Balance sheet (continued) $ million

At 31 December					2005
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Non-current assets					
Property, plant and equipment	5,852	—	80,095	—	85,947
Goodwill	—	—	10,371	—	10,371
Intangible assets	418	—	4,354	—	4,772
Investments in jointly controlled entities	—	—	13,556	—	13,556
Investments in associates	—	2	6,215	—	6,217
Other investments	—	—	967	—	967
Subsidiaries — equity-accounted basis	2,016	107,206	—	(109,222)	—
Fixed assets	8,286	107,208	115,558	(109,222)	121,830
Loans	1,800	1,434	(119)	(2,294)	821
Other receivables	—	—	770	—	770
Derivative financial instruments	—	—	3,909	—	3,909
Prepayments and accrued income	—	—	1,012	—	1,012
Defined benefit pension plan surplus	—	3,226	56	—	3,282
	10,086	111,868	121,186	(111,516)	131,624
Current assets					
Loans	—	—	132	—	132
Inventories	128	—	19,632	—	19,760
Trade and other receivables	13,780	1,211	50,313	(24,402)	40,902
Derivative financial instruments	—	—	10,056	—	10,056
Prepayments and accrued income	9	—	1,259	—	1,268
Current tax receivable	—	—	212	—	212
Cash and cash equivalents	(7)	3	2,964	—	2,960
	13,910	1,214	84,568	(24,402)	75,290
Total assets	23,996	113,082	205,754	(135,918)	206,914
Current liabilities					
Trade and other payables	4,512	6,719	55,307	(24,402)	42,136
Derivative financial instruments	—	—	10,036	—	10,036
Accruals and deferred income	—	—	5,017	—	5,017
Finance debt	55	—	8,877	—	8,932
Current tax payable	1,537	—	2,737	—	4,274

Provisions			1,602		1,602
	6,104	6,719	83,576	(24,402)	71,997
Non-current liabilities					
Other payables	495		3,734	(2,294)	1,935
Derivative financial instruments			5,871		5,871
Accruals and deferred income		27	962		989
Finance debt			10,230		10,230
Deferred tax liabilities	1,816	532	13,910		16,258
Provisions	536		9,418		9,954
Defined benefit pension plan and other post-retirement benefit plan deficits	82		9,148		9,230
	2,929	559	53,273	(2,294)	54,467
Total liabilities	9,033	7,278	136,849	(26,696)	126,464
Net assets	14,963	105,804	68,905	(109,222)	80,450
Equity					
BP shareholders equity	14,963	105,804	68,116	(109,222)	79,661
Minority interest			789		789
Total equity	14,963	105,804	68,905	(109,222)	80,450

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58 Condensed consolidating information on certain US subsidiaries *continued*

Balance sheet (continued) $ million

At 31 December					2005
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Capital and reserves					
Capital shares	3,353	5,185	—	(3,353)	5,185
Paid-in surplus	3,145	8,120	—	(3,145)	8,120
Merger reserve	—	26,493	697	—	27,190
Other reserves	—	16	—	—	16
Shares held by ESOP trusts	—	(140)	—	—	(140)
Available-for-sale investments	—	—	385	—	385
Cash flow hedges	—	—	(234)	—	(234)
Foreign currency translation reserve	—	—	2,943	—	2,943
Treasury shares	—	(10,598)	—	—	(10,598)
Share-based payments	—	665	—	—	665
Retained earnings	8,465	76,063	64,325	(102,724)	46,129
	14,963	105,804	68,116	(109,222)	79,661

The following is a summary of the adjustments to BP shareholders’ equity which would be required if US GAAP had been applied instead of IFRS.

$ million

At 31 December					2005
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
BP shareholders’ equity as reported	14,963	105,804	68,116	(109,222)	79,661
Adjustments					
Deferred taxation/business combinations	215	2,025	1,810	(2,025)	2,025
Provisions	31	(112)	(141)	110	(112)
Oil and natural gas reserves differences	—	41	41	(41)	41
Goodwill and intangible assets	—	171	171	(171)	171
Derivative financial instruments	—	225	225	(225)	225
Inventory valuation	(76)	(167)	(167)	243	(167)
Gain arising on asset exchange	239	239	—	(239)	239
Pensions and other post-retirement benefits	82	3,146	2,570	(2,652)	3,146
Impairments	—	327	327	(327)	327

Equity-accounted investments	—	(43)	(43)	43	(43)
Share-based payments	—	(334)	—	—	(334)
Other	—	(32)	(32)	32	(32)
BP shareholders’ equity as adjusted to accord with US GAAP	15,454	111,290	72,877	(114,474)	85,147

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58 Condensed consolidating information on certain US subsidiaries *continued*

Cash flow statement

$ 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

	Issuer	Guarantor			
2005	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

					$ million
					2004
	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	2,467	44,767	(4,621)	(18,566)	24,047
Net cash provided by (used in) operating activities of Innovene operations			(669)		(669)
Net cash provided by operating activities	2,467	44,767	(5,290)	(18,566)	23,378
Net cash used in investing activities	(364)	(31,517)	20,758	(208)	(11,331)
Net cash used in financing activities	(2,099)	(13,249)	(16,261)	18,774	(12,835)
Currency translation differences relating to cash and cash equivalents			91		91
(Decrease) increase in cash and cash equivalents	4	1	(702)		(697)
Cash and cash equivalents at beginning of year	(5)	3	2,058		2,056
Cash and cash equivalents at end of year	(1)	4	1,356		1,359

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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 13.

2006

Crude oil[a] **million barrels**

	UK	Rest of Europe	USA	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	–	–	–	–	–	–	–	–	–
Extensions, discoveries and other additions	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									
	–	–	–	(2)	–	–	1,215	(8)	1,205

Revisions of previous estimates									
Purchases of reserves-in-place	—	—	—	**28**	—	—	—	—	**28**
Extensions, discoveries and other additions	—	—	—	**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. Net proved reserves of crude oil exclude production royalties due to others, whether royalty is payable in cash or in kind.
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	USA	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	—	—	—	—	—	—	—	—	—
Extensions, discoveries and other additions	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									
	—	—	—	7	13	—	217	47	284

Revisions of previous estimates									
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—
Extensions, discoveries and other additions	—	—	—	**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 Net proved reserves of natural gas exclude production royalties due to others, whether royalty is payable in cash or in kind.
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.

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Supplementary information on oil and natural gas (unaudited) *continued*

Movements in estimated net proved reserves

Crude oil[a]									2005 million barrels
	UK	Rest of Europe	USA	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
Extensions, discoveries and other additions	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	–	–	–	–	–	–	–	–	–
	–	–	–	2	–	–	–	–	2

Extensions, discoveries and other additions									
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. Net proved reserves of crude oil exclude production royalties due to others, whether royalty is payable in cash or in kind.
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*

Movements in estimated net proved reserves

2005

Natural gas[a] — billion cubic feet

	UK	Rest of Europe	USA	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
Extensions, discoveries and other additions	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	–	–	–	–	–	–	–	–	–

Extensions, discoveries and other additions	—	—	—	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 Net proved reserves of natural gas exclude production royalties due to others, whether royalty is payable in cash or in kind.
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.

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Supplementary information on oil and natural gas (unaudited) *continued*

Movements in estimated net proved reserves 2004

Crude oil[a] million barrels

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Subsidiaries									
At 1 January 2004									
Developed	697	236	1,902	385	82	190	—	73	3,565
Undeveloped	245	127	1,499	354	81	632	—	711	3,649
	942	363	3,401	739	163	822	—	784	7,214
Changes attributable to									
Revisions of previous estimates	(133)	1	(44)	(92)	2	19	—	(192)	(439)
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—
Extensions, discoveries and other additions	24	—	74	5	8	48	—	213	372
Improved recovery	57	4	55	31	—	6	—	3	156
Production[b]	(121)	(28)	(217)	(63)	(17)	(48)	—	(21)	(515)
Sales of reserves-in-place	—	—	(17)	(10)	(6)	—	—	—	(33)
	(173)	(23)	(149)	(129)	(13)	25	—	3	(459)
At 31 December 2004[c]									
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[e]	610	150	847	—	787	6,755
Equity-accounted entities (BP share)									
At 1 January 2004									
Developed	—	—	—	206	1	—	1,384	705	2,296
Undeveloped	—	—	—	134	—	—	410	27	571
	—	—	—	340	1	—	1,794	732	2,867
Changes attributable to									
Revisions of previous estimates	—	—	—	(5)	—	—	382	15	392
Purchases of reserves-in-place	—	—	—	—	—	—	252	—	252
Extensions, discoveries and other additions	—	—	—	2	—	—	—	—	2

Improved recovery	—	—	—	17	—	—	37	—	54
Production	—	—	—	(25)	—	—	(304)	(55)	(384)
Sales of reserves-in-place	—	—	—	—	—	—	(4)	—	(4)
	—	—	—	(11)	—	—	363	(40)	312
At 31 December 2004[d]									
Developed	—	—	—	204	1	—	1,863	592	2,660
Undeveloped	—	—	—	125	—	—	294	100	519
	—	—	—	329	1	—	2,157	692	3,179

a Crude oil includes natural gas liquids (NGLs) and condensate. Net proved reserves of crude oil exclude production royalties due to others, whether royalty is payable in cash or in kind.
b Excludes NGLs from processing plants in which an interest is held of 58 thousand barrels a day.
c Includes 724 million barrels of NGLs. Also includes 40 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
d Includes 27 million barrels of NGLs. Also includes 127 million barrels of crude oil in respect of the 5.9% minority interest in TNK-BP.
e Proved reserves in the Prudhoe Bay field in Alaska include an estimated 77 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 — 2004

Natural gas[a] — billion cubic feet

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Subsidiaries									
At 1 January 2004									
Developed	2,996	262	11,482	4,212	1,976	640	–	255	21,823
Undeveloped	1,095	1,255	3,337	11,531	3,026	2,188	–	900	23,332
	4,091	1,517	14,819	15,743	5,002	2,828	–	1,155	45,155
Changes attributable to									
Revisions of previous estimates	(210)	28	(438)	(1,081)	106	16	–	558	(1,021)
Purchases of reserves-in-place	–	–	3	2	–	–	–	–	5
Extensions, discoveries and other additions	127	–	140	991	2,478	233	–	3	3,972
Improved recovery	134	4	870	76	–	29	–	38	1,151
Production[b]	(461)	(47)	(1,111)	(875)	(296)	(102)	–	(76)	(2,968)
Sales of reserves-in-place	–	–	(202)	(92)	(247)	(103)	–	–	(644)
	(410)	(15)	(738)	(979)	2,041	73	–	523	495
At 31 December 2004[c]									
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
Equity-accounted entities (BP share)									
At 1 January 2004									
Developed	–	–	–	1,591	136	–	46	58	1,831
Undeveloped	–	–	–	916	80	–	14	28	1,038
	–	–	–	2,507	216	–	60	86	2,869
Changes attributable to									
Revisions of previous estimates	–	–	–	(12)	(17)	–	341	–	312
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Extensions, discoveries and other additions	–	–	–	–	–	–	–	–	–

Improved recovery	—	—	—	23	—	—	—	—	23
Production	—	—	—	(144)	(23)	—	(177)	(3)	(347)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—
	—	—	—	(133)	(40)	—	164	(3)	(12)
At 31 December 2004[d]									
Developed	—	—	—	1,397	107	—	214	60	1,778
Undeveloped	—	—	—	977	69	—	10	23	1,079
	—	—	—	2,374	176	—	224	83	2,857

a Net proved reserves of natural gas exclude production royalties due to others, whether royalty is payable in cash or in kind.
b Includes 190 billion cubic feet of natural gas consumed in operations, 165 billion cubic feet in subsidiaries and 25 billion cubic feet in equity-accounted entities.
c Includes 4,064 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
d Includes 13 billion cubic feet of natural gas in respect of the 5.9% minority interest in TNK-BP.

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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 groups 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	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
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	2,200	1,000	16,300	4,300	3,500	6,100		4,600	38,000

cost[b]									
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
At 31 December 2004									
Future cash inflows[a]	47,400	21,700	169,500	52,600	27,200	35,000		34,200	387,600
Future production cost[b]	19,200	4,500	37,800	14,300	6,700	5,800		6,900	95,200
Future development cost[b]	2,200	1,900	10,800	4,400	3,500	4,700		5,100	32,600
Future taxation[c]	9,900	11,200	41,800	16,300	5,200	6,900		5,000	96,300
Future net cash flows	16,100	4,100	79,100	17,600	11,800	17,600		17,200	163,500
10% annual discount[d]	4,700	2,000	38,100	8,000	6,900	7,500		7,800	75,000
Standardized measure of discounted future net cash flows[e]	11,400	2,100	41,000	9,600	4,900	10,100		9,400	88,500

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

		$ million	
	2006	2005	2004
Sales and transfers of oil and gas produced, net of production costs	**(35,800)**	(24,300)	(24,100)
Development costs incurred during the year	**8,200**	7,100	6,300
Extensions, discoveries and improved recovery, less related costs	**7,900**	10,100	3,100
Net changes in prices and production cost[f]	**(43,900)**	84,200	27,600
Revisions of previous reserves estimates	**(9,500)**	(17,400)	(10,700)
Net change in taxation	**32,200**	(20,500)	1,900
Future development costs	**(7,000)**	(5,800)	(3,200)
Net change in purchase and sales of reserves-in-place	**(2,500)**	(2,500)	(1,000)
Addition of 10% annual discount	**12,800**	8,800	8,100

Total change in the standardized measure during the year	**(37,600)**	39,700	8,000

a The year end marker prices used were Brent $58.93/bbl, Henry Hub $5.52/mmBtu (2005 Brent $58.21/bbl, Henry Hub $9.52/mmBtu; 2004 Brent $40.24/bbl, Henry Hub $6.01/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 $1,300 million at 31 December 2006 ($2,700 million at 31 December 2005 and $1,600 million at 31 December 2004).
f Net changes in prices and production costs 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 2006 the group's share of the standardized measure of discounted future net cash flows of equity-accounted entities amounted to $14,700 million ($19,300 million at 31 December 2005 and $10,900 million at 31 December 2004).

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 2006, 2005 and 2004.

Production for the year[a]

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Subsidiaries									
Crude oil[b]							thousand barrels per day		
2006	**253**	**61**	**547**	**108**	**44**	**177**	—	**161**	**1,351**
2005	277	75	612	144	47	175	—	93	1,423
2004	330	77	666	173	48	130	—	56	1,480
Natural gas[c]							million cubic feet per day		
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
2004	1,174	125	2,749	2,334	775	267	—	200	7,624
Equity-accounted entities (BP share)									
Crude oil[b]							thousand barrels per day		
2006	—	—	—	**77**	**1**	—	**876**	**170**	**1,124**
2005	—	—	—	71	—	—	911	157	1,139
2004	—	—	—	68	2	—	831	150	1,051
Natural gas[c]							million cubic feet per day		
2006	—	—	—	**416**	**37**	—	**544**	**8**	**1,005**
2005	—	—	—	375	47	—	482	8	912
2004	—	—	—	353	60	—	458	8	879

[a] All volumes are net of royalty, whether payable in cash or in kind.
[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 2006. 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	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Number of productive wells at 31 December 2006										
Oil wells[a]	gross	**270**	**87**	**8,226**	**3,379**	**351**	**603**	**18,967**	**1,491**	**33,374**
	net	**145**	**27**	**2,402**	**1,839**	**151**	**524**	**8,090**	**198**	**13,376**
Gas wellsb	gross	**300**	**38**	**17,601**	**2,256**	**648**	**83**	**42**	**124**	**21,092**
	net	**140**	**14**	**11,318**	**1,377**	**238**	**40**	**20**	**52**	**13,199**

a Includes approximately 976 gross (281.8 net) multiple completion wells (more than one formation producing into the same well bore).

b Includes approximately 2,283 gross (1,524.6 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	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Oil and natural gas acreage at 31 December 2006										
Developed	gross	**433**	**138**	**7,392**	**3,161**	**1,072**	**477**	**3,991**	**1,865**	**18,529**
	net	**203**	**44**	**4,725**	**1,470**	**262**	**211**	**1,728**	**419**	**9,062**
Undevelopeda	gross	**2,100**	**1,053**	**6,809**	**12,436**	**7,765**	**16,215**	**13,778**	**18,684**	**78,840**
	net	**1,154**	**339**	**4,797**	**5,861**	**2,939**	**9,764**	**5,694**	**7,677**	**38,225**

a Undeveloped acreage includes leases and concessions.

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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	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
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
2004									
Exploratory									
Productive	–	–	2.1	1.3	–	6.6	11.0	1.3	22.3
Dry	–	–	3.2	1.5	–	2.0	5.2	1.1	13.0
Development									
Productive	10.0	0.3	513.3	138.2	8.6	12.9	166.8	16.0	866.1
Dry	0.1	–	3.0	1.8	–	2.0	8.7	2.4	18.0

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 2006. Suspended development wells and long-term suspended exploratory wells are also included in the table.

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
At 31 December 2006									
Exploratory									
Gross	**1**	–	**22**	**6**	**2**	**4**	**6**	**2**	**43**
Net	**0.5**	–	**10.8**	**2.8**	**0.3**	**1.6**	**2.2**	**0.5**	**18.7**
Development									
Gross	**3**	**2**	**194**	**43**	**7**	**19**	**30**	**20**	**318**
Net	**1.1**	**0.6**	**110.6**	**25.2**	**1.8**	**6.7**	**12.5**	**5.3**	**163.8**

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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: 6 March 2007