BP PLC
Form 20-F
March 04, 2008

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 20-F

(Mark One)

REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) or (g)
OF THE SECURITIES EXCHANGE ACT OF 1934
OR
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2007
OR
TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
OR
SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission file number: 1-6262

BP p.l.c.

(Exact name of Registrant as specified in its charter)
England and Wales

(Jurisdiction of incorporation or organization)

1 St James s Square
London
SW1Y 4PD
United Kingdom

(Address of principal executive offices)

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(Name, Telephone, Email and/or Facsimile number and Address of Company Contact Person)
Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Ordinary Shares of 25c each	**New York Stock Exchange*** **Chicago Stock Exchange***
4 7/8% Guaranteed Notes due 2010	**New York Stock Exchange**

Floating Rate Guaranteed Extendible Notes	**New York Stock Exchange**
	*Not for trading, but only in connection with the registration of American Depositary Shares, pursuant to the requirements of the Securities and Exchange Commission

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

None

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

None

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

Ordinary Shares of 25c each	**18,922,785,598**
Cumulative First Preference Shares of £1 each	**7,232,838**
Cumulative Second Preference Shares of £1 each	**5,473,414**

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

Yes No

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

Yes No

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

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

Yes No

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

Large accelerated filer Accelerated filer Non-accelerated filer

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

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

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

Item 17 Item 18

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

Yes No

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Cross reference to Form 20-F

Certain definitions

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

Oil and natural gas reserves

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

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

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

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

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

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

Proved undeveloped reserves Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances are estimates for proved undeveloped reserves attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

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Miscellaneous terms

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

ADR American depositary receipt.

ADS American depositary share.

AGM Annual general meeting.

Amoco The former Amoco Corporation and its subsidiaries.

Atlantic Richfield Atlantic Richfield Company and its subsidiaries.

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

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

Barrel 42 US gallons.

b/d barrels per day.

boe barrels of oil equivalent.

BP, BP group or the group BP p.l.c. and its subsidiaries.

Burmah Castrol Burmah Castrol plc and its subsidiaries.

Cent or c One-hundredth of the US dollar.

The company BP p.l.c.

Dollar or $ The US dollar.

EU European Union.

Gas Natural gas.

Hydrocarbons Crude oil and natural gas.

Liquids Crude oil, condensate and natural gas liquids.

LNG Liquefied natural gas.

London Stock Exchange or LSE London Stock Exchange plc.

LPG Liquefied petroleum gas.

mb/d thousand barrels per day.

mboe/d thousand barrels of oil equivalent per day.

mmBtu million British thermal units.

mmboe million barrels of oil equivalent.

mmcf million cubic feet.

mmcf/d million cubic feet per day.

MTBE Methyl tertiary butyl ether.

MW Megawatt.

NGLs Natural gas liquids.

OPEC Organization of Petroleum Exporting Countries.

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

Pence or p One-hundredth of a pound sterling.

Pound, sterling or £ The pound sterling.

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

PSA Production-sharing agreement.

IFRS International Financial Reporting Standards.

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

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

Jointly controlled entity A joint venture that involves the establishment of a company, partnership or other entity to engage in economic activity that the group jointly controls with fellow venturers.

SEC The United States Securities and Exchange Commission.

Subsidiary An entity that is controlled by the BP group. Control is the power to govern the financial and operating policies of an entity so as to obtain the benefits from its activities.

Tonne 2,204.6 pounds.

UK United Kingdom of Great Britain and Northern Ireland.

US United States of America.

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Performance review

Selected financial and operating information

This information, insofar as it relates to 2007, has been extracted or derived from the audited financial statements of the BP group presented on pages 93-180. Note 1 to the Financial statements includes details on the basis of preparation of these financial statements. The selected information should be read in conjunction with the audited financial statements and related Notes elsewhere herein.

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

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

$ million except per share amounts

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

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

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

[b] 2007 included $1,132 million for the acquisition of Chevron s Netherlands manufacturing company. There were no significant acquisitions in 2006 or in 2005. Capital expenditure in 2006 included $1 billion in respect of our investment in Rosneft. Capital expenditure and acquisitions for 2004 included $1,354 million for including TNK s interest in Slavneft within TNK-BP and $1,355 million for the acquisition of Solvay s interests in BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America.

Capital expenditure and acquisitions for 2003 included $5,794 million for the acquisition of our interest in TNK-BP. With the exception of the shares issued to Alfa Group and Access Renova (AAR) in connection with TNK-BP (2004-2006), all capital expenditure and acquisitions during the past five years have been financed from cash flow from operations, disposal proceeds and external financing.

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

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Production and net proved oil and natural gas reserves

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

Production and net proved reserves[a]

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

[a] Crude oil includes natural gas liquids (NGLs) and condensate. Production and proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option to make lifting and sales arrangements independently, and include minority interests in consolidated operations.

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

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

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

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

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

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

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

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Risk factors

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

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

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

Strategic risks

Access and renewal

Successful execution of our group plan depends critically on implementing activities to renew and reposition our portfolio. The challenges to renewal of our upstream portfolio are growing due to increasing competition for access to opportunities globally. Lack of material positions in new markets and/or inability to complete disposals could result in an inability to capture above-average market growth.

Prices and markets

Oil, gas and product prices are subject to international supply and demand. Political developments and the outcome of meetings of OPEC can particularly affect world supply and oil prices. Previous oil price increases have resulted in increased fiscal take, cost inflation and more onerous terms for access to resources. As a result, increased oil prices may not improve margin performance. In addition to the adverse effect on revenues, margins and profitability from any future fall in oil and natural gas prices, a prolonged period of low prices or other indicators would lead to a review for impairment of the group s oil and natural gas properties. This review would reflect management s view of long-term oil and natural gas prices. Such a review could result in a charge for impairment that could have a significant effect on the group s results of operations in the period in which it occurs.

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

Climate change and carbon pricing

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

Socio-political

We have operations in countries where political, economic and social transition is taking place. Some countries have experienced political instability, changes to the regulatory environment, expropriation or nationalization of property, civil strife, strikes, acts of war and insurrections. Any of these conditions occurring could disrupt or terminate our operations, causing our development activities to be curtailed or terminated in these areas or our production to decline and could cause us to incur additional costs.

We set ourselves high standards of corporate citizenship and aspire to contribute to a better quality of life through the products and services we provide. If it is perceived that we are not respecting or advancing the economic and social progress of the communities in which we operate, our reputation and shareholder value could be damaged.

Competition

The oil, gas and petrochemicals industries are highly competitive. There is strong competition, both within the oil and gas industry and with other industries, in supplying the fuel needs of commerce, industry and the

home. Competition puts pressure on product prices, affects oil products marketing and requires continuous management focus on reducing unit costs and improving efficiency. The implementation of group strategy requires continued technological advances and innovation including advances in exploration, production, refining, petrochemical manufacturing technology and advances in technology related to energy usage. Our performance could be impeded if competitors developed or acquired intellectual property rights to technology that we required or if our innovation lagged the industry.

Compliance and ethics risks

Regulatory

The oil industry is subject to regulation and intervention by governments throughout the world in such matters as the award of exploration and production interests, the imposition of specific drilling obligations, environmental protection controls, controls over the development and decommissioning of a field (including restrictions on production) and, possibly, nationalization, expropriation, cancellation or non-renewal of contract rights. We buy, sell and trade oil and gas products in certain regulated commodity markets. The oil industry is also subject to the payment of royalties and taxation, which tend to be high compared with those payable in respect of other commercial activities, and operates in certain tax jurisdictions that have a degree of uncertainty relating to the interpretation of, and changes to, tax law. As a result of new laws and regulations or other factors, we could be required to curtail or cease certain operations, or we could incur additional costs.

Ethical misconduct and non-compliance

Our code of conduct, which applies to all employees, defines our commitment to integrity, compliance with all applicable legal requirements, high ethical standards and the behaviours and actions we expect of our businesses and people wherever we operate. Incidents of non-compliance with applicable laws and regulation or ethical misconduct could be damaging to our reputation and shareholder value. Multiple events of non-compliance could call into question the integrity of our operations.

Financial control risks

Liquidity, financial capacity and financial exposure

The group has established a financial framework to ensure that it is able to maintain an appropriate level of liquidity and financial capacity and to constrain the level of assessed capital at risk for the purposes of positions taken in financial instruments. Failure to operate within our financial framework could lead to the group becoming financially distressed leading to a loss of shareholder value. Commercial credit risk is measured and controlled to determine the group s total credit risk. Inability to determine adequately our credit exposure could lead to financial loss. Crude oil prices are generally set in US dollars, while sales of refined products may be in a variety of currencies. Fluctuations in exchange rates can therefore give rise to foreign exchange exposures, with a consequent impact on underlying costs.

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

Liabilities and provisions

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

Operations risks

Operations safety and operations

Process safety

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

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Personal safety

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

Environmental

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

Product quality

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

Drilling and production

Exploration and production require high levels of investment and are subject to natural hazards and other uncertainties, including those relating to the physical characteristics of an oil or natural gas field. The cost of drilling, completing or operating wells is often uncertain. We may be required to curtail, delay or cancel drilling operations because of a variety of factors, including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, adverse weather conditions and compliance with governmental requirements.

Transportation

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

Operations planning and performance management

Investment efficiency

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

Major project delivery

Successful execution of our group plan (see page 11) depends critically on implementing the activities to deliver the major projects over the plan

period. Poor delivery of any major project that underpins production growth and/or a major programme designed to enhance shareholder value could adversely affect our financial performance.

Reserves replacement

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

Operations enterprise systems, security and continuity

Digital infrastructure

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

Security

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

Business continuity and disaster recovery

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

Crisis management

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

Operations people management

People and capability

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

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Forward-looking statements

Statements regarding competitive position

In order to utilize the Safe Harbor provisions of the United States Private Securities Litigation Reform Act of 1995, BP is providing the following cautionary statement. This document contains certain forward-looking statements with respect to the financial condition, results of operations and businesses of BP and certain of the plans and objectives of BP with respect to these items. These statements may generally, but not always, be identified by the use of words such as will , expects , is expected to , should , may , objective , is likely to , intends , believes , plans , we see or similar expressions. In particular, among other statements, (statements in Performance review (pages 6-55) with regard to management aims and objectives, future capital expenditure, future hydrocarbon production volume, date(s) or period(s) in which production is scheduled or expected to come onstream or a project or action is scheduled or expected to begin or be completed, capacity of planned plants or facilities and impact of health, safety and environmental regulations; (ii) the statements in Performance review (pages 6-44) with regard to planned expansion, investment or other projects and future regulatory actions; and (iii) the statements in Performance review (pages 45-55) with regard to the plans of the group, cash flows, opportunities for material acquisitions, the cost of and provision for future remediation programmes, liquidity and costs for providing pension and other post-retirement benefits; and including under Liquidity and capital resources with regard to future production, future refining availability, future capital expenditure, sources of funding, future revenues and financial performance, potential for cost efficiencies, level of free cash flow allocated to share buybacks, shareholder distributions and share buybacks, gearing, working capital and expected payments under contractual and commercial commitments; are all forward-looking in nature.

By their nature, forward-looking statements involve risk and uncertainty because they relate to events and depend on circumstances that will or may occur in the future and are outside the control of BP. Actual results may differ materially from those expressed in such statements, depending on a variety of factors, including the specific factors identified in the discussions accompanying such forward-looking statements; the timing of bringing new fields onstream; future levels of industry product supply, demand and pricing; operational problems; general economic conditions; political stability and economic growth in relevant areas of the world; changes in laws and governmental regulations; exchange rate fluctuations; development and use of new technology; the success or otherwise of partnering; the actions of competitors; natural disasters and adverse weather conditions; changes in public expectations and other changes to business conditions; wars and acts of terrorism or sabotage; and other factors discussed elsewhere in this report including under Risk factors on pages 8-9. In addition to factors set forth elsewhere in this report, those set out above are important factors, although not exhaustive, that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements.

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

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Information on the company

General

Unless otherwise indicated, information in this document reflects 100% of the assets and operations of the company and its subsidiaries that were consolidated at the date or for the periods indicated, including minority interests. Also, unless otherwise indicated, figures for business sales and other operating revenues include sales between BP businesses.

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

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

Overview of the group

BP is a global group, with interests and activities held or operated through subsidiaries, jointly controlled entities or associates established in, and subject to the laws and regulations of, many different jurisdictions. These interests and activities covered three business segments in 2007, supported by a number of organizational elements comprising group functions and regions.

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

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

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

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

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

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

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

We believe that BP has a strong portfolio of assets:

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

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

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

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

BP has interests in, and is the operator of, two fields and a pipeline located outside of Iran in which the National Iranian Oil Company (NIOC) and an affiliated entity have interests. In Iran, BP buys small quantities of crude oil. This is primarily for sale to third parties in Europe and a small portion is used by BP in its own refineries in South Africa and Europe. In addition, BP sells small quantities of crude oil into Iran and blends and markets small quantities of lubricants for sale to domestic consumers through a joint venture there, which has a blending facility. However, BP does not seek to obtain from the government of Iran licences or agreements for oil and gas projects in Iran, is not conducting any technical studies in Iran and does not own or operate any refineries or chemicals plants in Iran.

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

Acquisitions and disposals

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

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

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

Resegmentation in 2008

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

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

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

Exploration and Production

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

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

Our oil and gas production assets are located onshore or offshore and include wells, gathering centres, in-field flow lines, processing facilities, storage facilities, offshore platforms, export systems (e.g. transit lines), pipelines and LNG plant facilities.

Key statistics

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

Average West Texas Intermediate oil price	**72.20**	66.02	56.58
Average Brent oil price	**72.39**	65.14	54.48

		$ per thousand cubic feet	
Average BP natural gas realizations[b]	**4.53**	4.72	4.90
Average BP US natural gas realizations[b]	**5.43**	5.74	6.78

		$ per million British thermal units	
Average Henry Hub gas price[d]	**6.86**	7.24	8.65

		pence per therm	
Average UK National Balancing Point gas price	**29.95**	42.19	40.71

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

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

The Exploration and Production strategy is to build production by:

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

Building leadership positions in these areas.

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

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

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

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

Resegmentation in 2008

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

Upstream activities

Exploration

The group explores for oil and natural gas under a wide range of licensing, joint venture and other contractual agreements. We may do this alone or, more frequently, with partners. BP acts as operator for many of these ventures.

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

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

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

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

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

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

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

Reserves and production

Compliance

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

By their nature, there is always some risk involved in the ultimate development and production of reserves, including, but not limited to, final regulatory approval, the installation of new or additional infrastructure as well as changes in oil and gas prices and the continued availability of additional development capital.

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

Our proved reserves are associated with both concessions (tax and royalty arrangements) and agreements where the group is exposed to the upstream risks and rewards of ownership, but where title to the hydrocarbons is not conferred, such as PSAs. In a concession, the consortium of which we are a part is entitled to the reserves that can be produced over the licence period, which may be the life of the field. In a PSA, we are entitled to recover volumes that equate to costs incurred to develop and produce the reserves and an agreed share of the remaining volumes or the economic equivalent. As part of our entitlement is driven by the monetary amount of costs to be recovered, price fluctuations will have an impact on both production volumes and reserves. Thirteen per cent of our proved reserves are associated with PSAs. The main countries in which we operate under PSAs are Algeria, Angola, Azerbaijan, Egypt, Indonesia and Vietnam.

We separately disclose our share of reserves held in equity-accounted entities (jointly controlled entities and associates), although we do not control these entities or the assets held by such entities.

Resource progression

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

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

At the point of sanction, all booked reserves will be categorized as proved undeveloped (PUD). Volumes will subsequently be recategorized from PUD to proved developed (PD) as a consequence of development activity. When part of a well s reserves depends on a later phase of activity, only that portion of reserves associated with existing, available facilities and infrastructure moves to PD. The first PD bookings will occur at the point of first oil or gas production. Major development projects typically take one to four years from the time of initial booking of PUD reserves to the start of production. Changes to reserves bookings may be made due to analysis of new or existing data concerning production, reservoir performance, commercial factors, acquisition and divestment activity and additional reservoir development activity.

Governance

BP s centrally controlled process for proved reserves estimation approval forms part of a holistic and integrated system of internal control. It consists of the following elements:

- Accountabilities of certain officers of the group to ensure that there is review and approval of proved reserves bookings independent of the operating business and that there are effective controls in the approval process and verification that the proved reserves estimates and the related financial impacts are reported in a timely manner.
- Capital allocation processes, whereby delegated authority is exercised to commit to capital projects that are consistent with the delivery of the group s business plan. A formal review process exists to ensure that both technical and commercial criteria are met prior to the commitment of capital to projects.
- Internal Audit, whose role includes systematically examining the effectiveness of the group s financial controls designed to assure the reliability of reporting and safeguarding of assets and examining the group s compliance with laws, regulations and internal standards.
- Approval hierarchy whereby proved reserves changes above certain threshold volumes require central authorization and periodic reviews.

  The frequency of review is determined according to field size and ensures that more than 80% of the BP reserves base undergoes central review every two years and more than 90% is reviewed every four years.

For the executive directors and senior management, no specific portion of compensation bonuses is directly related to oil and gas reserves targets. Additions to proved reserves is one of several indicators by which the performance of the Exploration and Production segment is assessed by the remuneration committee for the purposes of determining compensation bonuses for the executive directors and senior management. Other indicators include a number of financial and operational measures.

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

Reserve replacement

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

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

The proved reserves replacement ratio (also known as the production replacement ratio) is the extent to which production is replaced by proved reserves additions. This ratio is expressed in oil equivalent terms and includes changes resulting from revisions to previous estimates, improved recovery and extensions and discoveries, and may be expressed as a replacement ratio excluding acquisitions and divestments or as a total replacement ratio including acquisitions and divestments.

			%
	2007	2006	2005
Proved reserves replacement ratio, excluding equity-accounted entities	**44**	34	68
Proved reserves replacement ratio, excluding equity-accounted entities, including sales and purchases of reserves-in-place	**38**	11	40
Proved reserves replacement ratio, for equity-accounted entities	**248**	272	151
Proved reserves replacement ratio, for equity-accounted entities, including sales and purchases of reserves-in-place	**248**	239	141

			million barrels of oil equivalent
Additions to proved developed reserves, excluding equity-accounted entities, including sales and purchases of reserves-in-place[a]	**929**	675	632
Additions to proved developed reserves, for equity-accounted entities, including sales and purchases of reserves-in-place[a]	**473**	936	474

			%
Proved developed reserves replacement ratio, excluding equity-accounted entities, including sales and purchases of reserves-in-place	**99**	70	63
Proved developed reserves replacement ratio, for equity-accounted entities, including sales and purchases of reserves-in-place	**101**	195	99

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

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

Production

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

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

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

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

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

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

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

Net proved reserves on an oil equivalent basis (mmboe)

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

a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently, and include minority interests in consolidated operations. We disclose our share of reserves held in joint ventures and associates that are accounted for by the equity method although we do not control these entities or the assets held by such entities.

[b] In certain deepwater fields, such as fields in the Gulf of Mexico, BP has claimed proved reserves before production flow tests are conducted, in part because of the significant safety, cost and environmental implications of conducting these tests. The industry has made substantial technological improvements in understanding, measuring and delineating reservoir properties without the need for flow tests. The general method of reserves assessment to determine reasonable certainty of commercial recovery that BP employs relies on the integration of three types of data: (1) well data used to assess the local characteristics and conditions of reservoirs and fluids; (2) field scale seismic data to allow the interpolation and extrapolation of these characteristics outside the immediate area of the local well control; and (3) data from relevant analogous fields. Well data includes appraisal wells or sidetrack holes, full logging suites, core data and fluid samples. BP considers the integration of this data in certain cases to be superior to a flow test in providing a better understanding of the overall reservoir performance. The collection of data from logs, cores, wireline formation testers, pressures and fluid samples calibrated to each other and to the seismic data can allow reservoir properties to be determined over a greater volume than the localized volume of investigation associated with a short-term flow test. Historically, proved reserves recorded using these methods have been validated by actual production levels. As at the end of 2007, BP had proved reserves in 22 fields in the deepwater Gulf of Mexico that had been initially booked prior to production flow testing. Of these fields, 19 are in production and one, Thunder Horse, is expected to begin production by the end of 2008. Two other fields are in the early stages of development.

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

[d] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 98 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

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

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

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

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

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

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

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

[a] Production excludes royalties due to others whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

[b] BP-operated.

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

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

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

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

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

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

[a] Production excludes royalties due to others whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

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

[c] BP-operated.

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

[e] Natural gas production volumes exclude gas consumed in operations within the lease boundaries of the producing field, but the related reserves are included in the group s reserves.

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United States

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

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

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

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

Deepwater Gulf of Mexico

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

Significant events were:

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

Lower 48 states

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

Production is derived primarily from two main areas:

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

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

Significant events were:

– In January 2007, we announced our investment of up to $2.4 billion expected over 13 years in the coalbed methane field development project in the San Juan basin in Colorado. The project includes the drilling of more than 700 wells, nearly all from existing well sites, and the installation of associated field facilities.
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Drilling continued during 2007 on the Wamsutter natural gas expansion project. The multi-year drilling programme is expected to increase production significantly by the end of 2010. We are currently testing horizontal fracturing technology and carrying out wireless seismic studies on the reservoir.

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

Alaska

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

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

Significant events in 2007 were:

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

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

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

United Kingdom

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

Significant events in 2007 were:

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

Rest of Europe

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

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Norway

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

Significant activities were:

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

Netherlands

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

Rest of World

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

Rest of Americas

Canada

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

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

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

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

Trinidad

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

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

Venezuela

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

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

Colombia

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

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

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

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

Argentina and Bolivia

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

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

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

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

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

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Africa

Algeria

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

Angola

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

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

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

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

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

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

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

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

Egypt

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

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

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

Progress continued on the Egypt Gas Phase 1 (Taurt) (BP 50%) development project, with first production expected in 2008.

In January 2007, BP drilled a successful well, Giza North-1, in the North Alexandria concession (BP 60% and operator) held by BP, RWE DEA and EGPC/The Egyptian Natural Gas Holding Company (EGAS). The Giza North-1 was drilled in 668 metres of water, some 56 kilometres offshore in the Pliocene formation where BP has made three previous discoveries.

In May 2007, BP drilled a successful well, Taurus Deep, in the North Alexandria A Concession (BP 60% and operator) held by BP, RWE DEA and EGPC. The Taurus Deep well was drilled in approximately 400 metres of water, some 70 kilometres offshore, and is in the Middle Miocene formation.

In January 2008, BP finished drilling a successful well, Satis-1, in the North El Burg offshore concession (BP 50% and operator) held by BP, IEOC and EGAS. The Satis-1 well was drilled in approximately 90 metres of water, some 50 kilometres offshore, and is in the Oligocene formation.

In December 2007, BP had first production from the Denise field where it holds a 50% interest.

Libya

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

Asia Pacific

Indonesia

BP produces crude oil and supplies natural gas to the island of Java through its holding in the Offshore Northwest Java PSA (BP 46%). In 2007, BP net production was 39mboe/d, a decrease of 8.8% from 43mboe/d in 2006 as a result of a higher-than-forecasted base decline, unplanned losses and the impact of higher realizations on the PSA.

During 2007, development continued on the Tangguh LNG project (BP 37.2% and operator). The project development includes offshore platforms, pipelines and an LNG plant with two production trains. First commercial delivery is expected in early 2009.

Vietnam

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

China

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

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

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

Australia

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

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

Russia

TNK-BP

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

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

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

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

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

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

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

Sakhalin

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

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

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

Other

Azerbaijan

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

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

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

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

Middle East and south Asia

Production in the Middle East consists principally of the production entitlement of associates in Abu Dhabi, where we have equity interests of 9.5% and 14.7% in onshore and offshore concessions respectively. In 2007, BP s share of production in Abu Dhabi was 192mb/d, down 3% from 2006 as a result of a major planned maintenance shutdown in the offshore concession in the fourth quarter of 2007.

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

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

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

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

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

Midstream activities

Oil and natural gas transportation

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

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

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

Assets and activity during 2007 included:

Alaska

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

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

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

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

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

North Sea

FPS (BP 100%) is an integrated oil and NGLs transportation and processing system that handles production from more than 50 fields in the Central North Sea. The system has a capacity of more than 1 million barrels per day, with average throughput in 2007 at 653mb/d. The tie-in of the Buzzard field was completed, with first Buzzard production flowing through the system in January 2007. The Greater Kittiwake Area also joined the system in late 2007.

BP operates and has a 29.5% interest in CATS, a 400-kilometre natural gas pipeline system in the central UK sector of the North Sea. The pipeline has a transportation capacity of 1,700mmcf/d to a natural gas terminal at Teesside in north-east England. CATS offers natural gas transportation and processing services. In 2007, throughput was 778mmcf/d (gross), 230mmcf/d (net). During September, the CATS pipeline resumed operation after divers installed a metal sleeve at the location where a large vessel had dragged its anchor causing damage to the pipeline. The pipeline was shutdown for 10 weeks resulting in a loss of production of 11mboe/d for the year.

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

Asia (including the former Soviet Union)

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

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

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

Liquefied natural gas

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

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

Assets and activity during 2007 included:

– In Trinidad, the Atlantic LNG Train 4 (BP 37.8%) is the largest producing LNG train in the world and is designed to produce 5.2 million tonnes (253,000mmcf) per year of LNG. BP expects to continue to supply at least two-thirds of the gas to the train. The Atlantic LNG Trains 2, 3, and 4 facilities are operated under a tolling arrangement, with the equity owners retaining ownership of their respective gas. The LNG is sold in the US, Dominican Republic and other destinations. BP s net share of the capacity of Atlantic LNG Trains 1, 2, 3 and 4 is 6.5 million tonnes (310,000mmcf) of LNG per year.
– In Indonesia, BP is involved in two of the three LNG centres in the country. BP participates in Indonesia s LNG exports through its holdings in the Sanga-Sanga PSA (BP 38%). Sanga-Sanga currently delivers around 14% of the total gas feed to Bontang, one of the world s largest LNG plants. The Bontang plant produced 18.4 million tonnes (831,000mmcf) of LNG in 2007, compared with 19.5 million tonnes in 2006.
– Also in Indonesia, BP has interests in the Tangguh LNG joint venture (BP 37.2% and operator) and in each of the Wiriagar (BP 38% and operator), Berau (BP 48% and operator) and Muturi (BP 1%) PSAs in north-west Papua that are expected to supply feed gas to the Tangguh LNG plant. During 2007, construction continued on two trains, with commercial delivery planned in early 2009. Tangguh will be the third LNG centre in Indonesia, with an initial capacity of 7.6 million tonnes (388,000mmcf) per year. Tangguh has signed sales contracts for delivery to China, Korea and North America s west coast.
– In Australia, we are one of seven partners in the NWS venture. Six partners (including BP) hold an equal 16.7% interest in the infrastructure and oil reserves and an equal 15.78% interest in the gas and condensate reserves, with a seventh partner owning the remaining 5.32% of gas and condensate reserves. The joint venture operation covers offshore production platforms, an FPSO, trunklines, onshore gas and LNG processing plants and LNG carriers. Construction continued during 2007 on a fifth LNG train that is expected to process 4.7 million tonnes of LNG per year and is expected to increase the plant s capacity to 16.6 million tonnes per year. The train is expected to be commissioned during the second half of 2008. NWS produced 1.96 million tonnes (102,000mmcf) of LNG, equal to 2006 production.
– We have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company, which in 2007 supplied 5.6 million tonnes (272,710mmcf) of LNG, up 4.2% on 2006.
– BP has a 13.6% share in the Angola LNG project, which is expected to receive approximately one billion cubic feet of associated gas per day from offshore producing blocks and produce 5.2 million tonnes per year of LNG, as well as related gas liquids products, with first LNG expected in 2012. With the completion of the necessary agreements and the approval of the Angolan government, the project investors have authorized Angola LNG Limited to proceed with the construction and implementation of the project.

Refining and Marketing

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

Key statistics

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

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

[b] The Global Indicator Refining Margin (GIM) is the average of regional industry indicator margins, which we weight for BP s crude refining capacity in each region. Each regional indicator margin is based on a single representative crude with product yields characteristic of the typical level of upgrading complexity. The refining margins are industry-specific rather than BP-specific measures, which we believe are useful to investors in analyzing trends in the industry and their impact on our results. The margins are calculated by BP based on published crude oil and product prices and take account of fuel utilization and catalyst costs. No account is taken of BP s other cash and non-cash costs of refining, such as wages and salaries and plant depreciation. The indicator margin may not be representative of the margins achieved by BP in any period because of BP s particular refining configurations and crude and product slate.

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

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

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

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

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

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

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

During 2007, significant events were:

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

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

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

Resegmentation in 2008

With effect from 1 January 2008:
– The Emerging Consumers Marketing Unit was transferred from Refining and Marketing to Alternative Energy (which is reported in Other businesses and corporate).
– The Biofuels business was transferred from Refining and Marketing to Alternative Energy (which is reported in Other businesses and corporate).
– The Shipping business was transferred from Refining and Marketing to Other businesses and corporate.

Texas City refinery

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

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

Governmental investigations

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

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

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

CSB agreeing to close out its recommendations.

Civil tort actions

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

See Legal proceedings on page 82 for further information.

Report of the BP US Refineries Independent Safety Review Panel

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

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

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Other regulatory actions

OSHA

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

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

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

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

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

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

EPA

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

Refining

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

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

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

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

* Indicates refineries operated by BP.
[a] Crude distillation capacity is gross rated capacity, which is defined as the maximum achievable utilization of capacity (24-hour assessment) based on standard feed.
[b] BP share of equity, which is not necessarily the same as BP share of processing entitlements.
[c] Subject to negotiation of final agreements and obtaining the necessary approval and permits, Husky Energy will take a 50% interest in BP s Toledo refinery as described on page 27.
[d] On 15 January 2008, it was announced that Essar Energy Overseas Ltd, a subsidiary of Essar Oil Limited, had entered into an agreement to acquire 50% of Kenya Petroleum Refineries Ltd. Subject to certain conditions, the acquisition, which includes all of BP s interest, is expected to

complete in early 2008.

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

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

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

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

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

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

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

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

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Marketing

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

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

a Excludes sales to other BP businesses and sales of Aromatics & Acetyls products.
b UK area includes the UK-based international activities of Refining and Marketing.
c Marketing sales are sales to service stations, end-consumers, bulk buyers and jobbers (i.e. third parties who own networks of a number of service stations and small resellers).
d Trading/supply sales are sales to large unbranded resellers and other oil companies.

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

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

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

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

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

Fuels marketing

Our Fuels marketing strategy focuses on optimising the fuels value chain and delivering refined products to the market. We do this by co-ordinating our marketing, refining and trading activities to maximize synergies across the whole value chain. Our priorities are to operate an advantaged infrastructure and logistics network, drive excellence in operating and transactional processes and deliver compelling customer offers in the various markets where we operate. The fuels business markets a comprehensive range of refined oil products focused on ground fuels, aviation, marine and bitumen sectors.

Ground fuels

The ground fuels business supplies fuel to retail consumers through company-owned and franchised retail sites as well as other channels

including wholesalers and jobbers. It also supplies commercial customers within the road and rail transport sectors.

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

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

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

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

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

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

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

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

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

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

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

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

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

Aviation fuels

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

Marine fuels

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

Bitumen

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

LPG

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

Lubricants

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

Aromatics & Acetyls

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

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

thousand tonnes per year

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

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

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

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

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

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

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

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

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

Supply and trading

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

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

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

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

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

Exchange-traded commodity derivatives

These contracts are typically in the form of futures and options traded on a recognized exchange, such as Nymex, Simex, ICE and Chicago Board of Trade. Such contracts are traded in standard specifications for the main marker crude oils, such as Brent and West Texas Intermediate, and the main product grades, such as gasoline and gasoil. Though potentially settled physically, these contracts are typically settled financially. Gains and losses, otherwise referred to as variation margins, are settled on a daily basis with the relevant exchange. These contracts are used for the trading and risk management of both crude and products. Realized and unrealized gains and losses on exchange-traded commodity derivatives are included in sales and other operating revenues for accounting purposes.

OTC contracts

These contracts are typically in the form of forwards, swaps and options. OTC contracts are negotiated between two parties and are not traded on an exchange. These contracts can be used both as part of trading and risk management activities. Realized and unrealized gains and losses on OTC contracts are included in sales and other operating revenues for accounting purposes.

The main grades of crude oil bought and sold forward using standard contracts are West Texas Intermediate and a standard North Sea crude blend (Brent, Forties and Osberg or BFO). Although the contracts specify physical delivery terms for each crude blend, a significant volume are not settled physically. The contracts contain standard delivery, pricing and settlement terms. Additionally, the BFO contract specifies a standard volume and tolerance given that the physically settled transactions are delivered by cargo.

Swaps are contractual obligations to exchange cash flows between two parties: one usually references a floating price and the other a fixed price with the net difference of the cash flows being settled. Options give the holder the right, but not the obligation, to buy or sell crude or oil products at a specified price on or before a specific future date. Amounts under these derivative financial instruments are settled at expiry, typically through netting agreements, to limit credit exposure and support liquidity.

Spot and term contracts

Spot contracts are contracts to purchase or sell crude and oil products at the market price prevailing on and around the delivery date when title to the inventory is taken. Term contracts are contracts to purchase or sell a commodity at regular intervals over an agreed term. Though spot and term contracts may have a standard form, there is no offsetting mechanism in place. These transactions result in physical delivery with operational and price risk. Spot and term contracts relate typically to purchases of crude for a refinery, sales of the group s oil production and sales of the group s oil products. For accounting purposes, spot and term sales are included in sales and other operating revenues, when title passes.

Similarly, spot and term purchases are included in purchases for accounting purposes.

Trading investigations

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

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

Transportation

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

Shipping

We transport our products across oceans, around coastlines and along waterways, using a combination of BP-operated, time-chartered and spot-chartered vessels. All vessels conducting BP activities are subject to our health, safety, security and environmental requirements.

International fleet

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

Regional and specialist vessels

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

Time-charter vessels

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

Spot-charter vessels

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

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Other vessels

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

Gas, Power and Renewables

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

Resegmentation in 2008

With effect from 1 January 2008:

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

Key statistics

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

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

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

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

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

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

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

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

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

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

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

Marketing and trading activities

Gas and power marketing and trading activity is undertaken primarily in the US, Canada, the UK and Europe to market BP s gas and power production and manage market price risk as well as to create incremental trading opportunities through the use of commodity derivative contracts. Additionally, this activity generates fee income and enhanced margins from sources such as the management of price risk on behalf of third-party customers. These markets are large, liquid and volatile and the group enters into these transactions on a large scale to meet these objectives.

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

In connection with the above activities, the group uses a range of commodity derivative contracts and storage and transport contracts. These include commodity derivatives such as futures, swaps and options to manage price risk and forward contracts used to buy and sell gas and power in the marketplace. Using these contracts, in combination with rights to access storage and transportation capacity, allows the group to access advantageous pricing differences between locations, time periods and arbitrage between markets. Gas futures and options are traded through exchanges, while over-the-counter (OTC) options and swaps are used for both gas and power transactions through bilateral arrangements. Futures and options are primarily used to trade the key index prices such as Henry Hub, while swaps can be tailored to price with reference to specific delivery locations where gas and power can be bought and sold. OTC forward contracts have evolved in both the US and UK markets, enabling gas and power to be sold forward in a variety of locations and future periods. These contracts are used both to sell production into the wholesale markets and as trading instruments to buy and sell gas and power in future periods. Capacity contracts allow the group to store, transport gas and transmit power between these locations. Additionally, activity is undertaken to risk-manage power generation margins related to the Texas City co-generation plant using a range of gas and power commodity derivatives.

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

– Exchange-traded commodity derivatives

  Exchange-traded commodity derivatives include gas and power futures contracts. Though potentially settled physically, these contracts are typically settled financially. Gains and losses, otherwise referred to as variation margins, are settled on a daily basis with the relevant exchange. Realized and unrealized gains and losses on exchange-traded commodity derivatives are included in sales and other operating revenues for accounting purposes.

– OTC contracts

  These contracts are typically in the form of forwards, swaps and options. OTC contracts are negotiated between two parties and are not traded on an exchange. These contracts can be used both as part of trading and risk management activities. Realized and unrealized gains and losses on OTC contracts are included in sales and other operating revenues for accounting purposes. Highly-developed markets exist in North America and the UK where gas and power can be bought and sold for delivery in future periods. These contracts are negotiated between two parties to purchase and sell gas and power at a specified price, with delivery and settlement at a future date. Although these contracts specify delivery terms for the underlying commodity, in practice a significant volume of these transactions are not settled physically. This can be achieved by transacting offsetting sale or purchase contracts for the same location and delivery period that are offset during the scheduling of delivery or dispatch. The contracts contain standard terms such as delivery point, pricing mechanism, settlement terms and specification of the commodity. Typically, volume and price are the main variable terms.

  Swaps are contractual obligations to exchange cash flows between two parties. One usually references a floating price and the other a fixed price, with the net difference of the cash flows being settled. Options give the holder the right, but not the obligation, to buy or sell natural gas products or power at a specified price on or before a specific future date. Amounts under these derivative financial instruments are settled at expiry, typically through netting agreements to limit credit exposure and support liquidity.

– Spot and term contracts
  Spot contracts are contracts to purchase or sell a commodity at the market price prevailing on the delivery date when title to the inventory passes. Term contracts are contracts to purchase or sell a commodity at regular intervals over an agreed term. Though spot and term contracts may have a standard form, there is no offsetting mechanism in place. These transactions result in physical delivery with operational and price risk. Spot and term contracts relate typically to purchases of third-party gas and sales of the group s gas production to third parties. Spot and term sales are included in sales and other operating revenues, when title passes. Similarly, spot and term purchases are included in purchases for accounting purposes.

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

Trading investigations

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

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

North America

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

Our North American natural gas marketing and trading strategy seeks to provide unconstrained market access for BP s equity gas. Our marketing strategy targets high-value customer segments through fully utilizing our rights to store and transport gas. These assets include those

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owned by BP and those contractually accessed through agreements with third parties such as pipelines and terminals.

Europe

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

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

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

Liquefied natural gas

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

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

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

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

In Nigeria, discussions are ongoing following the 2006 signing of a memorandum of understanding for the purchase of LNG from Brass River LNG. A final investment decision is expected in 2008 and could lead to first LNG in 2012.

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

Natural gas liquids

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

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

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

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

Alternative energy

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

Solar

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

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

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

Wind

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

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

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

Gas-fired power

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

Hydrogen power

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

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

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

Other businesses and corporate

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

Key statistics

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

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

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

Resegmentation in 2008

With effect from 1 January 2008:

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

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

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

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

Treasury

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

Aluminium

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

Research, technology and engineering

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

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

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

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

Insurance

The group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. This is because external insurance is not considered an economic means of financing losses for the group. Losses will therefore be borne as they arise, rather than being spread over time through insurance premiums with attendant transaction costs. This position is reviewed periodically.

Technology

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

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

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

The following guiding principles underpin our approach to technology:

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

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

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

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

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

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

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

Regulation of the group s business

BP s exploration and production activities are conducted in many different countries and are therefore subject to a broad range of legislation and regulations. These cover virtually all aspects of exploration and production activities, including matters such as licence acquisition, production rates, royalties, pricing, environmental protection, export, taxes and foreign exchange. The terms and conditions of the leases, licences and contracts under which these oil and gas interests are held vary from country to country. These leases, licences and contracts are generally granted by or entered into with a government entity or state company and are sometimes entered into with private property owners. These arrangements with governmental or state entities usually take the form of licences or production-sharing agreements. Arrangements with private property owners are usually in the form of leases.

Licences (or concessions) give the holder the right to explore for and exploit a commercial discovery. Under a licence, the holder bears the risk of exploration, development and production activities and provides the financing for these operations. In principle, the licence holder is entitled to all production, minus any royalties that are payable in kind. A licence holder is generally required to pay production taxes or royalties, which may be in cash or in kind. Less typically, BP may explore for and exploit hydrocarbons under a service agreement with the host entity in exchange for reimbursement of costs and/or a fee paid in cash rather than production.

Production-sharing agreements entered into with a government entity or state company generally require BP to provide all the financing and bear the risk of exploration and production activities in exchange for a share of the production remaining after royalties, if any.

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

Frequently, BP conducts its exploration and production activities in joint venture with other international oil companies, state companies or private companies.

In general, BP is required to pay income tax on income generated from production activities (whether under a licence or production-sharing agreement). In addition, depending on the area, BP s production activities may be subject to a range of other taxes, levies and assessments, including special petroleum taxes and revenue taxes. The taxes imposed on oil and gas production profits and activities may be substantially higher than those imposed on other activities, particularly in Angola, Norway, the UK, Russia, South America and Trinidad & Tobago.

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

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

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

Safety

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

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

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

Implementing Baker Panel recommendations

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

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

Leadership

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

Management systems

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

Knowledge and expertise

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

Culture

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

Indicators

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

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

Progress at Texas City and our other US refineries

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

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

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

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

Implementing the six-point plan

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

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

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

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

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Operational integrity

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

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

Continuing to focus on personal health and safety

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

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

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

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

Implementation of the OMS

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

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

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

Capability development

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

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

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

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

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

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

Environment

Health, safety and environmental regulation

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

The extent and cost of future environmental restoration, remediation and abatement programmes are often inherently difficult to estimate. They depend on the magnitude of any possible contamination, the timing and extent of the corrective actions required, technological feasibility and BP s share of liability relative to that of other solvent responsible parties. Though the costs of future restoration and remediation could be significant and may be material to the results of operations in the period in which they are recognized, it is not expected that such costs will be material to the group s overall results of operations or financial position. See Financial statements Note 37 on page 151 for the amounts provided in respect of environmental remediation and decommissioning.

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

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

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

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

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

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

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

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

Our operations and the environment

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

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

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

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

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

Climate change programmes

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

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

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

The US congress continues to develop and review proposed climate change legislation and regulation. President Bush signed an Energy bill into law in December 2007, which included stricter corporate average fuel emissions standards for automobiles sold in the US and biofuel mandates. A number of other bills currently under consideration propose stricter emissions limits on large GHG sources and/or the introduction of a cap-and-trade programme on CO_2 and other GHG emissions.

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

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

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

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

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

Maritime oil spill regulations

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

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

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

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

US regional review

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

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

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

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

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

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

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

BP has been identified as a Potentially Responsible Party (PRP) under CERCLA or otherwise named under similar state statutes at approximately 805 sites. A PRP or named party can incur joint and several liability for site remediation costs under some of these statutes and so BP may be required to assume, among other costs, the share attributed to insolvent, unidentified or other parties. BP has the most significant exposure for remediation costs at 52 of these sites. For the remaining sites, the number of parties can range up to 200 or more. BP expects its share of remediation costs at these sites to be small in comparison with the major sites. BP has estimated its potential exposure

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at all sites where it has been identified as a PRP or is otherwise named and has established provisions accordingly. BP does not anticipate that its ultimate exposure at these sites individually, or in aggregate, will be significant, except as reported for Atlantic Richfield Company in the matters below.

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

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

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

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

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

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

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

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

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

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

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

See also Legal proceedings on page 82.

European Union regional review

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Property, plants and equipment

BP has freehold and leasehold interests in real estate in numerous countries, but no individual property is significant to the group as a whole. See Exploration and Production on page 13 for a description of the group s significant reserves and sources of crude oil and natural gas. Significant plans to construct, expand or improve specific facilities are described under each of the business headings within this section.

Organizational structure

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

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Financial and operating performance

Group operating results

The following summarizes the group s operating results.

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

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

Business environment

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

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

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

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

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

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

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

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

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

Hydrocarbon production

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

Profit attributable to BP shareholders

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

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

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

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

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

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

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

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

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

[a] Inventory holding gains and losses represent the difference between the cost of sales calculated using the average cost of supplies incurred during the year and the cost of sales calculated on the first-in first-out (FIFO) method. Under the FIFO method, which we use for IFRS reporting, the cost of inventory charged to the income statement is based on the historic cost of acquisition or manufacture rather than the current replacement cost. In volatile energy markets, this can have a significant distorting effect on reported income. The amounts disclosed represent the difference between the charge to the income statement on a FIFO basis and the charge that would arise using average cost of supplies incurred during the period. For this purpose average cost of supplies incurred during the period is calculated by dividing the total cost of inventory purchased in the period by the number of barrels acquired. The amounts disclosed are not separately reflected in the financial statements as a gain or loss.

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

Capital expenditure and acquisitions

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

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

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

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

Finance costs and other finance income/expense

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

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

Taxation

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

Business results

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

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Exploration and Production

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

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

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

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

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

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

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

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

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

Profit before interest and tax for the year ended 31 December 2006 was $29,629 million, including net gains of $2,114 million on the sales of assets (primarily gains from the sales of our interest in the Shenzi discovery in the Gulf of Mexico in the US and interests in the North Sea offset by a loss on the sale of properties in the Gulf of Mexico Shelf), net fair value gains of $515 million on embedded derivatives and a net impairment credit of $203 million (comprising a $340 million credit for reversals of previously booked impairments partially offset by a charge of $109 million against intangible assets relating to properties in Alaska, and other individually insignificant impairments), and was after inventory holding losses of $18 million and charges for legal provisions of $335 million.

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

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

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

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

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

Refining and Marketing

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

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

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

[b] The GIM is the average of regional industry indicator margins that we weight for BP s crude refining capacity in each region. Each regional indicator margin is based on a single representative crude with product yields characteristic of the typical level of upgrading complexity. The refining margins are industry-specific rather than BP-specific measures, which we believe are useful to investors in analyzing trends in the industry and their impact on our results. The margins are calculated by BP based on published crude oil and product prices and take account of fuel utilization and catalyst costs. No account is taken of BP s other cash and non-cash costs of refining, such as wages and salaries and plant depreciation. The indicator margin may not be representative of the margins achieved by BP in any period because of BP s particular refining configurations and crude and product slate.

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

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

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

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

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

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

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

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

Profit before interest and tax for the year ended 31 December 2005 was $6,426 million, including inventory holding gains of $2,532 million and net gains of $177 million principally on the divestment of a number of regional retail networks in the US, and is after a charge of $1,200 million related to the March 2005 incident at the Texas City refinery, a charge of $140 million relating to new, and revisions to existing, environmental and other provisions, an impairment charge of $93 million and a charge of $33 million for the impairment of an equity-accounted entity.

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

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

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

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

Gas, Power and Renewables

			$ million
	2007	2006	2005

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

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

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

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

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

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

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

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

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

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

Profit before interest and tax for the year ended 31 December 2005 was $1,172 million, including inventory holding gains of $95 million, compensation of $265 million received on the cancellation of an intragroup gas supply contract and net gains of $55 million primarily on the

disposal of BP s interest in the Interconnector pipeline and a power plant in the UK, and was after net fair value losses of $346 million on embedded derivatives and a credit of $6 million related to new, and revisions to existing, environmental and other provisions.

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

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

Other businesses and corporate

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

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

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

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

The loss before interest and tax for the year ended 31 December 2006 was $885 million, including inventory holding gains of $62 million, a credit

of $94 million in relation to new, and revisions to existing, environmental and other provisions, a net gain on disposal of $95 million and a net fair value gain of $5 million on embedded derivatives; and was after a charge of $200 million relating to the reassessment of certain provisions and an impairment charge of $69 million.

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

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Non-GAAP information on fair value accounting effects

BP uses derivative instruments to manage the economic exposure relating to inventories above normal operating requirements of crude oil, natural gas and petroleum products as well as certain contracts to supply physical volumes at future dates. Under IFRS, these inventories and contracts are recorded at historic cost and on an accruals basis respectively. The related derivative instruments, however, are required to be recorded at fair value with gains and losses recognized in income because hedge accounting is either not permitted or not followed, principally due to the impracticality of effectiveness testing requirements. Therefore, measurement differences in relation to recognition of gains and losses occur. Gains and losses on these inventories and contracts are not recognized until the commodity is sold in a subsequent accounting period. Gains and losses on the related derivative commodity contracts are recognized in the income statement from the time the derivative commodity contract is entered into on a fair value basis using forward prices consistent with the contract maturity.

IFRS requires that inventory held for trading be recorded at its fair value using period end spot prices whereas any related derivative commodity instruments are required to be recorded at values based on forward prices consistent with the contract maturity. Depending on market conditions, these forward prices can be either higher or lower than spot prices resulting in measurement differences.

The Gas, Power and Renewables business enters into contracts for pipelines and storage capacity that, under IFRS, are recorded on an accruals basis. These contracts are risk managed using a variety of derivative instruments that are fair valued under IFRS. This results in measurement differences in relation to recognition of gains and losses.

The way that BP manages the economic exposures described above, and measures performance internally, differs from the way these activities are measured under IFRS. BP calculates this difference by comparing the IFRS result with management s internal measure of performance, under which the inventory and the supply and capacity contracts in question are valued based on fair value using relevant forward prices prevailing at the end of the period. We believe that disclosing management s estimate of this difference provides useful information for investors because it enables investors to see the economic effect of these activities as a whole. The impacts of fair value accounting effects, relative to management s internal measure of performance, are shown in the table below.

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

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

Environmental expenditure

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

Operating and capital expenditure on the prevention, control, abatement or elimination of air, water and solid waste pollution is often not incurred as a separately identifiable transaction. Instead, it forms part of a larger transaction that includes, for example, normal maintenance expenditure. The figures for environmental operating and capital expenditure in the table are therefore estimates, based on the definitions and guidelines of the American Petroleum Institute.

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

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

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

In addition, we make provisions on installation of our oil- and gas-producing assets and related pipelines to meet the cost of eventual decommissioning. On installation of an oil or natural gas production facility a provision is established that represents the discounted value of the expected future cost of decommissioning the asset. Additionally, we undertake periodic reviews of existing provisions. These reviews take account of revised cost assumptions, changes in decommissioning requirements and any technological developments. The level of increase in the decommissioning provision varies with the number of new fields coming onstream in a particular year and the outcome of the periodic reviews.

Provisions for environmental remediation and decommissioning are usually set up on a discounted basis, as required by IAS 37 Provisions, Contingent Liabilities and Contingent Assets .

Further details of decommissioning and environmental provisions appear in Financial statements Note 37 on page 151. See also Environment on page 40.

Suppliers and contractors

Our processes are designed to enable us to choose suppliers carefully on merit, avoiding conflicts of interest and inappropriate gifts and entertainment. We expect suppliers to comply with legal requirements and we seek to do business with suppliers who act in line with BP's commitments to compliance and ethics, as outlined in the code of conduct. We engage with suppliers in a variety of ways, including performance review meetings to identify mutually advantageous ways to improve performance.

Creditor payment policy and practice

Statutory regulations issued under the UK Companies Act 1985 require companies to make a statement of their policy and practice in respect of the payment of trade creditors. In view of the international nature of the group s operations there is no specific group-wide policy in respect of payments to suppliers. Relationships with suppliers are, however, governed by the group s policy commitment to long-term relationships founded on trust and mutual advantage. Within this overall policy, individual operating companies are responsible for agreeing terms and conditions for their business transactions and ensuring that suppliers are aware of the terms of payment.

Contributing to communities

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

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

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Liquidity and capital resources

Cash flow

The following table summarizes the group s cash flows.

$ million

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

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

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

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

$ billion

Sources	
Net cash provided by operating activities	79
Divestments	22
Movement in net debt	6

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

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

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

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

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

Trend information

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

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

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

Dividends and other distributions to shareholders and gearing

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

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

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

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

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

The discussion above and following contains forward-looking statements with regard to future production, future refining availability, future capital expenditure, sources of funding, future revenues and financial performance, potential for cost efficiencies, level of free cash flow allocated to share buybacks, shareholder distributions and share buybacks, gearing, working capital and expected payments under contractual and commercial commitments. These forward-looking statements are based on assumptions that management believes to be reasonable in the light of the group s operational and financial experience. However, no assurance can be given that the forward-looking statements will be realized. You are urged to read the cautionary statement under

Forward-looking statements on page 10 and Risk factors on pages 8-9, which describe the risks and uncertainties that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements. The company provides no commitment to update the forward-looking statements or to publish financial projections for forward-looking statements in the future.

Financing the group s activities

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

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

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

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

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

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

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

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

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

Off-balance sheet arrangements

In addition to reported debt, BP uses conventional off-balance sheet arrangements such as operating leases and borrowings in jointly controlled entities and associates. At 31 December 2007, the group s share of third-party finance debt of jointly controlled entities and associates was $5,894 million (2006 $4,942 million) and $870 million (2006 $1,143 million) respectively. These amounts are not reflected in the group s debt on the balance sheet.

The group has issued third-party guarantees under which amounts outstanding at 31 December 2007 are summarized below. Some guarantees outstanding are in respect of borrowings of jointly controlled entities and associates noted above. The analysis by time period indicates the ultimate expiry of the guarantees.

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

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

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Contractual commitments

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

$ million

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

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

[b] The future minimum lease payments are before deducting related rental income from operating sub-leases. Where an operating lease is entered into solely by the group as the operator of a jointly controlled asset, the total cost is included irrespective of any amounts that will be reimbursed by joint venture partners. Where operating lease costs are incurred in relation to the hire of equipment used in connection with a capital project, some or all of the cost may be capitalized as part of the capital cost of the project.

[c] Represents the expected future contributions to funded pension plans and payments by the group for unfunded pension plans and the expected future payments for other post-retirement benefits.

[d] Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas, feedstocks and pipeline systems. In addition, the amounts shown for 2008 include purchase commitments existing at 31 December 2007 entered into principally to meet the group s short-term manufacturing and marketing requirements. The price risk associated with these crude oil, natural gas and power contracts is discussed in Financial statements Note 28 on page 136.

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

$ million

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

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

The group expects its total capital expenditure, excluding acquisitions and asset exchanges and excluding the accounting related to our entry into the Canadian oil sands via two joint ventures with Husky Energy Inc., to be around $21-22 billion in 2008. This amount includes other investments in equity-accounted entities. The following table summarizes the group s capital expenditure commitments for property, plant and equipment at 31 December 2007 and the proportion of that expenditure for which contracts have been placed. Capital expenditure is considered to be committed when the project has received the appropriate level of internal management approval. For jointly controlled assets, the net BP share is included in the amounts shown. Where operating lease costs are incurred in connection with a capital project, some or all of the cost may be capitalized as part of the capital cost of the project. Such costs are included in the amounts shown.

$ million

Capital expenditure commitments	Total	2008	2009	2010	2011	2012	2013 and thereafter
Committed on major projects	24,013	5,329	3,799	1,646	742	1,403	11,094
Amounts for which contracts have been placed	8,263	5,200	1,999	747	187	57	73

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

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Critical accounting policies

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

Inherent in the application of many of the accounting policies used in preparing the financial statements is the need for BP management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual outcomes could differ from the estimates and assumptions used. The following summary provides further information about the critical accounting policies that could have a significant impact on the results of the group and should be read in conjunction with the Notes on financial statements.

The accounting policies and areas that require the most significant judgements and estimates used in the preparation of the consolidated financial statements are in relation to oil and natural gas accounting, including the estimation of reserves, the recoverability of asset carrying values, deferred taxation, provisions and contingencies, and pensions and other post-retirement benefits.

Oil and natural gas accounting

The group follows the successful efforts method of accounting for its oil and natural gas exploration and production activities.

The acquisition of geological and geophysical seismic information, prior to the discovery of proved reserves, is expensed as incurred.

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

For exploration wells and exploratory-type stratigraphic test wells, costs directly associated with the drilling of wells are temporarily capitalized within non-current intangible assets, pending determination of whether potentially economic oil and gas reserves have been discovered by the drilling effort. These costs include employee remuneration, materials and fuel used, rig costs, delay rentals and payments made to contractors. The determination is usually made within one year after well completion, but can take longer, depending on the complexity of the geological structure. If the well did not encounter potentially economic oil and gas quantities, the well costs are expensed as a dry hole and are reported in exploration expense. Exploration wells that discover potentially economic quantities of oil and gas and are in areas where major capital expenditure (e.g. offshore platform or a pipeline) would be required before production could begin, and where the economic viability of that major capital expenditure depends on the successful completion of further exploration work in the area, remain capitalized on the balance sheet as long as additional exploration appraisal work is under way or firmly planned.

It is not unusual to have exploration wells and exploratory-type stratigraphic test wells remaining suspended on the balance sheet for several years while additional appraisal drilling and seismic work on the potential oil and gas field is performed or while the optimum development plans and timing are established.

All such carried costs are subject to regular technical, commercial and management review on at least an annual basis to confirm the continued intent to develop, or otherwise extract value from, the discovery. Where this is no longer the case, the costs are immediately expensed.

Once a project is sanctioned for development, the carrying values of licence and property acquisition costs and exploration and appraisal costs are transferred to production assets within property, plant and equipment. Field development costs subject to depreciation are expenditures incurred to date, together with approved future development expenditure required to develop reserves.

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

The estimated proved reserves used in these unit-of-production calculations vary with the nature of the capitalized expenditure. The reserves used in the calculation of the unit-of-production amortization are as follows:

- Producing wells proved developed reserves.
- Licence and property acquisition, field development and future decommissioning costs total proved reserves.

The impact of changes in estimated proved reserves is dealt with prospectively by amortizing the remaining carrying value of the asset over the expected future production. If proved reserves estimates are revised downwards, earnings could be affected by higher depreciation expense or an immediate write-down of the property s carrying value (*see discussion of recoverability of asset carrying values below*).

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

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

The estimation of oil and natural gas reserves and BP s process to manage reserves bookings is described in Exploration and Production Reserves and production on page 14. As discussed below, oil and natural gas reserves have a direct impact on the assessment of the recoverability of asset carrying values reported in the financial statements.

The 2007 movements in proved reserves are reflected in the tables showing movements in oil and gas reserves by region in Financial statements Supplementary information on oil and natural gas on pages 181 to 189.

Recoverability of asset carrying values

BP assesses its fixed assets, including goodwill, for possible impairment if there are events or changes in circumstances that indicate that carrying values of the assets may not be recoverable and, as a result, charges for impairment are recognized in the group s results from time to time. Such indicators include changes in the group s business plans, changes in commodity prices leading to unprofitable performance, low plant utilization and, for oil and gas properties, significant downward revisions of estimated volumes or increases in estimated future development expenditure. If there are low oil prices, natural gas prices, refining margins or marketing margins during an extended period, the group may need to recognize significant impairment charges.

The assessment for impairment entails comparing the carrying value of the cash-generating unit and associated goodwill with the recoverable amount of the asset, that is, the higher of fair value less costs to sell and value in use. Value in use is usually determined on the basis of discounted estimated future net cash flows.

Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation on operating expenses, discount rates, production profiles and the outlook for global or regional market supply-and-demand conditions for crude oil, natural gas and refined products.

For oil and natural gas properties, the expected future cash flows are estimated based on the group s plans to continue to develop and produce proved reserves and associated risk-adjusted probable and possible volumes. Expected future cash flows from the sale or production of these volumes are calculated based on the group s best estimate of future oil and gas prices. Prices for oil and natural gas used for future cash flow calculations are based on market prices for the first five years and the group s long-term planning assumptions thereafter. As at 31 December 2007, the group s long-term planning assumptions were $60 per barrel for Brent and $7.50 per mmBtu for Henry Hub (2006 $40

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per barrel and $5.50 per mmBtu). These long-term planning assumptions are subject to periodic review and modification. The estimated future level of production is based on assumptions about future commodity prices, lifting and development costs, field decline rates, market demand and supply, economic regulatory climates and other factors.

The future cash flows are adjusted for risks specific to the asset where appropriate and are discounted using a pre-tax discount rate of 11% (2006 10%). This discount rate is derived from the group s post-tax weighted average cost of capital and is adjusted where applicable to take into account country-specific risk.

Irrespective of whether there is any indication of impairment, BP is required to test annually for impairment of goodwill acquired in a business combination. The group carries goodwill of approximately $11.0 billion on its balance sheet, principally relating to the Atlantic Richfield and Burmah Castrol acquisitions. In testing goodwill for impairment, the group uses a similar approach to that described above. The cash-generating units for impairment testing in this case are one level below business segments. As noted above, if there are low oil prices or natural gas prices or refining margins or marketing margins for an extended period, the group may need to recognize significant goodwill impairment charges.

Deferred taxation

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

Provisions and contingencies

The group holds provisions for the future decommissioning of oil and natural gas production facilities and pipelines at the end of their economic lives. The largest asset removal obligations facing BP relate to the removal and disposal of oil and natural gas platforms and pipelines around the world. The estimated discounted costs of dismantling and removing these facilities are accrued on the installation of those facilities, reflecting our legal obligations at that time. A corresponding asset of an amount equivalent to the provision is also created within property, plant and equipment. This asset is depreciated over the expected life of the production facility or pipeline. Most of these removal events are many years in the future and the precise requirements that will have to be met when the removal event actually occurs are uncertain. Asset removal technologies and costs are constantly changing, as well as political, environmental, safety and public expectations. Consequently, the timing and amounts of future cash flows are subject to significant uncertainty. Changes in the expected future costs are reflected in both the provision and the asset.

Decommissioning provisions associated with downstream and petrochemicals facilities are generally not provided for, as such potential obligations cannot be measured, given their indeterminate settlement dates. The group performs periodic reviews of its downstream and petrochemicals long-lived assets for any changes in facts and circumstances that might require the recognition of a decommissioning provision.

The timing and amount of future expenditures are reviewed annually, together with the interest rate used in discounting the cash flows. The interest rate used to determine the balance sheet obligation at the end of 2007 was 2%, unchanged from the end of 2006. The interest rate represents the real rate (i.e. adjusted for inflation) on long-dated government bonds.

Other provisions and liabilities are recognized in the period when it becomes probable that there will be a future outflow of funds resulting from past operations or events and the amount of cash outflow can be reliably estimated. The timing of recognition requires the application of judgement to existing facts and circumstances, which can be subject to change. Since the actual cash outflows can take place many years in the future, the carrying amounts of provisions and liabilities are reviewed regularly and adjusted to take account of changing facts and circumstances.

A change in estimate of a recognized provision or liability would result in a charge or credit to net income in the period in which the change occurs (with the exception of decommissioning costs as described above).

Provisions for environmental clean-up and remediation costs are based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, prices, discovery and analysis of site conditions and changes in clean-up technology.

The provision for environmental liabilities is reviewed at least annually. The interest rate used to determine the balance sheet obligation at 31 December 2007 was 2%, the same rate as at the previous balance sheet date.

As further described in Financial statements Note 44 on page 165, the group is subject to claims and actions. The facts and circumstances relating to particular cases are evaluated regularly in determining whether it is probable that there will be a future outflow of funds and, once established, whether a provision relating to a specific litigation should be adjusted. Accordingly, significant management judgement relating to contingent liabilities is required, since the outcome of litigation is difficult to predict.

Pensions and other post-retirement benefits

Accounting for pensions and other post-retirement benefits involves judgement about uncertain events, including estimated retirement dates, salary levels at retirement, mortality rates, rates of return on plan assets, determination of discount rates for measuring plan obligations, healthcare cost trend rates and rates of utilization of healthcare services by retirees. These assumptions are based on the environment in each country. Determination of the projected benefit obligations for the group s defined benefit pension and post-retirement plans is important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the income statement. The assumptions used may vary from year to year, which will affect future results of operations. Any differences between these assumptions and the actual outcome also affect future results of operations.

Pension and other post-retirement benefit assumptions are reviewed by management in December each year. These assumptions are used to determine the projected benefit obligation at the year end and hence the surpluses and deficits recorded on the group s balance sheet, and pension and post-retirement benefit expense for the following year.

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

The assumed rate of investment return, discount rate and the US healthcare cost trend rate have a significant effect on the amounts reported. A sensitivity analysis of the impact of changes in these assumptions on the benefit expense and obligation is provided in Financial statements Note 38 on page 152.

In addition to the financial assumptions, we regularly review the demographic and mortality assumptions. Mortality assumptions reflect best practice in the countries in which we provide pensions and have been chosen with regard to the latest available published tables adjusted where appropriate to reflect the experience of the group and an extrapolation of past longevity improvements into the future. BP s most substantial pension liabilities are in the UK, US and Germany and the mortality assumptions for these countries are detailed in Financial statements Note 38 on page 152.

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Directors, senior management and employees

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

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

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

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

Directors

Changes to the board

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

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

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

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

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

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

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

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

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

Peter Sutherland
Chairman

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P D Sutherland, SC, KCMG

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

Chairman of the chairman s and the nomination committees

Sir Ian Prosser

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

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

A Burgmans

Antony Burgmans (61) joined BP s board in 2004. He was appointed to the board of Unilever in 1991. In 1999, he became chairman of Unilever NV and vice chairman of Unilever PLC. In 2005, he became non-executive chairman of Unilever PLC and Unilever NV, retiring from these appointments in May 2007. He is also a member of the supervisory boards of Akzo Nobel NV and Aegon NV.

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

C B Carroll

Cynthia Carroll (51) joined BP s board on 6 June 2007. She started her career at Amoco and in 1989 she joined Alcan, where in 2002 she was appointed president and chief executive officer of Alcan s primary metals group and an officer of Alcan, Inc. She was appointed as chief executive of Anglo American plc, the global mining group, in March 2007. She is also a director of De Beers s.a. and Anglo Platinum Ltd.

Member of the chairman s committee

Sir William Castell, LVO

Sir William (60) joined BP s board in July 2006. From 1990 to 2004, he was chief executive of Amersham plc and subsequently president and chief executive officer of GE Healthcare. He was appointed as a vice chairman of the board of GE in 2004, stepping down from this post in 2006 when he became chairman of the Wellcome Trust. He remains a non-executive director of GE.

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

G David

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

Member of the chairman s committee

E B Davis, Jr

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

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

D J Flint, CBE

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

Internal Control. Between 2001 and 2004, he served on the Accounting Standards Board and the Standards Advisory Council of the International Accounting Standards Board.

Member of the chairman s and the audit committees

Dr D S Julius, CBE

DeAnne Julius (58) joined BP s board in 2001. She began her career as a project economist with the World Bank in Washington. From 1986 until 1997, she held a succession of posts, including chief economist at British Airways and Royal Dutch Shell Group. From 1997 to 2001, she was a full time member of the Monetary Policy Committee of the Bank of England. She is chairman of the Royal Institute of International Affairs and a non-executive director of Roche Holdings SA.

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

Sir Tom McKillop

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

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

Dr W E Massey

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

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

Dr A B Hayward

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

Dr D C Allen

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

I C Conn

Iain Conn (45) joined BP in 1986. Following a variety of roles in oil trading, commercial refining, retail and commercial marketing operations, and exploration and production, in 2000 he became group vice president of BP s refining and marketing business. From 2002 to 2004, he was chief executive of petrochemicals. He was appointed group executive officer with a range of regional and functional responsibilities and an executive director in 2004. He was appointed chief executive of refining and marketing in June 2007. He is a non-executive director of Rolls-Royce Group plc.

Dr B E Grote

Byron Grote (59) joined BP in 1987 following the acquisition of The Standard Oil Company of Ohio, where he had worked since 1979. He became group treasurer in 1992 and in 1994 regional chief executive in Latin America. In 1999, he was appointed an executive vice president of exploration and production, and chief executive of chemicals in 2000. He was appointed an executive director of BP in 2000 and chief financial officer in 2002. He is a non-executive director of Unilever NV and Unilever PLC.

A G Inglis

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

Senior management

P B P Bevan

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

S Bott

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

V Cox

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

R A Malone

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

J Mogford

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

S Westwell

Steve Westwell (49) joined BP in the manufacturing and supply division of BP Southern Africa in 1988. Following various retail positions in the UK and the US he was appointed head of retail and a member of the board of BP Southern Africa Pty. In 2003, he became president and chief executive officer of BP solar, and in 2004, group vice president of natural gas liquids, power, solar and renewables. In 2005, he was appointed group vice president of alternative energy. He was appointed executive vice president and group chief of staff on 1 January 2008.

Employees

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

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People

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

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

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

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

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

We run programmes designed to increase the number of local leaders and employees in our operations so that they reflect the communities in which we operate. For example, in Azerbaijan, we achieved our 2007 target of 75% of professional positions to be filled by national specialists.

At the end of 2007, 16% of our top 624 leaders were female and 19% came from countries other than the UK and the US. When we started tracking the composition of our group leadership in 2000, these percentages were 9% and 14% respectively. We have a number of programmes in place to help raise our senior level leaders awareness of diversity and inclusion (D&I), such as our Managing Inclusion programme in the US. D&I principles are also being incorporated into the Managing Essentials programme *(see below)*.

We aim to develop our leaders internally, although we recruit outside the group when we do not have specialist skills in-house or when exceptional people are available. In 2007, we appointed 72 people to positions in the 624-strong group leadership. Of these, 49 were internal candidates.

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

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

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

Communications with employees include magazines, intranet sites, DVDs, targeted e-mails and face-to-face communication. Team meetings are the core of our employee consultation, complemented by formal processes through works councils in parts of Europe. These communications, along with training programmes, are designed to contribute to employee development and motivation by raising awareness of financial, economic, social and environmental factors affecting our performance.

The group seeks to maintain constructive relationships with labour unions.

The code of conduct

We have a code of conduct, launched in 2005, designed to ensure that all employees comply with legal requirements and our own standards. The code defines what BP expects of its people in key areas such as safety, workplace behaviour, bribery and corruption and financial integrity. Our employee concerns programme, OpenTalk, enables employees to seek guidance on the code of conduct as well as to report suspected breaches of compliance or other concerns. The number of cases raised through OpenTalk in 2007 was 975, compared with 1,064 in 2006. In the US, former US district court judge Stanley Sporkin acts as an ombudsperson whom employees and contractors can contact confidentially to report any suspected breach of compliance, ethics or the code of conduct, including safety concerns.

We take steps to identify and correct areas of non-compliance and take disciplinary action where appropriate. In 2007, 944 dismissals were reported by BP s businesses for non-compliance or unethical behaviour. This number excludes some dismissals from the retail business, mainly at service station sites, for incidents such as thefts of small amounts of money.

BP continues to apply a policy that the group will not participate directly in party political activity or make any political contributions, whether in cash or in kind. BP specifically made no donations to UK or other EU political parties or organizations in 2007.

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Directors remuneration report

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

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Part 1: Summary

Dear Shareholder

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

Executive changes

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

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

2007 performance

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

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

Review of policy

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

For 2008, therefore, our policy is as follows:

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

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

– EDIP The share element will provide the primary long-term remuneration vehicle. Shares will be awarded to a level of 5.5 times salary for each executive director. These will vest after three years to the extent that performance relative to the other oil majors merits it.
  Performance is measured principally on TSR versus ExxonMobil, Shell, Total and Chevron. 100% of shares vest if first, 70% if second, 35% if third and nothing if fourth or fifth. The committee will also apply informed judgement, looking at overall performance in determining the final vesting level. Shares that vest must be retained for a further three years before being released to the executive director. In addition, each executive director is expected to build a significant personal shareholding in BP.
– Pensions Executive directors are eligible to participate in the appropriate pension schemes applying to their home countries.
  With this policy, the majority of executive directors target remuneration is performance-based.

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

Dr D S Julius

Chairman, Remuneration Committee
22 February 2008

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Summary of remuneration of executive directors in 2007[a]

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

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

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

Pensions

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

Historical TSR performance

This graph shows the growth in value of a hypothetical £100 holding in BP p.l.c. ordinary shares over five years, relative to the FTSE 100 Index (of which the company is a constituent). The values of the hypothetical £100 holdings at the end of the five-year period were £172.09 and £188.23 respectively.

Remuneration of non-executive directors in 2007[a]

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

a This information has been subject to audit.

b Appointed on 6 June 2007.

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

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Part 2: Executive directors remuneration

2007 remuneration

Salary increases

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

Annual bonus result

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

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

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

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

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

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

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

2005-2007 share element result

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

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

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

Remuneration policy

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

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

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

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

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

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

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

Salary

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

Annual bonus

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

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

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

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

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

25% people, including behaviour, values and culture.

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

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

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

Long-term incentives

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

Policy for performance share awards

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

In exceptional circumstances, the committee also has an overriding discretion to reduce the number of shares that vest or to decide that no shares vest.

The compulsory retention period will also be decided by the committee and will not normally be less than three years. Together with the performance period, this gives executive directors a six-year incentive structure, as shown in the timeline below, which is designed to ensure their interests are aligned with those of shareholders.

TIMELINE FOR 2008-2010 EDIP SHARE ELEMENT

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

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

Performance conditions

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

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

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

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

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

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

Special retention awards

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

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

Pensions

Executive directors are eligible to participate in the appropriate pension schemes applying in their home countries. Additional details are given on page 67.

UK directors

UK directors are members of the regular BP Pension Scheme. The core benefits under this scheme are non-contributory. They include a pension accrual of 1/60th of basic salary for each year of service, up to a maximum of two-thirds of final basic salary and a dependant s benefit of two-thirds of the member s pension. The scheme pension is not integrated with state pension benefits.

The rules of the BP Pension Scheme were amended in 2006 such that the normal retirement age is 65. Prior to 1 December 2006, scheme members could retire on or after age 60 without reduction. Special early retirement terms apply to pre-1 December 2006 service for members with long service as at 1 December 2006.

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Pension benefits in excess of the individual lifetime allowance set by legislation are paid via an unapproved, unfunded pension arrangement provided directly by the company.

US directors

Dr Grote participates in the US BP Retirement Accumulation Plan (US plan), which features a cash balance formula. Pension benefits are provided through a combination of tax-qualified and non-qualified benefit restoration plans, consistent with US tax regulations as applicable.

The Supplemental Executive Retirement Benefit (supplemental plan) is a non-qualified top-up arrangement that became effective on 1 January 2002 for US employees above a specified salary level. The benefit formula is 1.3% of final average earnings, which comprise base salary and bonus in accordance with standard US practice (and as specified under the qualified arrangement), multiplied by years of service.

There is an offset for benefits payable under all other BP qualified and non-qualified pension arrangements. This benefit is unfunded and therefore paid from corporate assets.

Dr Grote is eligible to participate under the supplemental plan. His pension accrual for 2007, shown in the table below, includes the total amount that could become payable under all plans.

Other benefits

Executive directors are eligible to participate in regular employee benefit plans and in all-employee share saving schemes and savings plans applying in their home countries. Benefits in kind are not pensionable. Expatriates may receive a resettlement allowance for a limited period.

Mr Inglis is currently based in Houston, US, and the company provides accommodation in London.

Pensions[a] thousand

	Service at 31 Dec 2007	Accrued pension entitlement at 31 Dec 2007	Additional pension earned during the year ended 31 Dec 2007[b]	Transfer value of accrued benefit[c] at 31 Dec 2006 (A)	Transfer value of accrued benefit[c] at 31 Dec 2007 (B)	Amount of B-A less contributions made by the director in 2007
Dr A B Hayward (UK)	26 years	£488	£250	£4,017	£7,986	£3,925
Dr D C Allen (UK)[d]	29 years	£248	£20	£4,006	£4,256	£250
I C Conn (UK)	22 years	£238	£69	£2,510	£3,375	£865
Dr B E Grote (US)	28 years	$778	$102	$7,591	$7,902	$311
A G Inglis (UK)	27 years	£296	£114	£2,936	£4,613	£1,677
Directors leaving the board in 2007						
Lord Browne (UK)	n/a	£1,050	£0	£21,700	£21,552	(£148)

J A Manzoni (UK)	n/a	£193	£5	£2,961	£4,195	£1,234

[a] This information has been subject to audit.
[b] Additional pension earned during the year includes an inflation increase of 4.4% for UK directors and 2.3% for US directors.
[c] Transfer values have been calculated in accordance with version 8.1 of guidance note GN11 issued by the actuarial profession.
[d] Dr Allen is due to retire on 31 March 2008 and will be entitled to take an immediate unreduced pension. The figures in the table relate to 2007 and so do not include anticipated incremental cost of the unreduced pension (£1.36 million).

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Share element of EDIP[a]

	Performance period	Date of award of performance shares	Market price of each share at date of award of performance shares £	Share element interests Potential maximum performance shares[b] At 1 Jan 2007	Awarded 2007	At 31 Dec 2007	Interests vested in 2007 and 2008 Number of ordinary shares vested[c]	Vesting date	Market price of each share at vesting date £
Dr A B Hayward	2004-2006	25 Feb 2004	4.25	376,470			112,941	15 Feb 2007	5.37
	2005-2007	**28 Apr 2005**	**5.33**	**436,623**		**436,623**	**0**	**n/a**	**n/a**
	2006-2008	16 Feb 2006	6.54	383,200		383,200			
	2007-2009	06 Mar 2007	5.12		706,311	706,311			
Dr D C Allen	2004-2006	25 Feb 2004	4.25	376,470			112,941	15 Feb 2007	5.37
	2005-2007	**28 Apr 2005**	**5.33**	**436,623**		**436,623**	**0**	**n/a**	**n/a**
	2006-2008	16 Feb 2006	6.54	383,200		383,200			
	2007-2009								