Making energy more

Annual Report and Accounts 2005

The Annual Report and Accounts for the year ended 31 December 2005, which includes comparative financial information for the years ended 31 December 2004 and 2003, comprises BP's first consolidated financial statements prepared under International Financial Reporting Standards (IFRSs) as adopted by the European Union (EU).

In preparing these financial statements, the group has complied with all IFRSs applicable for periods beginning on or after 1 January 2005. In addition, BP adopted early IFRS 6 'Exploration for and Evaluation of Mineral Resources', the amendment to IAS 19 'Employee Benefits: Actuarial Gains and Losses, Group Plans and Disclosures', the amendment to IAS 39 'Financial Instruments: Recognition and Measurement: Cash Flow Hedge Accounting of Forecast Intragroup Transactions' and IFRIC 4 'Determining whether an Arrangement contains a Lease'. The EU has adopted all standards and interpretations adopted by BP for its 2005 reporting.

The financial information for 2004 and 2003 has been restated to reflect the following, all with effect from 1 January 2005: (a) adoption by the group of IFRSs; (b) change in accounting policy for sales and purchases *(see Note 2 on financial statements)*; (c) transfer of the Mardi Gras pipeline system from Exploration and Production to Refining and Marketing; (d) transfer of the aromatics and acetyls operations and the petrochemicals assets that are integrated with our Gelsenkirchen refinery in Germany from the former Petrochemicals segment to Refining and Marketing; (e) transfer of the olefins and derivatives operations from the former Petrochemicals segment to the Olefins and Derivatives (O&D) business and the inclusion of the legacy historical results of other petrochemicals assets that had been divested during 2004 and 2003 within Other businesses and corporate; (f) transfer of the Grangemouth and Lavéra refineries from Refining and Marketing to the O&D business; and (g) transfer of the Hobbs fractionator from Gas, Power and Renewables to the O&D business. The O&D business is reported within Other businesses and corporate. This reorganization was a precursor to seeking to divest the O&D business. During 2005, we divested Innovene and show its activities as discontinued operations in these accounts. Innovene represented the majority of the O&D business.

Outside the financial statements, references within *BP Annual Report and Accounts 2005* to 'profits', 'result' and 'return on capital employed' are to those measures on a replacement cost basis unless otherwise indicated. The table below reconciles profit for the period to replacement cost profit.

RECONCILIATION OF PROFIT FOR THE PERIOD TO REPLACEMENT COST PROFIT

$ million

	2005	2004	2003
Profit before interest and tax for continuing operations	32,682	25,746	18,776
Finance costs and other finance expense	(761)	(780)	(1,045)
Taxation	(9,473)	(7,082)	(5,050)
Minority interest	(291)	(187)	(170)
Profit for the period for continuing operations attributable to BP shareholders	22,157	17,697	12,511
Profit (loss) for the period from Innovene operations	184	(622)	(63)
Profit for the period attributable to BP shareholders	22,341	17,075	12,448
Inventory holding (gains) losses	(3,027)	(1,643)	(16)
Replacement cost profit[a]	19,314	15,432	12,432
Replacement cost profit for continuing operations attributable to BP shareholders	19,513	16,336	12,460
Replacement cost profit for Innovene operations	(199)	(904)	(28)
Replacement cost profit	19,314	15,432	12,432
Per ordinary share – cents			
Profit for the period attributable to BP shareholders	105.74	78.24	56.14
Replacement cost profit	91.41	70.71	56.06
Dividends paid per ordinary share – cents	34.85	27.70	25.50
– pence	19.152	15.251	15.658
Dividends paid per American Depositary Share (ADS) – dollars	2.091	1.662	1.530

[a]Replacement cost profit reflects the current cost of supplies. The replacement cost profit for the period is determined by excluding from profit inventory holding gains and losses. BP uses this measure to assist investors to assess BP's performance from period to period.

The Annual Report and Accounts for the year ended 31 December 2005 contains the Directors' Report on pages 2-26, 158-163 and 174-176, and the Directors' Remuneration Report on pages 164-173. The consolidated financial statements are on pages 27-157. The reports of the auditor are on page 29 for the group and page 143 for the parent company.

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

The term 'shareholders' in the Report means, unless the context otherwise requires, investors in the equity capital of BP p.l.c., both direct and/or indirect.

BP Annual Report and Accounts 2005 and *BP Annual Review 2005* may be downloaded from *www.bp.com/annualreview*. No material on the BP website, other than the items identified as *BP Annual Report and Accounts 2005* and *BP Annual Review 2005*, forms any part of those documents.

As BP shares, in the form of ADSs, are listed on the New York Stock Exchange (NYSE), an Annual Report on Form 20-F will be filed with the US Securities and Exchange Commission in accordance with the US Securities Exchange Act of 1934. When filed, copies may be obtained, free of charge *(see page 177)*. BP discloses on its website at *www.bp.com* significant ways (if any) in which its corporate governance practices differ from those mandated for US companies under NYSE listing standards.

Cautionary statement

BP Annual Report and Accounts 2005 contains certain forward-looking statements, particularly those regarding BP's asset portfolio and changes in it, capital expenditure, community investment, costs, development of business strategy, discovery, development and management of oil and gas resources, dividends, share repurchases and other distributions to shareholders, earnings, availability of free cash flow, future performance, gearing, growth, investments, new markets, production, the progress and timing of projects, renewal of borrowing facilities, tax rates and the application of and spending on technology. By their nature, forward-looking statements involve risks and uncertainties because they relate to events and depend on circumstances that will or may occur in the future. Actual results may differ from those expressed in such statements, depending on a variety of factors, including the timing of bringing new fields on stream; future levels of industry product supply; demand and pricing; operational problems; general economic conditions; political stability and economic growth in relevant areas of the world; changes in laws and governmental regulations; exchange rate fluctuations; development and use of new technology; changes in public expectations and other changes in business conditions; the actions of competitors; natural disasters and adverse weather conditions; wars and acts of terrorism or sabotage; and other factors discussed elsewhere in this document.

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Registered in England and Wales No. 102498. Stock exchange symbol 'BP'.

Chairman's letter

DEAR SHAREHOLDER BP has just completed a demanding year. During 2005, we have seen the price of crude oil rise to levels that only two or three years ago would not have seemed at all likely. As a result, and coupled with a sound operational performance implementing our long-term strategy, we have seen the group produce record results. However, the group suffered the explosion at the Texas City refinery in the US. Our people and our performance were also affected by the Asian tsunami, by the hurricanes in the Gulf of Mexico that buffeted our offshore and onshore facilities, impairing production and distribution, and by other events. 2005 was therefore a year of contrasts, which has been testing for your board and immensely challenging for our executive management team, led by John Browne.

BP's ability to meet these challenges and, through them all, to deliver excellent performance depends on the work of the 96,200 people we employ. It also depends on the exemplary leadership provided by John Browne and the tremendously able team he heads. Their determination, experience and creativity are needed to rise to the challenges our business faces. I would like to thank John, his team and all our staff around the world for their contribution in 2005 and to recognize the value they have created for our shareholders.

During 2005, we continued our policy of returning cash in excess of our investment requirements to our shareholders both through buybacks and through our progressive dividend policy. I am pleased to confirm a dividend, to be paid in March, of 9.375 cents per share. The annual dividend paid of 34.85 cents per share or 19.152 pence per share represents an increase both in dollar and sterling terms over the past year of 26%. During 2005, we have repurchased some $11.6 billion of shares. Of these, 7% were cancelled and the remainder were placed into treasury.

I mentioned earlier that this had been a testing year for the board. In strategic terms, the advent of sustained high oil prices presents new and different demands for the development of the group's business over the long term. BP's business has always been one with a long stride; the group's continued development for the long-term benefit of shareholders over the next five to 10 years and beyond has been an area of strategic focus for the board throughout the year.

While our core strategy, explained in the Performance review section on pages 8-26, remains substantially unchanged, it is constantly reassessed in the light of developing circumstances. For example, the launch of the BP Alternative Energy business represents a greater focus on the manner in which this business is viewed and the importance we attach to alternative forms of energy production for the future.

While scrutiny and shaping of strategy are principal concerns of the board, the detailed monitoring work of our board committees has continued, with the amount of business they consider increasing annually. For instance, the ethics and environment assurance committee under Walter Massey's chairmanship enhanced its focus in the area of personal and process safety procedures in the light of the Texas City incident, while the challenge of meeting new financial reporting and accounting measures has been overseen by the audit committee, chaired by Sir Ian Prosser. Given the spread and complexity of the group's interests and assets, the work of the board committees is a major task and I would like to thank the chairmen and members of these committees for their efforts over the past year. Monitoring work carried out by those committees allows the board as a whole to focus on the strategic issues, which in turn leads to an effective use of board time. The work of each of the committees is described in more detail in the Governance: board performance report on pages 158-163.

I am pleased that, during the year, we have been able to contribute to the debate on corporate governance best practice. The past few years have seen a swathe of regulations in response to high-profile corporate scandals and failures. These interventions have led to detailed examinations of corporate governance regimes in the UK, US and Europe as well as the rest of the world. The frameworks within which companies and boards operate vary significantly, just as the systems of legal and financial regulation differ. Above all, governance systems and processes must be fit for purpose for each different company in the legal and capital markets in which they operate. Where markets do not offer adequate safeguards to shareholders, governance practices must evolve to fill that gap. While the board evaluation exercise we undertook this year indicated areas in which our practices should develop, the internal and external endorsement our board has received reassures us that the governance of your company is state-of-the-art.

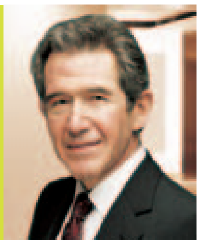
Our work on board succession and development continues. During 2005, we said farewell to our two longest-serving directors, Sir Robin Nicholson and Chuck Knight, whose substantial contributions we acknowledged last year. At the forthcoming AGM, Michael Miles will step down. Michael has served on the BP board since June 1994. He has made significant contributions to both the audit and the ethics and environment assurance committees. His experiences of working in the Far East have been of particular value to us in recent years as the markets in that region have become so important. We shall miss Michael's contributions at the board and his commitment to board and committee work.

Against this background, the work of the chairman's committee and the nomination committee, both of which I chair, continues. Processes have been established for executive and non-executive succession for the future. The nomination committee in particular is continuing to review the skills needed on the board to rise to the evolving challenges faced by BP and the work of the board in the coming years.

If 2005 was a demanding year, I am sure that 2006 will continue to stretch the abilities of both the board and the executive team. On behalf of the board, I would like to thank you for your support.

Peter Sutherland
Chairman
6 February 2006

Group chief executive's review



DEAR SHAREHOLDER We start from the view that the purpose of business is to satisfy human needs and, in doing so, to generate profits for investors. For BP, that means providing energy to fuel human progress and economic growth. It also means satisfying the need for a sustainable environment.

On many fronts, our performance in 2005 was very strong but the year was overshadowed by the industrial accident at our Texas City refinery in March, which caused 15 deaths and many more injuries. That incident has been the subject of rigorous and thorough investigation both by our own team and by external authorities and lessons have been learned. We are determined to do everything possible to ensure that no such accident recurs.

In addition to safety, the primary challenge for BP during 2005 was the maintenance of the flow of secure supplies of energy to our customers in the face of volatile markets and the instability caused by continued conflict in the Middle East, terrorism and extreme weather conditions in the US and elsewhere. Our success in meeting this fundamental element of our purpose was due to the talent and dedication of our staff, often working under conditions of severe difficulty.

FINANCIAL PERFORMANCE In terms of financial performance, 2005 was an exceptional year for BP, with profits of $19.3 billion, representing a return on average capital employed of 20%. High oil prices, which averaged $54.48 during 2005 against $38.27 in 2004 (dated Brent), contributed to the result but the underlying performance of the company is strong. These results reflect not just a positive operating environment but were the consequence of the long-run strategic position of the company and improvements in each part of our business. That performance is described in the following pages.

BP now produces more than 4 million barrels of oil equivalent per day of oil and gas for customers across the world. To sustain supplies and meet the growing levels of demand that population growth and prosperity are generating, we continue to invest for the future. Our profits fund not only the dividends, which we are delighted to have been able to increase once again during 2005, and the buybacks of shares, which totalled $11.6 billion during the year, but also the investment in new developments that will form the basis of the group's business for years to come.

Capital expenditure in the exploration and production segment totalled $10.1 billion in 2005, bringing the total so far since the turn of the century to more than $50 billion. That investment is aimed at providing sustainable supplies of oil and gas and enabling us to develop the extensive base of proved reserves and identified resources that we have built up in recent years. In 2005, we added 662 million barrels of oil and 4.6 trillion cubic feet of natural gas to our booked reserves for subsidiaries and equity-accounted entities. That success made 2005 the 13th consecutive year in which we have replaced, in accordance with UK generally accepted accounting practice Statement of Recommended Practice (SORP), 100% or more of the oil and gas we produced. Exploration success continues to augment this base. Major new discoveries were made in the deepwater Gulf of Mexico and Angola.

We have a strong and successful trading business and a growing presence as a producer and supplier of natural gas, with a daily output averaging 8.4 billion cubic feet during 2005 from fields in Trinidad and North Africa, as well as the US and the North Sea.

We are also investing in the refining and marketing businesses, developing new and strong positions in those areas of the world where energy demand is increasing most rapidly. Worldwide, we supply some 13 million customers a day. Our supply links, including a growing fleet of ships and the extensive networks of pipelines we operate in many different parts of the world, helped to sustain global supplies through all the disruptions experienced in 2005.

EXTERNAL CHALLENGES The oil and gas markets remain volatile. While we expect prices to remain above the long-run average for some years to come, we have taken care to ensure that the business is robust and capable of responding flexibly to unpredictable events.

Volatility is not the only challenge we face. No company in the oil and gas industry can fail to recognize that, as the demand for our products rises, so too does the risk that their use will contribute to the environmental challenges associated with an increasing concentration of carbon in the atmosphere. The science of climate change may be incomplete but we would be foolish to ignore the mounting evidence and the conclusion of the world's most eminent scientists that precautionary action is necessary.

Over recent years, we have taken steps to reduce emissions from our own operations and to improve further the quality of our products. In 2005, we took an important step with a substantial investment in the development of an alternative energy business that will offer our customers new choices of low-carbon energy. BP Alternative Energy is focused on the power generation sector – the largest single source of emissions from the use of fossil fuels – through investments in solar power, wind, gas and hydrogen power, where the latter employs the new technology of sequestration, in which carbon is captured and stored, allowing hydrogen to be used to generate clean, carbon-free electric power.

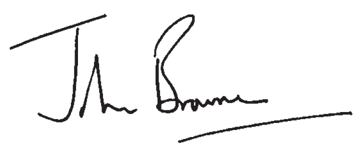
This is a long-term, but very exciting, development that we believe can help meet the energy needs of a growing world while minimizing the impact on our common environment.

HUMAN TALENT The other element essential for the long-term health of the company is the development of human talent. In all the places in which we operate, we are committed to the development of people. Within BP, that is reflected in our policies of inclusion and meritocracy and our determination to develop individuals, regardless of their background, creed or colour.

Beyond the company, we are committed to the development of enterprise and education in the communities in which we work. Our aim is that they are better able to take advantage of the wealth created by natural resource development. In 2005, we appointed our first director of education, whose role will be both to co-ordinate our existing activity and to develop a continuing programme to maximize our contribution to the development of human capacity.

Over the last 10 years, the group has broadened its base of activity – extending beyond the North Sea and Alaska and developing resources and markets across the world. In places as diverse as Russia, Angola, Germany, China and Egypt, BP is now a leading player. In those countries and in all the places in which we now work, we are committed to the principle of mutual advantage. BP, as a large multinational company, can only earn the privilege of operating on a global basis if in each and every case we can demonstrate that what we do benefits those with whom we do business as well as the company itself.

We have much to do and much to learn, but our aspiration remains unchanged – to be a company that works consistently and universally in ways that help to sustain the development of the world of which we are part.



The Lord Browne of Madingley
Group Chief Executive
6 February 2006

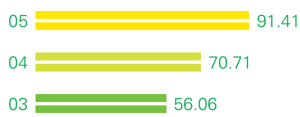
Measuring our progress

We have three targets:

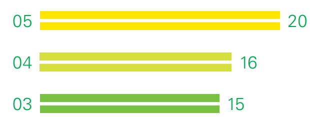
- To underpin growth by a focus on performance, particularly on returns, investing at a rate appropriate for long-term growth.
- To increase the dividend per share in light of our policy.
- To return to shareholders all free cash flows in excess of investment and dividend needs.

The charts opposite provide some measures of our progress in 2005.

REPLACEMENT COST PROFIT PER ORDINARY SHARE (cents)



RETURN ON AVERAGE CAPITAL EMPLOYED (%)

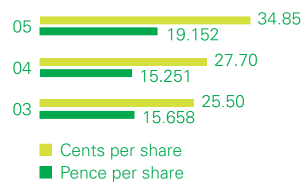


SHAREHOLDER DISTRIBUTION

$19 billion

returned to shareholders through dividends and share buybacks in 2005.

DIVIDENDS PAID PER SHARE



EXPLORATION AND PRODUCTION

100%

We have replaced 100% or more of our production for 13 consecutive years on a UK SORP basis.

REFINING AND MARKETING

1 or 2

We are number 1 or 2 in 85% of the retail markets in which we operate.

GAS, POWER AND RENEWABLES

$8bn

Planned investment in BP Alternative Energy business over next 10 years.

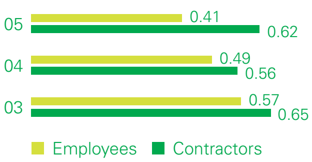
GREENHOUSE GAS EMISSIONS[a]

78 million tonnes (Mte)

compared with 81.7Mte in 2004.

[a]BP share of emissions expressed as an equivalent mass of carbon dioxide. TNK-BP emissions are not included.

SAFETY RIF[a]



[a]Recordable Injury Frequency (RIF): number of reported work-related incidents resulting in a fatality or injury (apart from minor first aid cases) per 200,000 hours worked.

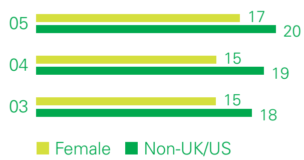
OIL SPILLS

541 spills of ≥ 1 barrel[a]

compared with 578 in 2004.

[a]1 barrel = 159 litres = 42 US gallons.

DIVERSITY[a] (%)



[a]Senior management in 2005 includes the top 606 positions in BP.

CONTRIBUTION TO COMMUNITIES[a]

$96 million

[a]Including UK charities $0.8 million.

Structure and strategy

BP operates globally, with business activities and customers in more than 100 countries in Europe, the US, Canada, Russia, South America, Australasia, Asia and Africa. We have exploration and production interests in 26 countries. Just under 40% of our fixed assets are located in the US and around 25% in the UK and the rest of Europe.

BP is organized into three business segments, 22 group functions and four regions.

Our three operating business segments are: Exploration and Production, which includes oil and natural gas exploration, development and production, together with related pipeline transportation and processing activities; Refining and Marketing, including oil supply and trading, and the manufacture and marketing of petroleum products, including aromatics and acetyls (A&A); and Gas, Power and Renewables, including the marketing and trading of natural gas, natural gas liquids (NGLs), liquefied natural gas (LNG), LNG shipping and regasification activities, and low-carbon power development, including solar and wholesale marketing and trading (BP Alternative Energy).

Group functions serve the three business segments, aiming to achieve coherence across the group, manage risk effectively and achieve economies of scale. Some functions, such as Economics, Group Compliance & Ethics (GC&E) and Financial Control & Accounting, are centralized. Others, such as Communications & External Affairs and Digital & Communications Technology, are fully or partly decentralized, to respond better to the specific needs of each segment. The group's research and engineering activities provide technological support for all business segments.

Each head of region ensures regional consistency of the activities of business segments and group functions and represents BP to external parties. However, each segment is managed on a global basis.

From 1 January 2005, our Petrochemicals segment ceased to report separately, following the announcement in 2004 of our intention to divest the Olefins and Derivatives (O&D) business. From that date, the retained A&A operations have been reported within Refining and Marketing and O&D within Other businesses and corporate, thus reducing the number of business segments from four to three. In the fourth quarter, we sold Innovene, which represented the majority of O&D, to INEOS. Innovene operations have subsequently been presented as discontinued operations and the retained portion of O&D continues to be reported within Other businesses and corporate.

STRATEGY

We make five-year and annual plans to execute our strategy in the context of time to achieve three targets:

- **To underpin growth by a focus on performance, particularly on returns, investing at a rate appropriate for long-term growth.**
- **To increase the dividend per share in light of our policy.**
- **To return to shareholders all free cash flows in excess of investment and dividend needs.**

Exploration and Production Our strategy remains to build production with improving returns by focusing on finding the largest fields, concentrating our involvement in a limited number of the world's most prolific hydrocarbon basins; by building leadership positions in these areas; and by managing the decline of existing producing assets, divesting assets when they no longer compete in our portfolio.

Refining and Marketing Our strategy remains to focus on our advantaged refineries, where we can achieve distinctive returns through scale, flexible configuration and operational excellence and develop supply opportunities around these assets. We plan to expand our A&A business by continuing to apply our advantaged technologies, building new acetic acid and purified terephthalic acid (PTA) capacity in Asia and maintaining our global competitive position. In our marketing business, we continue to grow our focused and differentiated offers. We operate in retail markets where we can create a competitive edge from supply positions, superior customer offers and efficiency across the value chain. We will continue to focus our investments in those areas where we have a distinctive position in the marketplace. We are building strategic relationships in the business-to-business sector, as well as increasing product loyalty in our Castrol and other branded lubricants activities and enhancing our strength in key growth markets. We also aim to improve operational efficiency in manufacturing and across the marketing base.

Gas, Power and Renewables Our strategy remains to capture distinctive world-scale gas market positions by accessing key pieces of infrastructure and to expand gross margin by providing distinctive products to selected customer segments and optimizing the gas and power value chains. We have created the BP Alternative Energy business to develop the world's leading low-carbon power generation and wholesale marketing and trading businesses.

In line with growing demand for cleaner fuels, BP seeks to participate on a large scale in fast-growing markets for natural gas, gas liquids and low-carbon power. We have strong upstream gas assets near the major markets, significant interests in gas pipelines and a series of integrated LNG positions in the Pacific and Atlantic basins. We are expanding our LNG business by accessing import terminals in Asia Pacific, North America and Europe. We are extending our significant strength in US NGLs processing and marketing on a global basis.

The board delegates to the group chief executive responsibility for developing BP's strategy and its implementation through five-year and annual plans (the group plan) that determine the setting of priorities and allocation of resources. The group chief executive is obliged to discuss with the board, on the basis of the strategy and group plan, all material matters currently or prospectively affecting BP's performance.

The group's system of internal control governs the further delegation of authority throughout the group. It sets out the roles and relationships of the different parts of the business and their constituent teams and individuals. It also sets out clear principles of delegation and the corresponding standards of behaviour expected from all staff. Accountability is achieved through setting detailed internal targets, monitoring and measuring against plans.

RISKS

We aim to deliver long-term sustainable value to shareholders by identifying and responding successfully to risks. An important device for identifying and managing risk is the development and delivery of the group plan. A detailed risk assessment by the business segments, group functions and regions shapes BP's medium-term plan, including agreed responses to the risks identified. The performance of each segment, function and region is monitored in order to respond appropriately; business objectives are updated based on the impact that the range of risks realized is having on our performance. Risk management is therefore integrated into the process of planning and performance management.

In the context of BP's system of internal control, different types of risk require different types of management response. In each case, we set milestones in the group plan to address the risks, with a well-defined process for assessing and reporting progress each year.

Monitoring and accountability for the management of these risks occur through quarterly performance reviews, when the metrics and milestones for delivery of the group plan are assessed.

Group-level risks have been identified and classified in three categories: delivery, inherent and enduring.

Delivery risks Delivery risks are those specific to implementing activities contained in our group plan. Successful execution of this plan depends critically on implementing the set of activities described. Hence, our delivery risks are those factors that would result in our failure to deliver these activities economically. The most significant risks include:

Upstream renewal Inability to renew the portfolio and sustain long-term reserves replacement. The challenge is growing due to increasing competition for access to opportunities globally.

Major project delivery Poor delivery of any major project that underpins production growth and/or a major programme designed to enhance shareholder value.

Portfolio repositioning Inability to complete planned disposals and/or lack of material positions in new markets (and hence the inability to capture above-average market growth).

Inherent risks There are a number of risks that arise as a result of the business climate, which are not directly controllable.

Competition risk 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.

Price risk Oil, gas and product prices are subject to international supply and demand. Political developments (especially in the Middle East) and the outcome of meetings of OPEC can particularly affect world supply and oil prices. In addition to the adverse effect on revenues, margins and profitability from any future fall in oil and natural gas prices, a prolonged period of low prices or other indicators would lead to a review for impairment of the group's oil and natural gas properties. This review would reflect management's view of long-term oil and natural gas prices. Such a review could result in a charge for impairment that could have a significant effect on the group's results of operations in the period in which it occurs.

Regulatory risk 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. 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, causing our production to decrease, or we could incur additional costs.

Developing country risk We have operations in developing countries where political, economic and social transition is taking place. Some countries have experienced political instability, 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.

Currency risk Crude oil prices are generally set in US dollars, while sales of refined products may be in a variety of currencies. Fluctuations in exchange rates can therefore give rise to foreign exchange exposures, with a consequent impact on underlying costs.

Economic risk – refining and petrochemicals market
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.

Enduring risks 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. This may create risks to our reputation if it is perceived that our actions are not aligned to these standards and aspirations.

Social responsibility risk Risk could arise if it is perceived that we are not respecting or advancing the economic and social progress of the communities in which we operate.
Environmental risk We seek to conduct our activities in such a manner that there is no or minimal damage to the environment. Risk could arise 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.
Compliance risk Incidents of non-compliance with applicable laws and regulation or ethical misconduct could be damaging to our reputation and shareholder value.

Inherent in our operations are hazards that require continual oversight and control. If operational risks materialized, loss of life, damage to the environment or loss of production could result.
Drilling and production risk Exploration and production require high levels of investment and have particular economic risks and opportunities and may often involve innovative technologies. They 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.
Technical integrity risk There is a risk of loss of containment of hydrocarbons and other hazardous material at operating sites, pipelines or during transportation by road, rail or sea.
Security risk Acts of terrorism that threaten our plants and offices, pipelines, transportation or computer systems would severely disrupt business and operations.

Financial performance

BUSINESS ENVIRONMENT

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

Crude oil prices reached record highs in 2005 in nominal terms, driven by continued oil demand growth and low surplus oil production capacity. The dated Brent price averaged $54.48 per barrel, an increase of more than $16 per barrel above the $38.27 per barrel average seen in 2004, and varied between $38.21 and $67.33 per barrel. Hurricanes Katrina and Rita severely disrupted oil and gas production in the Gulf of Mexico for an extended period, but supply availability was maintained.

We test exploration and production projects at $25 per barrel but, in the light of oil market developments, we also test them over a range of prices to ensure we maintain a portfolio of activities with strong returns.

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

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

RECONCILIATION OF PROFIT FOR THE PERIOD TO REPLACEMENT COST PROFIT

			$ million
	2005	2004	2003
Profit before interest and tax for continuing operations	32,682	25,746	18,776
Finance costs and other finance expense	(761)	(780)	(1,045)
Taxation	(9,473)	(7,082)	(5,050)
Minority interest	(291)	(187)	(170)
Profit for the period for continuing operations attributable to BP shareholders	22,157	17,697	12,511
Profit (loss) for the period from Innovene operations	184	(622)	(63)
Profit for the period attributable to BP shareholders	22,341	17,075	12,448
Inventory holding (gains) losses	(3,027)	(1,643)	(16)
Replacement cost profit[a]	19,314	15,432	12,432
Replacement cost profit for continuing operations attributable to BP shareholders	19,513	16,336	12,460
Replacement cost profit for Innovene operations	(199)	(904)	(28)
Replacement cost profit	19,314	15,432	12,432
Per ordinary share – cents			
Profit for the period attributable to BP shareholders	105.74	78.24	56.14
Replacement cost profit	91.41	70.71	56.06
Dividends paid per ordinary share – cents	34.85	27.70	25.50
– pence	19.152	15.251	15.658
Dividends paid per American Depositary Share (ADS) – dollars	2.091	1.662	1.530

[a] Replacement cost profit reflects the current cost of supplies. The replacement cost profit for the period is determined by excluding from profit inventory holding gains and losses. BP uses this measure to assist shareholders to assess BP's performance from period to period.

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

RESULTS

BP's replacement cost profit for 2005 was $19,314 million, compared with $15,432 million in 2004. Our profit including inventory holding gains was $22,341 million, compared with $17,075 million in 2004. Inventory holding gains or losses represent the difference between the cost of sales calculated using the average cost of supplies incurred during the period and the cost of sales calculated using the first-in first-out method.

On 16 December 2005, we completed the sale of Innovene to INEOS. The transaction included manufacturing sites, markets and technologies.

Our profit figures include a net charge for non-operating items of $1,754 million in 2005, compared with $1,072 million in 2004, as shown in the table on page 12.

Non-operating items in 2005 included net fair value losses on embedded derivatives of $2,047 million, a gain of more than $1 billion from the sale of our interest in the Ormen Lange field in Norway and a charge of $700 million for fatality and personal injury claims resulting from the incident at our Texas City refinery on 23 March 2005. The non-operating items related to Innovene primarily consist of the loss of $591 million on remeasurement to fair value resulting from its disposal.

Excluding the effects of the non-operating items, the primary factors contributing to the increase in profit for 2005, compared with 2004, were higher liquids and gas realizations, higher refining margins and higher contributions from the gas marketing and trading and natural gas liquids businesses. These increases were partly offset by lower retail marketing margins, higher costs (including those related to hurricanes, the Thunder Horse incident and the Texas City outage), planned restructuring actions and significant volatility resulting under IFRS fair value accounting. Operating incidents at our Texas City refinery and extreme weather events impacted our results by an estimated $2 billion post-tax, compared with 2004. This includes foregone production at prevailing prices and margins, as well as directly related response and repair costs. It does not include the charge for the Texas City fatality and personal injury claims nor Gulf of Mexico Shelf impairment charges related to hurricane damage, which are included in the non-operating items above.

Return on average capital employed on a replacement cost basis was 20%, compared with 16% in 2004; based on profit including inventory holding gains, it was 23% (2004 18%).

Finance costs were $616 million, compared with $440 million in 2004. The increase primarily reflects higher interest costs, offset by higher capitalized interest. Other finance expense was $145 million, compared with $340 million in 2004, primarily reflecting lower net pension costs.

Corporate tax expense was $9,473 million (2004 $7,082 million), representing an effective tax rate of 32% on replacement cost profit before tax of continuing operations.

Capital expenditure and acquisitions amounted to $14,149 million. There were no significant acquisitions during the year. Capital expenditure and acquisitions were $16,651 million in 2004, including $1,354 million for 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.

Net cash provided by operating activities for 2005 was $26,721 million, compared with $23,378 million in 2004. In addition to higher profits, the increase reflects higher dividends from jointly controlled entities, partially offset by higher working capital requirements and higher income tax payments.

Net cash used in investing activities was $1,729 million, compared with $11,331 million in 2004. This reflects capital expenditure and acquisitions of $13,145 million (2004 $16,379 million), partially offset by disposal proceeds of $11,200 million (2004 $4,961 million). The net cash proceeds from the sale of Innovene were $8,304 million after selling costs, closing adjustments and liabilities assumed by INEOS. Proceeds from the sale will add to the free cash flow available for distribution to shareholders.

Net debt, that is, debt less cash and cash equivalents, was $16,202 million at 31 December 2005, compared with $21,732 million at 31 December 2004.

The ratio of net debt to net debt plus equity was 17% at 31 December 2005, compared with 22% at 31 December 2004. This ratio shows the proportion of debt and equity used to finance our operations and can also be used to measure borrowing capacity. The ratio of 17% at the end of 2005 reflects stronger cash flows both from underlying operations and the sale of Innovene. We continue to believe that a 20-30% gearing band provides an efficient capital structure and the appropriate level of financial flexibility. Our aim is to return gearing to the lower half of the band.

In addition to reported debt, BP uses conventional off-balance sheet sources of finance such as operating leases and joint venture and associate borrowings.

BP's critical accounting policies are highlighted in Other financial issues on pages 21-24.

BP's approach to financial risk management, including the use of derivatives, is described in Other financial issues on pages 24-26.

DIVIDENDS AND SHARE REPURCHASES

The total dividend paid in 2005 was $7,359 million, compared with $6,041 million for 2004. The dividend paid per share was 34.85 cents, an increase of 26% compared with 2004. In sterling terms, the dividend was also 26% higher. The increase is the result of our strong cash flow and improvements in underlying performance in line with strategy.

Our dividend policy is to grow the dividend per share progressively. In pursuing this policy and in setting the levels of dividends, the board is 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 determine the dividend in US dollars, the economic currency of BP.

BP intends to continue the operation of the Dividend Reinvestment Plan (DRIP) for shareholders who wish to

EXTERNAL ENVIRONMENT

	2005	2004	2003
BP average liquids realizations ($/barrel)	48.51	35.39	27.25
Brent oil price ($/barrel)	54.48	38.27	28.83
BP average natural gas realizations ($/thousand cubic feet)	4.90	3.86	3.39
Henry Hub gas price ($/mmBtu)	8.65	6.13	5.37
Global indicator margin ($/barrel)	8.60	6.31	4.08

NON-OPERATING ITEMS

			$ million
	2005	2004	2003
Impairment and gain (loss) on sale of businesses and fixed assets	1,070	295	94
Environmental and other provisions	(412)	(489)	(582)
Restructuring, integration and rationalization costs	(134)	(134)	(399)
Fair value gain (loss) on embedded derivatives	(2,047)	–	–
Other	(668)	39	559
Total non-operating items before taxation for continuing operations	(2,191)	(289)	(328)
Taxation	717	83	94
Total non-operating items after taxation for continuing operations	(1,474)	(206)	(234)
Innovene operations			
Impairment and gain (loss) on sale of businesses and fixed assets	(647)	(1,119)	–
Taxation	367	253	–
Total after taxation for Innovene operations	(280)	(866)	–
Total after taxation	(1,754)	(1,072)	(234)

CAPITAL INVESTMENT

			$ million
	2005	2004	2003
Exploration and Production	10,149	9,654	9,398
Refining and Marketing	2,669	2,692	2,945
Gas, Power and Renewables	235	524	439
Other businesses and corporate	885	940	815
Capital expenditure	13,938	13,810	13,597
Acquisitions and asset exchanges	211	2,841	6,026
	14,149	16,651	19,623
Disposals	(11,200)	(4,961)	(6,356)
Net investment	2,949	11,690	13,267

OPERATING STATISTICS

	2005	2004	2003
Liquids production (thousand b/d)	2,562	2,531	2,121
Gas production (million cf/d)	8,424	8,503	8,613
Total production (thousand boe/d)	4,014	3,997	3,606
Refinery throughputs (thousand b/d)	2,399	2,607	2,723
Marketing sales (thousand b/d)	3,942	4,002	3,969

receive their dividend in the form of shares rather than cash. The BP Direct Access Plan for US and Canadian shareholders also includes a dividend reinvestment feature.

We remain committed to returning all free cash flows in excess of investment and dividend needs to our shareholders.

During 2005, the company repurchased 1,060 million of its own shares at a cost of $11,597 million. Of these, 77 million were cancelled and the remainder are held in treasury. The repurchased shares had a nominal value of $265 million and represented 4.9% of the ordinary shares in issue at the end of 2004. Since the inception of the share repurchase programme in 2000, we have repurchased 2,662 million shares at a cost of $25.2 billion. BP intends to continue its programme of share buybacks, subject to market conditions and constraints and to renewed authority at the April 2006 annual general meeting.

Business performance

EXPLORATION AND PRODUCTION

			$ million
	2005	2004	2003
Profit before interest and tax[a]	25,508	18,087	15,084
Inventory holding (gains) losses	(17)	(10)	(3)
Replacement cost profit before interest and tax	25,491	18,077	15,081
Results include:			
Impairment and gain (loss) on sale of business and fixed assets	893	(469)	175
Environmental and other provisions	–	–	–
Restructuring, integration and rationalization costs	–	–	(117)
Fair value gain (loss) on embedded derivatives	(1,688)	–	–
Other	(203)	(27)	–
Total non-operating items	(998)	(496)	58
Total hydrocarbon production (mboe/d)	4,014	3,997	3,606
Net proved reserves (million barrels)[b]	18,271	18,583	18,338
Reserves replacement ratio[b]	100%	110%	109%

[a]Profit from continuing operations and includes profit after interest and tax of equity-accounted entities.
[b]UK SORP basis including equity-accounted entities.

The segment's replacement cost profit before interest and tax of $25,491 million for the year was a record, representing an increase of 41% over 2004. The increase reflected higher realizations, partially offset by costs associated with the severe hurricanes and the Thunder Horse stability incident, and higher operating and revenue investment costs. The result included a net charge for non-operating items of $998 million, primarily related to fair value losses on embedded derivatives, net gains on sales of assets, mainly from the sale of Ormen Lange, and net impairment charges.

Capital expenditure was $10.1 billion in 2005 and is expected to be around $11 billion in 2006.

Production was 4,014 thousand barrels of oil equivalent a day in 2005. Increases in production in our new profit centres and TNK-BP were offset by the effects of severe weather disruptions, higher planned maintenance shutdowns, anticipated decline and operational issues in our existing profit centres.

New and existing profit centres We continued to make significant progress in our new profit centres in 2005. In the past three years, we have brought on stream 20 major projects.

BP is operating four major projects in Azerbaijan on behalf of its consortium partners: the Azeri-Chirag-Gunashli oil fields, the Baku-Tbilisi-Ceyhan (BTC) pipeline, the Shah Deniz gas field and the South Caucasus pipeline. The Central Azeri project achieved its first production in February 2005 and the West Azeri project achieved its first production in December 2005, four months ahead of schedule. Construction of the BTC pipeline progressed and line-fill of the pipeline started in 2005, with the official inauguration ceremony held on 25 May at the Sangachal terminal near Baku. The Georgian section was inaugurated in early October and the first tanker lifting from Ceyhan is expected in the second quarter of 2006. In-country assembly of the drilling rig and platform for the Shah Deniz field is on schedule for start-up in 2006 and the associated South Caucasus pipeline is also on course to be completed during 2006.

The Kizomba B development offshore Angola achieved its first oil production four months ahead of schedule in July 2005 and the Greater Plutonio project remains on track to deliver first oil in 2007.

In Trinidad & Tobago, the Atlantic LNG Train 4 commenced liquefaction at the end of the year. The Cannonball gas development, Trinidad & Tobago's first major offshore construction project executed locally, is due to start production in the first quarter of 2006.

In Algeria, the carbon dioxide (CO_2) capture system in our In Salah gas project started operations. This is one of the world's largest CO_2 capture projects, providing emissions savings estimated to be equivalent to taking a quarter of a million cars off the road. The In Amenas project is expected to start production in the first half of 2006. BP was awarded three blocks in Algeria's sixth international licensing round.

In Indonesia, we received the final governmental approvals for the Tangguh LNG project, which is proceeding on schedule.

In the Gulf of Mexico, the Mad Dog project achieved first production in January 2005. Following stability problems in July 2005, repairs to the Thunder Horse platform are proceeding offshore. Production, originally scheduled for the end of 2005, is now expected to start in the second half of 2006. This is due to be followed by Atlantis, with first production expected around the end of 2006.

In Russia, oil production from TNK-BP grew by just under 10% compared with 2004. Total production, including gas, exceeded 2 million boe/d for the first time in the third quarter of 2005. Total dividends received by BP amounted to $1.95 billion. Towards the end of the year, TNK-BP disposed of non-core producing assets in the Saratov region, along with the Orsk refinery. Future investment in TNK-BP's upstream business includes further extension drilling in the Ust Vakh area of the Samotlor field and in the Kammenoye field, as well as the greenfield Demiansky project in the Uvat area. BP's exploration successes in Sakhalin through Elvaryneftegas, a joint venture with Rosneft, continued in 2005 with a second discovery. The region is now beginning to show significant future potential.

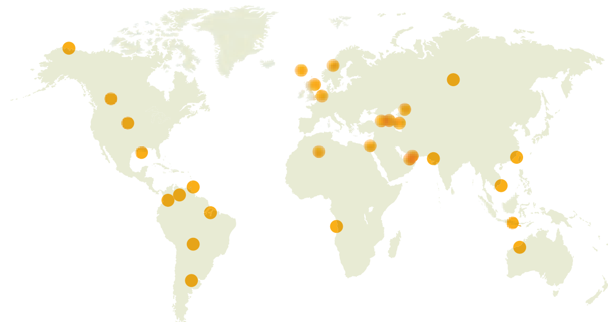
In Egypt, we sanctioned investment in the Saqqara field. We also extended two concessions in the Gulf of Suez, the Merged Concession Agreement and South Garib, which will extend the life of the existing oil fields, increase the recovery of remaining reserves and provide a foundation for future growth through exploration.

Progress also continued in our other existing profit centres. The North Sea completed its biggest maintenance campaign in several years in a demanding operational environment. Three new projects – Clair, Rhum and Farragon – started production in 2005. All three came on line successfully, underpinning our long-term commitment to this mature basin. In North America, a major project was sanctioned for the further development of the Wamsutter gas field in Wyoming for $2.2 billion. In Alaska, we continue to improve our knowledge of the extraction of viscous oil resources, while striving for greater operational efficiencies on our existing facilities.

We continually seek to enhance our portfolio through planned divestments. In 2005, these yielded proceeds of $1,416 million, mainly from the sale of our interests in the Ormen Lange field in Norway and also the Teak, Samaan and Poui fields in Trinidad & Tobago.

A total of 12 new oil and gas discoveries were made from a focused exploration programme. Major successes included a number of discoveries in the deepwater Gulf of Mexico and Angola, and a second discovery in offshore Sakhalin Island in Russia.

BUILDING PRODUCTION AND RETURNS THROUGH FOCUS AND CHOICE



● BP exploration and production locations

Reserves On the basis of UK generally accepted accounting practice (SORP), our proved reserves replacement ratio (RRR) was 100% (including equity-accounted entities), compared with 110% in 2004. On the same basis, excluding equity-accounted entities, the RRR was 71%. This was the 13th consecutive year in which our RRR was 100% or greater. We also prepare estimates of our proved reserves on the basis of the rules and interpretation required by the US Securities and Exchange Commission (SEC). On this basis, the reserves replacement ratio, excluding equity-accounted entities, was 68% (compared with 78% in 2004); including equity-accounted entities, the ratio was 95% (compared with 89% in 2004). The differences from our SORP-based estimates arise mainly from the SEC's requirement that year-end prices should be used. All our proved reserves replacement ratios are based on discoveries, extensions, revisions and improved recovery and exclude the effects of acquisitions and disposals. BP has a robust internal process to control the quality of its reserve bookings, which forms part of an integrated system of internal control. Details of that process and the applicable rules are described on pages 131-132.

BP's total hydrocarbon proved reserves, on an oil equivalent basis under SORP and including equity-accounted entities, stood at 18,271mmboe at 31 December 2005. Of this total, 43% was gas.

The management of our reserves is described under Other financial issues on pages 22-23.

REFINING AND MARKETING

			$ million
	2005	2004	2003
Profit before interest and tax[a]	6,942	6,544	3,235
Inventory holding (gains) losses	(2,537)	(1,304)	(43)
Replacement cost profit before interest and tax	4,405	5,240	3,192
Results include:			
Impairment and gain (loss) on sale of business and fixed assets	84	(456)	(214)
Environmental and other provisions	(140)	(206)	(369)
Restructuring, integration and rationalization costs	–	(32)	(287)
Fair value gain (loss) on embedded derivatives	–	–	–
Other	(733)	–	10
Total non-operating items	(789)	(694)	(860)
Refinery throughputs (mb/d)	2,399	2,607	2,723
Refining availability (%)	92.9	95.4	95.5
Oil sales volumes (mb/d)	8,692	9,089	9,524
Marketing sales (mb/d)	3,942	4,002	3,969
Global indicator margin ($/bbl)	8.60	6.31	4.08
Chemicals production (kte)	12,367	13,150	12,195

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

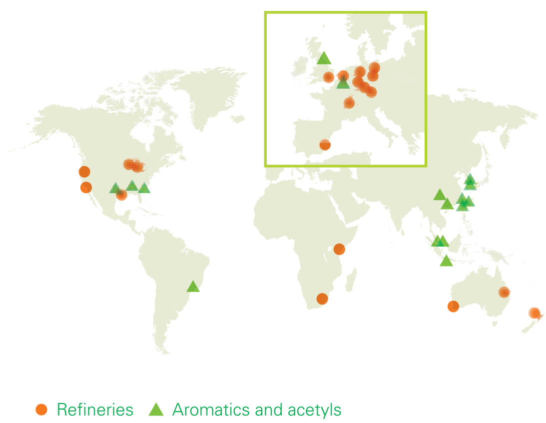
Replacement cost profit before interest and tax for the segment was $4,405 million, compared with $5,240 million in 2004. This was affected by the Texas City refinery outage, adverse impacts related to fair value accounting and costs associated with rationalization and efficiency programmes. The full year average GIM was higher than that for the full year 2004 and consistent with the increase in BP's actual realized refining margin. Retail marketing margins, despite the recovery in the fourth quarter, were significantly lower than those for the full year 2004, although partly offset by increases in our other marketing businesses. The result included a net charge for non-operating items of $789 million. Of this, $700 million was in respect of fatality and personal injury claims associated with the incident at the Texas City refinery on 23 March 2005.

Refining The average GIM was higher in 2005 than in 2004, owing to the strength of demand and concerns over supply disruptions, particularly in the US. BP's refining margin also reflected the benefits of locational advantages and supply optimization.

Refining volumes were lower in 2005, owing to the impact of disposal of the Mersin and Singapore refineries in 2004 and reduced availability at the Texas City refinery. The latter resulted from the explosion in the isomerization unit in March 2005 and the refinery's complete shutdown in late September, like other refineries in the area, owing to Hurricane Rita. Subsequent assessments revealed that this precautionary measure necessitated additional work to prepare the refinery for a safe and reliable start-up, prolonging the period of the shutdown. Following a comprehensive refurbishment, the steam system at the Texas City refinery was successfully recommissioned in December 2005. Initial production is expected to commence in the first quarter of 2006, with further units restarting in a phased programme, primarily in the second and third quarters. Refinery throughputs for 2005 were 2,399 thousand barrels a day (mb/d), compared with 2,607mb/d in 2004.

We have continued to upgrade our refining portfolio. Following the sale of the Lavéra, France, and Grangemouth, UK, refineries that were part of Innovene, our refining portfolio is weighted more heavily to the US, where margins are structurally higher. Our capital investments continue to focus on further enhancing our position in the US and repositioning our European activities by continuing to invest in upgrading existing facilities.

MANUFACTURING COVERAGE



Retail marketing Retail marketing margins were lower than in 2004, reflecting sustained pressure from rising crude and product prices. There was also unprecedented volatility in margins. This was partly due to the effects of Hurricanes Katrina and Rita on supply and pricing in the US.

Marketing sales were 3,942mb/d in 2005, compared with 4,002mb/d the previous year. The decrease was due mainly to the effects of the price increases as a result of the supply disruption and market uncertainty. Shop sales maintained a similar level to those of the previous year, despite the impact of the rise in fuel prices.

In 2005, the lubricants business was affected by significantly higher costs of base oil, additives, packaging and logistics. Marketing volumes were weaker than in 2004 in some developed markets. Volumes continued to grow in some emerging markets. In 2005, we launched Castrol Edge passenger car oils, initially in the UK and South Africa, seeking to bring a new generation of quality-conscious consumers to the Castrol brand. The range will be extended to other countries during 2006. We formed a joint venture between Castrol and the Dong Feng group, a Chinese automobile manufacturer, to supply lubricants to the Chinese market. Our strength in fast-growth emerging markets depends on strong brands and focused technological innovation.

BP enjoys strong market shares and leading technologies in the high-growth A&A business. In Asia, we continue to develop a strong position in PTA (the main component of polyester fibres and packaging) and acetic acid (commonly used for paints, adhesives and inks). Our investment is biased towards this high-growth region, especially China. Capital expenditure in our A&A business increased slightly in 2005 as we invested to maintain our leadership position.

BP and Sinopec Corporation of China signed a joint-venture contract to build a world-scale acetic acid plant in Nanjing, Jiangsu province. The 500,000-tonnes-a-year operation is planned to come on stream in the second half of 2007. The sale of BP's 70% shareholding in BP Malaysia Sdn Bhd to Lembaga Tabung Angkatan (LTAT), announced in 2004, was successfully concluded during the third quarter of 2005. We also announced plans for a second PTA plant at the BP Zhuhai Chemical Company's site in China's Guangdong province, subject to government approval. The new plant is designed to have an operating capacity of 900,000 tonnes a year and will be the first plant to use BP's new-generation proprietary PTA technology.

In October 2005, we signed a letter of intent with Hindustan Petroleum Corporation to form a 50:50 strategic joint venture in the refining and marketing sector in India.

GAS, POWER AND RENEWABLES

			$ million
	2005	2004	2003
Profit before interest and tax[a]	1,104	954	578
Inventory holding (gains) losses	(95)	(39)	(6)
Replacement cost profit before interest and tax	1,009	915	572
Results include:			
Impairment and gain (loss) on sale of business and fixed assets	55	56	(6)
Environmental and other provisions	6	–	–
Restructuring, integration and rationalization costs	–	–	–
Fair value gain (loss) on embedded derivatives	(346)	–	–
Other	265	–	–
Total non-operating items	(20)	56	(6)

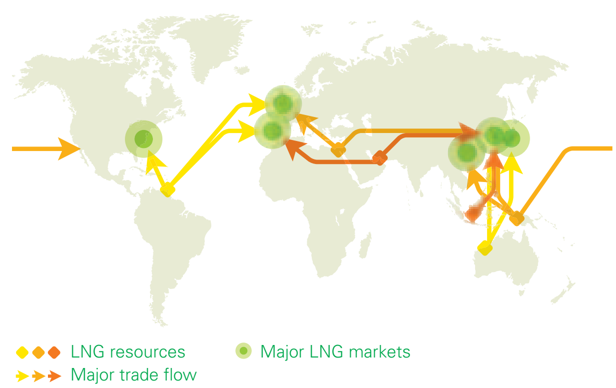
[a]Profit from continuing operations and includes profit after interest and tax of equity-accounted entities.

Replacement cost profit before interest and tax for the segment for the year was $1,009 million, compared with $915 million in 2004. The result includes a net charge for non-operating items of $20 million (2004 $56 million gain), which primarily comprises fair value losses on embedded derivatives of $346 million and compensation of $265 million received on cancellation of an intra-group gas supply contract. The operating business result has increased by 20% over 2004, with higher margins from gas marketing and trading and NGLs businesses. The volumes of gas supplied into liquefaction plants rose by 1%. Our solar and power businesses continued to grow profitably.

Gas Our intent is to grow the business in the medium term by 2-3% a year, in line with global gas demand. North America, where we continue to hold the largest market share, is our most important gas market. This position is anchored by our strong upstream positions around the Gulf of Mexico, the mid-continent, the Rockies, Canada and Trinidad & Tobago. We have strong positions in the North Sea, the Caspian and North Africa that, together with imports of LNG, give us the opportunity to support Europe's move towards cleaner gas-fired heat and power. We have significant gas sales via pipeline and LNG in Asia.

Our LNG plans remain on track. Our Atlantic basin LNG business is underpinned by our upstream positions in Trinidad & Tobago, Egypt and, in future, Angola. We are bringing this gas to market through investment in downstream regasification and logistics assets. In the US, we have long-term capacity agreements in place at Cove Point, Maryland, for 250 million standard cubic feet per day (mmscfd) and Elba Island, Georgia, for 150mmscfd. We are continuing to seek approval to develop a regasification facility at Crown Landing in New Jersey, where important progress was made in relation to associated shipping, environmental and legal matters. BP also has a long-term contract to supply LNG into the Dominican Republic.

LNG POSITIONS AND MARKETS



In the UK, we began to supply LNG cargoes to the new Isle of Grain terminal where, with Sonatrach, we have rights to 450mmscfd of capacity. Despite tightness in world LNG supplies, we were able to source cargoes of LNG successfully from Trinidad & Tobago and Algeria in response to increases in UK market prices. In Spain, we are partners (BP 25%) in the 700mmscfd Bilbao regasification plant and 800MW gas-fired power station. BP supplies LNG cargoes into the Pacific Basin, including Japan and Taiwan. We have also started LNG supply into the Gwangyang regasification terminal in South Korea since its start-up in mid-2005. Sales into this terminal will be sourced from Tangguh after its start-up, expected in 2008. Tangguh will also supply gas into new terminals in Fujian, China, and Baja, Mexico. In 2005, we made good progress in the construction of China's first LNG import facility in Guangdong, where BP is a joint-venture partner. When the facility becomes operational in 2006, gas will be supplied from the NWS partnership (BP 16.7%) in Australia.

We continue to be the largest NGLs marketer in the US. Our capacity utilization was well above plan, despite disruptions to supply following the summer's Gulf of Mexico hurricanes. Full operations at our joint venture NGLs plant in Egypt started in the first quarter of 2005 and the plant reached full gas processing capacity of close to 1.1bcf/d in the second half of the year.

BP Alternative Energy In 2005, we announced the launch of BP Alternative Energy, a business dedicated to the development and wholesale marketing and trading of low-carbon power. We believe we have sufficient new technologies and sound commercial opportunities within our reach to build a significant and sustainable business in alternative and renewable energy. BP Alternative Energy will manage a first phase of investment of around $1.8 billion during the next three years, the first part of our aim to invest $8 billion over 10 years. This first-phase investment will be spread in broadly equal proportions between solar, wind, hydrogen and high-efficiency gas-fired power generation. The business will initially employ around 2,500 people. It will bring together the group's existing activities in these technologies with our power marketing and trading capabilities to form a single business. In solar, our sales grew by 6% in 2005, and continued to generate profits. We are committed to doubling our manufacturing capacity of solar cells between 2004 and the end of 2006. In 2005, we successfully completed the Frederick solar plant expansion in Maryland, US. We also signed a joint venture agreement with Xinjiang SunOasis Company, a leading photovoltaic module manufacturer and system supplier in China.

We completed the construction and commissioning of our 9MW Amsterdam wind farm, and applied for planning permission for 10 turbines at the BP fuel terminal on the Isle of Grain, UK, to generate 18MW of power.

We finalized all the commercial agreements and commissioned the first unit of K-Power's 1,100MW gas-fired power plant in South Korea, where we have a 35% interest.

We successfully started commercial operations at our wholly owned 50MW combined heat and power plant in Hythe, UK, which supplies steam and electricity to local industrial customers. We sold our 100% interest in the Great Yarmouth 400MW gas-fired power station to RWE in November 2005 for $282 million. At the end of 2005, two new co-generation projects in North America, with capacity totalling over 700MW, were in the early stages of development.

In June 2005, together with our partners, we announced plans for the development of the world's first large project to generate electricity from hydrogen, while reducing CO_2 emissions and enhancing oil recovery in the North Sea. The hydrogen will be used at a power station in Peterhead, UK, to generate 350MW of 'clean' electricity and the CO_2 reinjected into the offshore Miller field. Work has begun on the front-end engineering design stage, addressing significant technical challenges that we believe we and our partners are well placed to manage. At the same time, we are keeping under constant review the schedule of the project and its commercial viability, which is itself dependent on clarification of the regulatory regime.

OTHER BUSINESSES AND CORPORATE

			$ million
	2005	2004	2003
Profit (loss) before interest and tax[a]	(1,191)	164	(253)
Inventory holding (gains) losses	5	(8)	1
Replacement cost profit (loss) before interest and tax	(1,186)	156	(252)
Results include:			
Impairment and gain (loss) on sale of business and fixed assets	38	1,164	139
Environmental and other provisions	(278)	(283)	(213)
Restructuring, integration and rationalization costs	(134)	(102)	5
Fair value gain (loss) on embedded derivatives	(13)	–	–
Other	3	66	549
Total non-operating items	(384)	845	480

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

Other businesses and corporate comprises Finance, the group's aluminium asset, interest income and costs relating to corporate activities, and also the portion of O&D not included in the sale of Innovene to INEOS. This includes the equity-accounted investments in China (the SECCO petrochemicals complex) and Malaysia (Polyethylene Malaysia Sdn Bhd and Ethylene Malaysia Sdn Bhd). The result includes a net charge for non-operating items of $384 million, of which $278 million is in respect of new, and revisions to existing, environmental and other provisions.

TECHNOLOGY

Technological innovation and know-how are central to our strategy and performance. Technology is vital in converting resources to reserves and meeting the needs of our customers.

We aim to align our technological activities with our business strategy, focusing on areas where BP can create a distinctive advantage. When we adopt new technologies we spread them as rapidly as possible through the group and apply them on a large scale. We aim to use the best talent inside and outside BP to develop and apply technologies.

Our five-year technology plan is intended to maximize our ability to access increasingly complex oil and gas fields, to develop better products for our customers – often by using alternative low-carbon technologies – and to improve our day-to-day operations continuously.

We are a world leader in advanced seismic imaging, from discovery through to field development and management, and a world-class formulator for creating fuels and lubricants that better meet customer needs. We have proprietary technologies in PTA that are substantially reducing manufacturing costs and environmental impact. Our Saturn solar technology is setting new records for solar cell efficiency and we aim to make solar energy competitive with utility power in a broader set of markets. These are just a few examples from a wide array of our technology capabilities.

Our long-term priorities are to develop technologies that help identify new energy resources in areas such as the Arctic and ever-deeper water, to exploit better existing areas through enhanced recovery and to unlock resources such as viscous oil and tight gas; to develop technologies that change the chemical form of hydrocarbons such as coal, biomass and gas to enable them to be used in a range of products; and to develop lower-carbon technologies, including CO_2 capture and storage and renewable technologies such as solar.

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 by developing proprietary technology and superior know-how; long-term technology investments to secure our future; and application and propagation of technology through formalized technology networks and knowledge management processes.

Our technology spending increased to around $825 million (excluding Innovene) in 2005 and is expected to grow in line with our capital employed through to 2010.

Environmental and social performance

In this section of the Report, we review our 2005 performance in managing some of the longer-term environmental and social risks we have identified. A more comprehensive overview of our non-financial performance will be found in *BP Sustainability Report 2005*.

We follow a framework in which we exercise responsibility and manage risks at three levels. At the first, fundamental, level we seek to comply with local laws and regulations. Beyond compliance, at the second level, we seek to be a progressive operator by setting our own standards, often higher than prevailing regulations. These first two levels relate to our own operations, where we control activities and outcomes. Beyond this sphere of control, we have an influence, and at this third level we seek to play a leading role in addressing risks and issues in selected areas that are relevant to our work and affect society more generally. These include climate change and the challenges of development.

In everything we do, we are guided by our group values. These are aspirations that cover such areas as health and safety, continuous improvement, human capability and environmentally sound operations. We aim to ensure that our relationships with customers, suppliers, governments, non-governmental organizations and communities are ones of mutual advantage.

INSIDE BP – RESPONSIBLE OPERATIONS

People Our priority is to attract, develop and retain highly talented people, using appropriate incentives, in order to maintain the capability of the group to deliver our strategy and plans.

As a global group, we believe our workforce, leadership and recruitment should reflect the communities in which we operate. We therefore run programmes designed to ensure that we increase the number of local leaders and employees in our operations.

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. At the end of 2005, 17% of our top 606 leaders were female and 20% came from countries other than the UK and US.

We recruit people in the hope that they will spend a significant portion of their careers with BP. We aim to develop our leaders internally, although we do recruit outside the group where we do not have specialist skills in-house or when exceptional people are available. In 2005, we appointed 89 people to positions in the 606-strong group leadership. Of these, 72 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 a year.

In our 2004 survey of employees, completed by 74% of those eligible, the level of satisfaction was the highest since we began the survey in its present form in 1999. The survey will continue to be conducted at two-year intervals, with shorter surveys of representative samples of employees in between.

We had 96,200 employees at 31 December 2005, compared with 102,900 at the end of 2004.

We continue to support employee share ownership. 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.

BP's commitment to integrity: the code of conduct During 2005, we launched a code of conduct designed to ensure that all employees comply with legal requirements and our own standards. The code defines what BP expects of its people, providing guidance in key areas and references to more detailed policy and further direction. The code updates, revises and summarizes BP's standards for employee conduct in a single framework. The code is the centrepiece of our group compliance programme, being developed and overseen by the central GC&E function.

One hundred and thirty-five senior level compliance and ethics leaders within BP take the lead in activities to ensure that the code is effectively implemented throughout the group. We have also enhanced our employee concerns programme, OpenTalk, to enable employees to seek guidance on the code. We believe these steps have resulted in the number of cases raised through OpenTalk increasing from 343 in 2004 to 634 in 2005. After the code launch on 15 June 2005, there were 490 cases to the end of the year, compared with 224 in the same period of 2004.

Our processes are designed 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.

Our mechanisms for managing relationships with suppliers focus on strategy, building common ground, delivery and performance management. We engage with suppliers in a variety of ways, including performance review meetings to identify mutual improvements in performance.

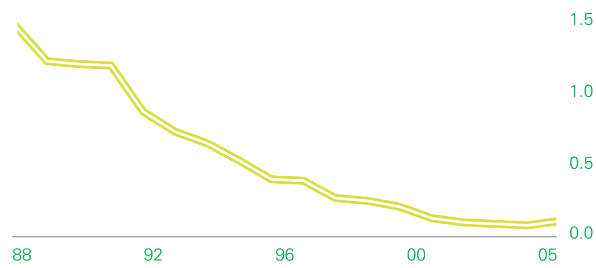
We apply a strict anti-corruption policy, including a prohibition on making facilitation payments, which is now incorporated in the code of conduct. We take steps to identify and correct areas of non-compliance and take disciplinary action where appropriate. In 2005, this included the reported dismissal of 478 people for non-compliance or unethical behaviour, including breaches of BP's health, safety, security and the environment (HSSE) policies, fraud, theft and dishonesty. (This number excludes retail site staff dismissals for 'petty' incidents.)

The code of conduct outlines our policy not to make corporate political donations anywhere in the world. BP specifically made no contributions to UK or other EU political parties or organizations in 2005.

Safety and operational integrity In total, there were 27 workforce fatalities in the course of BP operations during 2005. We deeply regret the loss of these lives. This was the worst year for BP's safety record since 1999, when there were 30 workforce fatalities. Fifteen of the deaths in 2005, as well as many injuries, resulted from an explosion and fire at the Texas City refinery. There were 12 other workforce fatalities in BP's operations, 10 of which were transport-related.

During 2005, there were 305 reported days away from work injury cases, of which 120 resulted from the Texas City incident. This compares with 230 cases in 2004 and 461 in 1999. An additional 1,139 reported injuries in 2005 required medical treatment, apart from minor cuts and bruises. Combining all the injuries and fatalities, our total recordable injury frequency for 2005 was 0.53 in 2005 (per 200,000 hours worked), compared with 0.53 in 2004 and 1.42 in 1999.

LONG-TERM SAFETY PERFORMANCE (DAFWCF)[a] 1988-2005



[a]Days away from work case frequency (DAFWCF) is the annual frequency (per 200,000 hours) of injuries that result in a person (employee or contractor) being unable to work for a day (shift) or more. For a full understanding of the underlying data on reported DAFWCF, please refer to our website.

The Texas City incident happened on 23 March 2005 in an isomerization unit used to make components for unleaded gasoline. BP has set aside $700 million in compensation and has reached settlements with many of the injured and bereaved. BP has also entered into a settlement with the US Occupational Safety and Health Administration (OSHA) to resolve more than 300 separate alleged violations of OSHA safety regulations. BP paid a fine of $21.3 million and agreed to a number of corrective actions. Under the agreement, BP does not admit the alleged violations or agree with the way OSHA has characterized them.

BP Products North America Inc. issued a final incident investigation report in December 2005 outlining the underlying causes of the incident. BP is undertaking corrective actions at the refinery as part of a settlement reached with OSHA and in response to the recommendations of BP's Joint Incident Investigation Committee's interim and final reports. The company expects to invest an estimated $1 billion to improve and maintain the site during the next five years.

Following a further fire in July and a leak from another unit at Texas City in August, the US Chemical Safety and Hazard Investigation Board issued an urgent recommendation that BP appoint an independent panel to study the safety culture of its US refineries. This panel started work under the chairmanship of former US Secretary of State James A Baker III.

The incident at Texas City led to a fundamental review of the systems, processes and organization needed to increase further the focus on safety and operational issues in our US refineries and across BP. We have introduced a new organizational structure to focus on these issues, including a new senior group vice president for safety and operations, a role filled by the senior executive who led the investigation into the Texas City incident. This team has drawn up plans for measures in three areas: plant, people and processes.

In terms of plant, we have been carrying out a programme of major accident risk assessments for our major plant and equipment and plan to invest more than $3.5 billion in integrity management at our sites during the next five years. We also plan to improve operating plant processes and clarify engineering authorities.

In terms of people, we aim to improve the safety and operational culture for all our people, including work to strengthen safety leadership and the awareness of process safety hazards among those who handle hydrocarbons. Measures are being taken to ensure that people have clear accountabilities and are fully competent to do their job.

In terms of processes, we are augmenting our current system, 'getting HSSE right', to produce a more comprehensive operating management system that aims to improve our safety management processes and better integrate them with our operational procedures. The new management system will embrace new group standards on integrity management and control of work to be launched in 2006.

One measure of our performance record on integrity management is the number of oil spills, most of which occur on land. During 2005, the total number of spills of 1 barrel or above from all of our operations was 541, compared with 578 in 2004 and 1,098 in 1999.

In 2005, we continued to increase and upgrade our operated shipping fleet to manage the risk of a major oil spill more effectively. Our international fleet has grown from 42 ships in 2004 to 52 in December 2005, all of which are double-hulled. This transformation is well ahead of the international requirements for phase-out of single-hulled vessels. We also have 16 regional and specialist vessels and 81 vessels on time charter, of which 66 are double-hulled and three double-bottomed. All these vessels are enrolled in BP's time charter assurance programme, which requires compliance with our safety standards. We also spot charter additional vessels, which are vetted prior to use to ensure they meet our safety and integrity standards.

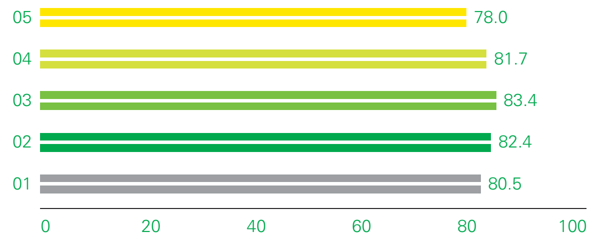
Our operations and the environment During 2005, we continued working to reduce the environmental impact of our operations, primarily by reducing our emissions of greenhouse gases (GHGs) and by implementing processes to drive continuous improvements in a wide range of other environmental issues.

In our operations, since 2001 we have been aiming to offset, through operational efficiency projects, half of the underlying GHG emission increases that result from our growing business. After four years, we estimate that emissions growth of some 10 million tonnes has been offset by around 5 million tonnes of sustainable reductions.

Our 2005 operational emissions of 78.0 million tonnes (Mte) of CO_2 on a direct equity basis were some 3.7Mte lower than 2004 (81.7Mte). The growth of our business generated an extra 2.9Mte of emissions, but these were offset by several factors. Newly implemented efficiency projects provided 0.9Mte of reductions that should be sustained in future years. Plant shutdowns resulting from hurricanes and other operational factors caused a substantial but transitory reduction in 2005 of around 3.5Mte. Finally, the net effect of disposals, acquisitions and methodology changes during the year was that emissions were lower by about 2.2Mte.

We have taken part in the EU Emissions Trading Scheme since its launch in January 2005. We began the year with 30 participating installations but, following divestments in the fourth quarter, we ended the year with 18, which represent around a quarter of our reported 2005 global GHG emissions.

DIRECT GHG EMISSIONS (million tonnes CO_2 equivalent)[a]



[a]Data is reported on an equity share basis. TNK-BP emissions are not included.

In 2005, we developed a new set of environmental principles designed to give us a consistent approach when assessing and entering new locations. The new process will be progressively implemented in new major projects. In 2005, 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 using natural resources responsibly and reducing waste and emissions. In 2004, we achieved our goal of 100% of our major sites being certified to the ISO 14001 international standard on environmental management, but our Texas City refinery had its ISO certification suspended in 2005. The refinery intends to recertify after completing planned work to strengthen its HSSE management systems.

We seek to have a positive influence on major issues beyond our own operations. The two main areas where we seek to do so are climate change and development.

BP AND CLIMATE CHANGE

BP has contributed significantly to the evolving public and policy debate on climate change. We support a precautionary stance, even though we recognize that aspects of the science remain the subject of expert debate and are not fully proved.

We also accept that this is a long-term issue. The goal must be to take urgent but informed measures that will stabilize GHG concentrations by delivering sustainable and cost-efficient long-term emission reductions. Fossil fuels currently supply the majority of all the primary energy people use and will remain fundamental to global energy supply for at least the next 20-30 years[a]. Innovation to reduce the CO_2 emissions from the use of fossil fuels will be a major contributor to stabilization during this period. Companies such as BP therefore have an important role to play in contributing to energy policy and education, in enabling market mechanisms such as emissions trading to operate and in developing innovative technological solutions.

We believe that governments and businesses must work together to develop appropriate policy responses. We support an approach that recognizes the existence

[a]*World Energy Outlook 2004*, IEA.

of different starting points, perspectives, priorities and solutions, and includes the many potential contributors to the common goal of addressing climate change. BP's own actions will focus on engaging in informed external dialogue to influence policy, regulation and innovation and on our own business activities.

BP Alternative Energy In 2005, BP established a new business called BP Alternative Energy to generate and market cleaner, low-carbon power from solar, wind, hydrogen and natural gas sources. Globally, the power sector is the biggest source of GHG emissions – responsible for about twice the emissions of the transport sector – so creating lower-carbon power is critical in the effort to stabilize global GHG emissions[a]. BP believes some 40% of the power-generating capacity required to meet projected world electricity demand in 2020 has yet to be built, which is why a major impact on emissions can be achieved by deploying lower-carbon technologies.

Sustainable transportation In 2005, we continued to create and market a range of cleaner fuels and products for the transport sector. We continued the roll-out of BP Ultimate, launched in 2003, in five new markets. This fuel delivers reductions in emissions such as carbon monoxide and nitrogen oxide compared with standard fuels.

We blend biocomponents into diesel fuels in Germany, Austria and France. In 2005, we also introduced bioderived ethyl tertiary butyl ether (ETBE) to gasoline markets in France and increased our production and supply in Germany. In the US, we are one of the largest blenders of bioethanol with gasoline and, in 2005, we introduced gasoline-ethanol blends to more than 20 new US markets. We also continue to carry out research on a new generation of advanced biofuels, which have potential to deliver substantially reduced overall emissions.

We contributed to the development of a revised directive on air quality, which was published by the European Commission in September 2005 with new draft proposals for controls on fine particle concentrations.

While there was a new focus on hydrogen for power generation in 2005, we also continued to explore the use of hydrogen as a transport fuel through a set of incubator activities. The aim of these is to understand how the market is likely to develop and how costs can be made competitive. Examples are the supply of hydrogen to fleets of cars under a US Department of Environment programme that started in 2004 and construction, in partnership with government agencies, of a hydrogen fuel station in Beijing, China, for a fleet of hydrogen buses for the 2008 Olympics.

BP is also supporting projects at Tsinghua University in Beijing and Imperial College London, UK, to investigate the transportation and energy issues arising from the growth of urban areas, especially in Asia.

[a] *World Energy Outlook 2004*, IEA.

BP AND DEVELOPMENT

We seek to make a positive contribution to social and economic development wherever we operate. Much of our impact comes from the hiring and training of local employees and the sourcing of supplies from local companies, often working towards specific targets in each area.

Development is also affected by the way in which resource revenues are spent by governments. During 2005, we continued to support the Extractive Industries Transparency Initiative (EITI), becoming a member of its International Advisory Group. The EITI provides guidelines for publicly disclosing the amount of revenue governments receive from energy companies, so people can see how much is available for public spending. In particular, BP continues to support the implementation of the EITI in Azerbaijan, publishing relevant figures in our reports there in 2005. We have also funded a new research centre at Oxford University, UK, which will conduct academic research on resource-rich economies and share best practice in managing energy revenues effectively.

We can also make direct contributions through community programmes. Our total contribution in 2005 was $95.5 million. This includes $0.8 million contributed by BP to UK charities. In 2005, our community investment totalled $79.7 million. The growing focus of this is on education, the development of local enterprise and providing access to energy in remote locations. We plan to spend about $500 million in each five-year cycle focusing on these areas, with enough flexibility to respond to local needs as appropriate.

In 2005, we spent $50.2 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.

In 2005, we also invested $9.6 million in support of enterprise development, encouraging the creation and growth of new businesses. In Azerbaijan, we support an enterprise centre that helps local start-ups and provides loans for small and medium-sized enterprises. We support micro-finance systems to make loans to small businesses in Trinidad & Tobago, Azerbaijan, Georgia, Colombia and Vietnam. In 2005, we launched a similar programme in Angola.

We also help combat poverty by providing access to energy in many countries, working alongside governments, NGOs and aid agencies. For example, we provide solar power for rural communities such as in Algeria, Sri Lanka and the Philippines, and we are developing a new business in India to help provide a cleaner system for cooking, combining a LPG and biomass burner.

Other financial issues

CRITICAL ACCOUNTING POLICIES AND NEW ACCOUNTING STANDARDS

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

In preparing these financial statements, the group has complied with all IFRSs applicable for periods beginning on or after 1 January 2005. In addition, BP has also decided to adopt early IFRS 6 'Exploration for and Evaluation of Mineral Resources', the amendment to IAS 19 'Amendment to International Accounting Standard IAS 19 Employee Benefits: Actuarial Gains and Losses, Group Plans and Disclosures', the amendment to IAS 39 'Amendment to International Accounting Standard IAS 39 Financial Instruments: Recognition and Measurement: Cash Flow Hedge Accounting of Forecast Intragroup Transactions' and IFRIC 4 'Determining whether an Arrangement contains a Lease'. The EU has adopted all standards and interpretations adopted by BP for its 2005 reporting.

The general principle that should be applied on first-time adoption of IFRS is that standards in force at the first reporting date (for BP, 31 December 2005) should be applied retrospectively. However, IFRS 1 'First-time Adoption of International Financial Reporting Standards' (IFRS 1) contains a number of exemptions that companies are permitted to apply. BP has taken the following exemptions:

- Comparative information on financial instruments is prepared in accordance with UK GAAP and the group has adopted IAS 32 'Financial Instruments: Disclosure and Presentation' (IAS 32) and IAS 39 'Financial Instruments: Recognition and Measurement' (IAS 39) from 1 January 2005.
- IFRS 3 'Business Combinations' has not been applied to acquisitions of subsidiaries or of interests in jointly controlled entities and associates that occurred before 1 January 2003.
- Cumulative currency translation differences for all foreign operations are deemed to be zero at 1 January 2003.
- The group has recognized all cumulative actuarial gains and losses on pensions and other post-retirement benefits as at 1 January 2003 directly in equity.
- IFRS 2 'Share-based Payment' has been applied retrospectively to all share-based payments that had not vested before 1 January 2003.

As indicated above, BP adopted IAS 32 and IAS 39 with effect from 1 January 2005 and, as permitted under IFRS 1, the group has not restated comparative information. Had IAS 32 and IAS 39 been applied from 1 January 2003, the following adjustments would have been necessary in the financial statements for the years ended 31 December 2004 and 2003:

- All derivatives, including embedded derivatives, would have been brought on to the balance sheet at fair value.
- Available-for-sale investments would have been carried at fair value rather than at cost.

The principal differences for the group between reporting on the basis of UK GAAP and IFRS are as follows:

- Ceasing to amortize goodwill.
- Setting up deferred taxation on acquisitions; inventory valuation differences; and unremitted earnings of subsidiaries, jointly controlled entities and associates.
- Expensing a greater proportion of major maintenance costs.
- No longer recognizing dividends proposed but not declared as a liability at the balance sheet date.
- Recognizing an expense for the fair value of employee share option schemes.
- Recording asset swaps on the basis of fair value.
- Recognizing changes in the fair value of embedded derivatives in the income statement.

Further information regarding the impact of adopting IFRS is shown in Note 50 on financial statements, First-time adoption of International Financial Reporting Standards.

The new accounting policies adopted by the group are summarized on pages 30-38.

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

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

Oil and natural gas accounting Accounting for oil and gas exploration and development activity is subject to special accounting rules that are unique to the oil and gas industry. In the absence of an IFRS dealing specifically with oil and gas accounting (IFRS 6 'Exploration for and Evaluation of Mineral Resources' only addresses limited areas), BP continues to have regard to the accounting guidance for oil and gas companies contained in the UK Statement of Recommended Practice, 'Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities' (UK SORP).

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

The acquisition of geological and geophysical seismic information, prior to the discovery of proved reserves, is expensed as incurred, similar to accounting for research and development costs.

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

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

For complicated offshore exploration discoveries, it is not unusual to have exploration wells and exploratory-type stratigraphic test wells remaining suspended on the balance sheet for several years while additional appraisal drilling and seismic work on the potential oil and gas field is performed or while the optimum development plans and timing are established. All such carried costs are subject to regular technical, commercial and management review, on at least an annual basis, to confirm the continued intent to develop, or otherwise extract value from, the discovery. If this is no longer the case, the costs are immediately expensed.

Once a project is sanctioned for development, the carrying values of licence and property acquisition costs and exploration and appraisal costs are transferred to production assets within tangible assets.

Field development costs subject to depreciation are expenditures incurred to date, together with sanctioned future development expenditure approved by the group.

The capitalized exploration and development costs for proved oil and gas properties (which include the costs of drilling unsuccessful wells) are amortized on the basis of oil-equivalent barrels that are produced in a period as a percentage of the estimated proved reserves. The estimated proved reserves used in these unit-of-production calculations vary with the nature of the capitalized expenditure. The reserves used in the calculation of the unit-of-production amortization are as follows:

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

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

Given the large number of producing fields in the group's portfolio, it is unlikely that any changes in reserve estimates, year on year, will have a significant effect on prospective charges for depreciation.

Oil and natural gas reserves The group manages its hydrocarbon resources in three major categories: prospect inventory, non-proved resources and proved reserves. When a discovery is made, volumes transfer from the prospect inventory to the non-proved resource category. The reserves move through various non-proved resources sub-categories as their technical and commercial maturity increases through appraisal activity. Reserves in a field will only be categorized as proved 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. 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. The first PD bookings will occur at the point of first oil or gas production. Major development projects typically take one to four years from the time of initial booking to the start of production. Adjustments may be made to booked reserves due to production, reservoir performance, commercial factors, acquisition and divestment activity and additional reservoir development activity.

The group reassesses its estimate of proved reserves on an annual basis. The estimated proved reserves of oil and natural gas are subject to future revision. As discussed below, oil and natural gas reserves have a direct impact on certain amounts reported in the financial statements.

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

The group estimates its reserves of oil and natural gas according to UK SORP. This differs from the basis of determining reserves required by the Securities and

Exchange Commission. Estimates of the group's proved reserves of oil and natural gas are shown on pages 131-136, together with more information about the group's process for booking reserves and the difference between the reserves determined for the group's UK and US reporting.

Recoverability of asset carrying values BP assesses its fixed assets, including goodwill, for possible impairment if there are events or changes in circumstances that indicate that carrying values of the assets may not be recoverable. Such indicators include changes in the group's business plans, changes in commodity prices leading to unprofitable performance and, for oil and gas properties, significant downward revisions of estimated proved reserve quantities. The assessment for impairment entails comparing the carrying value of the cash generating unit and associated goodwill with the recoverable amount of the asset, that is, the higher of net realizable value and value in use. Value in use is usually determined on the basis of discounted estimated future net cash flows.

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

For oil and natural gas properties, the expected future cash flows are estimated based on the group's plans to continue to produce and develop proved and associated risk-adjusted probable and possible reserves. Expected future cash flows from the sale or production of reserves are calculated based on the group's best estimate of future oil and gas prices. Prices for oil and natural gas used for future cash flow calculations are assumed to decline from existing levels in equal steps during the next three years to the long-term planning assumptions as at 31 December 2005 ($25 per barrel and $4.00 per mmBtu for Brent and Henry Hub respectively). Previously, the long-term planning assumptions were a Brent oil price of $20 per barrel and a Henry Hub gas price of $3.50 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.

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

Irrespective of whether there is any indication of impairment, BP is required to test for impairment any goodwill acquired in a business combination. The group carries goodwill of approximately $10.4 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.

Provisions and liabilities 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 tangible asset of an amount equivalent to the provision is also created. This asset is depreciated over the expected life of the production facility or pipeline. Most of these removal events are many years in the future and the precise requirements that will have to be met when the removal event actually occurs are uncertain. Asset removal technologies and costs are constantly changing, as well as political, environmental, safety and public expectations. Consequently, the timing and amounts of future cash flows are subject to significant uncertainty. Changes in the expected future costs are reflected in both the provision and tangible asset.

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

The timing and amount of future expenditures are reviewed annually, together with the interest rate to be used in discounting the cash flows. The interest rate used to determine the balance sheet obligation at the end of 2005 was 2.0%, unchanged from the end of 2004. The interest rate represents the real rate (i.e. adjusted for inflation) on long-dated government bonds.

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

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

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

The provision for environmental liabilities is reviewed at least annually. The interest rate used to determine the balance sheet obligation at 31 December 2005 was 2.0%, the same rate as at the previous balance sheet date.

As further described in Note 48 on financial statements, Contingent liabilities, 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 discussed and agreed with the independent actuaries in December each year. These assumptions are used to determine the projected benefit obligation at the year end and hence the surplus and deficits recorded on the group's balance sheet, and pension and post-retirement expense for the following year.

Deferred taxation The group has approximately $5 billion of carry forward tax losses in the UK and Germany, which would be available to offset against future taxable income. Carry forward tax losses in other taxing jurisdictions have not been recognized as deferred tax assets, and are unlikely to have a significant effect on the group's tax rate in future years.

FINANCIAL RISK MANAGEMENT

The group co-ordinates certain key activities on a global basis in order to optimize its financial position and performance. These include the management of the currency, maturity and interest rate profile of finance debt, cash, other significant financial risks and relationships with banks and other financial institutions. International oil, natural gas and power trading and risk management relating to business operations are carried out by the group's oil, natural gas and power trading units.

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

To this end, BP's supply and trading function uses the full range of conventional financial and commodity derivatives available in the related commodity markets. Forward contracts, swaps, options and futures are used to convert specific sales and purchases contracts from fixed prices to market prices. Swaps are also used to manage exposures to gas price differentials between locations. The group controls the scale of these exposures by using a value-at-risk model with a maximum value-at-risk limit authorized by the board.

The main financial risks faced by the group through its normal business activities are market risk, credit risk and liquidity risk. These risks and the group's approach to dealing with them are discussed below.

The adoption of IFRS from 1 January 2005 has not fundamentally changed BP's approach to managing financial risk.

Market risk Market risk is the possibility that changes in currency exchange rates, interest rates or oil, natural gas and power prices will adversely affect the value of the group's financial assets, liabilities or expected future cash flows. The group has developed policies aimed at managing the market risk inherent in its natural business activities and, in accordance with these policies, the group enters into various transactions using derivative financial and commodity instruments (derivatives). Derivatives are contracts whose value is derived from one or more underlying financial instruments, indices or prices that are defined in the contract. The group also trades derivatives in conjunction with these risk management activities.

All derivative activity, whether for risk management or trading, is carried out by specialist teams that have the appropriate skills, experience and supervision. These teams are subject to close financial and management control, in line with generally accepted industry practice and reflecting the principles of the Group of Thirty Global Derivatives Study recommendations. A Trading Risk Management Committee has oversight of the effectiveness of internal control in the group's trading function. Independent control functions monitor compliance with BP's policies. The control framework includes prescribed trading limits that are reviewed regularly by senior management, daily monitoring of risk exposure using value-at-risk principles, marking trading exposures to market, independent review of the market values applied to trading exposures and stress testing to assess the exposure to potentially extreme market situations. The group's operational, risk management and trading activities in oil, natural gas, power and financial markets are managed within a single integrated function. This has the responsibility for ensuring high and consistent standards of control, making investments in the necessary systems and supporting infrastructure and providing professional management oversight.

The group measures its market risk exposure, i.e. potential gain or loss in fair values, on its activity using value-at-risk techniques. These techniques are based on a variance/covariance model or a Monte Carlo simulation and make a statistical assessment of the market risk arising from possible future changes in market values over a 24-hour period. The calculation of the range of potential changes in fair value takes into account a snapshot of the end-of-day exposures and the history of one-day price movements over the previous 12 months, together with the correlation of these price movements. The potential movement in fair values is expressed to three standard deviations, which is equivalent to a 95% confidence level. This means that, in broad terms, one would expect to see an increase or a decrease in fair values greater than the value-at-risk on only 10 occasions per year if the portfolio were left unchanged.

Where derivatives constitute a fair value hedge, the group's exposure to market risk created by the derivative is offset by the opposite exposure arising from the asset or liability. Gains and losses relating to derivatives designated as part of a cash flow hedge are taken to reserves and recycled through income as the hedged item is recognized. All commodity and other financial derivatives, excluding those relating to own use activities, are fair valued, with resulting gains and losses recognized in income in the current period.

Currency risk Fluctuations in exchange rates can have significant effects on the group's reported profit. The effects of most exchange rate fluctuations are absorbed in business operating results through changing cost-competitiveness, lags in market adjustment to movements in rates and conversion differences accounted for on specific transactions. For this reason, the total effect of exchange rate fluctuations is not identifiable separately in the group's reported profit.

The main underlying economic currency of the group's cash flows is the US dollar. This is because BP's major products are priced internationally in US dollars. BP's foreign exchange management policy is to minimize economic and significant transactional exposures arising from currency movements against the US dollar. The group co-ordinates the handling of foreign exchange risks centrally, by netting off naturally occurring opposite exposures wherever possible to reduce the risks, and then dealing with any material residual foreign exchange risks. Significant residual non-dollar exposures are managed using a range of derivatives.

The most significant of such exposures are capital expenditure, UK and European operational requirements, and the sterling requirements for UK corporation tax. In addition, most of the group's borrowings are in US dollars or are hedged with respect to the US dollar. At 31 December 2005, the total of foreign currency borrowings not swapped into US dollars amounted to $424 million. The principal elements of this are $150 million of borrowings in euros, $76 million in sterling, $81 million in Canadian dollars and $83 million in Trinidad & Tobago dollars.

Interest rate risk The group is exposed to interest rate risk on short- and long-term floating rate instruments and as a result of the refinancing of fixed rate finance debt. The group is exposed predominantly to US dollar LIBOR (London Inter-Bank Offer Rate) interest rates as borrowings are mainly denominated in, or are swapped into, US dollars. To manage the balance between fixed and floating rate debt, the group enters into interest rate and cross-currency swaps in which the group agrees to exchange, at specified intervals, the difference between fixed and variable rate interest amounts calculated by reference to an agreed notional principal amount. The proportion of floating rate debt at 31 December 2005 was 96% of total finance debt outstanding.

Oil, natural gas and power prices BP's trading function uses financial and commodity derivatives as part of the overall optimization of the value of the group's equity oil production and as part of the associated trading of crude oil, products and related instruments. It also uses financial and commodity derivatives to manage certain of the group's exposures to price fluctuations on natural gas and power transactions.

Credit risk Credit risk is the potential exposure of the group to loss in the event of non-performance by a counterparty. The credit risk arising from the group's normal commercial operations is controlled by individual operating units within guidelines. In addition, as a result of its use of derivatives to manage market risk, the group has credit exposures through its dealings in the financial and specialized oil, natural gas and power markets. The group controls the related credit risk through credit approvals, limits, use of netting arrangements and monitoring procedures. Counterparty credit validation, independent of the dealers, is undertaken before contractual commitment.

Concentrations of credit risk The primary activities of the group are oil and natural gas exploration and production, gas and power marketing and trading, oil refining and marketing and the manufacture and marketing of petrochemicals. The group's principal customers, suppliers and financial institutions with which it conducts business are located throughout the world. The credit ratings of interest rate and currency swap counterparties are all of at least investment grade. The credit quality is actively managed over the life of the swap.

Liquidity risk Liquidity risk is the risk that suitable sources of funding for the group's business activities may not be available. The group has long-term debt ratings of Aa1 and AA+, assigned respectively by Moody's and Standard & Poor's. The group has access to a wide range of funding at competitive rates through the capital markets and banks. It co-ordinates relationships with banks, borrowing requirements, foreign exchange requirements and cash management centrally. The group believes it has access to sufficient funding and also has undrawn committed borrowing facilities to meet currently foreseeable borrowing requirements.

At 31 December 2005, the group had substantial amounts of undrawn borrowing facilities available, including committed facilities of $4,500 million expiring in 2006 (2004 $4,500 million expiring in 2005 and 2003 $3,700 million expiring in 2004). These facilities are with a number of international banks and borrowings under them would be at pre-agreed rates. The group expects to renew these facilities on an annual basis. Certain of these facilities support the group's commercial paper programme.

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 will be reviewed periodically.

ENVIRONMENTAL EXPENDITURE

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 below are therefore estimates, based on the definitions and guidelines of the American Petroleum Institute.

			$ million
	2005	2004	2003
Operating expenditure	494	526	498
Clean-ups	43	25	45
Capital expenditure	789	524	546
New provisions for environmental remediation	565	587	599
New provisions for decommissioning	1,023	286	1,159

Environmental operating expenditures for 2005 were broadly in line with 2004. The increase in capital expenditure is largely related to clean fuels investment. Similar levels of operating and capital expenditures are expected in the foreseeable future. In addition to operating and capital expenditures, we also create provisions for future environmental remediation. Expenditure against such provisions is normally in subsequent periods and is not included in environmental operating expenditure reported for such periods. The charge for environmental remediation provisions in 2005 includes $512 million resulting from a reassessment of existing site obligations and $53 million in respect of provisions for new sites.

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

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

In addition, we make provisions on installation of our oil- and gas-producing assets and related pipelines to meet the cost of eventual decommissioning. Provisions for environmental remediation and decommissioning are usually set up on a discounted basis, as required by IFRS 37 'Provisions, Contingent Liabilities and Contingent Assets'.

Further details of our environmental and decommissioning provisions appear in Note 41 on financial statements, Provisions, on page 86. New provisions for decommissioning in 2005 include increases in respect of reassessment of existing provisions and new provisions for certain fields on installation of facilities.

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. These terms are adhered to when payments are made, subject to terms and conditions being met by the supplier.

BP p.l.c. is a holding company with no business activity other than the holding of investments in the group and therefore had no trade creditors at 31 December 2005.

Financial statements contents

Statement of directors' responsibilities in respect of the consolidated financial statements

The directors are responsible for preparing the Annual Report and the financial statements in accordance with applicable United Kingdom law and those International Financial Reporting Standards (IFRSs) adopted by the European Union.

The directors are required to prepare financial statements for each financial year that present fairly the financial position of the group and the financial performance and cash flows of the group for that period. In preparing those financial statements, the directors are required:

- To select suitable accounting policies and then apply them consistently;
- To present information, including accounting policies, in a manner that provides relevant, reliable, comparable and understandable information;
- To provide additional disclosure when compliance with the specific requirements in IFRSs is insufficient to enable users to understand the impact of particular transactions, other events and conditions on the group's financial position and financial performance; and
- To state that the company has complied with IFRSs, subject to any material departures disclosed and explained in the financial statements.

The directors are responsible for keeping proper accounting records that disclose with reasonable accuracy at any time the financial position of the group and enable them to ensure that the financial statements comply with the Companies Act 1985 and Article 4 of the IAS Regulation. They are also responsible for safeguarding the assets of the group and hence for taking reasonable steps for the prevention and detection of fraud and other irregularities.

The directors confirm that they have complied with these requirements and, having a reasonable expectation that the group has adequate resources to continue in operational existence for the foreseeable future, continue to adopt the going concern basis in preparing the financial statements.

Independent auditors' report

We have audited the consolidated financial statements of BP p.l.c. for the year ended 31 December 2005 which comprise the group income statement, the group balance sheet, the group cash flow statement, the group statement of recognized income and expense, accounting policies and the related notes 1 to 52. These consolidated financial statements have been prepared under the accounting policies set out therein.

We have reported separately on the parent company financial statements of BP p.l.c. for the year ended 31 December 2005 and on the information in the Directors' Remuneration Report that is described as having been audited.

This report is made solely to the company's members, as a body, in accordance with Section 235 of the Companies Act 1985. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditors' report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for this report or for the opinions we have formed.

RESPECTIVE RESPONSIBILITIES OF DIRECTORS AND AUDITORS

The directors are responsible for preparing the Annual Report and the consolidated financial statements in accordance with applicable United Kingdom law and International Financial Reporting Standards (IFRSs) as adopted by the European Union as set out in the statement of directors' responsibilities in respect of the consolidated financial statements.

Our responsibility is to audit the consolidated financial statements in accordance with relevant legal and regulatory requirements and International Standards on Auditing (UK and Ireland).

We report to you our opinion as to whether the consolidated financial statements give a true and fair view and whether the consolidated financial statements have been properly prepared in accordance with the Companies Act 1985 and Article 4 of the IAS Regulation. We also report to you if, in our opinion, the Directors' Report is not consistent with the consolidated financial statements, if we have not received all the information and explanations we require for our audit, or if information specified by law regarding directors' remuneration and other transactions is not disclosed.

We review whether the Governance: board performance report reflects the company's compliance with the nine provisions of the 2003 FRC Combined Code specified for our review by the Listing Rules of the Financial Services Authority, and we report if it does not. We are not required to consider whether the board's statements on internal control cover all risks and controls, or form an opinion on the effectiveness of the group's corporate governance procedures or its risk and control procedures.

We read other information contained in the Annual Report and consider whether it is consistent with the audited consolidated financial statements. The other information comprises the United States accounting principles, the supplementary information on oil and natural gas quantities, the other financial and operating data, the Directors' Report, the Chairman's letter, and Governance: board performance report. We consider the implications for our report if we become aware of any apparent misstatements or material inconsistencies with the consolidated financial statements. Our responsibilities do not extend to any other information.

BASIS OF AUDIT OPINION

We conducted our audit in accordance with International Standards on Auditing (UK and Ireland) issued by the Auditing Practices Board. An audit includes examination, on a test basis, of evidence relevant to the amounts and disclosures in the consolidated financial statements. It also includes an assessment of the significant estimates and judgements made by the directors in the preparation of the consolidated financial statements and of whether the accounting policies are appropriate to the group's circumstances, consistently applied and adequately disclosed.

We planned and performed our audit so as to obtain all the information and explanations that we considered necessary in order to provide us with sufficient evidence to give reasonable assurance that the consolidated financial statements are free from material misstatement, whether caused by fraud or other irregularity or error. In forming our opinion we also evaluated the overall adequacy of the presentation of information in the consolidated financial statements.

OPINION

In our opinion the consolidated financial statements:

- give a true and fair view, in accordance with IFRSs as adopted by the European Union, of the state of the group's affairs as at 31 December 2005 and of its profit for the year then ended; and
- have been properly prepared in accordance with the Companies Act 1985 and Article 4 of the IAS Regulation.

SEPARATE OPINION IN RELATION TO IFRS

As explained in accounting policies to the consolidated financial statements, the group, in addition to complying with its legal obligation to comply with IFRSs as adopted by the European Union, has also complied with the IFRSs as issued by the International Accounting Standards Board.

In our opinion the consolidated financial statements give a true and fair view, in accordance with IFRSs, of the state of the group's affairs as at 31 December 2005 and of its profit for the year then ended.

Ernst & Young LLP
Registered auditor
London
6 February 2006

Accounting policies

AUTHORIZATION OF FINANCIAL STATEMENTS AND STATEMENT OF COMPLIANCE WITH INTERNATIONAL FINANCIAL REPORTING STANDARDS

The financial statements of the BP group for the year ended 31 December 2005 were authorized for issue by the results committee on behalf of the board of directors on 6 February 2006 and the balance sheet was signed on the board's behalf by Peter Sutherland and The Lord Browne of Madingley. BP p.l.c. is a public limited company incorporated and domiciled in England and Wales. The company's ordinary shares are traded on the London Stock Exchange. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRSs) as adopted by the European Union (EU) and in accordance with the provisions of the Companies Act 1985. The consolidated financial statements have also been prepared in accordance with IFRSs as issued by the International Accounting Standards Board (IASB). The principal accounting policies adopted by the group are set out below.

BASIS OF PREPARATION

This is the first year in which the group has prepared its financial statements under IFRSs and the comparative financial information has been restated from UK generally accepted accounting practice (UK GAAP) to comply with IFRSs. Reconciliations to IFRSs from the previously published UK GAAP primary financial statements are shown in Note 50. The accounting policies that follow set out those policies that apply in preparing the consolidated financial statements for the year ended 31 December 2005.

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

BASIS OF CONSOLIDATION

The group financial statements consolidate the financial statements of BP p.l.c. and the entities it controls (its subsidiaries) drawn up to 31 December each year. Control comprises the power to govern the financial and operating policies of the investee so as to obtain benefit from its activities and is achieved through direct and indirect ownership of voting rights; currently exercisable or convertible potential voting rights; or by way of contractual agreement. Subsidiaries are consolidated from the date of their acquisition, being the date on which the group obtains control, and continue to be consolidated until the date that such control ceases. The financial statements of subsidiaries are prepared for the same reporting year as the parent company, using consistent accounting policies.

All intercompany balances and transactions, including unrealized profits arising from intragroup transactions, have been eliminated in full. Unrealized losses are eliminated unless the transaction provides evidence of an impairment of the asset transferred.

Minority interests represent the portion of profit or loss and net assets in subsidiaries that is not held by the group and is presented separately within equity in the consolidated balance sheet.

INTERESTS IN JOINT VENTURES

A joint venture is a contractual arrangement whereby two or more parties (venturers) undertake an economic activity that is subject to joint control. Joint control exists only when the strategic financial and operating decisions relating to the activity require the unanimous consent of the venturers. A jointly controlled entity is a joint venture that involves the establishment of a company, partnership or other entity to engage in economic activity that the group jointly controls with its fellow venturers.

The results, assets and liabilities of a jointly controlled entity are incorporated in these financial statements using the equity method of accounting. Under the equity method, the investment in a jointly controlled entity is carried in the balance sheet at cost plus post-acquisition changes in the group's share of net assets of the jointly controlled entity, less distributions received and less any impairment in value of the investment. The group income statement reflects the group's share of the results after tax of the jointly controlled entity. The group statement of recognized income and expense reflects the group's share of any income and expense recognized by the jointly controlled entity outside profit and loss.

Financial statements of jointly controlled entities are prepared for the same reporting year as the group. Where necessary, adjustments are made to those financial statements to bring the accounting policies used into line with those of the group.

Unrealized gains on transactions between the group and its jointly controlled entities are eliminated to the extent of the group's interest in the jointly controlled entities. Unrealized losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred.

The group ceases to use the equity method of accounting on the date from which it no longer has joint control over, or significant influence in the joint venture, or when the interest becomes held for sale.

Certain of the group's activities, particularly in the Exploration and Production segment, are conducted through joint ventures where the venturers have a direct ownership interest in and jointly control the assets of the venture. The income, expenses, assets and liabilities of these jointly controlled assets are included in the consolidated financial statements in proportion to the group's interest.

INTERESTS IN ASSOCIATES

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

The results, assets and liabilities of an associate are incorporated in these financial statements using the equity method of accounting. Under the equity method, the investment in an associate is carried in the balance sheet at cost plus post-acquisition changes in the group's share of net assets of the associate, less distributions received and less any impairment in value of the investment. The group income statement reflects the group's share of the results after tax of the associate. The group statement of recognized income and expense reflects the group's share of any income and expense recognized by the associate outside profit and loss.

The financial statements of associates are prepared for the same reporting year as the group. Where necessary, adjustments are made to those financial statements to bring the accounting policies used into line with those of the group.

Unrealized gains on transactions between the group and its associates are eliminated to the extent of the group's interest in the associates. Unrealized losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred.

The group ceases to use the equity method of accounting on the date from which it no longer has significant influence in the associate or when the interest becomes held for sale.

FOREIGN CURRENCY TRANSLATION

In individual companies, transactions in foreign currencies are initially recorded in the functional currency by applying the rate of exchange ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated into the functional currency at the rate of exchange ruling at the balance sheet date. Any resulting exchange differences are included in the income statement. Non-monetary assets and liabilities that are measured in terms of historical cost in a foreign currency are translated into the functional currency using the rates of exchange as at the dates of the initial transactions. Non-monetary assets and liabilities measured at fair value in a foreign currency are translated into the functional currency using the rate of exchange at the date the fair value was determined.

In the consolidated financial statements, the assets and liabilities of non-US dollar functional currency subsidiaries, jointly controlled entities and associates, including related goodwill, are translated into US dollars at the rate of exchange ruling at the balance sheet date. The results and cash flows of non-US dollar functional currency subsidiaries, jointly controlled entities and associates are translated into US dollars using average rates of exchange. Exchange adjustments arising when the opening net assets and the profits for the year retained by non-US dollar functional currency subsidiaries, jointly controlled entities and associates are translated into US dollars are taken to a separate component of equity and reported in the statement of recognized income and expense. Exchange gains and losses arising on long-term foreign currency borrowings used to finance the group's non-US dollar investments are also taken to equity. On disposal of a non-US dollar functional currency subsidiary, jointly controlled entity or associate, the deferred cumulative amount recognized in equity relating to that particular non-US dollar operation is recognized in the income statement.

BUSINESS COMBINATIONS AND GOODWILL

Business combinations are accounted for using the acquisition method of accounting. The cost of an acquisition is measured as the cash paid and the fair value of other assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange, plus costs directly attributable to the acquisition. The acquired identifiable assets, liabilities and contingent liabilities are measured at their fair values at the date of acquisition. Any excess of the cost of acquisition over the net fair value of the identifiable assets acquired is recognized as goodwill. Any deficiency of the cost of acquisition below the fair values of the identifiable net assets acquired (i.e. discount on acquisition) is credited to the income statement in the period of acquisition. Where the group does not acquire 100% ownership of the acquired company, the interest of minority shareholders is stated at the minority's proportion of the fair values of the assets and liabilities recognized. Subsequently, any losses applicable to the minority shareholders in excess of the minority interest are allocated against the interests of the parent.

Goodwill on acquisition is initially measured at cost being the excess of the cost of the business combination over the acquirer's interest in the net fair value of the identifiable assets, liabilities and contingent liabilities. Following initial recognition, goodwill is measured at cost less any accumulated impairment losses. Goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate that the carrying value may be impaired.

As at the acquisition date, any goodwill acquired is allocated to each of the cash-generating units expected to benefit from the combination's synergies. For this purpose, cash-generating units are set at one level below a business segment. Impairment is determined by assessing the recoverable amount of the cash-generating unit to which the goodwill relates. Where the recoverable amount of the cash-generating unit is less than the carrying amount, an impairment loss is recognized.

Goodwill arising on business combinations prior to 1 January 2003 is stated at the previous UK GAAP carrying amount.

Goodwill may also arise upon investments in jointly controlled entities and associates, being the surplus of the cost of investment over the group's share of the net fair value of the identifiable assets. Such goodwill is recorded within investments in jointly controlled entities and associates, and any impairment of the goodwill is included within the income from jointly controlled entities and associates.

NON-CURRENT ASSETS HELD FOR SALE

Non-current assets and disposal groups classified as held for sale are measured at the lower of carrying amount and fair value less costs to sell.

Non-current assets and disposal groups are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is regarded as met only when the sale is highly probable and the asset or disposal group is available for immediate sale in its present condition. Management must be committed to the sale, which should be expected to qualify for recognition as a completed sale within one year from the date of classification.

Property, plant and equipment and intangible assets once classified as held for sale are not depreciated.

INTANGIBLE ASSETS

Intangible assets are stated at cost, less accumulated amortization and accumulated impairment losses. Intangible assets include expenditure on the exploration for and evaluation of oil and natural gas resources, computer software, patents, licences, trademarks and product development costs.

Intangible assets acquired separately from a business are carried initially at cost. The initial cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. An intangible asset acquired as part of a business combination is recognized separately from goodwill if the asset is separable or arises from contractual or other legal rights and its fair value can be measured reliably.

Product development costs are capitalized as intangible assets when a project has obtained internal sanction and the future recoverability of such costs can reasonably be regarded as assured.

Intangible assets with a finite life are amortized on a straight-line basis over their expected useful lives. For patents, licences and trademarks, expected useful life is the lower of the duration of the legal agreement and economic useful life, which can range from three to 15 years. Computer software costs have a useful life of three to five years.

The expected useful lives of the assets are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

The carrying value of intangible assets is reviewed for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. In addition, the carrying value of capitalized product development expenditure is reviewed for impairment annually before being brought into use.

OIL AND NATURAL GAS EXPLORATION AND DEVELOPMENT EXPENDITURE

Oil and natural gas exploration and development expenditure is accounted for using the successful efforts method of accounting.

Licence and property acquisition costs Exploration and property leasehold acquisition costs are capitalized within intangible fixed assets and amortized on a straight-line basis over the estimated period of exploration. Each property is reviewed on an annual basis to confirm that drilling activity is planned and it is not impaired. If no future activity is planned, the remaining balance of the licence and property acquisition costs is written off. Upon determination of economically recoverable reserves ('proved reserves' or 'commercial reserves'), amortization ceases and the remaining costs are aggregated with exploration expenditure and held on a field-by-field basis as proved properties awaiting approval within other intangible assets. When development is approved internally, the relevant expenditure is transferred to property, plant and equipment.

Exploration expenditure Geological and geophysical exploration costs are charged against income as incurred. Costs directly associated with an exploration well are capitalized as an intangible asset until the drilling of the well is complete and the results have been evaluated. These costs include employee remuneration, materials and fuel used, rig costs, delay rentals and payments made to contractors. If hydrocarbons are not found, the exploration expenditure is written off as a dry hole. If hydrocarbons are found and, subject to further appraisal activity, which may include the drilling of further wells (exploration or exploratory-type stratigraphic test wells), are likely to be capable of commercial development, the costs continue to be carried as an asset. All such carried costs are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off. When proved reserves of oil and natural gas are determined and development is sanctioned, the relevant expenditure is transferred to property, plant and equipment.

Development expenditure Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including unsuccessful development or delineation wells, is capitalized within property, plant and equipment.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is stated at cost, less accumulated depreciation and accumulated impairment losses.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of any decommissioning obligation, if any, and, for qualifying assets, borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. The capitalized value of a finance lease is also included within property, plant and equipment.

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

Expenditure on major maintenance refits or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset that was separately depreciated and is now written off is replaced and it is probable that future economic benefits associated with the item will flow to the group, the expenditure is capitalized. Inspection costs associated with major maintenance programmes are capitalized and amortized over the period to the next inspection. Overhaul costs for major maintenance programmes are expensed as incurred. All other maintenance costs are expensed as incurred.

Oil and natural gas properties are depreciated using a unit-of-production method. The cost of producing wells is amortized over proved developed reserves. Licence acquisition, decommissioning and field development costs are amortized over total proved reserves. The unit-of-production rate for the amortization of field development costs takes into account expenditures incurred to date, together with sanctioned future development expenditure.

Other property, plant and equipment is depreciated on a straight-line basis over its expected useful life.

The useful lives of the group's other property, plant and equipment are as follows:

Land improvements	15 to 25 years
Buildings	20 to 40 years
Refineries	20 to 30 years
Petrochemicals plants	20 years
Pipelines	Unit-of-throughput
	10 to 50 years
Service stations	15 years
Office equipment	3 to 7 years
Fixtures and fittings	5 to 15 years

The expected useful lives of property, plant and equipment are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

The carrying value of property, plant and equipment is reviewed for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable.

An item of property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in the income statement in the period the item is derecognized.

IMPAIRMENT OF INTANGIBLE ASSETS AND PROPERTY, PLANT AND EQUIPMENT

The group assesses assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. Individual assets are grouped for impairment assessment purposes at the lowest level at which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. If any such indication of impairment exists or when annual impairment testing for an asset group is required, the group makes an estimate of its recoverable amount. An asset group's recoverable amount is the higher of its fair value less costs to sell and its value in use. Where the carrying amount of an asset group exceeds its recoverable amount, the asset group is considered impaired and is written down to its recoverable amount. In assessing value in use, the estimated future cash flows are adjusted for the risks specific to the asset group and are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money.

An assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the recoverable amount is estimated. A previously recognized impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognized. If that is the case, the carrying amount of the asset is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years. Such reversal is recognized in profit or loss. After such a reversal, the depreciation charge is adjusted in future periods to allocate the asset's revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.

FINANCIAL ASSETS

Financial assets are classified as financial assets at fair value through profit or loss; loans and receivables; held-to-maturity investments; or as available-for-sale financial assets, as appropriate. Financial assets include cash and cash equivalents; trade receivables; other receivables; loans; other investments; and derivative financial instruments. The group determines the classification of its financial assets at initial recognition. When financial assets are recognized initially, they are measured at fair value, normally being the transaction price plus, in the case of financial assets not at fair value through profit or loss, directly attributable transaction costs. As explained in Note 50, the group has not restated comparative amounts, on first applying IAS 32 'Financial Instruments: Disclosure and Presentation' and IAS 39 'Financial Instruments: Recognition and Measurement', as permitted in IFRS 1 'First-time Adoption of International Financial Reporting Standards'.

All regular way purchases and sales of financial assets are recognized on the trade date, being the date that the group commits to purchase or sell the asset. Regular way transactions require delivery of assets within the timeframe generally established by regulation or convention in the marketplace. The subsequent measurement of financial assets depends on their classification, as follows:

Financial assets at fair value through profit or loss Financial assets classified as held for trading and other assets designated as such on inception are included in this category. Financial assets are classified as held for trading if they are acquired for sale in the short term. Derivatives are also classified as held for trading unless they are designated as hedging instruments. Assets are carried on the balance sheet at fair value with gains or losses recognized in the income statement.

Loans and receivables Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market, do not qualify as trading assets and have not been designated as either fair value through profit and loss or available-for-sale. Such assets are carried at amortized cost using the effective interest method if the time value of money is significant. Gains and losses are recognized in income when the loans and receivables are derecognized or impaired, as well as through the amortization process.

Held-to-maturity investments Non-derivative financial assets with fixed or determinable payments and fixed maturity are classified as held-to-maturity when the group has the positive intention and ability to hold to maturity. Held-to-maturity investments are carried at amortized cost using the effective interest method. Gains and losses are recognized in income when the investments are derecognized or impaired, as well as through the amortization process. Investments intended to be held for an undefined period are not included in this classification.

Available-for-sale financial assets Available-for-sale financial assets are those non-derivative financial assets that are designated as such or are not classified in any of the three preceding categories. After initial recognition, available-for-sale financial assets are measured at fair value, with gains or losses being recognized as a separate component of equity until the investment is derecognized or until the investment is determined to be impaired, at which time the cumulative gain or loss previously reported in equity is included in the income statement.

Fair values The fair value of quoted investments is determined by reference to bid prices at the close of business on the balance sheet date. Where there is no active market, fair value is determined using valuation techniques. These include using recent arm's-length market transactions; reference to the current market value of another instrument which is substantially the same; discounted cash flow analysis; and pricing models. Otherwise assets are carried at cost.

IMPAIRMENT OF FINANCIAL ASSETS

The group assesses at each balance sheet date whether a financial asset or group of financial assets is impaired.

Assets carried at amortized cost If there is objective evidence that an impairment loss on loans and receivables carried at amortized cost has been incurred, the amount of the loss is measured as the difference between the asset's carrying amount and the present value of estimated future cash flows discounted at the financial asset's original effective interest rate. The carrying amount of the asset is reduced, with the amount of the loss recognized in administration costs.

If, in a subsequent period, the amount of the impairment loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized, the previously recognized impairment loss is reversed. Any subsequent reversal of an impairment loss is recognized in the income statement, to the extent that the carrying value of the asset does not exceed its amortized cost at the reversal date.

Assets carried at cost If there is objective evidence that an impairment loss on an unquoted equity instrument that is not carried at fair value because its fair value cannot be reliably measured, or on a derivative asset that is linked to and must be settled by delivery of such an unquoted equity instrument, has been incurred, the amount of the loss is measured as the difference between the asset's carrying amount and the present value of estimated future cash flows discounted at the current market rate of return for a similar financial asset.

Available-for-sale financial assets If an available-for-sale asset is impaired, an amount comprising the difference between its cost (net of any principal payment and amortization) and its fair value is transferred from equity to the income statement.

Reversals of impairment losses on debt instruments are taken through the income statement if the increase in fair value of the instrument can be objectively related to an event occurring after the impairment loss was recognized in profit or loss. Reversals in respect of equity instruments classified as available-for-sale are not recognized in the income statement.

INVENTORIES

Inventories, other than inventory held for trading purposes, are stated at the lower of cost and net realizable value. Cost is determined by the first-in first-out method and comprises direct purchase costs, cost of production, transportation and manufacturing expenses.

Inventories held for trading purposes are stated at fair value less costs to sell and any changes in net realizable value are recognized in the income statement.

Supplies are valued at cost to the group mainly using the average method or net realizable value, whichever is the lower.

TRADE AND OTHER RECEIVABLES

Trade and other receivables are carried at the original invoice amount, less allowances made for doubtful receivables. Where the time value of money is material, receivables are carried at amortized cost. Provision is made when there is objective evidence that the group will be unable to recover balances in full. Balances are written off when the probability of recovery is assessed as being remote.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents comprise cash in hand; current balances with banks and similar institutions; and short-term highly liquid investments that are readily convertible to known amounts of cash, are subject to insignificant risk of changes in value and have a maturity of three months or less from the date of acquisition.

For the purpose of the group cash flow statement, cash and cash equivalents consist of cash and cash equivalents as defined above, net of outstanding bank overdrafts.

TRADE AND OTHER PAYABLES

Trade and other payables are carried at payment or settlement amounts. Where the time value of money is material, payables are carried at amortized cost.

INTEREST-BEARING LOANS AND BORROWINGS

All loans and borrowings are initially recognized at cost, being the fair value of the proceeds received net of issue costs associated with the borrowing.

After initial recognition, interest-bearing loans and borrowings are subsequently measured at amortized cost using the effective interest method. Amortized cost is calculated by taking into account any issue costs, and any discount or premium on settlement.

Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognized respectively in interest and other revenues and other finance expense.

LEASES

Finance leases, which transfer to the group substantially all the risks and benefits incidental to ownership of the leased item, are capitalized at the inception of the lease at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Lease payments are apportioned between the finance charges and reduction of the lease liability so as to achieve a constant rate of interest on the remaining balance of the liability. Finance charges are charged directly against income.

Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term.

Operating lease payments are recognized as an expense in the income statement on a straight-line basis over the lease term.

DERECOGNITION OF FINANCIAL ASSETS AND LIABILITIES

Financial assets A financial asset (or, where applicable, a part of a financial asset or part of a group of similar financial assets) is derecognized where:

- The rights to receive cash flows from the asset have expired;
- The group retains the right to receive cash flows from the asset, but has assumed an obligation to pay them in full without material delay to a third party under a 'pass-through' arrangement; or
- The group has transferred its rights to receive cash flows from the asset and either (a) has transferred substantially all the risks and rewards of the asset or (b) has neither transferred nor retained substantially all the risks and rewards of the asset but has transferred control of the asset.

Where the group has transferred its rights to receive cash flows from an asset and has neither transferred nor retained substantially all the risks and rewards of the asset nor transferred control of the asset, the asset is recognized to the extent of the group's continuing involvement in the asset. Continuing involvement that takes the form of a guarantee over the transferred asset is measured at the lower of the original carrying amount of the asset and the maximum amount of consideration that the group could be required to repay.

Where continuing involvement takes the form of a written and/or purchased option (including a cash-settled option or similar provision) on the transferred asset, the extent of the group's continuing involvement is the amount of the transferred asset that the group may repurchase, except that in the case of a written put option (including a cash-settled option or similar provision) on an asset measured at fair value, the extent of the group's continuing involvement is limited to the lower of the fair value of the transferred asset and the option exercise price.

Financial liabilities A financial liability is derecognized when the obligation under the liability is discharged, cancelled or expires. Where an existing financial liability is replaced by another from the same lender on substantially different terms or the terms of an existing liability are substantially modified, such an exchange or modification is treated as a derecognition of the original liability and the recognition of a new liability, such that the difference in the respective carrying amounts, together with any costs or fees incurred are recognized in profit or loss.

DERIVATIVE FINANCIAL INSTRUMENTS

The group uses derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates, interest rates and commodity prices. From 1 January 2005, such derivative financial instruments are initially recognized at fair value on the date on which a derivative contract is entered into and are subsequently remeasured at fair value. Derivatives are carried as assets when the fair value is positive and as liabilities when the fair value is negative.

Contracts to buy or sell a non-financial item that can be settled net in cash or another financial instrument, or by exchanging financial instruments, as if the contracts were financial instruments, with the exception of contracts that were entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the group's expected purchase, sale or usage requirements, are financial instruments.

For those derivatives designated as hedges and for which hedge accounting is desired, the hedging relationship is documented at its inception. This documentation identifies the hedging instrument, the hedged item or transaction, the nature of the risk being hedged and how effectiveness will be measured throughout its duration. Such hedges are expected at inception to be highly effective.

For the purpose of hedge accounting, hedges are classified as:

- Fair value hedges when hedging the exposure to changes in the fair value of a recognized asset or liability;
- Cash flow hedges when hedging exposure to variability in cash flows that is either attributable to a particular risk associated with a recognized asset or liability or a highly probable forecast transaction, including intra-group transactions; or
- Hedges of the net investment in a foreign entity.

Any gains or losses arising from changes in the fair value of all other derivatives, which are classified as held for trading, are taken to the income statement. These may arise from derivatives for which hedge accounting is not applied because they are either not designated or not effective as hedging instruments or from derivatives that are acquired for trading purposes.

The treatment of gains and losses arising from revaluing derivatives designated as hedging instruments depends on the nature of the hedging relationship, as follows:

Fair value hedges For fair value hedges, the carrying amount of the hedged item is adjusted for gains and losses attributable to the risk being hedged; the derivative is remeasured at fair value and gains and losses from both are taken to profit or loss. For hedged items carried at amortized cost, the adjustment is amortized through the income statement such that it is fully amortized by maturity. When an unrecognized firm commitment is designated as a hedged item, this gives rise to an asset or liability in the balance sheet, representing the cumulative change in the fair value of the firm commitment attributable to the hedged risk.

The group discontinues fair value hedge accounting if the hedging instrument expires or is sold, terminated or exercised, the hedge no longer meets the criteria for hedge accounting or the group revokes the designation.

Cash flow hedges For cash flow hedges, the effective portion of the gain or loss on the hedging instrument is recognized directly in equity, while the ineffective portion is recognized in profit or loss. Amounts taken to equity are transferred to the income statement when the hedged transaction affects profit or loss, such as when a forecast sale or purchase occurs. Where the hedged item is the cost of a non-financial asset or liability, the amounts taken to equity are transferred to the initial carrying amount of the non-financial asset or liability.

If the hedging instrument expires or is sold, terminated or exercised without replacement or rollover, the hedged transaction ceases to be highly probable, or if its designation as a hedge is revoked, amounts previously recognized in equity remain in equity until the forecast transaction occurs and are transferred to the income statement or to the initial carrying amount of a non-financial asset or liability as above. If a forecast transaction is no longer expected to occur, amounts previously recognized in equity are transferred to profit or loss.

Hedges of the net investment in a foreign entity For hedges of the net investment in a foreign entity, the effective portion of the gain or loss on the hedging instrument is recognized directly in equity, while the ineffective portion is recognized in profit or loss.

Amounts taken to equity are transferred to the income statement when the foreign entity is sold.

Embedded derivatives Derivatives embedded in other financial instruments or other host contracts are treated as separate derivatives when their risks and characteristics are not closely related to those of host contracts and the host contracts are not carried at fair value. Contracts are assessed for embedded derivatives when the group becomes a party to them, including at the date of a business combination. These embedded derivatives are measured at fair value at each period end. Any gains or losses arising from changes in fair value are taken directly to net profit or loss for the period.

PROVISIONS

Provisions are recognized when the group has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where the group expects some or all of a provision to be reimbursed, for example, under an insurance contract, the reimbursement is recognized as a separate asset, but only when the reimbursement is virtually certain. The expense relating to any provision is presented in the income statement net of any reimbursement. If the effect of the time value of money is material, provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and, where appropriate, the risks specific to the liability. Where discounting is used, the increase in the provision due to the passage of time is recognized as other finance expense. Any change in the amount recognized for environmental and litigation and other provisions arising through changes in discount rates is included within other finance expense.

A contingent liability is disclosed where the existence of an obligation will only be confirmed by future events or where the amount of the obligation cannot be measured with reasonable reliability. Contingent assets are not recognized, but are disclosed where an inflow of economic benefits is probable.

ENVIRONMENTAL LIABILITIES

Environmental expenditures that relate to current or future revenues are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations and do not contribute to current or future earnings are expensed.

Liabilities for environmental costs are recognized when environmental assessments or clean-ups are probable and the associated costs can be reasonably estimated. Generally, the timing of these provisions coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites. The amount recognized is the best estimate of the expenditure required. Where the liability will not be settled for a number of years, the amount recognized is the present value of the estimated future expenditure.

DECOMMISSIONING

Liabilities for decommissioning costs are recognized when the group has an obligation to dismantle and remove a facility or an item of plant and to restore the site on which it is located, and when a reasonable estimate of that liability can be made. Where an obligation exists for a new facility, such as oil and natural gas production or transportation facilities, this will be on construction or installation. An obligation for decommissioning may also crystallize during the period of operation of a facility through a change in legislation or through a decision to terminate operations. The amount recognized is the present value of the estimated future expenditure determined in accordance with local conditions and requirements.

A corresponding item of property, plant and equipment of an amount equivalent to the provision is also created. This is subsequently depreciated as part of the capital costs of the facility or item of plant.

Any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding property, plant and equipment.

EMPLOYEE BENEFITS

Wages, salaries, bonuses, social security contributions, paid annual leave and sick leave are accrued in the period in which the associated services are rendered by employees of the group. Deferred bonus arrangements that have a vesting date more than 12 months after the period end are valued on an actuarial basis using the projected unit credit method and amortized on a straight-line basis over the service period until the award vests. The accounting policy for pensions and other post-retirement benefits is described below.

SHARE-BASED PAYMENTS

Equity-settled transactions The cost of equity-settled transactions with employees is measured by reference to the fair value at the date at which they are granted and is recognized as an expense over the vesting period, which ends on the date on which the relevant employees become fully entitled to the award. Fair value is determined by using an appropriate valuation model. In valuing equity-settled transactions, no account is taken of any vesting conditions, other than conditions linked to the price of the shares of the company (market conditions).

No expense is recognized for awards that do not ultimately vest, except for awards where vesting is conditional upon a market condition, which are treated as vesting irrespective of whether or not the market condition is satisfied, provided that all other performance conditions are satisfied.

At each balance sheet date before vesting, the cumulative expense is calculated, representing the extent to which the vesting period has expired and management's best estimate of the achievement or otherwise of non-market conditions and the number of equity instruments that will ultimately vest or, in the case of an instrument subject to a market condition, be treated as vesting as described above. The movement in cumulative expense since the previous balance sheet date is recognized in the income statement, with a corresponding entry in equity.

Where the terms of an equity-settled award are modified or a new award is designated as replacing a cancelled or settled award, the cost based on the original award terms continues to be recognized over the original vesting period. In addition, an expense is recognized over the remainder of the new vesting period for the incremental fair value of any modification, based on the difference between the fair value of the original award and the fair value of the modified award, both as measured on the date of the modification. No reduction is recognized if this difference is negative.

Where an equity-settled award is cancelled, it is treated as if it had vested on the date of cancellation and any cost not yet recognized in the income statement for the award is expensed immediately. Any compensation paid up to the fair value of the award at the cancellation or settlement date is deducted from equity, with any excess over fair value being treated as an expense in the income statement.

Cash-settled transactions The cost of cash-settled transactions is measured at fair value using an appropriate option valuation model.

Fair value is established initially at the grant date and at each balance sheet date thereafter until the awards are settled. During the vesting period, a liability is recognized representing the product of the fair value of the award and the portion of the vesting period expired as at the balance sheet date. From the end of the vesting period until settlement, the liability represents the full fair value of the award as at the balance sheet date. Changes in the carrying amount for the liability are recognized in profit or loss for the period.

PENSIONS AND OTHER POST-RETIREMENT BENEFITS

The cost of providing benefits under the defined benefit plans is determined separately for each plan using the projected unit method, which attributes entitlement to benefits to the current period (to determine current service cost) and to the current and prior periods (to determine the present value of defined benefit obligation) and is based on actuarial advice. Past service costs are recognized in profit or loss on a straight-line basis over the vesting period or immediately if the benefits have vested. When a settlement (eliminating all obligations for benefits already accrued) or a curtailment (reducing future obligations as a result of a material reduction in the scheme membership or a reduction in future entitlement) occurs, the obligation and related plan assets are remeasured using current actuarial assumptions and the resultant gain or loss recognized in the income statement during the period in which the settlement or curtailment occurs.

The interest element of the defined benefit cost represents the change in present value of scheme obligations resulting from the passage of time, and is determined by applying the discount rate to the opening present value of the benefit obligation, taking into account material changes in the obligation during the year. The expected return on plan assets is based on an assessment made at the beginning of the year of long-term market returns on scheme assets, adjusted for the effect on the fair value of plan assets of contributions received and benefits paid during the year. The difference between the expected return on plan assets and the interest cost is recognized in the income statement as other finance income or expense.

Actuarial gains and losses are recognized in full in the group statement of recognized income and expense in the period in which they occur.

The defined benefit pension asset or liability in the balance sheet comprises the total for each plan of the present value of the defined benefit obligation (using a discount rate based on high quality corporate bonds), less any past service cost not yet recognized and less the fair value of plan assets out of which the obligations are to be settled directly. Fair value is based on market price information and, in the case of quoted securities, is the published bid price. The value of a net pension benefit asset is restricted to the sum of any unrecognized past service costs and the present value of any amount the group expects to recover by way of refunds from the plan or reductions in the future contributions.

Contributions to defined contribution schemes are recognized in the income statement in the period in which they become payable.

CORPORATE TAXES

Tax expense represents the sum of the tax currently payable and deferred tax.

The tax currently payable is based on the taxable profits for the period. Taxable profit differs from net profit as reported in the income statement because it excludes items of income or expense that are taxable or deductible in other periods and it further excludes items that are never taxable or deductible. The group's liability for current tax is calculated using tax rates that have been enacted or substantively enacted by the balance sheet date.

Deferred tax is provided, using the liability method, on all temporary differences at the balance sheet date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes.

Deferred tax liabilities are recognized for all taxable temporary differences:

- Except where the deferred tax liability arises on goodwill that is not tax deductible or the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss; and
- In respect of taxable temporary differences associated with investments in subsidiaries, jointly controlled entities and associates, except where the timing of the reversal of the temporary differences can be controlled by the group and it is probable that the temporary differences will not reverse in the foreseeable future.

Deferred tax assets are recognized for all deductible temporary differences, carry-forward of unused tax assets and unused tax losses, to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax assets and unused tax losses can be utilized:

- Except where the deferred income tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss; and
- In respect of deductible temporary differences associated with investments in subsidiaries, jointly controlled entities and associates, deferred tax assets are only recognized to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available against which the temporary differences can be utilized.

The carrying amount of deferred income tax assets is reviewed at each balance sheet date and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred income tax asset to be utilized.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply to the year when the asset is realized or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the balance sheet date.

Tax relating to items recognized directly in equity is recognized in equity and not in the income statement.

CUSTOMS DUTIES AND SALES TAXES

Revenues, expenses and assets are recognized net of the amount of customs duties or sales tax except:

- Where the customs duty or sales tax incurred on a purchase of goods and services is not recoverable from the taxation authority, in which case the customs duty or sales tax is recognized as part of the cost of acquisition of the asset or as part of the expense item as applicable; and
- Receivables and payables are stated with the amount of customs duty or sales tax included.

The net amount of sales tax recoverable from, or payable to, the taxation authority is included as part of receivables or payables in the balance sheet.

OWN EQUITY INSTRUMENTS

The group's holding in its own equity instruments, including shares held by Employee Share Ownership Plans (ESOPs), are classified as 'treasury shares', and shown as deductions from shareholders' equity at cost. Consideration received for the sale of such shares is also recognized in equity, with any difference between the proceeds from sale and the original cost being taken to revenue reserves. No gain or loss is recognized in the performance statements on the purchase, sale, issue or cancellation of equity shares.

REVENUE

Revenue arising from the sale of goods is recognized when the significant risks and rewards of ownership have passed to the buyer and it can be reliably measured. Revenue is measured at the fair value of the consideration received or receivable and represents amounts receivable for goods provided in the normal course of business, net of discounts, customs duties and sales taxes.

Revenues associated with the sale of oil, natural gas liquids, liquefied natural gas, petroleum and chemicals products and all other items are recognized when the title passes to the customer. Supply buy/sell arrangements with common counterparties are reported net as are physical exchanges. Similarly, oil and natural gas forward sales/purchase contracts and sales/purchases of trading inventory are included on a net basis in sales and other operating revenues. Generally, revenues from the production of oil and natural gas properties in which the group has an interest with other producers are recognized on the basis of the group's working interest in those properties (the entitlement method). Differences between the production sold and the group's share of production are not significant.

Interest income is recognized as the interest accrues (using the effective interest rate method that is the rate that exactly discounts estimated future cash receipts through the expected life of the financial instrument) to the net carrying amount of the financial asset.

Dividend income from investments is recognized when the shareholders' right to receive the payment is established.

RESEARCH

Research costs are expensed as incurred.

FINANCE COSTS

Finance costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use.

All other finance costs are recognized in the income statement in the period in which they are incurred.

USE OF ESTIMATES

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities as well as the disclosure of contingent assets and liabilities at the balance sheet date and the reported amounts of revenues and expenses during the reporting period. Actual outcomes could differ from those estimates.

NEW STANDARDS AND INTERPRETATIONS NOT APPLIED

During the year, the IASB and the International Financial Reporting Interpretations Committee (IFRIC) have issued the following standards and interpretations with an effective date after the date of these financial statements:

International Accounting Standards (IAS/IFRSs)		Effective date
IFRS 7	Financial Instruments: Disclosures	1 January 2007
IAS 1	Amendment – Presentation of Financial Statements: Capital Disclosures	1 January 2007
IAS 21	Amendment – Net Investment in Foreign Operation (Yet to be adopted by the EU)	1 January 2006
IAS 39	Fair Value Option	1 January 2006
IAS 39	Amendment to IAS 39 and IFRS 4 – Financial Guarantee Contracts	1 January 2006
IFRIC interpretations		
IFRIC 5	Rights to Interests Arising from Decommissioning, Restoration and Environmental Rehabilitation Funds	1 January 2006
IFRIC 6	Liabilities Arising from Participating in a Specific Market – Waste Electrical and Electronic Equipment	1 December 2005[a]
IFRIC 7	Applying IAS 29 for the First Time (Yet to be adopted by the EU)	1 March 2006
IFRIC 8	Scope of IFRS 2 (Yet to be adopted by the EU)	1 May 2006

The directors do not anticipate that the adoption of these standards and interpretations will have a material impact on the consolidated financial statements in the period of initial application.

Upon adoption of IFRS 7, the group will disclose additional information about its financial instruments, their significance and the nature and extent of risks to which they give rise. More specifically, the group will be required to disclose the fair value of its financial instruments and its risk exposure in greater detail. There will be no effect on reported income or net assets.

[a] IFRIC 6 is effective for financial periods beginning on or after 1 December 2005.

Group income statement

For the year ended 31 December				$ million
	Note	2005	2004	2003
Sales and other operating revenues	6	249,465	199,876	169,441
Earnings from jointly controlled entities – after interest and tax	7	3,083	1,818	826
Earnings from associates – after interest and tax	7	460	462	388
Interest and other revenues	8	613	615	746
Total revenues		253,621	202,771	171,401
Gains on sale of businesses and fixed assets	9	1,538	1,685	1,895
Total revenues and other income		255,159	204,456	173,296
Purchases		172,699	135,907	115,978
Production and manufacturing expenses		21,092	17,330	14,130
Production and similar taxes	10	3,010	2,149	1,723
Depreciation, depletion and amortization	11	8,771	8,529	8,076
Impairment and losses on sale of businesses and fixed assets	12	468	1,390	1,801
Exploration expense	18	684	637	542
Distribution and administration expenses	14	13,706	12,768	12,270
Fair value (gain) loss on embedded derivatives	35	2,047	–	–
Profit before interest and taxation from continuing operations		32,682	25,746	18,776
Finance costs	20	616	440	513
Other finance expense	21	145	340	532
Profit before taxation from continuing operations		31,921	24,966	17,731
Taxation	22	9,473	7,082	5,050
Profit from continuing operations		22,448	17,884	12,681
Profit (loss) from Innovene operations	4	184	(622)	(63)
Profit for the year		22,632	17,262	12,618
Attributable to				
BP shareholders		22,341	17,075	12,448
Minority interest		291	187	170
		22,632	17,262	12,618
Earnings per share – cents				
Profit for the year attributable to BP shareholders				
Basic	24	105.74	78.24	56.14
Diluted	24	104.52	76.87	55.61
Profit from continuing operations attributable to BP shareholders				
Basic		104.87	81.09	56.42
Diluted		103.66	79.66	55.89

Group balance sheet

At 31 December				$ million
	Note	2005	2004	2003
Non-current assets				
Property, plant and equipment	26	85,947	93,092	88,607
Goodwill	27	10,371	10,857	10,592
Intangible assets	28	4,772	4,205	4,471
Investments in jointly controlled entities	29	13,556	14,556	12,909
Investments in associates	30	6,217	5,486	4,868
Other investments		967	394	1,452
Fixed assets		121,830	128,590	122,899
Loans		821	811	852
Other receivables	32	770	429	495
Derivative financial instruments	35	3,652	898	534
Prepayments and accrued income		1,269	354	957
Defined benefit pension plan surplus	42	3,282	2,105	1,680
		131,624	133,187	127,417
Current assets				
Loans		132	193	182
Inventories	31	19,760	15,645	11,597
Trade and other receivables	32	40,902	37,099	27,881
Derivative financial instruments	35	9,726	5,317	1,891
Prepayments and accrued income		1,598	1,671	1,375
Current tax receivable		212	159	92
Cash and cash equivalents	33	2,960	1,359	2,056
		75,290	61,443	45,074
Total assets		206,914	194,630	172,491
Current liabilities				
Trade and other payables	34	42,136	38,540	29,740
Derivative financial instruments	35	9,083	5,074	4,145
Accruals and deferred income		5,970	4,482	2,266
Finance debt	39	8,932	10,184	9,456
Current tax payable		4,274	4,131	3,441
Provisions	41	1,102	715	735
		71,497	63,126	49,783
Non-current liabilities				
Other payables	34	1,935	3,581	4,630
Derivative financial instruments	35	3,696	158	344
Accruals and deferred income		3,164	699	864
Finance debt	39	10,230	12,907	12,869
Deferred tax liabilities	22	16,443	16,701	16,051
Provisions	41	9,954	8,884	7,864
Defined benefit pension plan and other post-retirement benefit plan deficits	42	9,230	10,339	9,822
		54,652	53,269	52,444
Total liabilities		126,149	116,395	102,227
Net assets		80,765	78,235	70,264
Equity				
Share capital	43	5,185	5,403	5,552
Reserves		74,791	71,489	63,587
BP shareholders' equity	44	79,976	76,892	69,139
Minority interest	44	789	1,343	1,125
Total equity	44	80,765	78,235	70,264

Peter Sutherland, Chairman
The Lord Browne of Madingley, Group Chief Executive

Group cash flow statement

For the year ended 31 December				$ million
	Note	2005	2004	2003
Operating activities				
Profit before taxation from continuing operations		31,921	24,966	17,731
Adjustments to reconcile profit before taxation to net cash provided by operating activities				
Exploration expenditure written off	18	305	274	297
Depreciation, depletion and amortization	11	8,771	8,529	8,076
Impairment and (gain) loss on sale of businesses and fixed assets	9,12	(1,070)	(295)	(94)
Earnings from jointly controlled entities and associates	7	(3,543)	(2,280)	(1,214)
Dividends received from jointly controlled entities and associates		2,833	2,199	548
Interest receivable		(479)	(284)	(212)
Interest received		401	331	186
Finance costs	20	616	440	513
Interest paid		(1,127)	(698)	(1,007)
Other finance expense	21	145	340	532
Share-based payments		278	224	208
Net operating charge for pensions and other post-retirement benefits, less contributions		(435)	(84)	(2,913)
Net charge for provisions, less payments		600	(110)	171
(Increase) decrease in inventories		(6,638)	(3,182)	(657)
(Increase) decrease in other current and non-current assets		(16,427)	(10,225)	(2,981)
Increase (decrease) in other current and non-current liabilities		18,628	10,290	1,575
Income taxes paid		(9,028)	(6,388)	(4,804)
Net cash provided by operating activities of continuing operations		25,751	24,047	15,955
Net cash provided by (used in) operating activities of Innovene operations	4	970	(669)	348
Net cash provided by operating activities		26,721	23,378	16,303
Investing activities				
Capital expenditures		(12,281)	(12,286)	(11,885)
Acquisitions, net of cash acquired		(60)	(1,503)	(211)
Investment in jointly controlled entities		(185)	(1,648)	(2,630)
Investment in associates		(619)	(942)	(987)
Proceeds from disposal of property, plant and equipment	5	2,803	4,236	6,177
Proceeds from disposal of businesses	5	8,397	725	179
Proceeds from loan repayments		123	87	76
Other		93	–	–
Net cash used in investing activities		(1,729)	(11,331)	(9,281)
Financing activities				
Net repurchase of shares		(11,315)	(7,208)	(1,889)
Proceeds from long-term financing		2,475	2,675	4,322
Repayments of long-term financing		(4,820)	(2,204)	(3,560)
Net increase (decrease) in short-term debt		(1,457)	(24)	(2)
Dividends paid				
BP shareholders	23	(7,359)	(6,041)	(5,654)
Minority interest		(827)	(33)	(20)
Net cash used in financing activities		(23,303)	(12,835)	(6,803)
Currency translation differences relating to cash and cash equivalents		(88)	91	121
Increase (decrease) in cash and cash equivalents		1,601	(697)	340
Cash and cash equivalents at beginning of year		1,359	2,056	1,716
Cash and cash equivalents at end of year		2,960	1,359	2,056

Group statement of recognized income and expense

For the year ended 31 December

	Note	2005	2004	2003
				$ million
Currency translation differences		(2,502)	2,283	3,656
Exchange gain on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets		(315)	(78)	–
Actuarial gain relating to pensions and other post-retirement benefits		975	107	76
Available-for-sale investments marked to market		322	–	–
Available-for-sale investments – recycled to the income statement		(60)	–	–
Cash flow hedges marked to market		(212)	–	–
Cash flow hedges – recycled to the income statement		36	–	–
Cash flow hedges – recycled to the balance sheet		–	–	–
Unrealized gain on acquisition of further investment in equity-accounted investments		–	94	–
Tax on currency translation differences		11	(208)	(37)
Tax on exchange gain on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets		95	–	–
Tax on actuarial gain (loss) relating to pensions and other post-retirement benefits		(356)	96	(16)
Tax on available-for-sale investments		(72)	–	–
Tax on cash flow hedges		63	–	–
Tax on share-based payment accrual		–	39	5
Net income recognized directly in equity		(2,015)	2,333	3,684
Profit for the year		22,632	17,262	12,618
Total recognized income and expense relating to the year		20,617	19,595	16,302
Change in accounting policy – adoption of IAS 32 and IAS 39 on 1 January 2005	50	(243)		
Total recognized income and expense since last annual accounts		20,374		
Attributable to				
BP shareholders		20,083	19,408	16,132
Minority interest		291	187	170
		20,374	19,595	16,302

Notes on financial statements

1 Resegmentation

With effect from 1 January 2005, there have been the following changes to the business segments reported by the group:

(a) The Mardi Gras pipeline system in the Gulf of Mexico has been transferred from Exploration and Production to Refining and Marketing.

(b) The aromatics and acetyls operations and the petrochemicals assets that are integrated with our Gelsenkirchen refinery in Germany have been transferred from the former Petrochemicals segment to Refining and Marketing.

(c) The olefins and derivatives operations have been transferred from the former Petrochemicals segment to the Olefins and Derivatives business. The legacy historical results of other petrochemicals assets that had been divested during 2004 and 2003 are included within Other businesses and corporate.

(d) The Grangemouth and Lavéra refineries have been transferred from Refining and Marketing to the Olefins and Derivatives business to maintain existing operating synergies with the co-located olefins and derivatives operations.

(e) A small US operation, the Hobbs fractionator, which supplies petrochemicals feedstock, has been transferred from Gas, Power and Renewables to the Olefins and Derivatives business.

The Olefins and Derivatives business is reported within Other businesses and corporate. This reorganization was a precursor to seeking to divest the Olefins and Derivatives business. As indicated in Note 4, Discontinued operations, during 2005 we divested Innovene and show its activities as discontinued operations in these accounts. Innovene represented the majority of the Olefins and Derivatives business.

Comparative financial and operating information is shown after resegmentation, the change in accounting policy and the adoption of International Financial Reporting Standards.

2 Change in accounting policy

The group's accounting policy has been to present oil, natural gas and power forward sales and purchases gross in the income statement. However, during 2005, a review was undertaken into the presentation of these commodity derivative transactions and related activity. These transactions have previously been presented gross in the income statement, although in certain areas of the group's activity, physical delivery can be optional and avoided by buying or selling offsetting contracts through a market mechanism. This led to the conclusion that it was more appropriate to represent transactions in these areas net rather than gross. These sale and purchase transactions are now offset and reported net in sales and other operating revenues. Other derivative contracts where physical delivery is the norm continue to be reported gross.

This change in accounting policy, while reducing sales and other operating revenues and purchases, has no impact on reported profit, cash flows and the balance sheet.

Sales and other operating revenues and purchases for prior periods have been restated as set out below. The impact of the change in accounting policy on sales and other operating revenues and purchases for the year ended 31 December 2005 was approximately $105,000 million.

$ million

Sales and other operating revenues									2004
By business – as reported	Exploration and Production	Refining and Marketing	Gas, Power and Renewables	Other businesses and corporate	Consolidation adjustment and eliminations	Total group	Innovene operations	Consolidation adjustment and eliminations	Total continuing operations
Segment revenues	34,700	192,917	83,320	17,994	(43,999)	284,932	(17,448)	6,169	273,653
Less: sales between businesses	(24,756)	(10,632)	(2,442)	(6,169)	43,999	–	6,169	(6,169)	–
Third party sales	9,944	182,285	80,878	11,825	–	284,932	(11,279)	–	273,653
By business – as restated									
Segment revenues	34,700	176,350	26,110	17,994	(43,999)	211,155	(17,448)	6,169	199,876
Less: sales between businesses	(24,756)	(10,632)	(2,442)	(6,169)	43,999	–	6,169	(6,169)	–
Third party sales	9,944	165,718	23,668	11,825	–	211,155	(11,279)	–	199,876

Sales and other operating revenues									2003
By business – as reported									
Segment revenues	30,621	159,263	65,639	13,978	(36,993)	232,508	(13,463)	4,501	223,546
Less: sales between businesses	(22,885)	(7,644)	(1,963)	(4,501)	36,993	–	4,501	(4,501)	–
Third party sales	7,736	151,619	63,676	9,477	–	232,508	(8,962)	–	223,546
By business – as restated									
Segment revenues	30,621	147,813	22,984	13,978	(36,993)	178,403	(13,463)	4,501	169,441
Less: sales between businesses	(22,885)	(7,644)	(1,963)	(4,501)	36,993	–	4,501	(4,501)	–
Third party sales	7,736	140,169	21,021	9,477	–	178,403	(8,962)	–	169,441

2 Change in accounting policy *continued*

$ million

Sales and other operating revenues					2004
By geographical area – as reported	UK	Rest of Europe	USA	Rest of World	Total
Segment revenues	81,155	54,570	130,652	67,777	334,154
Less: sales attributable to Innovene operations	(6,067)	(9,712)	(4,060)	(467)	(20,306)
Segment revenues from continuing operations	75,088	44,858	126,592	67,310	313,848
Less: sales between areas	(18,846)	(1,396)	(1,539)	(10,188)	(31,969)
Less: sales by continuing operations to Innovene	(5,263)	(896)	(2,064)	(3)	(8,226)
Third party sales of continuing operations	50,979	42,566	122,989	57,119	273,653
By geographical area – as restated					
Segment revenues	66,218	54,570	91,260	48,329	260,377
Less: sales attributable to Innovene operations	(6,067)	(9,712)	(4,060)	(467)	(20,306)
Segment revenues from continuing operations	60,151	44,858	87,200	47,862	240,071
Less: sales between areas	(18,846)	(1,396)	(1,539)	(10,188)	(31,969)
Less: sales by continuing operations to Innovene	(5,263)	(896)	(2,064)	(3)	(8,226)
Third party sales of continuing operations	36,042	42,566	83,597	37,671	199,876

Sales and other operating revenues					2003
By geographical area – as reported					
Segment revenues	54,971	50,703	108,910	52,314	266,898
Less: sales attributable to Innovene operations	(5,719)	(8,670)	(3,226)	(374)	(17,989)
Segment revenues from continuing operations	49,252	42,033	105,684	51,940	248,909
Less: sales between areas	(6,953)	(3,160)	(714)	(8,258)	(19,085)
Less: sales by continuing operations to Innovene	(3,947)	(876)	(1,455)	–	(6,278)
Third party sales of continuing operations	38,352	37,997	103,515	43,682	223,546
By geographical area – as restated					
Segment revenues	41,265	50,703	82,669	38,156	212,793
Less: sales attributable to Innovene operations	(5,719)	(8,670)	(3,226)	(374)	(17,989)
Segment revenues from continuing operations	35,546	42,033	79,443	37,782	194,804
Less: sales between areas	(6,953)	(3,160)	(714)	(8,258)	(19,085)
Less: sales by continuing operations to Innovene	(3,947)	(876)	(1,455)	–	(6,278)
Third party sales of continuing operations	24,646	37,997	77,274	29,524	169,441

$ million

Purchases		2004		2003
	Total group	Continuing operations	Total group	Continuing operations
As reported	217,614	209,684	176,160	170,083
As restated	143,837	135,907	122,055	115,978

3 Acquisitions

ACQUISITIONS IN 2005

BP made a number of minor acquisitions in 2005 for a total consideration of $84 million. All these business combinations were accounted for using the acquisition method of accounting. No significant fair value adjustments were made to the acquired assets and liabilities. Goodwill of $27 million arose on these acquisitions. There was also additional goodwill on the Solvay acquisition of $59 million *(see below)*.

ACQUISITIONS IN 2004

$ million

			2004
	Book value on acquisition	Fair value adjustments	Fair value
Property, plant and equipment	703	760	1,463
Intangible assets	15	–	15
Current assets (excluding cash)	721	–	721
Cash and cash equivalents	36	–	36
Trade and other payables	(329)	–	(329)
Deferred tax liabilities	–	(185)	(185)
Defined benefit pension plan deficits	(3)	–	(3)
Net investment in equity-accounted entities transferred to full consolidation	(547)	(94)	(641)
Net assets acquired	596	481	1,077
Goodwill			328
Consideration			1,405

On 2 November 2004, Solvay exercised its option to sell its interests in BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America to BP. Solvay held 50% of BP Solvay Polyethylene Europe and 51% of BP Solvay Polyethylene North America. On completion, the two entities, which manufacture and market high-density polyethylene, became wholly owned subsidiaries of BP. The total consideration for the acquisition was $1,391 million, subject to final closing adjustments. There were closing adjustments and selling costs in 2005 amounting to $59 million. These created additional goodwill of $59 million, which was written off. See Note 13, Impairment of goodwill, for further information. Other minor acquisitions were made for a total consideration of $14 million. All business combinations have been accounted for using the acquisition method of accounting. The fair value of the property, plant and equipment has been estimated by determining the net present value of future cash flows. No significant adjustments were made to the other assets and liabilities acquired. The assets and liabilities acquired as part of the 2004 acquisitions are shown in aggregate in the table above.

ACQUISITIONS IN 2003

BP made a number of minor acquisitions in 2003 for a total consideration of $232 million. All these business combinations were accounted for using the acquisition method of accounting. No significant fair value adjustments were made to the acquired assets and liabilities. Goodwill of $5 million arose on these acquisitions.

4 Discontinued operations

BP announced on 7 October 2005 its intention to sell Innovene, its olefins, derivatives and refining group, to INEOS. The transaction became unconditional on 9 December 2005 on receipt of European Commission clearance and was completed on 16 December 2005. The transaction included all Innovene's manufacturing sites, markets and technologies. The equity-accounted investments in China and Malaysia that were part of the Olefins and Derivatives business remain with BP and are included within Other businesses and corporate.

The Innovene operations represented a separate major line of business for BP. As a result of the sale, these operations have been treated as discontinued operations for the year ended 31 December 2005. A single amount is shown on the face of the income statement comprising the post-tax result of discontinued operations and the post-tax loss recognized on the remeasurement to fair value less costs to sell and on disposal of the discontinued operation. That is, the income and expenses of Innovene are reported separately from the continuing operations of the BP group. The table below provides further detail of the amount shown on the income statement. The income statements for prior periods have been restated to conform to this style of presentation.

In the cash flow statement, the cash provided by the operating activities of Innovene has been separated from that of the rest of the group and reported as a single line item.

Gross proceeds received amounted to $8,477 million. There were selling costs of $120 million and initial closing adjustments of $43 million. The proceeds are subject to final closing adjustments. The remeasurement to fair value less costs to sell resulted in a loss of $591 million before tax. The originally announced transaction value of $9,000 million has been reduced by the value of certain liabilities transferred to INEOS and certain assets retained by BP on closing.

Financial information for the Innovene operations after group eliminations is presented below.

$ million

	2005	2004	2003
Total revenues and other income	12,441	11,327	8,986
Expenses	11,709	12,041	9,034
Profit (loss) before interest and taxation	732	(714)	(48)
Other finance income (expense)	3	(17)	(15)
Profit (loss) before taxation and loss recognized on remeasurement to fair value less costs to sell and on disposal	735	(731)	(63)
Loss recognized on remeasurement to fair value less costs to sell and on disposal	(591)	–	–
Profit (loss) before taxation from Innovene operations	144	(731)	(63)
Tax (charge) credit			
On profit (loss) before loss recognized on remeasurement to fair value less costs to sell and on disposal	(306)	109	–
On loss recognized on remeasurement to fair value less costs to sell and on disposal	346	–	–
Profit (loss) from Innovene operations	184	(622)	(63)
Earnings (loss) per share from Innovene operations – cents			
Basic	0.87	(2.85)	(0.28)
Diluted	0.86	(2.79)	(0.28)
The cash flows of Innovene operations are presented below			
Net cash provided by (used in) operating activities	970	(669)	348
Net cash used in investing activities	(524)	(1,731)	(572)
Net cash provided by (used in) financing activities	(446)	2,400	224

Further information is contained in Note 5, Disposals.

5 Disposals

	2005	2004	2003
			$ million
Proceeds from the sale of Innovene operations	8,304	–	–
Proceeds from the sale of other businesses	93	725	179
Proceeds from the sale of businesses	8,397	725	179
Proceeds from the sale of property, plant and equipment	2,803	4,236	6,177
	11,200	4,961	6,356
Exploration and Production	1,416	914	4,801
Refining and Marketing	888	1,007	1,050
Gas, Power and Renewables	540	144	67
Other businesses and corporate	8,356	2,896	438
	11,200	4,961	6,356

As part of the strategy to upgrade the quality of its asset portfolio, the group has an active programme to dispose of non-strategic assets. In the normal course of business in any particular year, the group may sell interests in exploration and production properties, service stations and pipeline interests as well as non-core businesses.

Cash received during the year from disposals amounted to $11.2 billion (2004 $5.0 billion and 2003 $6.4 billion). The divestment of Innovene contributed $8.3 billion to this total. The major transactions in 2004 that generated over $2.3 billion of proceeds were the sale of the group's investments in PetroChina and Sinopec. For 2003, the major disposals representing over $3.0 billion of the proceeds were the divestment of a further 20% interest in BP Trinidad and Tobago LLC, the sale of 50% of our interest in the In Amenas gas condensate project and 49% of our interest in the In Salah gas development in Algeria, and the sale of the UK North Sea Forties oil field, together with a package of 61 shallow-water assets in the Gulf of Mexico. The principal transactions generating the proceeds for each segment are described below.

Exploration and Production The group divested interests in a number of oil and natural gas properties in all three years. During 2005, the major transaction was the sale of the group's interest in the Ormen Lange field in Norway. In addition, the group sold interests in oil and natural gas properties in Venezuela, Canada and the Gulf of Mexico. In 2004, in the US we sold 45% of our interest in King's Peak in the deepwater Gulf of Mexico to Marubeni Oil & Gas, divested our interest in Swordfish, and additionally sold various properties, including our interest in the South Pass 60 property in the Gulf of Mexico Shelf. In Canada, BP sold various assets in Alberta to Fairborne Energy. In Indonesia, we disposed of our interest in the Kangean Production Sharing Contract and our participating interest in the Muriah Production Sharing Contract. In 2003, the UK North Sea Forties oil field, together with a package of 61 shallow-water assets in the Gulf of Mexico, were sold to Apache. A 12.5% interest in the Tangguh liquefied natural gas project in Indonesia was sold to CNOOC. Interests in 14 UK Southern North Sea gas fields, together with associated pipelines and onshore processing facilities, including the Bacton terminal, were sold to Perenco. BP sold 50% of its interest in the In Amenas gas condensate project and 49% of its interest in the In Salah gas development in Algeria to Statoil. In January 2003, Repsol exercised its option to acquire a further 20% interest in BP Trinidad and Tobago LLC. BP's interest in the company is now 70%. In February 2003, BP called its $420 million exchangeable bonds, which were exchangeable for Lukoil American Depositary Shares (ADSs). Bondholders converted to ADSs before the redemption date.

Refining and Marketing The churn of retail assets represents a significant element of the total in all three years. During 2005, the group sold a number of regional retail networks in the US and in addition its retail network in Malaysia. During 2004, major asset transactions included the sale of the Singapore refinery, the divestment of the European speciality intermediate chemicals business and the Cushing and other pipeline interests in the US. As a condition of the approval of the acquisition of Veba in 2002, BP was, among other things, required to divest approximately 4% of its retail market share in Germany and a significant portion of its Bayernoil refining interests. The sale of 494 retail sites in the northern and north-eastern part of Germany to PKN Orlen and the sale of retail and refinery assets in Germany and central Europe to OMV in 2003 completed the divestments required.

Gas, Power and Renewables In 2005, the group sold its interest in the Interconnector pipeline. During 2004, the group sold its interest in two Canadian natural gas liquids plants.

Other businesses and corporate 2005 includes the proceeds from the sale of Innovene. The disposal of the group's investments in PetroChina and Sinopec were the major transactions in 2004. In addition, the group sold its US speciality intermediate chemicals and fabrics and fibres businesses. In 2003, the group sold its 50% interest in Kaltim Prima Coal, an Indonesian company, and completed the divestment of the former Burmah Castrol speciality chemicals business Sericol and Fosroc Mining.

Summarized financial information for the sale of businesses is shown below.

	2005	2004	2003
			$ million
The disposals comprise the following			
Non-current assets	6,452	1,046	104
Other current assets	4,779	477	111
Non-current liabilities	(364)	(44)	(7)
Other current liabilities	(2,488)	(59)	(1)
	8,379	1,420	207
Profit (loss) on sale of businesses	18	(695)	(28)
Total consideration and net cash inflow	8,397	725	179

6 Segmental analysis

The group's primary format for segment reporting is business segments and the secondary format is geographical segments. The risks and returns of the group's operations are primarily determined by the nature of the different activities that the group engages in, rather than the geographical location of these operations. This is reflected by the group's organizational structure and the group's internal financial reporting systems.

BP has three reportable operating segments: Exploration and Production; Refining and Marketing; and Gas, Power and Renewables. Exploration and Production's activities include oil and natural gas exploration and field development and production, together with pipeline transportation and natural gas processing. The activities of Refining and Marketing include oil supply and trading as well as refining and petrochemicals manufacturing and marketing. Gas, Power and Renewables activities include marketing and trading of natural gas, natural gas liquids, new market development, liquefied natural gas (LNG) and solar and renewables. The group is managed on an integrated basis.

The accounting policies of operating segments are the same as those described under the heading Accounting policies.

Sales between segments are made at prices that approximate market prices, taking into account the volumes involved. Segment revenue, segment expense and segment result include transactions between business segments. These transactions and any unrealized profits and losses are eliminated on consolidation.

The group's geographical segments are based on the location of the group's assets. The UK and US are significant countries of activity for the group; the other geographical segments are determined by geographical location.

Sales to external customers are based on the location of the seller, which in most circumstances is not materially different from the location of the customer. Crude oil and LNG are commodities for which there is an international market and buyers and sellers can be widely separated geographically. The UK segment includes the UK-based international activities of Refining and Marketing.

$ million

									2005
By business	Exploration and Production	Refining and Marketing	Gas, Power and Renewables	Other businesses and corporate	Consolidation adjustment and eliminations	Total group	Innovene operations	Consolidation adjustment and eliminations[a]	Total continuing operations
SALES AND OTHER OPERATING REVENUES									
Segment revenues	47,210	220,134	28,561	21,295	(55,359)	261,841	(20,627)	8,251	249,465
Less: sales between businesses	(32,606)	(11,407)	(3,095)	(8,251)	55,359	–	8,251	(8,251)	–
Third party sales	14,604	208,727	25,466	13,044	–	261,841	(12,376)	–	249,465
RESULTS									
Profit (loss) before interest and tax	25,508	6,942	1,104	(523)	(208)	32,823	(668)	527	32,682
Finance costs and other finance expense	–	–	–	–	(758)	(758)	(3)	–	(761)
Profit (loss) before taxation	25,508	6,942	1,104	(523)	(966)	32,065	(671)	527	31,921
Taxation	–	–	–	–	(9,433)	(9,433)	133	(173)	(9,473)
Profit (loss) for the year	25,508	6,942	1,104	(523)	(10,399)	22,632	(538)	354	22,448
Includes									
Equity-accounted income	3,238	238	19	34	–	3,529	14	–	3,543
ASSETS AND LIABILITIES									
Segment assets	93,479	77,352	28,441	12,756	(5,326)	206,702			
Tax receivable	–	–	–	–	212	212			
Total assets	93,479	77,352	28,441	12,756	(5,114)	206,914			
Includes									
Equity-accounted investments	14,657	4,012	483	621	–	19,773			
Segment liabilities	(20,387)	(31,727)	(23,346)	(15,358)	4,548	(86,270)			
Current tax payable	–	–	–	–	(4,274)	(4,274)			
Finance debt	–	–	–	–	(19,162)	(19,162)			
Deferred tax liabilities	–	–	–	–	(16,443)	(16,443)			
Total liabilities	(20,387)	(31,727)	(23,346)	(15,358)	(35,331)	(126,149)			
OTHER SEGMENT INFORMATION									
Capital expenditure									
Intangible assets	989	451	31	10	–	1,481			
Property, plant and equipment	8,751	2,036	199	779	–	11,765			
Other	497	285	5	116	–	903			
Total	10,237	2,772	235	905	–	14,149			
Depreciation, depletion and amortization	6,033	2,392	225	533	–	9,183	(412)	–	8,771
Impairment	266	93	–	59	–	418	(59)	–	359
Loss on remeasurement to fair value less costs to sell and on disposal of Innovene operations	–	–	–	591	–	591	(591)	–	–
Losses on sale of businesses and fixed assets	39	64	–	6	–	109	–	–	109
Gains on sale of businesses and fixed assets	1,198	241	55	47	–	1,541	(3)	–	1,538

6 Segmental analysis *continued*

$ million

									2004
By business	Exploration and Production	Refining and Marketing	Gas, Power and Renewables	Other businesses and corporate	Consolidation adjustment and eliminations	Total group	Innovene operations	Consolidation adjustment and eliminations[a]	Total continuing operations
SALES AND OTHER OPERATING REVENUES									
Segment revenues	34,700	176,350	26,110	17,994	(43,999)	211,155	(17,448)	6,169	199,876
Less: sales between businesses	(24,756)	(10,632)	(2,442)	(6,169)	43,999	–	6,169	(6,169)	–
Third party sales	9,944	165,718	23,668	11,825	–	211,155	(11,279)	–	199,876
RESULTS									
Profit (loss) before interest and tax	18,087	6,544	954	(362)	(191)	25,032	526	188	25,746
Finance costs and other finance expense	–	–	–	–	(797)	(797)	17	–	(780)
Profit (loss) before taxation	18,087	6,544	954	(362)	(988)	24,235	543	188	24,966
Taxation	–	–	–	–	(6,973)	(6,973)	(53)	(56)	(7,082)
Profit (loss) for the year	18,087	6,544	954	(362)	(7,961)	17,262	490	132	17,884
Includes									
Equity-accounted income	1,985	259	6	18	–	2,268	12	–	2,280
ASSETS AND LIABILITIES									
Segment assets	85,808	73,581	17,257	22,292	(4,467)	194,471			
Tax receivable	–	–	–	–	159	159			
Total assets	85,808	73,581	17,257	22,292	(4,308)	194,630			
Includes									
Equity-accounted investments	14,327	4,486	573	656	–	20,042			
Segment liabilities	(16,214)	(28,903)	(12,384)	(18,886)	3,915	(72,472)			
Current tax payable	–	–	–	–	(4,131)	(4,131)			
Finance debt	–	–	–	–	(23,091)	(23,091)			
Deferred tax liabilities	–	–	–	–	(16,701)	(16,701)			
Total liabilities	(16,214)	(28,903)	(12,384)	(18,886)	(40,008)	(116,395)			
OTHER SEGMENT INFORMATION									
Capital expenditure									
Intangible assets	406	670	25	5	–	1,106			
Property, plant and equipment	8,696	1,960	328	690	–	11,674			
Other	1,906	189	171	1,605	–	3,871			
Total	11,008	2,819	524	2,300	–	16,651			
Depreciation, depletion and amortization	5,583	2,540	210	679	–	9,012	(483)	–	8,529
Impairment	404	195	–	891	–	1,490	(879)	–	611
Losses on sale of businesses and fixed assets	227	371	–	416	–	1,014	(235)	–	779
Gains on sale of businesses and fixed assets	162	104	56	1,365	–	1,687	(2)	–	1,685

[a] In the circumstances of discontinued operations, International Accounting Standards 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 is supplied by BP and most of the refined products manufactured are 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. Neither does this representation indicate the profits earned by continuing or Innovene operations, as if they were standalone entities, for past periods or likely to be earned in future periods.

6 Segmental analysis *continued*

$ million

2003

By business	Exploration and Production	Refining and Marketing	Gas, Power and Renewables	Other businesses and corporate	Consolidation adjustment and eliminations	Total group	Innovene operations	Consolidation adjustment and eliminations[a]	Total continuing operations
SALES AND OTHER OPERATING REVENUES									
Segment revenues	30,621	147,813	22,984	13,978	(36,993)	178,403	(13,463)	4,501	169,441
Less: sales between businesses	(22,885)	(7,644)	(1,963)	(4,501)	36,993	–	4,501	(4,501)	–
Third party sales	7,736	140,169	21,021	9,477	–	178,403	(8,962)	–	169,441
RESULTS									
Profit (loss) before interest and tax	15,084	3,235	578	(108)	(61)	18,728	(145)	193	18,776
Finance costs and other finance expense	–	–	–	–	(1,060)	(1,060)	15	–	(1,045)
Profit (loss) before taxation	15,084	3,235	578	(108)	(1,121)	17,668	(130)	193	17,731
Taxation	–	–	–	–	(5,050)	(5,050)	54	(54)	(5,050)
Profit (loss) for the year	15,084	3,235	578	(108)	(6,171)	12,618	(76)	139	12,681
Includes									
Equity-accounted income	949	241	(5)	14	–	1,199	15	–	1,214
ASSETS AND LIABILITIES									
Segment assets	79,446	73,397	10,859	11,002	(2,305)	172,399			
Tax receivable	–	–	–	–	92	92			
Total assets	79,446	73,397	10,859	11,002	(2,213)	172,491			
Includes									
Equity-accounted investments	12,897	3,764	362	754	–	17,777			
Segment liabilities	(15,723)	(32,999)	(6,584)	(7,048)	1,944	(60,410)			
Current tax payable	–	–	–	–	(3,441)	(3,441)			
Finance debt	–	–	–	–	(22,325)	(22,325)			
Deferred tax liabilities	–	–	–	–	(16,051)	(16,051)			
Total liabilities	(15,723)	(32,999)	(6,584)	(7,048)	(39,873)	(102,227)			
OTHER SEGMENT INFORMATION									
Capital expenditure									
Intangible assets	566	131	18	–	–	715			
Property, plant and equipment	8,390	2,750	243	266	–	11,649			
Other	6,236	138	178	707	–	7,259			
Total	15,192	3,019	439	973	–	19,623			
Depreciation, depletion and amortization	5,539	2,198	160	708	–	8,605	(529)	–	8,076
Impairment	1,013	–	–	–	–	1,013	–	–	1,013
Losses on sale of businesses and fixed assets	403	318	17	50	–	788	–	–	788
Gains on sale of businesses and fixed assets	1,591	104	11	189	–	1,895	–	–	1,895

[a] In the circumstances of discontinued operations, International Accounting Standards 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 is supplied by BP and most of the refined products manufactured are 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. Neither does this representation indicate the profits earned by continuing or Innovene operations, as if they were standalone entities, for past periods or likely to be earned in future periods.

6 Segmental analysis *continued*

$ million

By geographical area	UK	Rest of Europe	USA	Rest of World	Consolidation adjustment and eliminations	Total
						2005
SALES AND OTHER OPERATING REVENUES						
Segment revenues	98,744	72,972	107,494	60,314	–	339,524
Less: sales attributable to Innovene operations	(2,610)	(8,667)	(4,309)	(686)	–	(16,272)
Segment revenues from continuing operations	96,134	64,305	103,185	59,628	–	323,252
Less: sales between areas	(38,081)	(5,013)	(2,362)	(16,541)	–	(61,997)
Less: sales by continuing operations to Innovene	(5,599)	(4,640)	(1,508)	(43)	–	(11,790)
Third party sales of continuing operations	52,454	54,652	99,315	43,044	–	249,465
RESULTS						
Profit (loss) before interest and tax from continuing operations	1,167	5,206	13,139	13,170	–	32,682
Finance costs and other finance expense	(80)	(268)	(366)	(47)	–	(761)
Profit before taxation from continuing operations	1,087	4,938	12,773	13,123	–	31,921
Taxation	(289)	(1,646)	(3,983)	(3,555)	–	(9,473)
Profit for the year from continuing operations	798	3,292	8,790	9,568	–	22,448
Profit (loss) from Innovene operations	234	109	(165)	6	–	184
Profit for the year	1,032	3,401	8,625	9,574	–	22,632
Includes						
Equity-accounted income	(8)	18	86	3,447	–	3,543
ASSETS AND LIABILITIES						
Segment assets	44,007	26,560	79,838	64,129	(7,832)	206,702
Tax receivable	2	158	6	46	–	212
Total assets	44,009	26,718	79,844	64,175	(7,832)	206,914
Includes						
Equity-accounted investments	74	1,496	1,420	16,783	–	19,773
Segment liabilities	(25,079)	(16,824)	(33,646)	(18,553)	7,832	(86,270)
Current tax payable	(798)	(1,057)	(678)	(1,741)	–	(4,274)
Finance debt	(9,706)	(433)	(6,159)	(2,864)	–	(19,162)
Deferred tax liabilities	(2,223)	(936)	(9,585)	(3,699)	–	(16,443)
Total liabilities	(37,806)	(19,250)	(50,068)	(26,857)	7,832	(126,149)
OTHER SEGMENT INFORMATION						
Capital expenditure						
Intangible assets	205	43	579	654	–	1,481
Property, plant and equipment	1,340	919	4,804	4,702	–	11,765
Other	53	18	86	746	–	903
Total	1,598	980	5,469	6,102	–	14,149
Depreciation, depletion and amortization	2,080	932	3,685	2,074	–	8,771
Exploration expense	32	2	425	225	–	684
Impairment	53	7	238	61	–	359
Loss on remeasurement to fair value less costs to sell and on disposal of Innovene operations	24	273	262	32	–	591
Losses on sale of businesses and fixed assets	–	37	8	64	–	109
Gains on sale of businesses and fixed assets	107	1,017	282	132	–	1,538

6 Segmental analysis *continued*

$ million

By geographical area	UK	Rest of Europe	USA	Rest of World	Consolidation adjustment and eliminations	Total
						2004
SALES AND OTHER OPERATING REVENUES						
Segment revenues	62,516	52,540	91,309	48,534	–	254,899
Less: sales attributable to Innovene operations	(2,365)	(7,682)	(4,109)	(672)	–	(14,828)
Segment revenues from continuing operations	60,151	44,858	87,200	47,862	–	240,071
Less: sales between areas	(18,846)	(1,396)	(1,539)	(10,188)	–	(31,969)
Less: sales by continuing operations to Innovene	(5,263)	(896)	(2,064)	(3)	–	(8,226)
Third party sales of continuing operations	36,042	42,566	83,597	37,671	–	199,876
RESULTS						
Profit (loss) before interest and tax from continuing operations	2,875	3,121	9,725	10,025	–	25,746
Finance costs and other finance expense	155	(261)	(513)	(161)	–	(780)
Profit before taxation from continuing operations	3,030	2,860	9,212	9,864	–	24,966
Taxation	(1,745)	(779)	(2,596)	(1,962)	–	(7,082)
Profit for the year from continuing operations	1,285	2,081	6,616	7,902	–	17,884
Profit (loss) from Innovene operations	(327)	(110)	(96)	(89)	–	(622)
Profit for the year	958	1,971	6,520	7,813	–	17,262
Includes						
Equity-accounted income	9	17	92	2,162	–	2,280
ASSETS AND LIABILITIES						
Segment assets	42,073	31,437	71,272	56,464	(6,775)	194,471
Tax receivable	–	135	–	24	–	159
Total assets	42,073	31,572	71,272	56,488	(6,775)	194,630
Includes						
Equity-accounted investments	338	1,951	1,556	16,197	–	20,042
Segment liabilities	(18,031)	(18,049)	(27,124)	(16,043)	6,775	(72,472)
Current tax payable	(1,588)	(712)	(651)	(1,180)	–	(4,131)
Finance debt	(13,237)	(455)	(6,360)	(3,039)	–	(23,091)
Deferred tax liabilities	(3,177)	(1,242)	(9,011)	(3,271)	–	(16,701)
Total liabilities	(36,033)	(20,458)	(43,146)	(23,533)	6,775	(116,395)
OTHER SEGMENT INFORMATION						
Capital expenditure						
Intangible assets	170	4	404	528	–	1,106
Property, plant and equipment	1,480	1,079	4,959	4,156	–	11,674
Other	92	814	642	2,323	–	3,871
Total	1,742	1,897	6,005	7,007	–	16,651
Depreciation, depletion and amortization	2,030	930	3,906	1,663	–	8,529
Exploration expense	26	25	361	225	–	637
Impairment	–	–	570	41	–	611
Losses on sale of businesses and fixed assets	282	–	177	320	–	779
Gains on sale of businesses and fixed assets	–	–	133	1,552	–	1,685

6 Segmental analysis *continued*

$ million

By geographical area	UK	Rest of Europe	USA	Rest of World	Consolidation adjustment and eliminations	Total
						2003
SALES AND OTHER OPERATING REVENUES						
Segment revenues	37,425	48,138	82,708	38,316	–	206,587
Less: sales attributable to Innovene operations	(1,879)	(6,105)	(3,265)	(534)	–	(11,783)
Segment revenues from continuing operations	35,546	42,033	79,443	37,782	–	194,804
Less: sales between areas	(6,953)	(3,160)	(714)	(8,258)	–	(19,085)
Less: sales by continuing operations to Innovene	(3,947)	(876)	(1,455)	–	–	(6,278)
Third party sales of continuing operations	24,646	37,997	77,274	29,524	–	169,441
RESULTS						
Profit (loss) before interest and tax from continuing operations	3,348	1,819	7,008	6,601	–	18,776
Finance costs and other finance expense	52	(258)	(737)	(102)	–	(1,045)
Profit before taxation from continuing operations	3,400	1,561	6,271	6,499	–	17,731
Taxation	(1,287)	(725)	(1,548)	(1,490)	–	(5,050)
Profit for the year from continuing operations	2,113	836	4,723	5,009	–	12,681
Profit (loss) from Innovene operations	(150)	166	(83)	4	–	(63)
Profit for the year	1,963	1,002	4,640	5,013	–	12,618
Includes						
Equity-accounted income	11	39	99	1,065	–	1,214
ASSETS AND LIABILITIES						
Segment assets	36,282	27,155	64,414	48,835	(4,287)	172,399
Tax receivable	–	84	–	8	–	92
Total assets	36,282	27,239	64,414	48,843	(4,287)	172,491
Includes						
Equity-accounted investments	188	2,052	2,146	13,391		17,777
Segment liabilities	(15,569)	(16,162)	(20,060)	(12,906)	4,287	(60,410)
Current tax payable	(1,057)	(522)	(494)	(1,368)	–	(3,441)
Finance debt	(11,804)	(393)	(7,295)	(2,833)	–	(22,325)
Deferred tax liabilities	(2,973)	(1,017)	(8,636)	(3,425)	–	(16,051)
Total liabilities	(31,403)	(18,094)	(36,485)	(20,532)	4,287	(102,227)
OTHER SEGMENT INFORMATION						
Capital expenditure						
Intangible assets	1	77	289	348	–	715
Property, plant and equipment	1,528	1,157	5,302	3,662	–	11,649
Other	–	12	376	6,871	–	7,259
Total	1,529	1,246	5,967	10,881	–	19,623
Depreciation, depletion and amortization	1,952	819	3,937	1,368	–	8,076
Exploration expense	17	37	204	284	–	542
Impairment	183	–	343	487	–	1,013
Losses on sale of businesses and fixed assets	213	410	72	93	–	788
Gains on sale of businesses and fixed assets	931	259	–	705	–	1,895

7 Earnings from jointly controlled entities and associates

$ million

	Profit (loss) before interest and tax	Interest	Tax	Minority interest	Profit (loss) for the year
					2005
By business					
Exploration and Production	4,819	227	1,250	104	3,238
Refining and Marketing	343	24	81	–	238
Gas, Power and Renewables	34	7	8	–	19
Other businesses and corporate	65	31	–	–	34
	5,261	289	1,339	104	3,529
Innovene operations	14	–	–	–	14
Continuing operations	5,275	289	1,339	104	3,543
Earnings from jointly controlled entities	4,615	232	1,196	104	3,083
Earnings from associates	660	57	143	–	460
	5,275	289	1,339	104	3,543

7 Earnings from jointly controlled entities and associates *continued*

$ million

2004	Profit (loss) before interest and tax	Interest	Tax	Minority interest	Profit (loss) for the year
By business					
Exploration and Production	3,246	189	1,029	43	1,985
Refining and Marketing	357	15	83	–	259
Gas, Power and Renewables	15	7	2	–	6
Other businesses and corporate	21	7	(4)	–	18
	3,639	218	1,110	43	2,268
Innovene operations	9	(3)	–	–	12
Continuing operations	3,648	215	1,110	43	2,280
Earnings from jointly controlled entities	3,017	167	989	43	1,818
Earnings from associates	631	48	121	–	462
	3,648	215	1,110	43	2,280

$ million

2003	Profit (loss) before interest and tax	Interest	Tax	Minority interest	Profit (loss) for the year
By business					
Exploration and Production	1,222	120	153	–	949
Refining and Marketing	275	17	17	–	241
Gas, Power and Renewables	(3)	2	–	–	(5)
Other businesses and corporate	29	5	10	–	14
	1,523	144	180	–	1,199
Innovene operations	15	–	–	–	15
Continuing operations	1,538	144	180	–	1,214
Earnings from jointly controlled entities	1,028	102	100	–	826
Earnings from associates	510	42	80	–	388
	1,538	144	180	–	1,214

8 Interest and other revenues

$ million

	2005	2004	2003
Dividends	52	37	36
Interest from loans and other investments	73	34	121
Other interest	324	244	184
Miscellaneous income	240	358	444
	689	673	785
Innovene operations	(76)	(58)	(39)
Continuing operations	613	615	746

9 Gains on sale of businesses and fixed assets

$ million

	2005	2004	2003
Gains on sale of businesses			
Refining and Marketing	18	–	–
	18	–	–
Gains on sale of fixed assets			
Exploration and Production	1,198	162	1,591
Refining and Marketing	223	104	104
Gas, Power and Renewables	55	56	11
Other businesses and corporate	47	1,365	189
	1,523	1,687	1,895
	1,541	1,687	1,895
Innovene operations	(3)	(2)	–
Continuing operations	1,538	1,685	1,895

9 Gains on sale of businesses and fixed assets *continued*

The principal transactions giving rise to these gains for each segment are described below.

GAINS ON SALE OF FIXED ASSETS

Exploration and Production The group divested interests in a number of oil and natural gas properties in all three years. The major divestment during 2005 was the sale of the group's interest in the Ormen Lange field in Norway. BP also sold various oil and gas properties in Trinidad & Tobago, Canada and the Gulf of Mexico. For 2004, divestments included interests in oil and natural gas properties in Australia, Canada and the Gulf of Mexico. In 2003, transactions included the divestment of a further 20% interest in BP Trinidad and Tobago LLC to Repsol, the sale of the group's 96.14% interest in the Forties oil field in the UK North Sea, the sale of a package of UK Southern North Sea gas fields and the divestment of our interest in the In Amenas gas condensate project in Algeria to Statoil.

Refining and Marketing During 2005, the group divested a number of regional retail networks in the US. For 2004, divestments included the sale of the Cushing and other pipeline interests in the US and the churn of retail assets. In 2003, disposals included the sale of pipeline interests in the US.

Gas, Power and Renewables In 2005, transactions included the disposal of the group's interest in the Interconnector pipeline. During 2004, the group divested its interest in two natural gas liquids plants in Canada.

Other businesses and corporate For 2004, the major disposals were the divestment of the group's investments in PetroChina and Sinopec. In 2003, the group sold its 50% interest in Kaltim Prima Coal, an Indonesian company, its interest in AG International Chemical Company, a purified isophthalic acid associate in Japan, and certain other investments.

Additional information on the sale of businesses and fixed assets is given in Note 5, Disposals.

10 Production and similar taxes

$ million

	2005	2004	2003
UK	495	335	300
Overseas	2,515	1,814	1,423
Continuing operations	3,010	2,149	1,723

11 Depreciation, depletion and amortization

$ million

By business	2005	2004	2003
Exploration and Production			
UK	1,663	1,642	1,612
Rest of Europe	228	184	168
USA	2,426	2,407	2,627
Rest of World	1,716	1,350	1,132
	6,033	5,583	5,539
Refining and Marketing			
UK[a]	316	318	252
Rest of Europe	687	645	606
USA	1,092	1,246	1,063
Rest of World	297	331	277
	2,392	2,540	2,198
Gas, Power and Renewables			
UK	47	37	34
Rest of Europe	20	24	22
USA	99	80	69
Rest of World	59	69	35
	225	210	160
Other businesses and corporate			
UK	203	251	294
Rest of Europe	130	204	166
USA	187	199	205
Rest of World	13	25	43
	533	679	708
By geographical area			
UK[a]	2,229	2,248	2,192
Rest of Europe	1,065	1,057	962
USA	3,804	3,932	3,964
Rest of World	2,085	1,775	1,487
	9,183	9,012	8,605
Innovene operations	(412)	(483)	(529)
Continuing operations	8,771	8,529	8,076

[a] UK area includes the UK-based international activities of Refining and Marketing.

12 Impairment and losses on sale of businesses and fixed assets

$ million

	2005	2004	2003
Impairment			
Exploration and Production	266	404	1,013
Refining and Marketing	93	195	–
Other businesses and corporate	59	891	–
	418	1,490	1,013
Loss on sale of businesses or termination of operations			
Refining and Marketing	–	279	28
Other businesses and corporate	–	416	–
	–	695	28
Loss on sale of fixed assets			
Exploration and Production	39	227	403
Refining and Marketing	64	92	290
Gas, Power and Renewables	–	–	17
Other businesses and corporate	6	–	50
	109	319	760
Loss on remeasurement to fair value less costs to sell and on disposal of Innovene operations	591	–	–
	1,118	2,504	1,801
Innovene operations	(650)	(1,114)	–
Continuing operations	468	1,390	1,801

IMPAIRMENT

In assessing whether a write-down is required in the carrying value of a potentially impaired asset, its carrying value is compared with its recoverable amount. The recoverable amount is the higher of the asset's fair value less costs to sell and value in use. Given the nature of the group's activities, information on the fair value of an asset is usually difficult to obtain unless negotiations with potential purchasers are taking place. Consequently, unless indicated otherwise, the recoverable amount used in assessing the impairment charges described below is value in use. The group generally estimates value in use using a discounted cash flow model. The future cash flows are usually adjusted for risks specific to the asset and discounted using a pre-tax discount rate of 10% (2004 9% and 2003 9%). This discount rate is derived from the group's post-tax weighted average cost of capital. A different pre-tax discount rate is used where the local tax rate is significantly different from the UK or US corporate tax rates.

Exploration and Production During 2005, Exploration and Production recognized total charges of $266 million for impairment in respect of producing oil and gas properties. The major element of this was a charge of $226 million relating to fields in the Shelf and Coastal areas of the Gulf of Mexico. The triggers for the impairment tests were primarily the effect of Hurricane Rita, which extensively damaged certain offshore and onshore production facilities, leading to repair costs and higher estimates of the eventual cost of decommissioning the production facilities and, in addition, reduced estimates of the quantities of hydrocarbons recoverable from some of these fields. The recoverable amount was based on management's estimate of fair value less costs to sell consistent with recent transactions in the area. The remainder related to fields in the UK North Sea, which were tested for impairment following a review of the economic performance of these assets. During 2004, as a result of impairment triggers, reviews were conducted that have resulted in impairment charges of $83 million in respect of King's Peak in the Gulf of Mexico, $20 million in respect of two fields in the Gulf of Mexico Shelf Matagorda Island area and $184 million in respect of various US onshore fields. A charge of $88 million was reflected in respect of a gas processing plant in the US and a charge of $60 million following the blow-out of the Temsah platform in Egypt. In addition, following the lapse of the sale agreement for oil and gas properties in Venezuela, $31 million of the previously booked impairment charge was released. The 2003 charge for impairment includes a charge of $296 million for four fields in the Gulf of Mexico, following technical reassessment and re-evaluation of future investment options; charges of $133 million and $49 million respectively for the Miller and Viscount fields in the UK North Sea as a result of a decision not to proceed with waterflood and gas import options and a reserve write-down respectively; a charge of $105 million for the Yacheng field in China; a charge of $108 million for the Kepadong field in Indonesia; and $47 million for the Eugene Island/West Cameron fields in the US as a result of reserve write-downs following completion of our routine full technical reviews. In addition, there were impairment charges of $217 million and $58 million for oil and gas properties in Venezuela and Canada respectively, based on fair value less costs to sell for transactions expected to complete in early 2004.

Refining and Marketing During 2005, certain retail assets were written down to fair value less costs to sell. With the formation of Olefins and Derivatives at the end of 2004, certain agreements and assets were restructured to reflect the arm's-length relationship that would exist in the future. This has resulted in an impairment of the petrochemicals facilities at Hull, UK.

Other businesses and corporate The impairment charge for 2005 relates to the write-off of additional goodwill on the Solvay transactions. In 2004, in connection with the Solvay transactions, the group recognized impairment charges of $325 million for goodwill and $270 million for property, plant and equipment in BP Solvay Polyethylene Europe. As part of a restructuring of the North American Olefins and Derivatives businesses, decisions were taken to exit certain businesses and facilities, resulting in impairments and write-downs of $294 million.

LOSS ON SALE OF BUSINESSES OR TERMINATION OF OPERATIONS

The principal transactions that give rise to these losses for each segment are described below.

Refining and Marketing In 2004, activities included the closure of two manufacturing plants at Hull, UK, which produced acids; the sale of the European speciality intermediate chemicals business; and the closure of the lubricants operation of the Coryton refinery in the UK and of refining operations at the ATAS refinery in Mersin, Turkey. For 2003, divestments included the sale of the group's European oil speciality products business.

Other businesses and corporate For 2004, activities included the sale of the US speciality intermediate chemicals business; the sale of the fabrics and fibres business; and the closure of the linear alpha-olefins production facility at Pasadena, Texas.

LOSS ON SALE OF FIXED ASSETS

The principal transactions that give rise to these losses for each segment are described below.

Exploration and Production The group divested interests in a number of oil and natural gas properties in all three years. For 2004, this included interests in oil and natural gas properties in Indonesia and the Gulf of Mexico. In 2003, this included losses on exploration and production properties in China, Norway and the US.

Refining and Marketing For 2004, the principal transactions contributing to the loss were divestment of the Singapore refinery and retail churn. For 2003, loss arose from retail churn and the sale of refinery and retail interests in Germany and central Europe.

13 Impairment of goodwill

	2005	2004	2003
			$ million
Exploration and Production	4,371	4,371	4,371
Refining and Marketing	5,955	6,418	6,151
Gas, Power and Renewables	45	43	49
Other businesses and corporate	–	25	21
Goodwill as at 31 December	10,371	10,857	10,592

Goodwill acquired through business combinations has been allocated first to segments and then down to the next level of cash-generating unit that is expected to benefit from the synergies of the acquisition. For Exploration and Production, goodwill has been allocated to each geographic region, that is UK, Rest of Europe, US and Rest of World, and for Refining and Marketing, goodwill has been allocated to strategic performance units (SPUs), namely Refining, Retail, Lubricants, Aromatics and Acetyls and Business Marketing.

In assessing whether goodwill has been impaired, the carrying amount of the cash-generating unit (including goodwill) is compared with the recoverable amount of the cash-generating unit. The recoverable amount is the higher of fair value less costs to sell and value in use. In the absence of any information about the fair value of a cash-generating unit, the recoverable amount is deemed to be the value in use.

The group generally estimates value in use using a discounted cash flow model. The future cash flows are usually adjusted for risks specific to the asset and discounted using a pre-tax discount rate of 10% (2004 9% and 2003 9%). This discount rate is derived from the group's post-tax weighted average cost of capital. A different pre-tax discount rate is used where the local tax rate is significantly different from the UK or US corporate tax rates.

The five-year group plan, which is approved on an annual basis by senior management, is the source for information for the determination of the various values in use. It contains implicit forecasts for oil and natural gas production, refinery throughputs, sales volumes for various types of refined products (e.g. gasoline and lubricants), revenues, costs and capital expenditure. As an initial step to the preparation of this plan, various environmental assumptions, such as oil prices, natural gas prices, refining margins, refined product margins and cost inflation rates, are set by senior management. These environmental assumptions take account of existing prices, global supply-demand equilibrium for oil and natural gas, other macroeconomic factors and historical trends and variability.

For the purposes of impairment testing, the group's oil price assumption is for the Brent oil price to drop from an average 2005 price of $55 per barrel in equal annual steps over the next three years to $25 per barrel in 2009 and to remain flat thereafter (2004 $38 per barrel stepping down to $20 per barrel in 2008 and beyond and 2003 $29 per barrel stepping down to $20 per barrel in 2007 and beyond). Similarly, Henry Hub natural gas prices drop from an average $8.65 per mmBtu in 2005 to $4.00 per mmBtu in 2009 and beyond (2004 $6.15 per mmBtu stepping down to $3.50 per mmBtu in 2008 and beyond and 2003 $5.35 per mmBtu stepping down to $3.50 per mmBtu in 2007 and beyond). These prices are adjusted to arrive at appropriate consistent price assumptions for different qualities of oil and gas.

EXPLORATION AND PRODUCTION

The value in use is based on the cash flows expected to be generated by the projected oil or natural gas production profiles up to the expected dates of cessation of production of each producing field. The date of cessation of production depends on the interaction of a number of variables, such as the recoverable quantities of hydrocarbons, the production profile of the hydrocarbons, the cost of the development of the infrastructure necessary to recover the hydrocarbons, the production costs, the contractual duration of the production concession and the selling price of the hydrocarbons produced. As each producing field has specific reservoir characteristics and economic circumstances, the cash flows of the fields are computed using appropriate individual economic models and key assumptions agreed by BP's management for the purpose. Cash outflows and hydrocarbon production quantities for the first five years are agreed as part of the annual planning process. Thereafter, estimated production quantities and cash outflows up to the date of cessation of production are developed to be consistent with this.

The following table shows the carrying value of the goodwill allocated to each of the regions of the Exploration and Production segment and the amount by which the recoverable amount (value in use) exceeds the carrying amount of the goodwill and other non-current assets in the cash-generating units to which the goodwill has been allocated. No impairment charge is required.

					$ million
					2005
	UK	Rest of Europe	USA	Rest of World	Total
Goodwill	341	–	3,515	515	4,371
Excess of recoverable amount over carrying amount	3,205	n/a	6,421	28,088	–

					$ million
					2004
	UK	Rest of Europe	USA	Rest of World	Total
Goodwill	341	–	3,515	515	4,371
Excess of recoverable amount over carrying amount	2,045	n/a	3,332	14,094	–

					$ million
					2003
	UK	Rest of Europe	USA	Rest of World	Total
Goodwill	341	–	3,515	515	4,371
Excess of recoverable amount over carrying amount	3,466	n/a	4,734	15,119	–

13 Impairment of goodwill *continued*

The key assumptions required for the value in use estimation are the oil and natural gas prices, production volumes and the discount rate. To test the sensitivity of the excess of the recoverable amount over the carrying amount of goodwill and other non-current assets shown above (the headroom) to changes in production volumes and oil and natural gas prices, management has developed 'rules of thumb' for these two key assumptions. Applying these gives an indication of the impact on the headroom of possible changes in the key assumptions.

On the basis of the rules of thumb using estimated 2006 production profiles extrapolated over an average 15-year production life, it is estimated that a long-term decrease of $1 per barrel in the price of Brent crude or $0.1 per mmBtu of Henry Hub gas with corresponding adjustments to other prices would cause the above excess of recoverable amount over carrying amount to be reduced by $3.3 billion in respect of oil production and $0.6 billion for gas production. Consequently, it is estimated that the long-term price of Brent crude that would cause the total recoverable amount to be equal to the total carrying amount of the goodwill and related non-current assets for individual cash-generating units would be of the order of $25 per barrel for the UK and $26 per barrel for the US. No reasonably possible change in oil or gas prices would cause the headroom in Rest of World to be reduced to zero.

Estimated production volumes are based on detailed data for the fields and take into account development plans for the fields agreed by management as part of the long-term planning process. It is estimated that, if all our production were to be reduced by 10% for the whole of the next 15 years, this would not be sufficient to reduce the excess of recoverable amount over the carrying amounts of the individual cash-generating units to zero. Consequently, management believes no reasonably possible change in the production assumption would cause the carrying amount of goodwill and other non-current assets to exceed their recoverable amount.

REFINING AND MARKETING

For all cash-generating units, the cash flows for the next five years are derived from the five-year group plan. The cost inflation rate is assumed to be 2.5% (2004 2.5% and 2003 2.5%) throughout the period. For determining the value in use for each of the SPUs, cash flows for a period of 10 years have been discounted and aggregated with its terminal value.

Refining Cash flows beyond the five-year period are extrapolated using a 2% growth rate (2004 4% and 2003 2%).

The key assumptions to which the calculation of value in use for the Refining unit is most sensitive are gross margins, production volumes and the terminal value. The value assigned to the gross margin is based on $5.25 per barrel global indicator margin (GIM), which is then adjusted for specific refinery configurations (2004 $2.70 per barrel and 2003 $2.70 per barrel), except in the first year of the plan period when a GIM of $7.25 is used, reflecting market conditions expected in the near term. The value assigned to the production volume is 900mmbbl a year (2004 900mmbbl and 2003 1,100mmbbl) and remains constant over the plan period. The value assigned to the terminal value assumption is 5 times earnings (2004 5 times and 2003 5 times), which is indicative of similar assets in the current market. These key assumptions reflect past experience and are consistent with external sources.

The Refining unit's recoverable amount exceeds its carrying amount by $13.6 billion. Based on sensitivity analysis, it is estimated that if the GIM changes by $1 per barrel, the Refining unit's value in use changes by $7.7 billion and, if there is an adverse change in the GIM of $1.75 per barrel, the recoverable amount of the Refining unit would equal its carrying amount. If the volume assumption changes by 5% the Refining unit's value in use changes by $3.1 billion and if there is an adverse change in Refining volumes of 200mmbbl a year, the recoverable amount of the Refining unit would equal its carrying amount. If the multiple of earnings used in the terminal value changes by 1 then the Refining unit's value in use changes by $1.7 billion. Management believes no reasonably possible change in the multiple of earnings used in the terminal value would lead to the Refining value in use being equal to its carrying amount.

Retail The cash flows beyond the five-year period assume no growth in fuel margins (2004 1% decline and 2003 no growth), reflecting a competitive marketplace.

The key assumptions to which the calculation of value in use for the Retail unit is most sensitive are unit gross margins, branded marketing volumes, the terminal value and discount rate. The value assigned to the unit gross margin varies between markets. For the purpose of planning, each market develops a gross margin based on a market-specific reference price adjusted for the different income streams within the market and other market specific factors. The weighted average Retail reference margin used in the plan was 5.4 cents per litre (2004 4.6 cents per litre and 2003 4.3 cents per litre). The value assigned to the branded marketing volume assumption is 101 billion litres a year (2004 106 billion litres a year and 2003 107 billion litres a year). The unit gross margin assumptions decline on average by 0.8% a year over the plan period and marketing volume assumptions grow by an average of 2% a year over the plan period. The value assigned to the terminal value assumption is 6.5 times earnings (2004 6.5 times and 2003 6.5 times), which is indicative of similar assets in the current market. These key assumptions reflect past experience and are consistent with external sources.

The Retail unit's recoverable amount exceeds its carrying amount by $1.5 billion. It is estimated that, if there is an adverse change in the unit gross margin of 7.5%, the recoverable amount of the Retail unit would equal its carrying amount. It is estimated that, if the volume assumption changes by 5%, the Retail unit's value in use changes by $1 billion and, if there is an adverse change in Retail volumes of 8 billion litres a year, the recoverable amount of the Retail unit would equal its carrying amount. If the multiple of earnings used in the terminal value changes by 1 then the Retail unit's value in use changes by $0.5 billion and, if the multiple of earnings falls to 3 times, then the Retail value in use would equal its carrying amount. A change of 1% in the discount rate would change the Retail value in use by $0.7 billion and, if the discount rate increases to 12%, the value in use of the Retail unit would equal its carrying amount.

Lubricants Cash flows beyond the five-year period are extrapolated using a 3% sales volume growth rate (2004 3% and 2003 3%), which is lower than the long-term average growth rate for the first five years. The terminal value for the Lubricants unit represents cash flows discounted to perpetuity. For the Lubricants unit, the key assumptions to which the calculation of value in use is most sensitive are operating margin, sales volumes and the discount rate. The values assigned to the operating margin and sales volumes are 49 cents per litre (2004 51 cents per litre and 2003 55 cents per litre) and 3.3 billion litres a year (2004 3.3 billion litres and 2003 3.4 billion litres). These key assumptions reflect past experience.

The Lubricants unit's recoverable amount exceeds its carrying amount by $4.0 billion. If there is an adverse change in the operating gross margin of 10 cents per litre, the recoverable amount of the Lubricants unit would equal its carrying amount. If the sales volume assumption changes by 5%, the Lubricants unit's value in use changes by $1.1 billion and, if there is an adverse change in Lubricants sales volumes of 600 million litres, the recoverable amount of the Lubricants unit would equal its carrying amount. A change of 1% in the discount rate would change the Lubricants unit's value in use by $0.7 billion and, if the discount rate increases to 17%, the value in use of the Lubricants unit would equal its carrying amount.

13 Impairment of goodwill *continued*

$ million					
					2005
	Refining	Retail	Lubricants	Other	Total
Goodwill	1,388	832	3,612	123	5,955
Excess of recoverable amount over carrying amount	13,593	1,511	3,953	n/a	–

$ million					
					2004
	Refining	Retail	Lubricants	Other	Total
Goodwill	1,404	878	4,008	128	6,418
Excess of recoverable amount over carrying amount	13,250	4,111	4,082	n/a	–

$ million					
					2003
	Refining	Retail	Lubricants	Other	Total
Goodwill	1,398	907	3,703	143	6,151
Excess of recoverable amount over carrying amount	12,728	3,083	3,685	n/a	–

OTHER BUSINESSES AND CORPORATE

In November 2004, Solvay exercised its option to sell its interests in BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America to BP. Solvay held 50% of BP Solvay Polyethylene Europe and 51% of BP Solvay Polyethylene North America. The total consideration for the acquisition was $1,391 million. See Note 3, Acquisitions, for more information.

The methodology to determine the option exercise price was laid out in the original agreement creating the polyethylene joint venture. Management believed that this price was high compared with the likely recoverable amount for the businesses and conducted an impairment test.

The cash flows for the next five years were derived from the five-year group plan. Cost inflation rate was assumed to be 2% throughout the period. For determining the value in use for each of the businesses, a period of 20 years was used, with a terminal value based on the value of working capital releases. Cash flows beyond the five-year period were extrapolated based on the final year of the five-year group plan using unchanged margin and volume assumptions for the subsequent years.

The key assumptions to which the calculations of value in use were most sensitive were variable contribution margin, production volumes and discount rate. The values assigned to the variable contribution margin were rising across the plan period from $175 to $179 per tonne for Europe and $153 to $194 per tonne for US and annual sales volumes were also rising in the plan period from 1,065,000 tonnes to 1,273,000 tonnes in Europe and from 882,000 tonnes to 907,000 tonnes in the US. These key assumptions reflected past experience and were consistent with external sources.

The recoverable amount of the European business was $631 million lower than the acquisition fair values. This impairment was first applied to the goodwill amount of $325 million and the balance recognized against the carrying value of property, plant and equipment. The recoverable amount of the US business exceeded its carrying amount by $289 million. There were additional selling costs and closing adjustments of $59 million in 2005, which created additional goodwill of $59 million. This was impaired in 2005.

14 Distribution and administration expenses

$ million	2005	2004	2003
Distribution	13,187	12,325	11,570
Administration	1,325	1,284	1,384
	14,512	13,609	12,954
Innovene operations	(806)	(841)	(684)
Continuing operations	13,706	12,768	12,270

15 Currency exchange gains and losses

$ million	2005	2004	2003
Currency exchange (gains) and losses charged (credited) to income	94	55	(129)
Innovene operations	(80)	(13)	(3)
Continuing operations	14	42	(132)

16 Research

$ million	2005	2004	2003
Expenditure on research	502	439	349
Innovene operations	(128)	(139)	(115)
Continuing operations	374	300	234

17 Operating leases

$ million	2005	2004	2003
Minimum lease payments	1,841	1,840	1,447
Sub-lease rentals	(110)	(109)	(128)
	1,731	1,731	1,319
Innovene operations	(49)	(89)	(68)
Continuing operations	1,682	1,642	1,251

17 Operating leases *continued*

The minimum future lease payments (before deducting related rental income from operating sub-leases of $718 million) were as follows:

$ million

	2005	2004	2003
Payable within			
1 year	1,643	1,534	1,369
2 to 5 years	4,666	3,778	3,783
Thereafter	4,579	3,275	3,572
	10,888	8,587	8,724

The group has entered into operating leases on ships, plant and machinery, commercial vehicles, land and buildings, including service station sites and office accommodation. The ship leases represent approximately 52% of the minimum future lease payments. The typical durations of the leases are as follows:

	Years
Ships	up to 25
Plant and machinery	up to 10
Commercial vehicles	up to 15
Land and buildings	up to 40

Generally these leases have no renewal options. There are no financial restrictions placed upon the lessee by entering into these leases. The group also routinely enters into time charters and spot charters for ships on standard industry terms.

18 Exploration for and evaluation of oil and natural gas resources

The following financial information represents the amounts included within the corresponding group and Exploration and Production segment totals for the exploration for and evaluation of oil and natural gas resources activity.

$ million

	2005	2004	2003
Exploration and evaluation costs			
Exploration expenditure written off	305	274	297
Other exploration costs	379	363	245
Exploration expense for the year	684	637	542
Intangible assets	4,008	3,761	4,236
Net assets	4,008	3,761	4,236
Capital expenditure	950	754	579
Net cash used in operating activities	379	363	245
Net cash used in investing activities	950	754	579

19 Auditors' remuneration

$ million

	2005		2004		2003	
Audit fees – Ernst & Young	UK	Total	UK	Total	UK	Total
Group audit	25	47	13	27	8	18
Audit-related regulatory reporting	3	6	4	7	2	5
Statutory audit of subsidiaries	7	23	4	16	3	13
	35	76	21	50	13	36
Innovene operations	(8)	(8)	(2)	(2)	(2)	(2)
Continuing operations	27	68	19	48	11	34
Fees for other services – Ernst & Young						
Further assurance services						
Acquisition and disposal due diligence	2	2	6	7	9	9
Pension scheme audits	–	1	–	1	–	1
Other further assurance services	6	7	6	9	5	9
Tax services						
Compliance services	5	10	3	13	3	17
Advisory services	–	–	–	1	–	2
	13	20	15	31	17	38
Innovene operations	–	(1)	–	(1)	–	–
Continuing operations	13	19	15	30	17	38

Audit fees for 2005 include $4 million of additional fees for 2004. Audit fees are included in the income statement within distribution and administration expenses.

The audit committee has established pre-approval policies and procedures for the engagement of Ernst & Young to render audit and certain assurance and tax services. The audit fees payable to Ernst & Young are reviewed by the audit committee in the context of other global companies for cost-effectiveness. Ernst & Young performed further assurance and tax services that were not prohibited by regulatory or other professional requirements and were pre-approved by the committee. Ernst & Young is engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit nature. Tax services were awarded either through a full competitive tender process or following an assessment of the expertise of Ernst & Young relative to that of other potential service providers. These services are for a fixed term.

Fees paid to major firms of accountants other than Ernst & Young for other services amount to $151 million (2004 $82 million and 2003 $44 million).

20 Finance costs

$ million

	2005	2004	2003
Bank loans and overdrafts	44	34	38
Other loans	828	573	600
Finance leases	38	37	34
Interest payable	910	644	672
Capitalized at 4.25% (2004 3% and 2003 3%)[a]	(351)	(204)	(190)
Early redemption of borrowings and finance leases	57	–	31
Continuing operations	616	440	513

[a] Tax relief on capitalized interest is $123 million (2004 $73 million and 2003 $68 million).

21 Other finance expense

$ million

	2005	2004	2003
Interest on pension and other post-retirement benefit plan liabilities	2,022	2,012	1,840
Expected return on pension and other post-retirement benefit plan assets	(2,138)	(1,983)	(1,500)
Interest net of expected return on plan assets	(116)	29	340
Unwinding of discount on provisions	201	196	173
Unwinding of discount on deferred consideration for acquisition of investment in TNK-BP	57	91	34
Change in discount rate for provisions[a]	–	41	–
	142	357	547
Innovene operations	3	(17)	(15)
Continuing operations	145	340	532

[a] Revaluation of environmental and litigation and other provisions at a different discount rate.

22 Taxation

$ million

TAX ON PROFIT	2005	2004	2003
Current tax			
Charge for the year	10,511	7,217	5,061
Adjustment in respect of prior years	(977)	(308)	(392)
	9,534	6,909	4,669
Innovene operations	(910)	(48)	54
Continuing operations	8,624	6,861	4,723
Deferred tax			
Origination and reversal of temporary differences in the current year	349	138	448
Adjustment in respect of prior years	(450)	(74)	(67)
	(101)	64	381
Innovene operations	950	157	(54)
Continuing operations	849	221	327
Tax on profit from continuing operations	9,473	7,082	5,050

Tax on profit from continuing operations may be analysed as follows:

	2005	2004	2003
Current tax charge			
UK	880	1,839	1,142
Overseas	7,744	5,022	3,581
	8,624	6,861	4,723
Deferred tax charge			
UK	(489)	(218)	289
Overseas	1,338	439	38
	849	221	327
Total			
UK	391	1,621	1,431
Overseas	9,082	5,461	3,619
	9,473	7,082	5,050

22 Taxation *continued*

TAX INCLUDED IN STATEMENT OF RECOGNIZED INCOME AND EXPENSE	2005	2004	2003
			$ million
Current tax			
Charge for the year	45	23	(11)
	45	23	(11)
Innovene operations	–	–	–
Continuing operations	45	23	(11)
Deferred tax			
Origination and reversal of temporary differences in the current year	309	50	59
Adjustment in respect of prior years	(95)	–	–
	214	50	59
Innovene operations	–	–	–
Continuing operations	214	50	59
Tax included in statement of recognized income and expense	259	73	48

This comprises:			$ million
Currency translation differences	(11)	208	37
Exchange gain on translation of foreign operations transferred to loss on sale of businesses	(95)	–	–
Actuarial gain relating to pensions and other post-retirement benefits	356	(96)	16
Share-based payment accrual	–	(39)	(5)
Net (gain) loss on revaluation of cash flow hedges	(63)	–	–
Unrealized (gain) loss on available-for-sale financial assets	72	–	–
Tax included in statement of recognized income and expense	259	73	48

RECONCILIATION OF THE EFFECTIVE TAX RATE

The following table provides a reconciliation of the UK statutory corporation tax rate to the effective tax rate of the group on profit before taxation from continuing operations.

			$ million
	2005	2004	2003
Profit before taxation from continuing operations	31,921	24,966	17,731
Tax on profit from continuing operations	9,473	7,082	5,050
Effective tax rate	30%	28%	28%

	% of profit before tax from continuing operations		
UK statutory corporation tax rate	30	30	30
Increase (decrease) resulting from			
UK supplementary and overseas taxes at higher rates	9	8	8
Tax reported in equity-accounted entities	(3)	(3)	(3)
Adjustments in respect of prior years	(3)	(1)	(1)
Restructuring benefits	(1)	(2)	(2)
Current year losses unrelieved (prior year losses utilized)	(3)	(3)	(3)
Other	1	(1)	(1)
Effective tax rate	30	28	28

22 Taxation *continued*

DEFERRED TAX

$ million

	Income statement			Balance sheet		
	2005	2004	2003	2005	2004	2003
Deferred tax liability						
Depreciation	(778)	492	(716)	18,529	19,873	18,783
Pension plan surplus	170	10	199	957	520	468
Other taxable temporary differences	887	(113)	132	3,864	2,979	2,956
	279	389	(385)	23,350	23,372	22,207
Deferred tax asset						
Petroleum revenue tax	121	77	26	(407)	(581)	(613)
Pension plan and other post-retirement benefit plan deficits	220	92	501	(1,822)	(2,068)	(2,530)
Decommissioning, environmental and other provisions	(144)	106	76	(2,033)	(2,015)	(2,015)
Derivative financial instruments	(629)	–	–	(807)	–	–
Tax credit and loss carry forward	(245)	6	231	(253)	(5)	(12)
Other deductible temporary differences	297	(606)	(68)	(1,585)	(2,002)	(986)
	(380)	(325)	766	(6,907)	(6,671)	(6,156)
Net deferred tax liability	(101)	64	381	16,443	16,701	16,051

$ million

	2005	2004	2003
Analysis of movements during the year			
At 1 January	16,701	16,051	15,045
Adoption of IAS 32 and IAS 39	(112)	–	–
Restated	16,589	16,051	15,045
Exchange adjustments	(178)	358	566
Charge for the year on ordinary activities	(101)	64	381
Charge for the year in the statement of recognized income and expense	214	50	59
Other movements	(81)	178	–
At 31 December	16,443	16,701	16,051

FACTORS THAT MAY AFFECT FUTURE TAX CHARGES

The group earns income in many different countries and, on average, pays taxes at rates higher than the UK statutory rate. The overall impact of these higher taxes, which include the supplementary charge of 10% on UK North Sea profits, is subject to changes in enacted tax rates and the country mix of the group's income. The UK government has announced that the supplementary charge will be increased to 20% with effect from 1 January 2006. If this change is enacted, it will increase the group's ongoing effective tax rate by 1-2%, and will also require a deferred tax adjustment resulting in a further 2% increase in the tax rate for 2006. The impact of this increase, together with the other factors outlined below, is likely to increase the effective tax rate by around 4-5% in future years.

Under International Financial Reporting Standards, the results of equity-accounted entities are reported within the group's profit before taxation on a post-tax basis. The impact of this treatment is to reduce the reported effective tax rate by around 3%. This effect is expected to continue for the foreseeable future.

In 2005, the group released around $1 billion of income tax provisions that had been set up in previous years, reflecting a revised assessment of risks. It is unlikely that a similar release of provisions will occur in future years.

At 31 December 2005, deferred tax liabilities were recognized for all taxable temporary differences:

- Except where the deferred tax liability arises on goodwill that is not tax deductible or the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss; and
- In respect of taxable temporary differences associated with investments in subsidiaries, associates and jointly controlled entities, except where the timing of the reversal of the temporary differences can be controlled by the group and it is probable that the temporary differences will not reverse in the foreseeable future.

At 31 December 2005, deferred tax assets were recognized for all deductible temporary differences, carry forward of unused tax assets and unused tax losses, to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry forward of unused tax assets and unused tax losses can be utilized:

- Except where the deferred income tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss; and
- In respect of deductible temporary differences associated with investments in subsidiaries, associates and jointly controlled entities, deferred tax assets are only recognized to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available against which the temporary differences can be utilized.

The group has around $5.1 billion (2004 $7.7 billion and 2003 $4.5 billion) of carry-forward tax losses in the UK and Germany, which would be available to offset against future taxable income. At the end of 2005, $176 million of deferred tax assets were recognized on these losses (2004 no tax asset and 2003 $86 million of assets were recognized). Tax assets are recognized only to the extent that it is considered more likely than not that suitable taxable income will arise. Carry-forward losses in other taxing jurisdictions have not been recognized as deferred tax assets and are unlikely to have a significant effect on the group's tax rate in future years.

The major component of temporary differences in the current year are tax depreciation, US inventory holding gains (classified under other taxable temporary differences) and derivative financial instruments. Based on current capital investment plans, the group expects that temporary differences arising in future years from differences between tax allowances and depreciation will be at levels similar to the current year.

23 Dividends

	pence per share			cents per share			$ million		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
Dividends announced and paid									
Preference shares							2	2	2
Ordinary shares									
March	4.522	3.674	3.815	8.50	6.75	6.25	1,823	1,492	1,397
June	4.450	3.807	3.947	8.50	6.75	6.25	1,808	1,477	1,385
September	5.119	3.860	4.039	8.925	7.10	6.50	1,871	1,536	1,433
December	5.061	3.910	3.857	8.925	7.10	6.50	1,855	1,534	1,437
	19.152	15.251	15.658	34.85	27.70	25.50	7,359	6,041	5,654
Dividend announced per ordinary share, payable in March 2006	5.288	–	–	9.375	–	–	1,923	–	–

The group does not account for dividends until they have been paid. The accounts for the year ended 31 December 2005 do not reflect the dividend to be announced on 7 February 2006 and payable in March 2006; this will be treated as an appropriation of profit in the year ended 31 December 2006.

24 Earnings per ordinary share

	cents per share		
	2005	2004	2003
Basic earnings per share	105.74	78.24	56.14
Diluted earnings per share	104.52	76.87	55.61

Basic earnings per ordinary share amounts are calculated by dividing the profit for the year attributable to ordinary shareholders by the weighted average number of ordinary shares outstanding during the year. The average number of shares outstanding excludes treasury shares and the shares held by the Employee Share Ownership Plans.

For the diluted earnings per share calculation, the profit attributable to ordinary shareholders is adjusted for the unwinding of the discount on the deferred consideration for the acquisition of our interest in TNK-BP. The weighted average number of shares outstanding during the year is adjusted for the number of shares to be issued for the deferred consideration for the acquisition of our interest in TNK-BP and the number of shares that would be issued on conversion of outstanding share options into ordinary shares using the treasury stock method.

	$ million		
	2005	2004	2003
Profit for the year attributable to BP shareholders			
Continuing operations	22,157	17,697	12,511
Discontinued operations	184	(622)	(63)
	22,341	17,075	12,448
Unwinding of discount on deferred consideration for acquisition of investment in TNK-BP (net of tax)	40	64	24
Diluted profit for the year attributable to BP shareholders	22,381	17,139	12,472

	shares thousand		
	2005	2004	2003
Basic weighted average number of ordinary shares	21,125,902	21,820,535	22,170,741
Potential dilutive effect of ordinary shares issuable under employee share schemes	87,743	56,985	65,931
Potential dilutive effect of ordinary shares issuable as consideration for BP's interest in the TNK-BP joint venture	197,802	415,016	186,980
	21,411,447	22,292,536	22,423,652

The number of ordinary shares outstanding at 31 December 2005 was 20,657,044,719. Between the reporting date and the date of completion of these financial statements there has been a net decrease of 69,765,632 in the number of ordinary shares outstanding as a result of share buybacks net of share issues. The number of potential ordinary shares through the exercise of employee share options was 108,596,993 at 31 December 2005. There has been an increase of 20,768,209 in the number of potential ordinary shares between the reporting date and the completion of the financial statements.

Earnings (loss) per share for the discontinued operations is derived from the net profit (loss) attributable to ordinary shareholders from discontinued operations of $184 million profit (2004 $622 million loss and 2003 $63 million loss), divided by the weighted average number of ordinary shares for both basic and diluted amounts as shown above.

25 Group balance sheet analysis

$ million

	Capital expenditure and acquisitions			Operating capital employed[a]		
By business	2005	2004	2003	2005	2004	2003
Exploration and Production						
UK	821	762	786	6,265	9,144	9,070
Rest of Europe	197	255	279	1,451	1,558	1,476
USA	3,870	3,913	3,906	28,958	27,860	26,823
Rest of World	5,349	6,078	10,221	36,418	31,032	26,354
	10,237	11,008	15,192	73,092	69,594	63,723
Refining and Marketing						
UK[b]	408	411	430	7,260	7,455	7,154
Rest of Europe	568	599	728	12,012	13,005	11,138
USA	1,226	1,314	1,480	19,342	17,452	15,977
Rest of World	570	495	381	7,011	6,766	6,129
	2,772	2,819	3,019	45,625	44,678	40,398
Gas, Power and Renewables						
UK	30	166	69	241	880	786
Rest of Europe	26	19	76	541	463	425
USA	96	80	158	2,576	1,694	1,659
Rest of World	83	259	136	1,737	1,836	1,405
	235	524	439	5,095	4,873	4,275
Other businesses and corporate						
UK	339	403	244	5,187	6,563	3,703
Rest of Europe	189	1,024	163	(4,268)	(1,638)	(2,046)
USA	277	698	423	(3,953)	(2,306)	256
Rest of World	100	175	143	432	787	2,041
	905	2,300	973	(2,602)	3,406	3,954
Consolidation adjustment				(778)	(552)	(361)
	14,149	16,651	19,623	120,432	121,999	111,989
By geographical area						
UK[b]	1,598	1,742	1,529	18,928	24,042	20,713
Rest of Europe	980	1,897	1,246	9,736	13,388	10,993
USA	5,469	6,005	5,967	46,192	44,148	44,354
Rest of World	6,102	7,007	10,881	45,576	40,421	35,929
	14,149	16,651	19,623	120,432	121,999	111,989
Operating capital employed				120,432	121,999	111,989
Liabilities for current and deferred taxation				(20,505)	(20,673)	(19,400)
Capital employed				99,927	101,326	92,589
Financed by						
Finance debt				19,162	23,091	22,325
Minority interest				789	1,343	1,125
BP shareholders' equity				79,976	76,892	69,139
				99,927	101,326	92,589

[a] Operating capital employed is total assets less total liabilities, excluding finance debt and current and deferred taxation.
[b] UK area includes the UK-based international activities of Refining and Marketing.

Notes on financial statements *continued*

26 Property, plant and equipment

$ million

	Land	Buildings	Oil and gas properties	Plant, machinery and equipment	Fixtures, fittings and office equipment	Transport-ation	Oil depots, storage tanks and service stations	Total	Of which: assets under construction
Cost									
At 1 January 2005	5,471	1,965	103,967	42,302	1,694	13,588	14,435	183,422	15,038
Exchange adjustments	(387)	(136)	(15)	(2,364)	(180)	(4)	(1,117)	(4,203)	(66)
Acquisitions	19	3	–	–	1	–	–	23	27
Additions	41	191	8,773	2,451	383	133	816	12,788	10,467
Transfers	–	–	325	–	–	–	–	325	(8,668)
Deletions	(568)	(69)	(2,675)	(13,609)	(784)	(451)	(885)	(19,041)	(683)
At 31 December 2005	4,576	1,954	110,375	28,780	1,114	13,266	13,249	173,314	16,115
Depreciation									
At 1 January 2005	863	538	54,012	19,556	726	7,141	7,494	90,330	
Exchange adjustments	(17)	(60)	(7)	(916)	(67)	(76)	(496)	(1,639)	
Charge for the year	79	143	5,696	1,691	399	309	704	9,021	
Impairment losses	–	–	266	590	–	–	42	898	
Transfers	–	–	6	–	–	–	–	6	
Deletions	(216)	(65)	(1,819)	(7,504)	(741)	(270)	(634)	(11,249)	
At 31 December 2005	709	556	58,154	13,417	317	7,104	7,110	87,367	
Net book amount at 31 December 2005	3,867	1,398	52,221	15,363	797	6,162	6,139	85,947	16,115
Cost									
At 1 January 2004	4,799	2,191	96,991	39,840	1,458	13,099	13,529	171,907	13,957
Exchange adjustments	477	68	1,641	1,916	37	182	725	5,046	158
Acquisitions	10	–	–	1,453	–	–	–	1,463	–
Additions	308	121	8,048	1,863	513	672	869	12,394	10,084
Transfers	–	–	1,036	–	–	–	–	1,036	(8,879)
Deletions	(123)	(415)	(3,749)	(2,770)	(314)	(365)	(688)	(8,424)	(282)
At 31 December 2004	5,471	1,965	103,967	42,302	1,694	13,588	14,435	183,422	15,038
Depreciation									
At 1 January 2004	815	700	50,028	17,363	796	7,031	6,567	83,300	
Exchange adjustments	87	27	948	1,193	3	83	369	2,710	
Charge for the year	50	96	5,203	2,142	197	229	917	8,834	
Impairment losses	–	–	404	761	–	–	–	1,165	
Transfers	–	–	196	–	–	–	–	196	
Deletions	(89)	(285)	(2,767)	(1,903)	(270)	(202)	(359)	(5,875)	
At 31 December 2004	863	538	54,012	19,556	726	7,141	7,494	90,330	
Net book amount at 31 December 2004	4,608	1,427	49,955	22,746	968	6,447	6,941	93,092	15,038
Cost									
At 1 January 2003	3,838	2,048	98,250	36,214	1,141	12,398	12,184	166,073	12,127
Exchange adjustments	713	102	2,461	3,831	56	283	1,073	8,519	216
Acquisitions	–	–	–	34	–	–	–	34	–
Additions	297	113	8,737	1,693	497	672	799	12,808	10,800
Transfers	–	–	820	184	–	–	–	1,004	(7,359)
Fair value adjustment	–	–	(76)	–	–	–	–	(76)	–
Deletions	(49)	(72)	(13,201)	(2,116)	(236)	(254)	(527)	(16,455)	(1,827)
At 31 December 2003	4,799	2,191	96,991	39,840	1,458	13,099	13,529	171,907	13,957
Depreciation									
At 1 January 2003	677	612	51,731	15,159	620	6,826	5,505	81,130	
Exchange adjustments	114	10	1,041	1,383	15	97	430	3,090	
Charge for the year	44	112	5,310	1,687	290	244	841	8,528	
Impairment losses	–	–	1,013	–	–	–	–	1,013	
Transfers	–	–	66	(9)	–	–	–	57	
Deletions	(20)	(34)	(9,133)	(857)	(129)	(136)	(209)	(10,518)	
At 31 December 2003	815	700	50,028	17,363	796	7,031	6,567	83,300	
Net book amount at 31 December 2003	3,984	1,491	46,963	22,477	662	6,068	6,962	88,607	13,957
Assets held under finance leases at net book amount included above									
At 31 December 2005	8	24	46	315	2	9	35	439	
At 31 December 2004	12	7	45	1,583	7	10	40	1,704	
At 31 December 2003	14	8	48	1,648	8	12	44	1,782	

Decommissioning asset at net book amount included above

	Cost	Depreciation	Net
At 31 December 2005	5,398	2,342	3,056
At 31 December 2004	4,425	1,908	2,517
At 31 December 2003	3,686	1,606	2,080

27 Goodwill

$ million

	2005	2004	2003
Cost			
At 1 January	11,182	10,592	10,440
Exchange adjustments	(488)	332	476
Acquisitions	86	328	5
Fair value adjustment	–	–	(289)
Deletions	(409)	(70)	(40)
At 31 December	10,371	11,182	10,592
Impairment losses			
At 1 January	325	–	–
Exchange adjustments	–	–	–
Impairment in the year	59	325	–
Deletions	(384)	–	–
At 31 December	–	325	–
Net book amount at 31 December	10,371	10,857	10,592

28 Intangible assets

$ million

	2005			2004			2003		
	Exploration expenditure	Other intangibles	Total	Exploration expenditure	Other intangibles	Total	Exploration expenditure	Other intangibles	Total
Cost									
At 1 January	4,311	1,377	5,688	4,977	950	5,927	5,630	900	6,530
Exchange adjustments	(66)	(44)	(110)	41	60	101	72	2	74
Acquisitions	–	–	–	–	15	15	–	–	–
Additions	950	531	1,481	754	352	1,106	579	136	715
Transfers	(325)	–	(325)	(1,036)	–	(1,036)	(820)	–	(820)
Deletions	(209)	(124)	(333)	(425)	–	(425)	(484)	(88)	(572)
At 31 December	4,661	1,740	6,401	4,311	1,377	5,688	4,977	950	5,927
Amortization									
At 1 January	550	933	1,483	741	715	1,456	686	717	1,403
Exchange adjustments	(8)	(32)	(40)	1	40	41	10	2	12
Charge for the year	305	161	466	274	178	452	297	77	374
Transfers	(6)	–	(6)	(196)	–	(196)	(66)	–	(66)
Deletions	(188)	(86)	(274)	(270)	–	(270)	(186)	(81)	(267)
At 31 December	653	976	1,629	550	933	1,483	741	715	1,456
Net book amount at 31 December	4,008	764	4,772	3,761	444	4,205	4,236	235	4,471

29 Investments in jointly controlled entities

The significant jointly controlled entities of the BP group at 31 December 2005 are shown in Note 51. The principal joint venture is the TNK-BP joint venture. Summarized financial information for the group's share of jointly controlled entities is shown below.

$ million

			2005			2004			2003
	TNK-BP	Other	Total	TNK-BP	Other	Total	TNK-BP	Other	Total
Sales and other operating revenues	15,122	4,255	19,377	7,839	2,225	10,064	1,864	1,795	3,659
Profit before interest and taxation	3,817	779	4,596	2,421	586	3,007	521	489	1,010
Finance costs and other finance expense	128	104	232	101	69	170	37	65	102
Profit before taxation	3,689	675	4,364	2,320	517	2,837	484	424	908
Taxation	976	220	1,196	675	314	989	43	57	100
Minority interest	104	–	104	43	–	43	–	–	–
Profit for the year	2,609	455	3,064	1,602	203	1,805	441	367	808
Innovene operations	–	19	19	–	13	13	–	18	18
Continuing operations	2,609	474	3,083	1,602	216	1,818	441	385	826
Non-current assets	11,564	6,310	17,874	11,715	5,112	16,827	10,312	3,663	13,975
Current assets	4,278	1,682	5,960	2,565	1,283	3,848	1,950	1,427	3,377
Total assets	15,842	7,992	23,834	14,280	6,395	20,675	12,262	5,090	17,352
Current liabilities	3,617	914	4,531	1,959	981	2,940	1,575	773	2,348
Non-current liabilities	3,553	2,550	6,103	3,485	560	4,045	3,062	68	3,130
Total liabilities	7,170	3,464	10,634	5,444	1,541	6,985	4,637	841	5,478
Minority interest	583	–	583	542	–	542	527	–	527
	8,089	4,528	12,617	8,294	4,854	13,148	7,098	4,249	11,347
Group investment in jointly controlled entities									
Group share of net assets (as above)	8,089	4,528	12,617	8,294	4,854	13,148	7,098	4,249	11,347
Loans made by group companies to jointly controlled entities	–	939	939	–	1,408	1,408	–	1,562	1,562
	8,089	5,467	13,556	8,294	6,262	14,556	7,098	5,811	12,909

On 29 August 2003, BP and the Alfa Group and Access-Renova (AAR) combined certain of their Russian and Ukrainian oil and gas businesses to create TNK-BP, a new company owned and managed 50:50 by BP and AAR. TNK-BP is a jointly controlled entity accounted for under the equity method. BP contributed its 29% interest in Sidanco, its 29% interest in Rusia Petroleum and its holding in the BP Moscow retail network. There was additional consideration from BP to AAR comprising an immediate $2,604 million in cash (which was subsequently reduced by receipt of pre-acquisition dividends, net of other adjustments, of $298 million) together with annual tranches of $1,250 million in BP shares payable in 2004, 2005 and 2006. There were costs of $45 million in connection with the transaction. The first two tranches were issued in September 2004 and 2005.

BP also agreed with AAR to incorporate AAR's 50% interest in Slavneft into TNK-BP in return for $1,418 million in cash (which was subsequently reduced by receipt of pre-acquisition dividends of $64 million to $1,354 million). This transaction was completed on 16 January 2004.

BP Solvay Polyethylene Europe became a subsidiary with effect from 2 November 2004. See Note 3, Acquisitions, for further information. In 2005, it was sold as part of the Innovene operations.

During 2004, BP China and Sinopec announced the establishment of the BP-Sinopec (Zhejiang) Petroleum Co. Ltd, a retail joint venture between BP and Sinopec. Based on the existing service station network of Sinopec, the joint venture will build, operate and manage a network of 500 service stations in Hangzhou, Ningbo and Shaoxing. Also during 2004, BP China and PetroChina announced the establishment of BP-PetroChina Petroleum Company Ltd. Located in Guangdong, one of the most developed provinces in China, the joint venture will acquire, build, operate and manage 500 service stations in the province. The initial investment in both joint ventures amounted to $106 million.

Transactions between the significant jointly controlled entities and the group are summarized below. In addition to the amount receivable at 31 December 2005 shown below, a further $771 million was receivable from TNK-BP in respect of dividends.

Sales to jointly controlled entities

$ million

			2005		2004		2003
	Product	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
BP Solvay Polyethylene Europe[a]	Chemicals feedstocks	–	–	230	–	259	33
Pan American Energy	Crude oil	75	2	118	4	171	5
Ruhr Oel	Employee services	169	527	192	780	188	587
TNK-BP	Employee services	125	14	49	–	–	–
Watson Cogeneration	Natural gas	272	31	214	10	73	6

Purchases from jointly controlled entities

$ million

			2005		2004		2003
	Product	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December
BP Solvay Polyethylene Europe[a]	Chemicals feedstocks	–	–	–	–	18	14
Pan American Energy	Crude oil	661	81	481	43	381	48
Ruhr Oel	Refinery operating costs	384	134	477	249	435	131
TNK-BP[b]	Crude oil and oil products	908	17	1,809	80	349	52
Watson Cogeneration	Electricity and steam	185	19	149	14	248	12

[a] The 2004 BP Solvay Polyethylene Europe sales and purchases shown above relate to the period to 2 November 2004.
[b] The 2003 TNK-BP sales and purchases shown above relate to the period from 29 August to 31 December 2003.

30 Investments in associates

The significant associates of the group are shown in Note 51. Summarized financial information for the group's share of the aggregate total of revenues, profit, assets and liabilities of associates is set out below.

$ million

	2005	2004	2003
Sales and other operating revenues	6,879	5,509	4,101
Profit before interest and taxation	665	632	513
Finance costs and other finance expense	57	48	42
Profit before taxation	608	584	471
Taxation	143	121	80
Profit for the year	465	463	391
Innovene operations	(5)	(1)	(3)
Continuing operations	460	462	388
Non-current assets	5,514	6,023	5,143
Current assets	2,248	2,212	1,720
Total assets	7,762	8,235	6,863
Current liabilities	1,755	1,988	1,614
Non-current liabilities	2,037	2,171	1,280
Total liabilities	3,792	4,159	2,894
Net assets	3,970	4,076	3,969
Group investment in associates			
Group share of net assets (as above)	3,970	4,076	3,969
Loans made by group companies to associates	2,247	1,410	899
	6,217	5,486	4,868

BP Solvay Polyethylene North America became a subsidiary with effect from 2 November 2004. See Note 3, Acquisitions, for further information. In 2005, it was sold as part of the Innovene operations.

Transactions between the significant associates and the group are summarized below.

Sales to associates

$ million

		2005		2004		2003	
	Product	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
Atlantic LNG Company of Trinidad and Tobago	LNG	579	–	414	–	348	–
Atlantic LNG 2/3 Company of Trinidad and Tobago	LNG	1,157	–	532	–	420	–
BP Solvay Polyethylene North America[a]	Chemicals feedstocks	–	–	217	–	241	17
China American Petrochemical Co.	Chemicals feedstocks	393	48	385	81	240	67
Samsung Petrochemical Co.	Chemicals feedstocks	92	13	62	8	55	10

Purchases from associates

$ million

		2005		2004		2003	
	Product	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December
Abu Dhabi Marine Areas	Crude oil	1,355	164	866	91	661	61
Abu Dhabi Petroleum Co.	Crude oil	2,260	214	1,547	145	1,122	118
Atlantic LNG 2/3 Company of Trinidad and Tobago	Natural gas	190	–	120	–	83	10
BP Solvay Polyethylene North America[a]	Chemicals feedstocks	–	–	9	–	11	1
China American Petrochemical Co.	Petrochemicals	547	109	455	111	197	83
Samsung Petrochemical Co.	Chemicals feedstocks	626	140	290	17	187	38

[a] The 2004 BP Solvay Polyethylene North America sales and purchases shown above relate to the period to 2 November 2004.

31 Inventories

$ million

	2005	2004	2003
Crude oil	5,457	3,659	2,044
Natural gas	164	75	605
Refined petroleum and petrochemicals products	10,700	8,103	6,080
	16,321	11,837	8,729
Supplies	919	911	938
	17,240	12,748	9,667
Trading inventories	2,520	2,897	1,930
	19,760	15,645	11,597
Cost of inventories expensed in the income statement	172,699	135,907	115,978

32 Trade and other receivables

$ million

	2005		2004		2003	
	Current	Non-current	Current	Non-current	Current	Non-current
Trade	33,565	–	30,657	–	23,449	–
Jointly controlled entities	1,345	–	886	–	122	–
Associates	186	–	210	23	337	53
Other	5,806	770	5,346	406	3,973	442
	40,902	770	37,099	429	27,881	495

Trade and other receivables of the group at 31 December 2005 in currencies other than the functional currency of individual operating units are summarized below.

$ million

	US dollar	Sterling	Euro	Other currencies	Total
					2005
Functional currency					
US dollar	–	404	1,496	458	2,358
Sterling	1,111	–	1	1	1,113
Euro	354	453	–	1	808
Other currencies	6,045	15	948	–	7,008
Total	7,510	872	2,445	460	11,287

Trade and other receivables of the group at 31 December 2005 have the maturities shown below.

$ million

	2005
Within one year	40,902
1 to 2 years	129
2 to 3 years	82
3 to 4 years	56
4 to 5 years	51
Over 5 years	452
	41,672

The movement in the valuation allowance for trade receivables is set out below.

$ million

	2005	2004	2003
At 1 January	526	441	445
Exchange adjustments	(30)	6	29
Charge for the year	67	254	139
Utilization	(189)	(175)	(172)
At 31 December	374	526	441

The carrying amounts of Trade and other receivables approximate their fair value. Trade and other receivables are predominantly non-interest bearing.

33 Cash and cash equivalents

$ million

	2005	2004	2003
Cash at bank and in hand	1,594	1,031	1,871
Cash equivalents			
Listed	73	63	79
Unlisted	1,293	265	106
Carrying amount at 31 December	2,960	1,359	2,056

For IFRS, cash equivalents are classified as available-for-sale financial assets and as such are recorded at fair value. Prior to 2005, cash equivalents were stated at cost.

34 Trade and other payables

$ million

	2005		2004		2003	
	Current	Non-current	Current	Non-current	Current	Non-current
Trade	28,614	–	27,471	–	20,830	–
Jointly controlled entities	251	–	637	–	126	–
Associates	627	–	865	5	322	4
Production and similar taxes	763	1,281	517	1,520	421	1,544
Social security	78	–	122	–	96	–
Other	11,803	654	8,928	2,056	7,945	3,082
	42,136	1,935	38,540	3,581	29,740	4,630

Trade and other payables of the group at 31 December 2005 in currencies other than the functional currency of individual operating units are summarized below.

$ million

	US dollar	Sterling	Euro	Other currencies	Total
					2005
Functional currency					
US dollar	–	133	611	339	1,083
Sterling	1,802	–	4	12	1,818
Euro	157	306	–	38	501
Other currencies	6,640	–	17	–	6,657
Total	8,599	439	632	389	10,059

Trade and other payables of the group at 31 December 2005 have the maturities shown below.

$ million

	2005
Within one year	42,136
1 to 2 years	276
2 to 3 years	211
3 to 4 years	182
4 to 5 years	179
Over 5 years	1,087
	44,071

The carrying amounts of Trade and other payables approximate their fair value. Included within Other payables is the deferred consideration for the acquisition of our interest in TNK-BP, which was discounted on initial recognition. The remaining Trade and other payables are predominantly interest-free.

35 Derivative financial instruments

An outline of the group's financial risks and the policies and objectives pursued in relation to those risks is set out in the financial risk management section on pages 24-26.

This note contains the disclosures required by IAS 32 for derivative financial instruments. IAS 39 prescribes strict criteria for hedge accounting, whether as a cash flow or fair value hedge, and requires that any derivative that does not meet these criteria should be classified as trading and marked-to-market. BP adopted IAS 32 and IAS 39 with effect from 1 January 2005 without restating prior periods. Consequently, the group's accounting policy under UK GAAP has been used for 2004 and 2003. The policy under UK GAAP and the disclosures required by UK GAAP for derivative financial instruments are shown in Note 37.

In the normal course of business the group is a party to derivative financial instruments (derivatives) with off-balance sheet risk, primarily to manage its exposure to fluctuations in foreign currency exchange rates and interest rates, including management of the balance between floating rate and fixed rate debt. The group also manages certain of its exposures to movements in oil, natural gas and power prices. In addition, the group trades derivatives in conjunction with these risk management activities.

The fair value of derivative financial instruments at 31 December 2005 are set out below.

$ million

				2005
	Fair value asset	Contractual or notional amounts	Fair value liability	Contractual or notional amounts
Cash flow hedges				
Currency forwards, futures and swaps	34	666	(94)	3,100
Currency options	–	693	(35)	1,470
Commodity futures	57	274	–	–
	91	1,633	(129)	4,570
Fair value hedges				
Currency forwards, futures and swaps	222	2,566	(124)	1,967
Interest rate swaps	19	324	(217)	7,521
	241	2,890	(341)	9,488
Hedges of net investments in foreign entities	63	346	–	–
Derivatives held for trading				
Currency derivatives	41	634	(18)	1,687
Oil derivatives	2,765	56,394	(2,826)	52,524
Natural gas derivatives	6,836	148,794	(6,307)	128,330
Power derivatives	3,341	25,793	(3,158)	26,618
	12,983	231,615	(12,309)	209,159
	13,378	236,484	(12,779)	223,217
Of which – current	3,652		(9,083)	
– non-current	9,726		(3,696)	
Embedded derivatives held for trading				
Natural gas contracts	587	4,620	(3,098)	8,563
Interest rate contracts	–	–	(30)	150
	587	4,620	(3,128)	8,713

CASH FLOW HEDGES

At 31 December 2005, the group held forward currency contracts, cylinders and options that were being used to hedge the foreign currency risk of highly probable transactions. Changes in the fair value of instruments used as hedges are not recognized in the accounts until the position matures. The hedges were assessed to be highly effective.

An analysis of these changes in fair value is as follows:

$ million

	Net fair value
Fair value of cash flow hedges at 1 January 2005	198
Change in fair value during the year	(191)
Fair value recognized in income statement during the year	(8)
Fair value on capital expenditure hedging recycled into carrying value of assets during the year	(37)
Fair value of cash flow hedges at 31 December 2005	(38)

Cash flow hedges have the following maturities:

$ million

		2005
	Fair value asset	Fair value liability
Within one year	54	(108)
1 to 2 years	19	(17)
2 to 3 years	3	(3)
3 to 4 years	6	(1)
4 to 5 years	2	–
Over 5 years	7	–
	91	(129)

35 Derivative financial instruments *continued*

Derivative assets related to foreign exchange risks of cash flow hedges are denominated in the following currencies: $ million

					2005
	Currencies purchased forward				
	US dollar	Sterling	Euro	Other currencies	Total
Currencies sold forward					
US dollar	57	15	15	1	88
Sterling	–	–	3	–	3
	57	15	18	1	91

Derivative liabilities related to foreign exchange risks of cash flow hedges are denominated in the following currencies: $ million

					2005
	Currencies purchased forward				
	US dollar	Sterling	Euro	Other currencies	Total
Currencies sold forward					
US dollar	–	(70)	(40)	(19)	(129)

FAIR VALUE HEDGES

At 31 December 2005, the group held interest rate and currency swap contracts as fair value hedges of the interest rate risk on fixed rate debt issued by the group. These hedges were assessed to be highly effective. At 31 December 2005, the loss on fair value hedges included in the carrying value of fixed rate debt was $100 million.

Fair value hedges have the following maturities: $ million

		2005
	Fair value asset	Fair value liability
Within one year	185	(51)
1 to 2 years	–	(110)
2 to 3 years	15	(66)
3 to 4 years	23	(68)
4 to 5 years	–	(9)
Over 5 years	18	(37)
	241	(341)

Derivative assets related to foreign exchange risks of fair value hedges are denominated in the following currencies: $ million

					2005
	Currencies purchased forward				
	US dollar	Sterling	Euro	Other currencies	Total
Currencies sold forward					
US dollar	19	53	96	50	218
Sterling	–	–	17	–	17
Euro	–	–	6	–	6
	19	53	119	50	241

Derivative liabilities related to foreign exchange risks of fair value hedges are denominated in the following currencies: $ million

					2005
	Currencies purchased forward				
	US dollar	Sterling	Euro	Other currencies	Total
Currencies sold forward					
US dollar	(217)	(92)	–	(32)	(341)

The following table shows the fair value of contracts deferred on the balance sheet. This is where, at contract inception, derivatives are required to be recognized on the balance sheet at fair value, but any gain or loss is not recognized immediately but deferred on the balance sheet. The gain or loss is recognized in the income statement only when the full remaining term of the derivative can be valued against market inputs.

$ million

	Fair value interest rate contracts	Fair value exchange rate contracts
Fair value of contracts not recognized through the income statement at 1 January 2005	(73)	247
Fair value of new contracts at inception not recognized in the income statement	–	–
Fair value recycled from equity into the income statement	(3)	(109)
Other changes in fair values	(122)	(202)
Fair value of contracts not recognized through profit at 31 December 2005	(198)	(64)

35 Derivative financial instruments *continued*

HEDGES OF NET INVESTMENTS IN FOREIGN ENTITIES

At 31 December 2005, the group held currency swap contracts as a hedge of a long-term investment in a UK subsidiary. The hedge was assessed to be highly effective. At 31 December 2005, the hedge had a fair value of $63 million and the gain on the hedge recognized in equity was $58 million. US dollars have been sold forward for sterling purchased, with a maturity of 3 to 4 years.

DERIVATIVES HELD FOR TRADING

The group maintains active trading positions in a variety of derivatives. This activity is undertaken in conjunction with risk management activities. Derivatives held for trading purposes are marked-to-market and any gain or loss recognized in the income statement. For traded derivatives, many positions have been neutralized, with trading initiatives being concluded by taking opposite positions to fix a gain or loss, thereby achieving a zero net market risk.

The following table shows the fair value at 31 December of derivatives and other financial instruments held for trading purposes. The fair values at the year end are not materially unrepresentative of the position throughout the year.

Derivatives held for trading have the following maturities: $ million

	2005	
	Fair value asset	Fair value liability
Within one year	9,487	(8,924)
1 to 2 years	2,019	(2,155)
2 to 3 years	685	(677)
3 to 4 years	455	(278)
4 to 5 years	145	(121)
Over 5 years	192	(154)
	12,983	(12,309)

Derivative assets held for trading are denominated in the following currencies: $ million

	2005				
	Currency of denomination				
	US dollar	Sterling	Euro	Other currencies	Total
Functional currency					
US dollar	10,232	137	–	4	10,373
Sterling	–	1,106	1,504	–	2,610
	10,232	1,243	1,504	4	12,983

Derivative liabilities held for trading are denominated in the following currencies: $ million

	2005				
	Currency of denomination				
	US dollar	Sterling	Euro	Other currencies	Total
Functional currency					
US dollar	(9,223)	(110)	–	–	(9,333)
Sterling	–	(1,453)	(1,523)	–	(2,976)
	(9,223)	(1,563)	(1,523)	–	(12,309)

Derivative assets held for trading have the following contractual or notional values and maturities: $ million

	2005						
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total fair value
Currency derivatives							
Fair value	28	6	1	1	1	4	41
Notional value	358	73	51	28	32	92	634
Oil price derivatives							
Fair value	2,476	225	37	19	8	–	2,765
Notional value	52,260	3,378	676	45	35	–	56,394
Natural gas price derivatives							
Fair value	4,509	1,194	528	292	125	188	6,836
Notional value	113,897	17,562	8,560	4,021	2,068	2,686	148,794
Power price derivatives							
Fair value	2,474	594	119	143	11	–	3,341
Notional value	19,149	5,049	857	535	196	–	25,786

35 Derivative financial instruments *continued*

Derivative liabilities held for trading have the following contractual or notional values and maturities:

$ million

							2005
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total fair value
Currency derivatives							
Fair value	(12)	(4)	(1)	(1)	–	–	(18)
Notional value	1,013	177	119	170	67	141	1,687
Oil price derivatives							
Fair value	(2,486)	(275)	(26)	(20)	(19)	–	(2,826)
Notional value	49,732	2,276	446	35	35	–	52,524
Natural gas price derivatives							
Fair value	(3,967)	(1,319)	(591)	(187)	(89)	(154)	(6,307)
Notional value	90,916	25,269	6,457	2,903	1,577	1,208	128,330
Power price derivatives							
Fair value	(2,459)	(557)	(59)	(70)	(13)	–	(3,158)
Notional value	20,030	4,990	778	625	195	–	26,618

The following tables show the changes during the year in the net fair value of derivatives held for trading purposes for 2005.

$ million

	Fair value exchange rate contracts	Fair value oil price contracts	Fair value natural gas price contracts	Fair value power price contracts
Fair value of contracts at 1 January 2005	(54)	(171)	558	177
Contracts realized or settled in the year	23	175	(735)	76
Fair value of new contracts when entered into during the year	–	–	24	10
Fair value of over-the-counter options at inception	–	(73)	(65)	(9)
Change in fair value due to changes in valuation techniques or key assumptions	–	–	–	–
Other changes in fair values	54	8	747	(71)
Fair value of contracts at 31 December 2005	23	(61)	529	183

The following table shows the fair value of 'day one profit' deferred on the balance sheet.

$ million

	Fair value natural gas price contracts	Fair value power price contracts
Fair value of contracts not recognized through the income statement at 1 January 2005	(15)	–
Fair value of new contracts at inception not recognized in the income statement	(14)	(10)
Fair value recycled from equity into the income statement	–	–
Other changes in fair values	–	–
Fair value of contracts not recognized through profit at 31 December 2005	(29)	(10)

The following table shows the net fair value of derivatives held for trading at 31 December 2005 analysed by maturity period and by methodology of fair value estimation.

$ million

							2005
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total fair value
Prices actively quoted	(100)	(86)	46	42	33	(8)	(73)
Prices sourced from observable data or market corroboration	660	(48)	(41)	60	(11)	–	620
Prices based on models and other valuation methods	3	(2)	3	75	2	46	127
	563	(136)	8	177	24	38	674

Prices actively quoted refers to the fair value of contracts valued in whole using prices actively quoted, for example, exchange-traded and UK National Balancing Point (NBP) contracts. Prices provided by other external sources refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data or internal inputs, for example, swaps and physical forward contracts. Prices based on models and other valuation methods refers to the fair value of a contract valued in part using internal models due to the absence of quoted prices, including over-the-counter options. The net change in fair value of contracts based on models and other valuation methods during the year is a gain of $130 million.

35 Derivative financial instruments *continued*

Market risk exposure The group measures its market risk exposure, i.e. potential gain or loss in fair values, on its held-for-trading activity using value-at-risk techniques. These techniques are based on a variance/covariance model or a Monte Carlo simulation and make a statistical assessment of the market risk arising from possible future changes in market values over a 24-hour period. The calculation of the range of potential changes in fair value takes into account a snapshot of the end-of-day exposures and the history of one-day price movements, together with the correlation of these price movements. The group calculates value-at-risk for the bulk of instruments and exposures in the held-for-trading category, other than the UK North Sea natural gas embedded derivatives, for which a sensitivity analysis is calculated.

The group has previously calculated and published value-at-risk expressed to three standard deviations for the internal delegation of market risk limits and control purposes. This is equivalent to a 99.7% confidence interval or a probability of one day per year where the daily gain or loss will exceed the calculated value at risk if the portfolio was left unchanged. In order to improve the practical application of this tool, the group has adopted a 95% confidence level, or calculation to 1.65 standard deviations. This has the effect of increasing the expected frequency of occasions when the daily gain or loss may exceed the calculated value-at-risk to one per month if the portfolio is left unchanged. This provides a better opportunity for verifying models and assumptions and improving accuracy of the value-at-risk calculation. For completeness, 2005 value-at-risk data has been disclosed using both the 95% and 99.7% confidence levels. The value-at-risk model takes account of derivative financial instruments types such as interest rate forward and futures contracts, swap agreements, options and swaptions; foreign exchange forward and futures contracts, swap agreements and options, and oil, natural gas and power price futures, swap agreements and options. Financial assets and liabilities and physical crude oil and refined products that are treated as held for trading positions are also included in these calculations. The value-at-risk calculation for oil, natural gas and power price exposure also includes cash-settled commodity contracts such as forward contracts. For options, a linear approximation is included in the value-at-risk models.

The following table shows values at risk for held for trading activities described above.

Value at risk on three standard deviations — $ million

	2005			
	High	Low	Average	Year end
Interest rate trading	2	–	–	–
Foreign exchange trading	9	2	4	2
Oil price trading	145	31	60	56
Natural gas price trading	71	9	26	30
Power price trading	30	4	14	16

Value at risk on 1.65 standard deviations — $ million

	2005			
	High	Low	Average	Year end
Interest rate trading	1	–	–	–
Foreign exchange trading	5	1	2	1
Oil price trading	80	17	33	31
Natural gas price trading	39	6	15	17
Power price trading	16	2	7	9

The presentation of held-for-trading results shown in the table below includes the results of the group's trading units that involve the use of derivatives in conjunction with physical and paper trading of oil, natural gas and power. It is considered that a more comprehensive representation of the group's oil, natural gas and power price trading activities is given by aggregating the gain or loss on such derivatives, together with the gain or loss arising from the physical and paper trades to which they relate, representing the net result of the trading portfolio. Also included in the net result of the held-for-trading portfolio are broker fees, transportation costs and trader bonuses. Held-for-trading results include the results of risk management activity in respect of the group's supply and marketing activities that do not qualify for hedge accounting.

$ million

	2005
	Net gain (loss)
Interest rate trading	10
Foreign exchange trading	162
Oil trading	1,552
Natural gas trading	1,312
Power trading	(64)
	2,972

Gains and losses relating to derivative contracts presented net in the income statement are included within other operating revenues. These contract types include futures, options, swaps and certain forward sales and purchase contracts where delivery is routinely obviated by the sale or purchase of offsetting contracts. Also included are the gains and losses relating to the change in the fair value of all derivative contracts held at the balance sheet dates, including derivative contracts presented gross when settled. The gain for the year presented net in the income statement was $838 million (2004 $1,216 million and 2003 $1,081 million).

35 Derivative financial instruments *continued*

EMBEDDED DERIVATIVES HELD FOR TRADING

Prior to the development of an active gas trading market, UK gas contracts were priced using a basket of available price indices, primarily relating to oil products. Post the development of an active UK gas market, certain contracts were entered into or renegotiated using pricing formulae not directly related to gas prices, for example, oil product and power prices. In these circumstances, pricing formulae have been determined to be derivatives, embedded within the overall contractual arrangements that are not clearly and closely related to the underlying commodity. The resulting fair value relating to these contracts is recognized on the balance sheet with gains or losses recognized in the income statement.

These contracts are valued using price curves for each of the different products that are built up from active market pricing data and extrapolated to 2018 using the maximum available external pricing information. Additionally, where limited data exists for certain products, prices are interpolated using historic and long-term pricing relationships.

The fair values of embedded derivatives are included on the balance sheet within the following headings.

$ million

			2005
	Current	Non-current	Total
Prepayments and accrued income	330	257	587
Accruals and deferred income	(953)	(2,175)	(3,128)
	(623)	(1,918)	(2,541)

Embedded derivatives have the following maturities: $ million

		2005
	Fair value asset	Fair value liability
Within one year	330	(953)
1 to 2 years	176	(703)
2 to 3 years	76	(502)
3 to 4 years	5	(237)
4 to 5 years	–	(180)
Over 5 years	–	(553)
	587	(3,128)

Embedded derivative assets are denominated in the following currencies: $ million

					2005
					Currency of denomination
	US dollar	Sterling	Euro	Other currencies	Total
Functional currency					
US dollar	79	–	–	–	79
Sterling	–	508	–	–	508
	79	508	–	–	587

Embedded derivative liabilities are denominated in the following currencies: $ million

					2005
					Currency of denomination
	US dollar	Sterling	Euro	Other currencies	Total
Functional currency					
US dollar	(30)	–	–	–	(30)
Sterling	–	(3,098)	–	–	(3,098)
	(30)	(3,098)	–	–	(3,128)

Embedded derivative assets held for trading have the following contractual or notional values and maturities: $ million

							2005
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total fair value
Natural gas embedded derivatives							
Fair value	330	176	76	5	–	–	587
Notional value	425	484	465	450	429	2,367	4,620

Embedded derivative liabilities held for trading have the following contractual or notional values and maturities: $ million

							2005
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total fair value
Natural gas embedded derivatives							
Fair value	(953)	(703)	(472)	(237)	(180)	(553)	(3,098)
Notional value	740	870	1,097	832	767	4,257	8,563
Interest rate embedded derivatives							
Fair value	–	–	(30)	–	–	–	(30)
Notional value	–	–	150	–	–	–	150

35 Derivative financial instruments *continued*

The following table shows the changes during the year in the net fair value of embedded derivatives held for trading purposes for 2005.

$ million

	Fair value interest rate contracts	Fair value natural gas price contracts
Fair value of contracts at 1 January 2005	(17)	(659)
Contracts realized or settled in the year	–	138
Fair value of new contracts when entered into during the year	–	–
Change in fair value due to changes in valuation techniques or key assumptions	–	–
Other changes in fair values	(13)	(1,990)
Fair value of contracts at 31 December 2005	(30)	(2,511)

There are no fair value amounts for embedded derivatives held for trading that are deferred on the balance sheet.

The following table shows the net fair value of embedded derivatives held for trading purposes at 31 December 2005 analysed by maturity period and by methodology of fair value estimation.

$ million

							2005
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total fair value
Prices actively quoted	–	–	–	–	–	–	–
Prices sourced from observable data or market corroboration	51	28	–	–	–	–	79
Prices based on models and other valuation methods	(674)	(542)	(426)	(231)	(182)	(565)	(2,620)
	(623)	(514)	(426)	(231)	(182)	(565)	(2,541)

The net change in fair value of contracts based on models and other valuation methods during the year is a loss of $1,773 million.

Sensitivity analysis Detailed below for the embedded derivatives is a sensitivity of the fair value to immediate 10% favourable and adverse changes in the key assumptions.

	At 31 December 2005
Remaining contract terms	3 to 13 years
Contractual/notional amount	8,220 million therms
Discount rate – nominal risk free	4.5%
Fair value asset (liability)	$(2,590) million

$ million

	Natural gas price	Gas oil and fuel oil price	Power price	Discount rate
Favourable 10% change	408	30	(63)	34
Unfavourable 10% change	(427)	(45)	58	(34)

These sensitivities are hypothetical and should not be considered to be predictive of future performance. Changes in fair value generally cannot be extrapolated because the relationship of change in assumption to change in fair value may not be linear. Also, in this table, the effect of a variation in a particular assumption on the fair value of the embedded derivatives is calculated independently of any change in another assumption. In reality, changes in one factor may contribute to changes in another, which may magnify or counteract the sensitivities. Furthermore, the estimated fair values as disclosed should not be considered indicative of future earnings on these contracts.

The trading result of embedded derivatives held for trading is shown below.

$ million

	2005
	Net gain (loss)
Natural gas embedded derivatives	(2,034)
Interest rate embedded derivatives	(13)
	(2,047)

36 Financial instruments (UK GAAP)

The following information for 2004 and 2003 shows certain of the disclosures required by UK GAAP (FRS 13 'Derivatives and Other Financial Instruments: Disclosures') (FRS 13).

Financial instruments comprise primary financial instruments (cash and cash equivalents, trade and other receivables, loans, other investments, trade and other payables, finance debt and provisions) and derivative financial instruments (interest rate contracts, foreign exchange contracts, oil price contracts, natural gas price contracts and power price contracts). Interest rate contracts include futures contracts, swap agreements and options. Foreign exchange contracts include forwards, futures contracts, swap agreements and options. Oil, natural gas and power price contracts are those that require settlement in cash and include futures contracts, swap agreements and options. Oil, natural gas and power price contracts that require physical delivery are not financial instruments. However, if it is normal market practice for a particular type of oil, natural gas and power contract, despite having contract terms that require settlement by delivery, to be extinguished other than by physical delivery (e.g. by cash payment), it is called a cash-settled commodity contract. Contracts of this type are included with derivatives in the disclosures in Notes 37 and 38.

With the exception of the table of currency exposures shown on page 80, short-term trade and other receivables and trade and other payables that arise directly from the group's operations have been excluded from the disclosures contained in this note, as permitted by FRS 13.

36 Financial instruments (UK GAAP) *continued*

MATURITY PROFILE OF FINANCIAL LIABILITIES

The profile of the maturity of the financial liabilities included in the group's balance sheet at 31 December is shown in the table below.

$ million

	2004			2003		
	Finance debt	Other financial liabilities	Total	Finance debt	Other financial liabilities	Total
Due within						
1 year	10,184	5,152	15,336	9,456	4,857	14,313
1 to 2 years	3,046	2,640	5,686	2,702	1,617	4,319
2 to 5 years	6,105	810	6,915	5,105	2,034	7,139
Thereafter	3,756	1,603	5,359	5,062	2,042	7,104
	23,091	10,205	33,296	22,325	10,550	32,875

INTEREST RATE AND CURRENCY OF FINANCIAL LIABILITIES

The interest rate and currency profile of the financial liabilities of the group at 31 December, after taking into account the effect of interest rate swaps, currency swaps and forward contracts, is set out below.

	Fixed rate			Floating rate		Interest free		
	Weighted average interest rate %	Weighted average time for which rate is fixed Years	Amount $ million	Weighted average interest rate %	Amount $ million	Weighted average time until maturity Years	Amount $ million	Total $ million
								2004
Finance debt								
US dollar	7	11	707	3	21,789	–	–	22,496
Sterling	–	–	–	5	96	–	–	96
Other currencies	9	15	167	4	332	–	–	499
			874		22,217		–	23,091
Other financial liabilities								
US dollar	3	2	1,522	5	573	4	6,561	8,656
Sterling	–	–	–	–	–	4	716	716
Other currencies	4	4	15	2	46	4	772	833
			1,537		619		8,049	10,205
Total			2,411		22,836		8,049	33,296
								2003
Finance debt								
US dollar	8	14	578	2	20,991	–	–	21,569
Sterling	–	–	–	4	107	–	–	107
Other currencies	9	15	141	3	508	–	–	649
			719		21,606			22,325
Other financial liabilities								
US dollar	3	3	2,899	6	242	4	5,552	8,693
Sterling	–	–	–	–	–	5	716	716
Other currencies	5	4	303	–	–	6	838	1,141
			3,202		242		7,106	10,550
Total			3,921		21,848		7,106	32,875

$ million

	2004	2003
Analysis of the above financial liabilities by balance sheet caption		
Current liabilities		
Finance debt	10,184	9,456
Derivative financial instruments	5,074	4,145
Provisions	78	214
Non-current liabilities		
Other payables	3,581	4,630
Derivative financial instruments	158	344
Finance debt	12,907	12,869
Provisions	1,314	1,217
	33,296	32,875

The other financial liabilities comprise various accruals, sundry creditors and provisions relating to the group's normal commercial operations, with payment dates spread over a number of years.

The proportion of floating rate debt at 31 December 2004 was 96% of total finance debt outstanding. Aside from debt issued in the US municipal bond markets, interest rates on floating rate debt denominated in US dollars are linked principally to London Inter-Bank Offer Rate (LIBOR), while rates on debt in other currencies are based on local market equivalents. The group monitors interest rate risk using a process of sensitivity analysis. Assuming no changes to the finance debt and hedges described above, it is estimated that a change of 1% in the general level of interest rates on 1 January 2005 would change 2005 profit before tax by approximately $215 million.

36 Financial instruments (UK GAAP) *continued*

Interest rate swaps and futures are used by the group to modify the interest characteristics of its long-term finance debt from a fixed to a floating rate basis or vice versa. The following table indicates the types of instruments used and their weighted average interest rates as at 31 December.

	$ million except percentages	
	2004	2003
Receive fixed rate swaps – notional amount	8,182	7,432
Average receive fixed rate	3.1%	3.1%
Average pay floating rate	2.3%	1.1%

CURRENCY EXCHANGE RATE RISK

The monetary assets and monetary liabilities of the group in currencies other than the functional currency of individual operating units are summarized below. These currency exposures arise from normal trading activities.

					$ million
	Net foreign currency monetary assets (liabilities)				
Functional currency	US dollar	Sterling	Euro	Other currencies	Total
					2004
US dollar	–	374	2	(942)	(566)
Sterling	314	–	380	66	760
Other currencies	(269)	(51)	(25)	(237)	(582)
Total	45	323	357	(1,113)	(388)
					2003
US dollar	–	191	(24)	39	206
Sterling	67	–	308	34	409
Other currencies	(1,148)	(25)	(27)	(131)	(1,331)
Total	(1,081)	166	257	(58)	(716)

In accordance with its policy for managing foreign exchange rate risk, the group enters into various types of foreign exchange contracts, such as currency swaps, forwards and options. The fair values and carrying amounts of these derivatives are shown in the fair value table in Note 38.

INTEREST RATE AND CURRENCY OF FINANCIAL ASSETS

The following table shows the interest rate and currency profile of the group's material financial assets at 31 December.

	Fixed rate			Floating rate		Interest free		
	Weighted average interest rate %	Weighted average time for which rate is fixed Years	Amount $ million	Weighted average interest rate %	Amount $ million	Weighted average time until maturity Years	Amount $ million	Total $ million
								2004
US dollar	10	11	72	4	661	5	5,224	5,957
Sterling	8	2	101	3	428	5	864	1,393
Other currencies	–	–	–	3	830	5	1,221	2,051
			173		1,919		7,309	9,401
								2003
US dollar	–	–	–	3	1,015	4	2,060	3,075
Sterling	8	2	91	3	947	5	560	1,598
Other currencies	3	2	19	4	697	5	2,073	2,789
			110		2,659		4,693	7,462

		$ million
	2004	2003
Analysis of the above financial assets by balance sheet caption		
Non-current assets		
Other investments	394	1,452
Loans	811	852
Other receivables	429	495
Derivative financial instruments	898	534
Current assets		
Loans	193	182
Derivative financial instruments	5,317	1,891
Cash and cash equivalents	1,359	2,056
	9,401	7,462

The floating rate financial assets earn interest at various rates set principally with respect to LIBOR or the local market equivalent. Fixed asset investments included in the table above are held for the long term and have no maturity period. They are excluded from the calculation of weighted average time until maturity. Similarly, cash and cash equivalents and derivative financial instruments, which are highly liquid financial assets, are excluded from the calculation of weighted average time until maturity.

37 Derivative financial instruments (UK GAAP)

The following information for 2004 and 2003 shows certain of the disclosures required by UK GAAP (FRS 13 'Derivatives and other Financial Instruments: Disclosures').

The group uses derivative financial instruments (derivatives) to manage certain exposures to fluctuations in foreign currency exchange rates and interest rates and to manage some of its margin exposure from changes in oil, natural gas and power prices. Derivatives are also traded in conjunction with these risk management activities.

The purpose for which a derivative contract is used is identified at inception. To qualify as a derivative for risk management, the contract must be in accordance with established guidelines that ensure it is effective in achieving its objective. All contracts not identified at inception as being for the purpose of risk management are designated as being held for trading purposes and accounted for using the fair value method, as are all oil price derivatives.

The group accounts for derivatives using the following methods:

Fair value method Derivatives are carried on the balance sheet at fair value ('marked to market'), with changes in that value recognized in earnings of the period. This method is used for all derivatives that are held for trading purposes. Interest rate contracts traded by the group include futures, swaps, options and swaptions. Foreign exchange contracts traded include forwards and options. Oil, natural gas and power price contracts traded include swaps, options and futures.

Accrual method Amounts payable or receivable in respect of derivatives are recognized ratably in earnings over the period of the contracts. This method is used for derivatives held to manage interest rate risk. These are principally swap agreements used to manage the balance between fixed and floating interest rates on long-term finance debt. Other derivatives held for this purpose may include swaptions and futures contracts. Amounts payable or receivable in respect of these derivatives are recognized as adjustments to interest expense over the period of the contracts. Changes in the derivative's fair value are not recognized.

Deferral method Gains and losses from derivatives are deferred and recognized in earnings or as adjustments to carrying amounts, as appropriate, when the underlying debt matures or the hedged transaction occurs. This method is used for derivatives used to convert non-US dollar borrowings into US dollars, to hedge significant non-US dollar firm commitments or anticipated transactions, and to manage some of the group's exposure to natural gas and power price fluctuations. Derivatives used to convert non-US dollar borrowings into US dollars include foreign currency swap agreements and forward contracts. Gains and losses on these derivatives are deferred and recognized on maturity of the underlying debt, together with the matching loss or gain on the debt. Derivatives used to hedge significant non-US dollar transactions include foreign currency forward contracts and options and to hedge natural gas and power price exposures include swaps, futures and options. Gains and losses on these contracts and option premiums paid are also deferred and recognized in the income statement or as adjustments to carrying amounts, as appropriate, when the hedged transaction occurs.

Where derivatives used to manage interest rate risk or to convert non-US dollar debt or to hedge other anticipated cash flows are terminated before the underlying debt matures or the hedged transaction occurs, the resulting gain or loss is recognized on a basis that matches the timing and accounting treatment of the underlying debt or hedged transaction. When an anticipated transaction is no longer likely to occur or finance debt is terminated before maturity, any deferred gain or loss that has arisen on the related derivative is recognized in the income statement, together with any gain or loss on the terminated item.

RISK MANAGEMENT

Gains and losses on derivatives used for risk management purposes are deferred and recognized in earnings or as adjustments to carrying amounts, as appropriate, when the underlying debt matures or the hedged transaction occurs. When an anticipated transaction is no longer likely to occur or finance debt is terminated before maturity, any deferred gain or loss that has arisen on the related derivative is recognized in the income statement, together with any gain or loss on the terminated item. Where such derivatives used for hedging purposes are terminated before the underlying debt matures or the hedged transaction occurs, the resulting gain or loss is recognized on a basis that matches the timing and accounting treatment of the underlying hedged item. The unrecognized and carried-forward gains and losses on derivatives used for hedging, and the movements therein, are shown in the following table:

$ million

	Unrecognized			Carried forward in the balance sheet		
	Gains	Losses	Total	Gains	Losses	Total
Gains and losses at 1 January 2004	331	(130)	201	1,003	(425)	578
of which accounted for in income in 2004	98	(28)	70	438	(75)	363
Gains and losses at 31 December 2004	487	(408)	79	1,063	(364)	699
of which expected to be recognized in income in 2005	259	(267)	(8)	265	(77)	188
Gains and losses at 1 January 2003	526	(450)	76	352	(28)	324
of which accounted for in income in 2003	96	(51)	45	200	(14)	186
Gains and losses at 31 December 2003	331	(130)	201	1,003	(425)	578
of which expected to be recognized in income in 2004	98	(28)	70	438	(75)	363

TRADING ACTIVITIES

The group maintains active trading positions in a variety of derivatives. This activity is undertaken in conjunction with risk management activities. Derivatives held for trading purposes are marked-to-market and any gain or loss recognized in the income statement. For traded derivatives, many positions have been neutralized, with trading initiatives being concluded by taking opposite positions to fix a gain or loss, thereby achieving a zero net market risk.

37 Derivative financial instruments (UK GAAP) *continued*

The following table shows the fair value at 31 December of derivatives and other financial instruments held for trading purposes. The fair values at the year end are not materially unrepresentative of the position throughout the year.

$ million

	2004		2003	
	Fair value asset	Fair value liability	Fair value asset	Fair value liability
Interest rate contracts	–	–	–	–
Foreign exchange contracts	36	(90)	30	(54)
Oil price contracts	1,162	(1,177)	586	(667)
Natural gas price contracts	802	(624)	858	(711)
Power price contracts	82	(12)	548	(514)
	2,082	(1,903)	2,022	(1,946)

The group measures its market risk exposure, i.e. potential gain or loss in fair values, on its trading activity using value-at-risk techniques.

These techniques are based on a variance/covariance model or a Monte Carlo simulation and make a statistical assessment of the market risk arising from possible future changes in market values over a 24-hour period. The calculation of the range of potential changes in fair value takes into account a snapshot of the end-of-day exposures and the history of one-day price movements over the previous 12 months, together with the correlation of these price movements. The potential movement in fair values is expressed to three standard deviations, which is equivalent to a 99.7% confidence level. This means that, in broad terms, one would expect to see an increase or a decrease in fair values greater than the value at risk on only one occasion per year if the portfolio were left unchanged.

The group calculates value at risk on all instruments that are held for trading purposes and that therefore give an exposure to market risk. The value-at-risk model takes account of derivative financial instruments such as interest rate forward and futures contracts, swap agreements, options and swaptions; foreign exchange forward and futures contracts, swap agreements and options; and oil, natural gas and power price futures, swap agreements and options. Financial assets and liabilities and physical crude oil and refined products that are treated as trading positions are also included in these calculations. The value-at-risk calculation for oil, natural gas and power price exposure also includes cash-settled commodity contracts such as forward contracts.

The following table shows values at risk for trading activities.

$ million

				2004
	High	Low	Average	Year end
Interest rate trading	1	–	–	–
Foreign exchange trading	4	1	1	1
Oil price trading	55	18	29	45
Natural gas price trading	23	6	13	10
Power price trading	10	1	4	4

$ million

				2003
	High	Low	Average	Year end
Interest rate trading	1	–	–	–
Foreign exchange trading	4	–	2	1
Oil price trading	34	17	26	27
Natural gas price trading	29	4	16	18
Power price trading	13	–	4	6

The presentation of trading results shown in the table below includes certain activities of BP's trading units that involve the use of derivative financial instruments in conjunction with physical and paper trading of oil, natural gas and power. It is considered that a more comprehensive representation of the group's oil, natural gas and power price trading activities is given by aggregating the gain or loss on such derivatives together with the gain or loss arising from the physical and paper trades to which they relate, representing the net result of the trading portfolio.

$ million

	2004	2003
	Net gain (loss)	Net gain (loss)
Interest rate trading	4	9
Foreign exchange trading	136	118
Oil price trading	1,371	825
Natural gas price trading	461	341
Power price trading	160	119
	2,132	1,412

38 Fair values of financial assets and liabilities (UK GAAP)

The following information for 2004 and 2003 shows certain of the disclosures required by UK GAAP (FRS 13 'Derivatives and other Financial Instruments: Disclosures').

The estimated fair value of the group's financial instruments is shown in the table below. The table also shows the 'net carrying amount' of the financial asset or liability. This amount represents the net book value, i.e. market value when acquired or later marked-to-market. Interest rate contracts include futures contracts, swap agreements and options. Foreign exchange contracts include forward and futures contracts, swap agreements and options. Oil, natural gas and power price contracts include futures contracts, swap agreements and options and cash-settled commodity contracts such as forward contracts.

Short-term trade and other receivables and trade and other payables that arise directly from the group's operations have been excluded from the disclosures contained in this note, as permitted by FRS 13.

The fair value and carrying amounts of finance debt shown below exclude the effects of currency swaps, interest rate swaps and forward contracts (which are included for presentation in the balance sheet). Long-term borrowings in the table below include debt that matures in the year from 31 December 2004, whereas in the balance sheet long-term debt of current maturity is reported under amounts falling due within one year. Long-term borrowings also include US Industrial Revenue/Municipal Bonds classified on the balance sheet as repayable within one year.

$ million

	2004		2003	
	Net fair value asset (liability)	Net carrying amount asset (liability)	Net fair value asset (liability)	Net carrying amount asset (liability)
Non-current assets				
Other investments	738	394	3,380	1,452
Loans	811	811	852	852
Other receivables	429	429	495	495
Derivative financial instruments	898	898	534	534
Current assets				
Loans	193	193	182	182
Derivative financial instruments	5,317	5,317	1,891	1,891
Cash and cash equivalents	1,359	1,359	2,056	2,056
Finance debt				
Short-term borrowings	(5,003)	(5,003)	(5,059)	(5,059)
Long-term borrowings	(16,800)	(16,344)	(16,190)	(15,559)
Net obligations under finance leases	(2,608)	(2,579)	(2,479)	(2,452)
Derivative financial instruments	1,084	835	941	745
Non-current liabilities				
Other payables	(3,581)	(3,581)	(4,630)	(4,630)
Provisions	(1,314)	(1,314)	(1,217)	(1,217)
Derivative financial instruments	(158)	(158)	(344)	(344)
Current liabilities				
Derivative financial instruments	(5,074)	(5,074)	(4,145)	(4,145)
Provisions	(78)	(78)	(214)	(214)

The following methods and assumptions were used by the group in estimating its fair value disclosures for its financial instruments:

Non-current assets – Other investments The fair value of listed fixed asset investments has been determined by reference to market prices. The carrying amount reported in the balance sheet for unlisted fixed asset investments approximates their fair value.

Non-current assets – Loans The loans generally bear interest at floating rates, so the fair value of loans is estimated not to be materially different from its carrying value.

Non-current assets – Other receivables The fair value of other receivables is estimated not to be materially different from its carrying value.

Current assets – Loans The loans generally bear interest at floating rates, so the fair value of loans is estimated not to be materially different from its carrying value.

Current assets – Cash and cash equivalents As a result of their short maturities, the carrying value of cash equivalents approximates their fair value.

Finance debt The carrying amount of the group's short-term borrowings, which mainly comprise commercial paper, bank loans and overdrafts, approximates their fair value. The fair value of the group's long-term borrowings and finance lease obligations is estimated using quoted prices or, where these are not available, discounted cash flow analyses, based on the group's current incremental borrowing rates for similar types and maturities of borrowing. Swaps and forward contracts used to hedge finance debt is offset against the carrying value of the debt.

Non-current liabilities – Other payables Deferred consideration for the acquisition of our interest in TNK-BP is discounted to the present value of the future payments. The carrying value thus approximates the fair value. The remaining liabilities are predominantly interest-free. In view of their short maturities, the reported carrying amount is estimated to approximate the fair value.

Non-current liabilities – Provisions Where the liability will not be settled for a number of years, the amount recognized is the present value of the estimated future expenditure. The carrying amount of provisions thus approximates the fair value.

Current liabilities – Provisions Where the liability will not be settled for a number of years, the amount recognized is the present value of the estimated future expenditure. The carrying amount of provisions thus approximates the fair value.

Derivative financial instruments (including cash-settled commodity contracts) The fair values of the group's interest rate and foreign exchange contracts are based on pricing models that take into account relevant market data. The fair value of the group's oil, natural gas and power price contracts (future contracts, swap agreements, options and forward contracts) is based on market prices.

39 Finance debt

$ million

	2005			2004			2003		
	Within 1 year	After 1 year	Total	Within 1 year	After 1 year	Total	Within 1 year	After 1 year	Total
Bank loans	155	547	702	250	457	707	205	253	458
Other loans	8,717	8,962	17,679	9,819	10,167	19,986	9,161	10,524	19,685
Total borrowings	8,872	9,509	18,381	10,069	10,624	20,693	9,366	10,777	20,143
Net obligations under finance leases	60	721	781	115	2,283	2,398	90	2,092	2,182
	8,932	10,230	19,162	10,184	12,907	23,091	9,456	12,869	22,325

Included within Other loans repayable within one year above are US Industrial Revenue/Municipal Bonds of $2,462 million (2004 $2,344 million and 2003 $2,362 million) with maturity periods ranging from 2 to 35 years. They are classified as repayable within one year, as required under IFRS, as the bondholders typically have the option to tender these bonds for repayment on interest reset dates. Any bonds that are tendered are usually remarketed and BP has not experienced any significant repurchases. BP considers these bonds to represent long-term funding when assessing the maturity profile of its finance debt and they are reflected as such in the borrowings repayment schedule below. Other similar loans linked to long-term gas supply contracts of $992 million (2004 $280 million and 2003 nil) that mature over 10 years have been reported in the same way.

At 31 December 2005, the group had substantial amounts of undrawn borrowing facilities available, including committed facilities of $4,500 million expiring in 2006 ($4,500 million expiring in 2005 and $3,700 million expiring in 2004). These facilities are with a number of international banks and borrowings under them would be at pre-agreed rates. The group expects to renew the facilities on an annual basis. Certain of these facilities support the group's commercial paper programme.

At 31 December 2005, the group's share of third-party finance debt of jointly controlled entities and associates was $3,266 million (2004 $2,821 million and 2003 $2,151 million) and $970 million (2004 $1,048 million and 2003 $922 million) respectively. These amounts are not reflected in the group's debt on the balance sheet.

Under UK GAAP, where finance debt is swapped into another currency, the finance debt is accounted in the swap currency and not in the original currency of denomination. Total finance debt in 2004 and 2003 included an asset of $835 million and $745 million respectively for the carrying value of currency swaps and forward contracts.

FAIR VALUES OF FINANCE DEBT

For 2005, the estimated fair value of finance debt is shown in the table below together with the carrying amount as reflected in the balance sheet. Both the fair value and the carrying amount include the effects of currency swaps, interest rate swaps and forward contracts.

Long-term borrowings in the table below include debt that matures in the year from 31 December 2005, whereas in the balance sheet the amount would be reported under current liabilities. Long-term borrowings also include US Industrial Revenue/Municipal Bonds classified on the balance sheet as current liabilities.

The carrying value of the group's short-term borrowings, comprising mainly commercial paper, bank loans and overdrafts, approximates their fair value. The fair value of the group's long-term borrowings and finance lease obligations is estimated using quoted prices or, where these are not available, discounted cash flow analyses based on the group's current incremental borrowing rates for similar types and maturities of borrowing.

$ million

	2005	
	Fair value	Carrying amount
Short-term borrowings	3,297	3,297
Long-term borrowings	15,313	15,084
Net obligations under finance leases	803	781
Total finance debt	19,413	19,162

$ million

	2005			2004			2003		
Analysis of borrowings by year of expected repayment	Bank loans	Other loans	Total	Bank loans	Other loans	Total	Bank loans	Other loans	Total
Due after 10 years	–	2,842	2,842	1	2,845	2,846	–	2,865	2,865
Due within 10 years	18	203	221	29	68	97	–	24	24
9 years	21	182	203	20	83	103	–	377	377
8 years	24	188	212	22	478	500	–	291	291
7 years	26	558	584	28	330	358	–	–	–
6 years	34	446	480	36	139	175	7	1,737	1,744
5 years	35	537	572	33	1,742	1,775	7	996	1,003
4 years	35	2,223	2,258	29	1,579	1,608	8	1,362	1,370
3 years	98	2,219	2,317	251	2,510	2,761	193	2,593	2,786
2 years	256	3,018	3,274	8	3,017	3,025	38	2,641	2,679
	547	12,416	12,963	457	12,791	13,248	253	12,886	13,139
1 year	155	5,263	5,418	250	7,195	7,445	205	6,799	7,004
	702	17,679	18,381	707	19,986	20,693	458	19,685	20,143
Amounts included above repayable by instalments, part of which falls due after five years from 31 December, are as follows:									
After 5 years			192			204			14
Within 5 years			118			76			82
			310			280			96

39 Finance debt *continued*

Interest rates on borrowings repayable wholly or partly more than five years from 31 December 2005 range from 2% to 12%, with a weighted average of 5%. The weighted average interest rate on finance debt is 5%.

	Fixed rate			Floating rate		Interest free		
	Weighted average interest rate %	Weighted average time for which rate is fixed Years	Amount $ million	Weighted average interest rate %	Amount $ million	Weighted average time until maturity Years	Amount $ million	Total $ million
								2005
US dollar	7	11	665	5	18,073	–	–	18,738
Sterling	–	–	–	6	76	–	–	76
Euro	–	–	–	3	150	–	–	150
Other currencies	9	14	157	12	41	–	–	198
			822		18,340		–	19,162
								2004
US dollar	7	11	707	3	21,789	–	–	22,496
Sterling	–	–	–	5	96	–	–	96
Euro	–	–	–	3	297	–	–	297
Other currencies	9	15	167	8	35	–	–	202
			874		22,217		–	23,091
								2003
US dollar	8	14	578	2	20,991	–	–	21,569
Sterling	–	–	–	4	107	–	–	107
Euro	–	–	–	3	125	–	–	125
Other currencies	9	15	141	3	383	–	–	524
			719		21,606		–	22,325

The proportion of floating rate debt at 31 December 2005 was 96% of total finance debt outstanding. Aside from debt issued in the US municipal bond markets, interest rates on floating rate debt denominated in US dollars are linked principally to London Inter-Bank Offer Rate (LIBOR), while rates on debt in other currencies are based on local market equivalents. The group monitors interest rate risk using a process of sensitivity analysis. Assuming no changes to the finance debt and hedges described above, it is estimated that a change of 1% in the general level of interest rates on 1 January 2006 would change 2006 profit before tax by approximately $180 million.

The group uses finance leases to acquire property, plant and equipment. These leases have terms of renewal but no purchase options and escalation clauses. Renewals are at the option of the lessee. During the year, the group terminated its finance leases on the petrochemicals manufacturing plant at Grangemouth, Scotland. Future minimum lease payments under finance leases are set out below.

			$ million
Obligations under finance leases	2005	2004	2003
Minimum future lease payments payable within			
1 year	78	152	127
2 to 5 years	320	1,060	979
Thereafter	838	3,540	3,528
	1,236	4,752	4,634
Less finance charges	455	2,354	2,452
Net obligations	781	2,398	2,182
Of which – payable within 1 year	60	115	90
– payable within 2 to 5 years	133	187	111
– payable thereafter	588	2,096	1,981

40 Analysis of changes in net debt

Net debt is current and non-current finance debt less cash and cash equivalents. The net debt ratio is the ratio of net debt to net debt plus total equity. The net debt ratio at 31 December 2005 was 17% (2004 22% and 2003 22%).

$ million

			2005			2004			2003
Movement in net debt	Finance debt	Cash and cash equivalents	Net debt	Finance debt	Cash and cash equivalents	Net debt	Finance debt	Cash and cash equivalents	Net debt
At 1 January	(23,091)	1,359	(21,732)	(22,325)	2,056	(20,269)	(22,008)	1,716	(20,292)
Adoption of IAS 39	(147)	–	(147)	–	–	–	–	–	–
Restated	(23,238)	1,359	(21,879)	(22,325)	2,056	(20,269)	(22,008)	1,716	(20,292)
Exchange adjustments	(44)	(88)	(132)	(403)	91	(312)	(199)	121	(78)
Debt acquired	–	–	–	–	–	–	(15)	–	(15)
Net cash flow	3,803	1,689	5,492	(431)	(788)	(1,219)	(760)	219	(541)
Fair value hedge adjustment	171	–	171	–	–	–	–	–	–
Debt transferred to TNK-BP	–	–	–	–	–	–	93	–	93
Exchange of Exchangeable Bonds for			–						
Lukoil American Depositary Shares	–	–	–	–	–	–	420	–	420
Other movements	146	–	146	68	–	68	144	–	144
At 31 December	(19,162)	2,960	(16,202)	(23,091)	1,359	(21,732)	(22,325)	2,056	(20,269)
Equity			80,765			78,235			70,264

41 Provisions

$ million

	Decom-missioning	Environ-mental	Litigation and other	Total
At 1 January 2005	5,572	2,457	1,570	9,599
Exchange adjustments	(38)	(32)	(35)	(105)
New provisions	1,023	565	1,464	3,052
Write-back of unused provisions	–	(335)	(86)	(421)
Unwinding of discount	122	47	32	201
Utilization	(128)	(366)	(650)	(1,144)
Deletions	(101)	(25)	–	(126)
At 31 December 2005	6,450	2,311	2,295	11,056
Of which – expected to be incurred within 1 year	162	489	451	1,102
– expected to be incurred in more than 1 year	6,288	1,822	1,844	9,954

$ million

	Decom-missioning	Environ-mental	Litigation and other	Total
At 1 January 2004	4,720	2,298	1,581	8,599
Exchange adjustments	213	21	25	259
New provisions	286	587	298	1,171
Write-back of unused provisions	–	(151)	(64)	(215)
Unwinding of discount	118	55	23	196
Change in discount rate	434	40	1	475
Utilization	(87)	(393)	(294)	(774)
Deletions	(112)	–	–	(112)
At 31 December 2004	5,572	2,457	1,570	9,599
Of which – expected to be incurred within 1 year	124	513	78	715
– expected to be incurred in more than 1 year	5,448	1,944	1,492	8,884

$ million

	Decom-missioning	Environ-mental	Litigation and other	Total
At 1 January 2003	4,168	2,122	1,546	7,836
Exchange adjustments	257	28	28	313
New provisions	1,159	599	331	2,089
Write-back of unused provisions	–	(84)	(64)	(148)
Unwinding of discount	107	46	20	173
Utilization	(121)	(337)	(273)	(731)
Deletions	(850)	(76)	(7)	(933)
At 31 December 2003	4,720	2,298	1,581	8,599
Of which – expected to be incurred within 1 year	99	272	364	735
– expected to be incurred in more than 1 year	4,621	2,026	1,217	7,864

41 Provisions *continued*

The group makes full provision for the future cost of decommissioning oil and natural gas production facilities and related pipelines on a discounted basis on the installation of those facilities. At 31 December 2005, the provision for the costs of decommissioning these production facilities and pipelines at the end of their economic lives was $6,450 million (2004 $5,572 million and 2003 $4,720 million). The provision has been estimated using existing technology, at current prices and discounted using a real discount rate of 2.0% (2004 2.0% and 2003 2.5%). These costs are expected to be incurred over the next 30 years. While the provision is based on the best estimate of future costs and the economic lives of the facilities and pipelines, there is uncertainty regarding both the amount and timing of incurring these costs.

Provisions for environmental remediation are made when a clean-up is probable and the amount reasonably determinable. Generally, this coincides with commitment to a formal plan of action or, if earlier, on divestment or closure of inactive sites. The provision for environmental liabilities at 31 December 2005 was $2,311 million (2004 $2,457 million and 2003 $2,298 million). The provision has been estimated using existing technology, at current prices and discounted using a real discount rate of 2.0% (2004 2.0% and 2003 2.5%). The majority of these costs are expected to be incurred over the next 10 years. The extent and cost of future remediation programmes are inherently difficult to estimate. They depend on the scale of any possible contamination, the timing and extent of corrective actions, and also the group's share of liability.

The group also holds provisions for litigation, expected rental shortfalls on surplus properties, and sundry other liabilities. Included within the new provisions made for 2005 is an amount of $700 million in respect of the Texas City incident of which $492 million has been disbursed to claimants. To the extent that these liabilities are not expected to be settled within the next three years, the provisions are discounted using either a nominal discount rate of 4.5% (2004 4.5% and 2003 4.5%) or a real discount rate of 2.0% (2004 2.0% and 2003 2.5%), as appropriate.

42 Pensions and other post-retirement benefits

Most group companies have pension plans, the forms and benefits of which vary with conditions and practices in the countries concerned. Pension benefits may be provided through defined contribution plans (money purchase schemes) or defined benefit plans (final salary and other types of schemes with committed pension payments). For defined contribution plans, retirement benefits are determined by the value of funds arising from contributions paid in respect of each employee. For defined benefit plans, retirement benefits are based on such factors as the employees' pensionable salary and length of service. Defined benefit plans may be externally funded or unfunded. The assets of funded plans are generally held in separately administered trusts.

Contributions to funded defined benefit plans are based on advice from independent actuaries using actuarial methods, the objective of which is to provide adequate funds to meet pension obligations as they fall due. During 2005, contributions of $340 million (2004 $249 million and 2003 $258 million) and $279 million (2004 $30 million and 2003 $2,189 million) were made to the UK plans and US plans respectively. In addition, contributions of $140 million (2004 $116 million and 2003 $86 million) were made to other funded defined benefit plans. The aggregate level of contributions in 2006 is expected to be approximately $750 million.

Certain group companies, principally in the US, provide post-retirement healthcare and life insurance benefits to their retired employees and dependants. The entitlement to these benefits is usually based on the employee remaining in service until retirement age and completion of a minimum period of service. The plans are funded to a limited extent.

The cost of providing pensions and other post-retirement benefits is assessed annually by independent actuaries using the projected unit method. The date of the most recent actuarial review was 31 December 2005.

The material financial assumptions used for estimating the benefit obligations of the various plans are set out below. The assumptions used to evaluate accrued pension and other post-retirement benefits at 31 December in any year are used to determine pension and other post-retirement expense for the following year, that is, the assumptions at 31 December 2005 are used to determine the pension liabilities at that date and the pension cost for 2006.

									%
			UK			USA			Other
	2005	2004	2003	2005	2004	2003	2005	2004	2003
Discount rate for plan liabilities	4.75	5.25	5.5	5.50	5.75	6.0	4.0	5.0	5.5
Rate of increase in salaries	4.25	4.0	4.0	4.25	4.0	4.0	3.25	4.0	4.0
Rate of increase for pensions in payment	2.5	2.5	2.5	nil	nil	nil	1.75	2.5	2.5
Rate of increase in deferred pensions	2.5	2.5	2.5	nil	nil	nil	1.0	2.5	2.5
Inflation	2.5	2.5	2.5	2.50	2.5	2.5	2.0	2.5	2.5

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 tables adjusted where appropriate to reflect the experience of the group. BP's most substantial pension liabilities are in the UK and US, where these tables lead to a further life expectancy for a male/female currently aged 60 of 23/26 years in the UK and 22/26 years in the US.

Assumed future US healthcare cost trend rate

								%
	2006	2007	2008	2009	2010	2011	2012	2013 and subsequent years
Beneficiaries aged under 65	9.0	8.0	7.0	6.0	5.5	5.0	5.0	5.0
Beneficiaries aged over 65	11.0	9.5	8.5	7.5	6.5	6.0	5.5	5.0

42 Pensions and other post-retirement benefits *continued*

BP's post-retirement medical plans in the US provide among other things prescription drug coverage for Medicare-eligible retirees. The group's obligation for other post-retirement benefits at 31 December 2004 and 2005 reflects the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The provisions of the Act provide for a federal subsidy for plans that provide prescription drug benefits and meet certain qualifications, and alternatively would allow prescription drug plan sponsors to co-ordinate with the Medicare benefit. BP reflected the impact of the legislation by reducing its actuarially determined obligation for post-retirement benefits at 31 December 2004 and reducing the net cost for post-retirement benefits in subsequent periods. The reduction in liability was reflected in the 2004 results as an actuarial gain (assumption change).

Pension plan assets are generally held in trusts. The primary objective of the trusts is to accumulate pools of assets sufficient to meet the obligation of the various plans. The assets of the trusts are invested in a manner consistent with fiduciary obligations and principles that reflect current practices in portfolio management.

A significant proportion of the assets are held in equities, owing to a higher expected level of return over the long term with an acceptable level of risk. In order to provide reasonable assurance that no single security or type of security has an unwarranted impact on the total portfolio, the investment portfolios are highly diversified. The long-term asset allocation policy for the major plans is as follows:

Asset category	Policy range (%)
Total equity	55-85
Fixed income/cash	15-35
Property/real estate	0-10

Some of the group's pension funds use derivatives to manage their asset mix and the level of risk. The group's main pension funds do not directly invest in either securities or real property of the company or of any affiliate.

Return on asset assumptions reflect the group's expectations built up by asset class and by country. The group's expectation is derived from a combination of historical returns over the long term and the forecasts of market professionals.

The expected long-term rates of return and market values of the various categories of asset held by the significant defined benefit plans at 31 December are set out below.

		2005		2004		2003
	Expected long-term rate of return %	Market value $ million	Expected long-term rate of return %	Market value $ million	Expected long-term rate of return %	Market value $ million
UK pension plans						
Equities	7.50	18,465	7.50	17,329	7.50	14,642
Bonds	4.25	2,719	4.50	2,859	4.75	2,477
Property	6.50	1,097	6.50	1,660	6.50	1,336
Cash	3.50	1,001	4.00	459	4.00	769
	7.00	23,282	7.00	22,307	7.00	19,224
US pension plans						
Equities	8.50	5,961	8.50	6,043	8.50	5,650
Bonds	4.75	1,079	4.75	1,057	4.75	1,018
Property	8.00	21	8.00	28	8.00	41
Cash	3.00	256	3.00	55	3.50	148
	8.00	7,317	8.00	7,183	8.00	6,857
US other post-retirement benefit plans						
Equities	8.50	20	8.50	21	8.50	24
Bonds	4.75	8	4.75	9	4.75	9
	7.25	28	7.25	30	8.00	33
Other plans						
Equities	7.50	991	8.00	933	7.50	686
Bonds	4.00	943	4.25	857	4.75	737
Property	5.75	130	5.25	114	6.50	129
Cash	1.50	216	3.50	288	4.00	187
	5.50	2,280	6.00	2,192	6.00	1,739

The assumed rate of investment return and discount rate have a significant effect on the amounts reported. A one-percentage-point change in these assumptions for the group's plans would have had the following effects:

		$ million
	One-percentage point	
	Increase	Decrease
Investment return		
Effect on pension expense in 2006	(346)	348
Discount rate		
Effect on pension expense in 2006	(78)	93
Effect on pension obligation at 31 December 2005	(4,911)	6,379

The assumed US healthcare cost trend rate has a significant effect on the amounts reported. A one-percentage-point change in the assumed US healthcare cost trend rate would have had the following effects:

		$ million
	One-percentage point	
	Increase	Decrease
Effect on US post-retirement benefit expense in 2006	32	(26)
Effect on US post-retirement obligation at 31 December 2005	388	(319)

$ million

					2005
ANALYSIS OF THE AMOUNT CHARGED TO PROFIT BEFORE INTEREST AND TAXATION	UK pension plans	US pension plans	US post-retirement benefit plans	Other plans	Total
Current service cost	379	216	50	140	785
Past service cost	5	(10)	(5)	51	41
Settlement, curtailment and special termination benefits	37	–	–	10	47
Payments to defined contribution plans	–	158	–	14	172
Total operating charge (income)	421	364	45	215	1,045
Innovene operations	(38)	(24)	(3)	(21)	(86)
Continuing operations[a]	383	340	42	194	959
ANALYSIS OF THE AMOUNT CREDITED (CHARGED) TO OTHER FINANCE EXPENSE					
Expected return on plan assets	1,456	557	2	123	2,138
Interest on plan liabilities	(1,003)	(444)	(207)	(368)	(2,022)
Other finance income (expense)	453	113	(205)	(245)	116
Innovene operations	(10)	(5)	2	10	(3)
Continuing operations	443	108	(203)	(235)	113
ANALYSIS OF THE AMOUNT RECOGNIZED IN THE STATEMENT OF RECOGNIZED INCOME AND EXPENSE					
Actual return less expected return on pension plan assets	3,111	96	–	157	3,364
Experience gains and losses arising on the plan liabilities	(14)	(197)	(17)	16	(212)
Change in assumptions underlying the present value of the plan liabilities	(1,884)	(59)	236	(470)	(2,177)
Actuarial gain (loss) recognized in statement of recognized income and expense	1,213	(160)	219	(297)	975
MOVEMENTS IN SURPLUS (DEFICIT) DURING THE YEAR					
Benefit obligation at 1 January	20,399	7,826	3,676	8,044	39,945
Exchange adjustment	(2,194)	–	–	(928)	(3,122)
Current service cost	379	216	50	140	785
Plan amendments	5	(10)	(5)	51	41
Interest cost	1,003	444	207	368	2,022
Special termination benefits	37	–	–	10	47
Contributions by plan participants	37	–	–	5	42
Benefit payments	(923)	(600)	(208)	(430)	(2,161)
Acquisitions	–	20	16	3	39
Disposals	(578)	(252)	(39)	(303)	(1,172)
Actuarial (gain) loss on obligation	1,898	256	(219)	454	2,389
Benefit obligation at 31 December	20,063	7,900	3,478	7,414	38,855
Fair value of plan assets at 1 January	22,307	7,183	30	2,192	31,712
Exchange adjustment	(2,469)	–	–	(195)	(2,664)
Expected return on plan assets	1,456	557	2	123	2,138
Contributions by plan participants	37	–	–	5	42
Contributions by employers (funded plans)	340	279	–	140	759
Contributions by employers (unfunded plans)	1	30	204	314	549
Benefit payments	(923)	(600)	(208)	(430)	(2,161)
Acquisitions	–	8	–	–	8
Disposals	(578)	(236)	–	(26)	(840)
Actuarial gain (loss) on plan assets	3,111	96	–	157	3,364
Fair value of plan assets at 31 December	23,282	7,317	28	2,280	32,907
Surplus (deficit)	3,219	(583)	(3,450)	(5,134)	(5,948)
Represented by					
Asset recognized	3,240	–	–	42	3,282
Liability recognized	(21)	(583)	(3,450)	(5,176)	(9,230)
	3,219	(583)	(3,450)	(5,134)	(5,948)
The surplus (deficit) may be analysed between wholly or partly funded and wholly unfunded plans as follows					
Funded	3,240	(226)	(32)	(476)	2,506
Unfunded	(21)	(357)	(3,418)	(4,658)	(8,454)
	3,219	(583)	(3,450)	(5,134)	(5,948)
The defined benefit obligation may be analysed between wholly or partly funded and wholly unfunded plans as follows					
Funded	(20,042)	(7,543)	(60)	(2,756)	(30,401)
Unfunded	(21)	(357)	(3,418)	(4,658)	(8,454)
	(20,063)	(7,900)	(3,478)	(7,414)	(38,855)

[a] Included within production and manufacturing expenses and distribution and administration expenses.

42 Pensions and other post-retirement benefits *continued*

$ million

					2004
ANALYSIS OF THE AMOUNT CHARGED TO PROFIT BEFORE INTEREST AND TAXATION	UK pension plans	US pension plans	US post-retirement benefit plans	Other plans	Total
Current service cost	363	215	61	118	757
Past service cost	5	–	(4)	38	39
Settlement, curtailment and special termination benefits	37	–	–	27	64
Payments to defined contribution plans	–	150	–	12	162
Total operating charge (income)	405	365	57	195	1,022
Innovene operations	(35)	(25)	(3)	(22)	(85)
Continuing operations[a]	370	340	54	173	937
ANALYSIS OF THE AMOUNT CREDITED (CHARGED) TO OTHER FINANCE EXPENSE					
Expected return on plan assets	1,351	526	2	104	1,983
Interest on plan liabilities	(981)	(445)	(240)	(346)	(2,012)
Other finance income (expense)	370	81	(238)	(242)	(29)
Innovene operations	(6)	(3)	14	12	17
Continuing operations	364	78	(224)	(230)	(12)
ANALYSIS OF THE AMOUNT RECOGNIZED IN THE STATEMENT OF RECOGNIZED INCOME AND EXPENSE					
Actual return less expected return on pension plan assets	818	379	–	152	1,349
Experience gains and losses arising on the plan liabilities	83	(22)	33	(562)	(468)
Change in assumptions underlying the present value of the plan liabilities	(795)	(108)	495	(366)	(774)
Actuarial gain (loss) recognized in statement of recognized income and expense	106	249	528	(776)	107
MOVEMENT IN SURPLUS (DEFICIT) DURING THE YEAR					
Benefit obligation at 1 January	17,766	7,709	4,143	6,376	35,994
Exchange adjustment	1,445	–	–	647	2,092
Current service cost	363	215	61	118	757
Plan amendments	5	–	(4)	38	39
Interest cost	981	445	240	346	2,012
Special termination benefits	37	–	–	27	64
Contributions by plan participants	33	–	–	4	37
Benefit payments	(943)	(578)	(218)	(383)	(2,122)
Acquisitions	–	–	–	3	3
Disposals	–	(95)	(18)	(59)	(172)
Actuarial (gain) loss on obligation	712	130	(528)	928	1,242
Benefit obligation at 31 December	20,399	7,826	3,676	8,045	39,946
Fair value of plan assets at 1 January	19,224	6,857	33	1,739	27,853
Exchange adjustment	1,575	–	–	175	1,750
Expected return on plan assets	1,351	526	2	104	1,983
Contributions by plan participants	33	–	–	4	37
Contributions by employers (funded plans)	249	30	–	116	395
Contributions by employers (unfunded plans)	–	32	213	285	530
Benefit payments	(943)	(578)	(218)	(383)	(2,122)
Acquisitions	–	–	–	–	–
Disposals	–	(63)	–	–	(63)
Actuarial gain (loss) on plan assets	818	379	–	152	1,349
Fair value of plan assets at 31 December	22,307	7,183	30	2,192	31,712
Surplus (deficit)	1,908	(643)	(3,646)	(5,853)	(8,234)
Represented by					
Asset recognized	2,093	–	–	12	2,105
Liability recognized	(185)	(643)	(3,646)	(5,865)	(10,339)
	1,908	(643)	(3,646)	(5,853)	(8,234)
The surplus (deficit) may be analysed between wholly or partly funded and wholly unfunded plans as follows					
Funded	1,942	(296)	(43)	(506)	1,097
Unfunded	(34)	(347)	(3,603)	(5,347)	(9,331)
	1,908	(643)	(3,646)	(5,853)	(8,234)
The defined benefit obligation may be analysed between wholly or partly funded and wholly unfunded plans as follows					
Funded	(20,365)	(7,479)	(73)	(2,698)	(30,615)
Unfunded	(34)	(347)	(3,603)	(5,347)	(9.331)
	(20,399)	(7,826)	(3,676)	(8,045)	(39,946)

[a] Included within production and manufacturing expenses and distribution and administration expenses.

$ million

					2003
ANALYSIS OF THE AMOUNT CHARGED TO PROFIT BEFORE INTEREST AND TAXATION	UK pension plans	US pension plans	US post-retirement benefit plans	Other plans	Total
Current service cost	290	177	54	116	637
Past service cost	–	14	14	–	28
Settlement, curtailment and special termination benefits	–	(11)	(669)	87	(593)
Payments to defined contribution plans	–	134	–	36	170
Total operating charge (income)	290	314	(601)	239	242
Innovene operations	(29)	(23)	(3)	(19)	(74)
Continuing operations[a]	261	291	(604)	220	168
ANALYSIS OF THE AMOUNT CREDITED (CHARGED) TO OTHER FINANCE EXPENSE					
Expected return on plan assets	1,053	351	2	94	1,500
Interest on plan liabilities	(848)	(432)	(259)	(301)	(1,840)
Other finance income (expense)	205	(81)	(257)	(207)	(340)
Innovene operations	(7)	(2)	14	10	15
Continuing operations	198	(83)	(243)	(197)	(325)
ANALYSIS OF THE AMOUNT RECOGNIZED IN THE STATEMENT OF RECOGNIZED INCOME AND EXPENSE					
Actual return less expected return on pension plan assets	1,639	749	2	2	2,392
Experience gains and losses arising on the plan liabilities	641	30	67	135	873
Change in assumptions underlying the present value of the plan liabilities	(1,437)	(1,030)	(443)	(279)	(3,189)
Actuarial gain (loss) recognized in statement of recognized income and expense	843	(251)	(374)	(142)	76
MOVEMENT IN SURPLUS (DEFICIT) DURING THE YEAR					
Benefit obligation at 1 January	14,822	6,765	4,326	5,141	31,054
Exchange adjustment	1,738	–	–	910	2,648
Current service cost	290	177	54	116	637
Plan amendments	–	14	14	–	28
Interest cost	848	432	259	301	1,840
Special termination benefits	–	(11)	(669)	87	(593)
Contributions by plan participants	33	–	–	2	35
Benefit payments	(761)	(668)	(217)	(325)	(1,971)
Acquisitions	–	–	–	1	1
Disposals	–	–	–	–	–
Actuarial (gain) loss on obligation	796	1,000	376	144	2,316
Benefit obligation at 31 December	17,766	7,709	4,143	6,377	35,995
Fair value of plan assets at 1 January	15,138	4,206	33	1,447	20,824
Exchange adjustment	1,864	–	–	222	2,086
Expected return on plan assets	1,053	351	2	94	1,500
Contributions by plan participants	33	–	–	2	35
Contributions by employers (funded plans)	258	2,189	–	86	2,533
Contributions by employers (unfunded plans)	–	30	213	209	452
Benefit payments	(761)	(668)	(217)	(325)	(1,971)
Acquisitions	–	–	–	2	2
Disposals	–	–	–	–	–
Actuarial gain (loss) on plan assets	1,639	749	2	2	2,392
Fair value of plan assets at 31 December	19,224	6,857	33	1,739	27,853
Surplus (deficit)	1,458	(852)	(4,110)	(4,638)	(8,142)
Represented by					
Asset recognized	1,562	–	–	118	1,680
Liability recognized	(104)	(852)	(4,110)	(4,756)	(9,822)
	1,458	(852)	(4,110)	(4,638)	(8,142)
The surplus (deficit) may be analysed between wholly or partly funded and wholly unfunded plans as follows					
Funded	1,458	(494)	(72)	(308)	584
Unfunded	–	(358)	(4.038)	(4,330)	(8,726)
	1,458	(852)	(4,110)	(4,638)	(8,142)
The defined benefit obligation may be analysed between wholly or partly funded and wholly unfunded plans as follows					
Funded	(17,766)	(7,351)	(105)	(2,047)	(27,269)
Unfunded	–	(358)	(4,038)	(4,330)	(8,726)
	(17,766)	(7,709)	(4,143)	(6,377)	(35,995)

[a] Included within production and manufacturing expenses and distribution and administration expenses.

Pension and other post-retirement benefit surpluses and deficits are disclosed on a pre-tax basis. On a post-tax basis the pension and other post-retirement benefit surplus (deficit) at 31 December 2005 would be $(4,770) million (2004 $(6,514) million and 2003 $(6,489) million).

42 Pensions and other post-retirement benefits *continued*

HISTORY OF EXPERIENCE GAINS AND LOSSES	UK pension plans	US pension plans	US post-retirement benefit plans	Other plans	Total
					2005
Difference between the expected and actual return on plan assets					
Amount ($ million)	3,111	96	–	157	3,364
Percentage of plan assets	13%	1%	0%	7%	10%
Actual return on plan assets					
Amount ($ million)	4,567	653	2	280	5,502
Percentage of plan assets	20%	9%	7%	12%	17%
Experience gains and losses on plan liabilities					
Amount ($ million)	(14)	(197)	(17)	14	(214)
Percentage of the present value of plan liabilities	0%	(2)%	0%	0%	(1)%
Total amount recognized in statement of recognized income and expense					
Amount ($ million)	1,213	(160)	219	(297)	975
Percentage of the present value of plan liabilities	6%	(2)%	6%	(4)%	3%
Cumulative amount recognized in statement of recognized income and expense					
Amount ($ million)	2,162	(162)	373	(1,215)	1,158
Percentage of the present value of plan liabilities	11%	(2)%	11%	(16)%	3%
					2004
Difference between the expected and actual return on plan assets					
Amount ($ million)	818	379	–	152	1,349
Percentage of plan assets	4%	5%	0%	7%	4%
Actual return on plan assets					
Amount ($ million)	2,169	905	2	256	3,332
Percentage of plan assets	10%	13%	7%	12%	11%
Experience gains and losses on plan liabilities					
Amount ($ million)	83	(22)	33	(562)	(468)
Percentage of the present value of plan liabilities	0%	0%	1%	(7)%	(1)%
Total amount recognized in statement of recognized income and expense					
Amount ($ million)	106	249	528	(776)	107
Percentage of the present value of plan liabilities	1%	3%	14%	(10)%	0%
Cumulative amount recognized in statement of recognized income and expense					
Amount ($ million)	949	(2)	154	(918)	183
Percentage of the present value of plan liabilities	5%	0%	4%	(11)%	0%
					2003
Difference between the expected and actual return on plan assets					
Amount ($ million)	1,639	749	2	2	2,392
Percentage of plan assets	9%	11%	6%	0%	9%
Actual return on plan assets					
Amount ($ million)	2,692	1,100	4	96	3,892
Percentage of plan assets	14%	16%	12%	6%	14%
Experience gains and losses on plan liabilities					
Amount ($ million)	641	30	67	135	873
Percentage of the present value of plan liabilities	4%	0%	2%	2%	2%
Total amount recognized in statement of recognized income and expense					
Amount ($ million)	843	(251)	(374)	(142)	76
Percentage of the present value of plan liabilities	5%	(3)%	(9)%	(2)%	0%
Cumulative amount recognized in statement of recognized income and expense					
Amount ($ million)	843	(251)	(374)	(142)	76
Percentage of the present value of plan liabilities	5%	(3)%	(9)%	(2)%	0%

43 Called up share capital

The company's authorized ordinary share capital remains unchanged at 36 billion shares of 25 cents each, amounting to $9 billion. In addition, the company has authorized preference share capital of 12,750,000 shares of £1 each ($21 million).

The allotted, called up and fully paid share capital at 31 December was as follows:

	2005		2004		2003	
Issued	shares (thousand)	$ million	shares (thousand)	$ million	shares (thousand)	$ million
8% cumulative first preference shares of £1 each	7,233	12	7,233	12	7,233	12
9% cumulative second preference shares of £1 each	5,473	9	5,473	9	5,473	9
		21		21		21
Ordinary shares of 25 cents each						
1 January	21,525,978	5,382	22,122,610	5,531	22,378,651	5,595
Employee share schemes	68,500	17	62,224	16	32,889	8
Atlantic Richfield	13,644	3	29,288	7	9,786	2
Issue of ordinary share capital for TNK-BP	108,629	27	139,096	35	–	–
Repurchase of ordinary share capital	(1,059,706)	(265)	(827,240)	(207)	(298,716)	(74)
31 December	20,657,045	5,164	21,525,978	5,382	22,122,610	5,531
		5,185		5,403		5,552
Authorized						
8% cumulative first preference shares of £1 each	7,250		7,250		7,250	
9% cumulative second preference shares of £1 each	5,500		5,500		5,500	
Ordinary shares of 25 cents each	36,000,000		36,000,000		36,000,000	

Voting on substantive resolutions tabled at a general meeting is on a poll. On a poll, shareholders present in person or by proxy have two votes for every £5 in nominal amount of the first and second preference shares held and one vote for every ordinary share held. On a show-of-hands vote on other resolutions (procedural matters) at a general meeting, shareholders present in person or by proxy have one vote each.

In the event of the winding up of the company, preference shareholders would be entitled to a sum equal to the capital paid up on the preference shares, plus an amount in respect of accrued and unpaid dividends and a premium equal to the higher of (i) 10% of the capital paid up on the preference shares and (ii) the excess of the average market price of such shares on the London Stock Exchange during the previous six months over par value.

EMPLOYEE SHARE SCHEMES

During the year 68,499,852 ordinary shares (2004 62,224,092 and 2003 32,889,234 ordinary shares) were issued under the BP, Amoco and Burmah Castrol employee share schemes.

ATLANTIC RICHFIELD

13,644,462 ordinary shares (2004 29,288,178 and 2003 9,786,396 ordinary shares) were issued in respect of Atlantic Richfield employee share option schemes.

REPURCHASE OF ORDINARY SHARE CAPITAL

The company purchased 1,059,706,481 ordinary shares (2004 827,240,360 and 2003 298,716,391 ordinary shares) for a total consideration of $11,597 million (2004 $7,548 million and 2003 $1,999 million), of which 76,800,000 were cancelled and 982,906,481 were retained in treasury. All the shares repurchased in 2004 and 2003 were cancelled. At 31 December 2005, 982,624,971 shares of nominal value $246 million were held in treasury. Transaction costs of share repurchases amounted to $63 million (2004 $43 million and 2003 $11 million).

44 Capital and reserves

	Share capital	Share premium account	Capital redemption reserve	Merger reserve
At 31 December 2004	5,403	5,636	730	27,162
Adoption of IAS 39	–	–	–	–
At 1 January 2005	5,403	5,636	730	27,162
Currency translation differences (net of tax)	–	–	–	–
Exchange gain on translation of foreign operations transferred to (profit) or loss on sale (net of tax)	–	–	–	–
Actuarial gain (loss) (net of tax)	–	–	–	–
Employee share schemes	17	436	–	–
Atlantic Richfield	3	76	–	28
Issue of ordinary share capital for TNK-BP	27	1,223	–	–
Purchase of shares by ESOP trusts	–	–	–	–
Available-for-sale investments marked to market (net of tax)	–	–	–	–
Available-for-sale investments recycling (net of tax)	–	–	–	–
Repurchase of ordinary share capital	(265)	–	19	–
Share-based payments (net of tax)	–	–	–	–
Cash flow hedges marked to market (net of tax)	–	–	–	–
Cash flow hedges recycling (net of tax)	–	–	–	–
Profit for the year	–	–	–	–
Dividends	–	–	–	–
At 31 December 2005	5,185	7,371	749	27,190

	Share capital	Share premium account	Capital redemption reserve	Merger reserve
At 1 January 2004	5,552	3,957	523	27,077
Currency translation differences (net of tax)	–	–	–	–
Exchange gain on translation of foreign operations transferred to (profit) or loss on sale (net of tax)	–	–	–	–
Actuarial gain (loss) (net of tax)	–	–	–	–
Unrealized gain on acquisition of further investment in equity-accounted investments	–	–	–	–
Employee share schemes	16	311	–	–
Atlantic Richfield	7	153	–	85
Issue of ordinary share capital for TNK-BP	35	1,215	–	–
Purchase of shares by ESOP trusts	–	–	–	–
Repurchase of ordinary share capital	(207)	–	207	–
Share-based payments (net of tax)	–	–	–	–
Profit for the year	–	–	–	–
Dividends	–	–	–	–
At 31 December 2004	5,403	5,636	730	27,162

	Share capital	Share premium account	Capital redemption reserve	Merger reserve
At 1 January 2003	5,616	3,794	449	27,033
Currency translation differences (net of tax)	–	–	–	–
Actuarial gain (loss) (net of tax)	–	–	–	–
Employee share schemes	8	127	–	–
Atlantic Richfield	2	36	–	44
Purchase of shares by ESOP trusts	–	–	–	–
Repurchase of ordinary share capital	(74)	–	74	–
Share-based payments (net of tax)	–	–	–	–
Increased minority participation	–	–	–	–
Profit for the year	–	–	–	–
Dividends	–	–	–	–
At 31 December 2003	5,552	3,957	523	27,077

$ million

Other reserve	Own shares	Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
44	(82)	–	5,616	–	–	32,383	76,892	1,343	78,235
–	–	–	–	230	(118)	(355)	(243)	–	(243)
44	(82)	–	5,616	230	(118)	32,028	76,649	1,343	77,992
–	12	–	(2,453)	(35)	(3)	–	(2,479)	(18)	(2,497)
–	–	–	(220)	–	–	–	(220)	–	(220)
–	–	–	–	–	–	619	619	–	619
–	–	3	–	–	–	(1)	455	–	455
(28)	–	–	–	–	–	–	79	–	79
–	–	–	–	–	–	–	1,250	–	1,250
–	(251)	–	–	–	–	–	(251)	–	(251)
–	–	–	–	232	–	–	232	–	232
–	–	–	–	(42)	–	–	(42)	–	(42)
–	–	(10,601)	–	–	–	(750)	(11,597)	–	(11,597)
–	181	–	–	–	–	231	412	–	412
–	–	–	–	–	(149)	–	(149)	–	(149)
–	–	–	–	–	36	–	36	–	36
–	–	–	–	–	–	22,341	22,341	291	22,632
–	–	–	–	–	–	(7,359)	(7,359)	(827)	(8,186)
16	(140)	(10,598)	2,943	385	(234)	47,109	79,976	789	80,765

$ million

Other reserve	Own shares	Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
129	(96)	–	3,619	–	–	28,378	69,139	1,125	70,264
–	(7)	–	2,075	–	–	–	2,068	64	2,132
–	–	–	(78)	–	–	–	(78)	–	(78)
–	–	–	–	–	–	203	203	–	203
–	–	–	–	–	–	94	94	–	94
–	–	–	–	–	–	–	327	–	327
(85)	–	–	–	–	–	–	160	–	160
–	–	–	–	–	–	–	1,250	–	1,250
–	(147)	–	–	–	–	–	(147)	–	(147)
–	–	–	–	–	–	(7,548)	(7,548)	–	(7,548)
–	168	–	–	–	–	222	390	–	390
–	–	–	–	–	–	17,075	17,075	187	17,262
–	–	–	–	–	–	(6,041)	(6,041)	(33)	(6,074)
44	(82)	–	5,616	–	–	32,383	76,892	1,343	78,235

$ million

Other reserve	Own shares	Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
173	(159)	–	–	–	–	23,323	60,229	638	60,867
–	(8)	–	3,619	–	–	–	3,611	20	3,631
–	–	–	–	–	–	60	60	–	60
–	–	–	–	–	–	–	135	–	135
(44)	–	–	–	–	–	–	38	–	38
–	(63)	–	–	–	–	–	(63)	–	(63)
–	–	–	–	–	–	(1,999)	(1,999)	–	(1,999)
–	134	–	–	–	–	200	334	–	334
–	–	–	–	–	–	–	–	317	317
–	–	–	–	–	–	12,448	12,448	170	12,618
–	–	–	–	–	–	(5,654)	(5,654)	(20)	(5,674)
129	(96)	–	3,619	–	–	28,378	69,139	1,125	70,264

44 Capital and reserves *continued*

The profit and loss account reserve includes the following amounts, the distribution of which is limited by statutory or other restrictions:

			$ million
	2005	2004	2003
Parent company	27,391	25,026	24,107
Subsidiaries	2,463	2,927	2,115
Jointly controlled entities and associates	492	441	566
	30,346	28,394	26,788

Share capital The balance on the share capital account represents the aggregate nominal value of all ordinary and preference shares in issue.

Share premium account The balance on the share premium account represents the amounts received in excess of the nominal value of the ordinary and preference shares.

Capital redemption reserve The balance on the capital redemption reserve represents the aggregate nominal value of all the ordinary shares repurchased and cancelled.

Merger reserve The balance on the merger reserve represents the fair value of the consideration given in excess of the nominal value of the ordinary shares issued in an acquisition made by the issue of shares.

Other reserve The balance on the other reserve represents the fair value of the consideration given in excess of the nominal value of the ordinary shares to be issued in the ARCO acquisition on the exercise of ARCO share options.

Own shares Own shares represent BP shares held in Employee Share Ownership Plans (ESOPs) to meet the future requirements of the employee share-based payment arrangements.

Treasury shares Treasury shares represent BP shares repurchased and available for issue.

Foreign currency translation reserve The foreign currency translation reserve is used to record exchange differences arising from the translations of the financial statements of foreign operations. It is also used to record the effect of hedging net investments in foreign operations.

Available-for-sale investments This reserve records the changes in fair value on available-for-sale investments. On disposal, the cumulative changes in fair value are recycled to the income statement.

Cash flow hedges This reserve records the portion of the gain or loss on a hedging instrument in a cash flow hedge that is determined to be an effective hedge. On maturity, the cumulative gain or loss is recycled to the income statement or balance sheet as appropriate.

Profit and loss account The balance held on this reserve is the accumulated retained profits of the group.

45 Share-based payments

EFFECT OF SHARE-BASED PAYMENT TRANSACTIONS ON THE GROUP'S RESULT AND FINANCIAL POSITION

			$ million
	2005	2004	2003
Total expense recognized for equity-settled share-based payment transactions	348	289	268
Total expense recognized for cash-settled share-based payment transactions	20	36	25
Total expense recognized for share-based payment transactions	368	325	293
Closing balance of liability for cash-settled share-based payment transactions	48	59	51
Total intrinsic value for vested cash-settled share-based payments	41	53	50

For ease of presentation, option and share holdings detailed in the tables within this note are stated as UK ordinary share equivalents in US dollars. US employees are granted American Depositary Shares (ADSs) or options over the company's ADSs (one ADS is equivalent to six ordinary shares). The share-based payment plans that existed during the year are detailed below. All plans are ongoing unless otherwise stated.

45 Share-based payments *continued*

PLANS FOR EXECUTIVE DIRECTORS

Executive Directors' Incentive Plan (EDIP) – share element (2005 onwards) An equity-settled incentive share plan for executive directors driven by one performance measure over a three-year performance period. The award of shares is determined by comparing BP's total shareholder return (TSR) against the other oil majors. In addition, for the group chief executive, 27% of the grant is based on long-term leadership (LTL) measures. After the performance period, the shares that vest (net of tax) are then subject to a three-year retention period. The directors' remuneration report on pages 164-173 includes full details of this plan.

Executive Directors' Incentive Plan (EDIP) – share element (pre-2005) An equity-settled incentive share plan for executive directors driven by three performance measures over a three-year performance period. The primary measure is BP's shareholder return against the market (SHRAM) versus that of the companies within the FTSE All World Oil & Gas Index. This accounts for nearly two-thirds of the potential total award, with the remainder being assessed on BP's relative return on average capital employed (ROACE) and earnings per share (EPS) growth compared with the other oil majors. After the performance period, the shares that vest (net of tax) are then subject to a three-year retention period. The directors' remuneration report on pages 164-173 includes full details of this plan. For 2005 and subsequent years, the share element of EDIP was amended as described above.

Executive Directors' Incentive Plan (EDIP) – share option element (pre-2005) An equity-settled share option plan for executive directors that permits options to be granted at an exercise price no lower than the market price of a share on the date that the option is granted. Options vest over three years (one-third each after one, two and three years respectively) and must be exercised within seven years of the date of grant. Last grants were made in 2004. For 2005 onwards the remuneration committee's policy is not to make further grants of share options to executive directors.

PLANS FOR SENIOR EMPLOYEES

Medium Term Performance Plan (MTPP) (2005 onwards) An equity-settled incentive share plan for senior employees driven by two performance measures over a three-year performance period. The award of shares is determined by comparing BP's TSR against the other oil majors and, additionally, by comparing free cash flow (FCF) against a threshold established for the period. For a small group of particularly senior employees, only the TSR measure is applicable in determining the award. The number of shares awarded is increased to take account of the net dividends that would have been received during the performance period, assuming that such dividends had been reinvested. With regard to leaver provisions, the general rule is that leaving employment during the performance period will preclude an award of shares. However, special arrangements apply where the participant leaves for a qualifying reason and employment ceases after completion of the first year of the performance period.

Long Term Performance Plan (LTPP) (pre-2005) An equity-settled incentive share plan for senior employees driven by three performance measures over a three-year performance period. The primary measure is BP's SHRAM versus that of the companies within the FTSE All World Oil & Gas Index. This accounts for nearly two-thirds of the potential total award, with the remainder being assessed on BP's relative ROACE and EPS growth compared with the other oil majors. Shares are awarded at the end of the performance period and are then subject to a three-year restriction period. With regard to leaver provisions, the general rule is that leaving during the performance period will preclude an award of shares. However, special arrangements apply where the participant leaves for a qualifying reason and employment ceases after completion of the first year of the performance period. This plan was replaced by the MTPP for 2005 onwards.

Deferred Annual Bonus Plan (DAB) An equity-settled restricted share plan for senior employees. The award value is equal to 50% of the annual cash bonus awarded for the preceding performance year (the 'performance period'). The shares are restricted for a period of three years (the 'restriction period'). Shares accrue dividends during the restriction period and these are reinvested. With regard to leaver provisions, if a participant ceases to be employed by BP prior to the end of the performance period, then the general rule is that this will preclude an award of shares. However, special arrangements apply where the participant leaves for a qualifying reason. Similarly, if a participant ceases to be employed by BP prior to the end of the restriction period, the general rule is that the restricted shares will be forfeited. Special arrangements apply where the participant leaves for a qualifying reason.

Restricted Share Plan (RSP) An equity-settled restricted share plan used predominantly for senior employees in special circumstances (such as recruitment and retention). There are no performance conditions but the shares are subject to a three-year restriction period. During the restriction period, shares accrue dividends, which are reinvested. With regard to leaver provisions, the general rule is that ceasing employment during the restriction period will result in the forfeit of shares. However, special arrangements apply where the participant leaves for a qualifying reason.

BP Share Option Plan (BPSOP) An equity-settled share option plan that applies to certain categories of employees. Participants are granted share options with an exercise price no lower than market price of a share immediately preceding the date of grant. There are no performance conditions and the options are exercisable between the third and 10th anniversaries of the grant date. The general rule is that the options will lapse if the participant leaves employment before the end of the third calendar year from the date of grant (and that vested options are exercisable within 3½ years from the date of leaving). However, special arrangements apply where the participant leaves for a qualifying reason and employment ceases after the end of the calendar year of the date of grant. Share options are no longer offered to the most senior employees.

45 Share-based payments *continued*

SAVINGS AND MATCHING PLANS

BP ShareSave Plan A savings-related share option plan, under which employees save on a monthly basis, over a three- or five-year period, towards the purchase of shares at a fixed price determined when the option is granted. This price is usually set at a 20% discount to the market price at the time of grant. The option must be exercised within six months of maturity of the savings contract; otherwise it lapses. The plan is run in the UK and options are granted annually, usually in June. Until 2003, a three-year savings plan was also run in a small number of other countries. Options will remain outstanding in respect of these countries until the end of June 2007. Participants leaving for a qualifying reason will have six months in which to use their savings to exercise their options on a pro-rated basis.

BP ShareMatch Plans Matching share plans, under which BP matches employees' own contributions of shares up to a predetermined limit. The plans are run in the UK and in over 70 other countries. The UK plan is run on a monthly basis with shares being held in trust for five years before they can be released free of any income tax and national insurance liability. In other countries, the plan is run on an annual basis with shares being held in trust for three years. The plan is operated on a cash basis in those countries where there are regulatory restrictions preventing the holding of BP shares. When the employee leaves BP, all shares must be removed from trust and units under the plan operated on a cash basis must be encashed.

CASH PLANS

Cash Options/Stock Appreciation Rights (SARs) These are cash-settled share-based payments available to certain employees that require the group to pay the intrinsic value of the cash option/SAR to the employee at the date of exercise. There are no performance conditions; however, participants must continue in employment with BP for the first three calendar years of the plan for the options/SARs to vest. Special arrangements may apply for qualifying leavers. The options/SARs are exercisable between the third and 10th anniversaries of the grant date.

EMPLOYEE SHARE OWNERSHIP PLANS (ESOPS)

ESOPs have been established to acquire BP shares to satisfy any awards made to participants under EDIP, LTPP, MTPP, DAB and the BP ShareMatch Plans. The ESOPs have waived their rights to dividends on shares held for future awards and are funded by the group. Until such time as the company's own shares held by the ESOP trusts vest unconditionally in employees, the amount paid for those shares is deducted in arriving at shareholders' interest. See Note 44, Capital and reserves. Assets and liabilities of the ESOPs are recognized as assets and liabilities of the group.

At 31 December 2005, the ESOPs held 14,560,003 shares (2004 8,621,219 shares and 2003 11,930,379 shares) for potential future awards, which had a market value of $156 million (2004 $84 million and 2003 $96 million).

Share option transactions		2005		2004		2003
	Number of options	Weighted average exercise price ($)	Number of options	Weighted average exercise price ($)	Number of options	Weighted average exercise price ($)
Outstanding at beginning of the period	470,263,808	7.16	461,885,881	6.76	410,986,179	6.70
Granted during the period	54,482,053	10.24	80,394,760	7.93	104,758,602	6.22
Forfeited during the period	(4,844,827)	8.30	(7,043,911)	6.77	(20,412,529)	7.11
Exercised during the period	(68,687,976)	6.40	(62,625,182)	5.18	(32,988,942)	4.11
Expired during the period	(759,556)	6.75	(2,347,740)	7.55	(457,429)	6.40
Outstanding at end of the period	450,453,502	7.64	470,263,808	7.16	461,885,881	6.76
Exercisable at the end of the period	222,729,398	7.54	224,627,758	7.00	229,198,494	6.21

As share options are exercised continuously throughout the year, the weighted average share price during the year of $10.77 (2004 $8.95 and 2003 $6.81) is representative of the weighted average share price at the date of exercise. For the options outstanding at 31 December 2005, the exercise price ranges and weighted average remaining contractual lives are shown below.

	Options outstanding			Options exercisable	
Range of exercise prices	Number of shares	Weighted average remaining life (yrs)	Weighted average exercise price ($)	Number of shares	Weighted average exercise price ($)
$4.22–$6.14	74,255,790	1.88	5.51	52,734,810	5.44
$6.15–$8.06	151,161,264	6.15	7.02	36,840,758	7.70
$8.07–$9.99	176,892,928	5.95	8.29	133,128,330	8.32
$10.00–$11.92	48,143,520	9.19	10.45	25,500	10.53
	450,453,502	5.69	7.64	222,729,398	7.54

45 Share-based payments *continued*

FAIR VALUES AND ASSOCIATED DETAILS FOR OPTIONS AND SHARES GRANTED

Options granted in 2005	BPSOP	ShareSave 3 year	ShareSave 5 year
Option pricing model used	Binomial	Binomial	Binomial
Weighted average fair value	$2.34	$2.76	$2.94
Weighted average share price	$10.85	$10.49	$10.49
Weighted average exercise price	$10.63	$7.96	$7.96
Expected volatility	18%	18%	18%
Option life	10 years	3.5 years	5.5 years
Expected dividends	2.72%	3.00%	3.00%
Risk free interest rate	4.25%	4.00%	4.25%
Expected exercise behaviour	5% years 4-9 70% year 10	100% year 4	100% year 6

Options granted in 2004	EDIP Options	BPSOP	ShareSave 3 year	ShareSave 5 year
Option pricing model used	Binomial	Binomial	Binomial	Binomial
Weighted average fair value	$1.34	$1.55	$1.94	$2.13
Weighted average share price	$8.09	$8.12	$8.75	$8.75
Weighted average exercise price	$8.09	$8.09	$7.00	$7.00
Expected volatility	22%	22%	22%	22%
Option life	7 years	10 years	3.5 years	5.5 years
Expected dividends	3.75%	3.75%	3.75%	3.75%
Risk free interest rate	3.50%	4.00%	3.00%	3.75%
Expected exercise behaviour	5% years 2-6 75% year 7	5% years 4-9 70% year 10	100% year 4	100% year 6

Options granted in 2003	EDIP Options	BPSOP	ShareSave 3 year	ShareSave 5 year
Option pricing model used	Binomial	Binomial	Binomial	Binomial
Weighted average fair value	$1.37	$1.50	$1.91	$2.02
Weighted average share price	$6.29	$6.43	$7.23	$7.23
Weighted average exercise price	$6.29	$6.35	$5.79	$5.79
Expected volatility	30%	30%	30%	30%
Option life	7 years	10 years	3.5 years	5.5 years
Expected dividends	4.00%	4.00%	4.00%	4.00%
Risk free interest rate	3.50%	3.50%	3.50%	3.50%
Expected exercise behaviour	5% years 2-6 75% year 7	5% years 4-9 70% year 10	100% year 4	100% year 6

The group uses a third party estimate of expected volatility of US ADSs for the quarter within which the grant date of the relevant plan falls. This estimate takes into account the volatility implied by options in the market.

Shares granted in 2005	MTPP – TSR	MTPP – FCF	EDIP – TSR	EDIP – LTL	RSP
Number of equity instruments granted (million)	9.3	8.4	3.7	0.5	0.3
Weighted average fair value	$5.72	$11.04	$3.87	$10.13	$11.04
Fair value measurement basis	Monte Carlo	Market value	Monte Carlo	Market value	Market value

The group used a Monte Carlo simulation to fair value the TSR element of the 2005 MTPP and EDIP plans. In accordance with the rules of the plans the model simulates BP's TSR and compares it against our principal strategic competitors over the three-year period of the plans. The model takes into account the historic dividends, share price volatilities and covariances of BP and each comparator company to produce a predicted distribution of relative share performance. This is applied to the reward criteria to give an expected value of the TSR element.

45 Share-based payments *continued*

Shares granted in 2004	LTPP – SHRAM	LTPP – EPS/ROACE	EDIP – SHRAM	EDIP – EPS/ROACE	RSP
Number of equity instruments granted (million)	6.8	4.1	0.9	0.5	0.1
Weighted average fair value	$4.06	$7.21	$4.06	$7.21	$8.12
Fair value measurement basis	Monte Carlo	Market value	Monte Carlo	Market value	Market value

Shares granted in 2003	LTPP – SHRAM	LTPP – EPS/ROACE	EDIP – SHRAM	EDIP – EPS/ROACE	RSP
Number of equity instruments granted (million)	6.8	4.1	1.1	0.6	0.1
Weighted average fair value	$3.53	$5.65	$3.53	$5.65	$6.43
Fair value measurement basis	Monte Carlo	Market value	Monte Carlo	Market value	Market value

The group used a Monte Carlo simulation to fair value the SHRAM element of the 2003 and 2004 LTPP and EDIP plans. In accordance with the rules of the plans, the model simulates BP's SHRAM and compares it with the comparator companies (all companies in the FTSE All World Oil & Gas Index) over the three-year period of the plans. The SHRAMs of the comparator companies have been determined from market data over the preceding three-year period. The model takes into account the historic dividend yields, share price volatilities and covariances of BP and each comparator company to produce a predicted distribution of relative share performance. This is applied to the reward criteria to give an expected value of the SHRAM element.

Accounting expense does not necessarily represent the actual value of share-based payments made to recipients which are determined by the Remuneration Committee according to established criteria.

46 Employee costs and numbers

$ million

Employee costs	2005	2004	2003
Wages and salaries	8,695	7,922	7,142
Social security costs	754	667	622
Share-based payments	368	325	293
Pension and other post-retirement benefit costs	929	1,051	582
	10,746	9,965	8,639
Innovene operations	(892)	(898)	(882)
	9,854	9,067	7,757

Number of employees at 31 December	2005	2004	2003
Exploration and Production	17,000	15,600	15,100
Refining and Marketing[a]	70,800	69,800	69,000
Gas, Power and Renewables	4,100	4,000	3,800
Other businesses and corporate	4,300	13,500	15,800
	96,200	102,900	103,700
By geographical area			
UK	16,500	17,500	17,100
Rest of Europe	21,300	25,900	25,300
USA	34,400	36,900	39,100
Rest of World	24,000	22,600	22,200
	96,200	102,900	103,700

[a] Includes 27,800 (2004 27,900 and 2003 27,000) service station staff.

					2005					2004
Average number of employees	UK	Rest of Europe	USA	Rest of World	Total	UK	Rest of Europe	USA	Rest of World	Total
Exploration and Production	3,000	600	5,300	7,300	16,200	2,900	700	4,900	6,900	15,400
Refining and Marketing	11,100	19,700	26,200	14,000	71,000	10,300	19,200	27,200	12,900	69,600
Gas, Power and Renewables	200	800	1,500	1,400	3,900	200	800	1,400	1,600	4,000
Other businesses and corporate	3,800	3,900	3,600	300	11,600	3,700	4,800	5,700	1,000	15,200
	18,100	25,000	36,600	23,000	102,700	17,100	25,500	39,200	22,400	104,200

					2003
Average number of employees	UK	Rest of Europe	USA	Rest of World	Total
Exploration and Production	3,200	700	5,000	6,900	15,800
Refining and Marketing	10,100	20,600	28,300	12,700	71,700
Gas, Power and Renewables	200	900	1,500	1,600	4,200
Other businesses and corporate	3,700	4,900	6,300	1,500	16,400
	17,200	27,100	41,100	22,700	108,100

47 Remuneration of directors and key management

REMUNERATION OF DIRECTORS

			$ million
	2005	2004	2003
Total for all directors			
Emoluments	18	19	17
Ex-gratia payments to executive directors retiring in the year	–	–	1
Gains made on the exercise of share options	–	3	1
Amounts awarded under incentive schemes	8	6	4

Emoluments These amounts comprise fees paid to the non-executive chairman and the non-executive directors and, for executive directors, salary and benefits earned during the relevant financial year, plus bonuses awarded for the year.

Pension contributions Five executive directors participated in a non-contributory pension scheme established for UK staff by a separate trust fund to which contributions are made by BP based on actuarial advice. One US executive director participated in the US BP Retirement Accumulation Plan during 2005.

Office facilities for former chairmen and deputy chairmen It is customary for the company to make available to former chairmen and deputy chairmen, who were previously employed executives, the use of office and basic secretarial facilities following their retirement. The cost involved in doing so is not significant.

Further information Full details of individual directors' remuneration are given in the directors' remuneration report on pages 164-173.

REMUNERATION OF KEY MANAGEMENT

			$ million
	2005	2004	2003
Total for all key management			
Short-term employee benefits	25	24	20
Post-retirement benefits	4	3	2
Share-based payment	27	20	20

Key management, in addition to executive and non-executive directors, includes certain senior managers who are members of the Group Chief Executive's Meeting.

Short-term employee benefits In addition to fees paid to the non-executive chairman and non-executive directors, these amounts comprise, for executive directors and senior managers, salary and benefits earned during the year, plus bonuses awarded for the year.

Post-retirement benefits The amounts represent the estimated cost to the group of providing pensions and other post-retirement benefits to key management in respect of the current year of service measured in accordance with IAS 19 'Employee Benefits'.

Share-based payments This is the cost to the group of key management's participation in share-based payment plans, as measured by the fair value of options and shares granted accounted for in accordance with IFRS 2 'Share-based Payments'. The main plans in which key management have participated are the Executive Directors' Incentive Plan (EDIP), the Medium Term Performance Plan (MTPP) and the Long Term Performance Plan (LTPP). For details of these plans refer to Note 45, Share-based payments.

48 Contingent liabilities

There were contingent liabilities at 31 December 2005 in respect of guarantees and indemnities entered into as part of the ordinary course of the group's business. No material losses are likely to arise from such contingent liabilities. Group companies have issued guarantees under which amounts outstanding at 31 December 2005 were $1,228 million (2004 $1,281 million and 2003 $635 million) in respect of borrowings of jointly controlled entities and associates and $736 million (2004 $650 million and 2003 $304 million) in respect of liabilities of other third parties.

Approximately 200 lawsuits were filed in State and Federal Courts in Alaska seeking compensatory and punitive damages arising out of the Exxon Valdez oil spill in Prince William Sound in March 1989. Most of those suits named Exxon (now ExxonMobil), Alyeska Pipeline Service Company (Alyeska), which operates the oil terminal at Valdez, and the other oil companies that own Alyeska. Alyeska initially responded to the spill until the response was taken over by Exxon. BP owns a 47% interest (reduced during 2001 from 50% by a sale of 3% to Phillips) in Alyeska through a subsidiary of BP America Inc. and briefly indirectly owned a further 20% interest in Alyeska following BP's combination with Atlantic Richfield Company (Atlantic Richfield). Alyeska and its owners have settled all the claims against them under these lawsuits. Exxon has indicated that it may file a claim for contribution against Alyeska for a portion of the costs and damages which it has incurred. If any claims are asserted by Exxon that affect Alyeska and its owners, BP will defend the claims vigorously.

Since 1987, Atlantic Richfield, a current subsidiary of BP, has been named as a co-defendant in numerous lawsuits brought in the US alleging injury to persons and property caused by lead pigment in paint. The majority of the lawsuits have been abandoned or dismissed as against Atlantic Richfield. Atlantic Richfield is named in these lawsuits as alleged successor to International Smelting & Refining which, along with a predecessor company, manufactured lead pigment during the period 1920-1946. Plaintiffs include individuals and governmental entities. Several of the lawsuits purport to be class actions. The lawsuits (depending on plaintiff) seek various remedies, including: compensation to lead-poisoned children; cost to find and remove lead paint from buildings; medical monitoring and screening programmes; public warning and education on lead hazards; reimbursement of government healthcare costs and special education for lead-poisoned citizens; and punitive damages. No lawsuit against Atlantic Richfield has been settled nor has Atlantic Richfield been subject to a final adverse judgement in any proceeding. The amounts claimed and, if such suits were successful, the costs of implementing the remedies sought in the various cases could be substantial. While it is not possible to predict the outcome of these legal actions, Atlantic Richfield believes that it has valid defences and it intends to defend such actions vigorously and thus the incurrence of a liability by Atlantic Richfield is remote. Consequently, BP believes that the impact of these lawsuits on the group's results of operations, financial position or liquidity will not be material.

In addition, various group companies are parties to legal actions and claims that arise in the ordinary course of the group's business. While the outcome of such legal proceedings cannot be readily foreseen, BP believes that they will be resolved without material effect on the group's results of operations, financial position or liquidity.

The group is subject to numerous national and local environmental laws and regulations concerning its products, operations and other activities. These laws and regulations may require the group to take future action to remediate the effects on the environment of prior disposal or release of chemicals or petroleum substances by the group or other parties. Such contingencies may exist for various sites including refineries, chemical plants, oil fields, service stations, terminals and waste disposal sites. In addition, the group may have obligations relating to prior asset sales or closed facilities. The ultimate requirement for remediation and its cost are inherently difficult to estimate. However, the estimated cost of known environmental obligations has been provided in these accounts in accordance with the group's accounting policies. While the amounts of future costs could be significant and could be material to the group's results of operations in the period in which they are recognized, BP does not expect these costs to have a material effect on the group's financial position or liquidity.

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

49 Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been placed at 31 December 2005 amounted to $7,596 million (2004 $6,765 million and 2003 $6,420 million). Capital commitments of equity-accounted entities amounted to $733 million (2004 $2,056 million and 2003 $1,175 million).

50 First-time adoption of International Financial Reporting Standards

INTRODUCTION

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

In preparing these financial statements, the group has complied with all IFRSs applicable for periods beginning on or after 1 January 2005. In addition, BP has also decided to adopt early IFRS 6 'Exploration for and Evaluation of Mineral Resources', the amendment to IAS 19 'Amendment to International Accounting Standard IAS 19 Employee Benefits: Actuarial Gains and Losses, Group Plans and Disclosures', the amendment to IAS 39 'Amendment to International Accounting Standard IAS 39 Financial Instruments: Recognition and Measurement: Cash Flow Hedge Accounting of Forecast Intragroup Transactions' and IFRIC 4 'Determining whether an Arrangement contains a Lease'. The EU has adopted all standards and interpretations adopted by BP for its 2005 reporting.

The general principle that should be applied on first-time adoption of IFRS is that standards in force at the first reporting date (for BP, 31 December 2005) should be applied retrospectively. However, IFRS 1 'First-time Adoption of International Financial Reporting Standards' (IFRS 1) contains a number of exemptions which companies are permitted to apply. BP has taken the following exemptions:

- Comparative information on financial instruments is prepared in accordance with UK GAAP and the group has adopted IAS 32 'Financial Instruments: Disclosure and Presentation' (IAS 32) and IAS 39 'Financial Instruments: Recognition and Measurement' (IAS 39) from 1 January 2005.
- IFRS 3 'Business Combinations' has not been applied to acquisitions of subsidiaries or of interests in jointly controlled entities and associates that occurred before 1 January 2003.
- Cumulative currency translation differences for all foreign operations are deemed to be zero at 1 January 2003.
- The group has recognized all cumulative actuarial gains and losses on pensions and other post-retirement benefits as at 1 January 2003 directly in equity.
- IFRS 2 'Share-based Payment' has been applied retrospectively to all share-based payments that had not vested before 1 January 2003.

As indicated above, BP adopted IAS 32 and IAS 39 with effect from 1 January 2005 and, as permitted under IFRS 1, the group has not restated comparative information. Had IAS 32 and IAS 39 been applied from 1 January 2003, the following adjustments would have been necessary in the financial statements for the years ended 31 December 2004 and 2003:

- All derivatives, including embedded derivatives, would have been brought on to the balance sheet at fair value.
- Available-for-sale investments would have been carried at fair value rather than at cost.

The principal differences for the group between reporting on the basis of UK GAAP and IFRS are as follows:

- Ceasing to amortize goodwill.
- Setting up deferred taxation on: acquisitions; inventory valuation differences; unremitted earnings of subsidiaries, jointly controlled entities and associates.
- Expensing a greater proportion of major maintenance costs.
- No longer recognizing dividends proposed but not declared as a liability at the balance sheet date.
- Recognizing an expense for the fair value of employee share option schemes.
- Recording asset swaps on the basis of fair value.
- Recognizing changes in the fair value of embedded derivatives in the income statement.

The new accounting policies adopted by the group are summarized on pages 30-38.

The financial information presented in this note does not take account of the Innovene operations treated as discontinued in 2005.

50 First-time adoption of International Financial Reporting Standards *continued*

GROUP INCOME STATEMENT RECONCILIATIONS FROM UK GAAP TO IFRS

For the year ended 31 December 2004

	UK GAAP in IFRS format	Joint arrangements
Sales and other operating revenues	285,059	(274)
Earnings from jointly controlled entities – after interest and tax	2,943	34
Earnings from associates – after interest and tax	634	–
Interest and other revenues	675	(3)
Total revenues	289,311	(243)
Gain on sale of businesses and fixed assets	1,829	–
Total revenues and other income	291,140	(243)
Purchases	217,659	(82)
Production and manufacturing expenses	18,330	(44)
Production and similar taxes	2,149	–
Depreciation, depletion and amortization	10,840	(110)
Impairment and losses on sale of businesses and fixed assets	2,757	–
Exploration expense	637	–
Distribution and administration expenses	13,526	9
Profit before interest and taxation	25,242	(16)
Finance costs	642	–
Other finance expense	357	–
Profit before taxation	24,243	(16)
Taxation	8,282	(16)
Profit for the year	15,961	–
Attributable to		
BP shareholders	15,731	–
Minority interest	230	–
	15,961	–

For the year ended 31 December 2003

	UK GAAP in IFRS format	Joint arrangements
Sales and other operating revenues	232,571	(185)
Earnings from jointly controlled entities – after interest and tax	924	72
Earnings from associates – after interest and tax	514	–
Interest and other revenues	786	(2)
Total revenues	234,795	(115)
Gain on sale of businesses and fixed assets	1,894	–
Total revenues and other income	236,689	(115)
Purchases	176,185	(93)
Production and manufacturing expenses	15,402	(7)
Production and similar taxes	1,723	–
Depreciation, depletion and amortization	10,202	(11)
Impairment and losses on sale of businesses and fixed assets	1,801	–
Exploration expense	542	–
Distribution and administration expenses	12,880	–
Profit before interest and taxation	17,954	(4)
Finance costs	644	–
Other finance expense	547	–
Profit before taxation	16,763	(4)
Taxation	6,111	(4)
Profit for the year	10,652	–
Attributable to		
BP shareholders	10,482	–
Minority interest	170	–
	10,652	–

$ million

Net equity accounting	Goodwill amortization	Deferred tax	Major maintenance expenditure	Share-based payments	Asset swaps	Recycling foreign exchange on disposal	Other	Total IFRS adjustments	IFRS
–	–	–	–	–	–	–	147	(127)	284,932
(1,251)	–	–	–	–	–	–	79	(1,138)	1,805
(171)	–	–	–	–	–	–	–	(171)	463
–	–	–	–	–	–	–	1	(2)	673
(1,422)	–	–	–	–	–	–	227	(1,438)	287,873
–	–	–	–	–	–	78	(3)	75	1,904
(1,422)	–	–	–	–	–	78	224	(1,363)	289,777
–	–	–	–	–	–	–	37	(45)	217,614
–	–	–	586	28	–	–	103	673	19,003
–	–	–	–	–	–	–	–	–	2,149
–	(1,428)	–	(296)	–	(12)	–	18	(1,828)	9,012
–	(61)	25	–	–	–	–	–	(36)	2,721
–	–	–	–	–	–	–	–	–	637
–	–	–	–	58	–	–	16	83	13,609
(1,422)	1,489	(25)	(290)	(86)	12	78	50	(210)	25,032
(206)	–	–	–	–	–	–	4	(202)	440
–	–	–	–	–	–	–	–	–	357
(1,216)	1,489	(25)	(290)	(86)	12	78	46	(8)	24,235
(1,173)	–	49	(73)	(62)	(27)	–	(7)	(1,309)	6,973
(43)	1,489	(74)	(217)	(24)	39	78	53	1,301	17,262
–	1,489	(74)	(217)	(24)	39	78	53	1,344	17,075
(43)	–	–	–	–	–	–	–	(43)	187
(43)	1,489	(74)	(217)	(24)	39	78	53	1,301	17,262

$ million

–	–	–	–	–	–	–	122	(63)	232,508
(233)	–	–	–	–	–	–	45	(116)	808
(125)	–	–	–	–	–	–	2	(123)	391
–	–	–	–	–	–	–	1	(1)	785
(358)	–	–	–	–	–	–	170	(303)	234,492
–	–	–	–	–	–	–	1	1	1,895
(358)	–	–	–	–	–	–	171	(302)	236,387
–	–	–	–	–	–	–	68	(25)	176,160
–	–	–	417	25	–	–	37	472	15,874
–	–	–	–	–	–	–	–	–	1,723
–	(1,376)	–	(216)	–	(5)	–	11	(1,597)	8,605
–	–	–	–	–	–	–	–	–	1,801
–	–	–	–	–	–	–	–	–	542
–	–	–	–	70	–	–	4	74	12,954
(358)	1,376	–	(201)	(95)	5	–	51	774	18,728
(134)	–	–	–	–	–	–	3	(131)	513
–	–	–	–	–	–	–	–	–	547
(224)	1,376	–	(201)	(95)	5	–	48	905	17,668
(224)	–	(708)	(81)	(56)	3	–	9	(1,061)	5,050
–	1,376	708	(120)	(39)	2	–	39	1,966	12,618
–	1,376	708	(120)	(39)	2	–	39	1,966	12,448
–	–	–	–	–	–	–	–	–	170
–	1,376	708	(120)	(39)	2	–	39	1,966	12,618

50 First-time adoption of International Financial Reporting Standards *continued*

GROUP BALANCE SHEET RECONCILIATION FROM UK GAAP TO IFRS

At 31 December 2004

	UK GAAP in IFRS format	Joint arrangements	Pension reclassification	Leasehold premiums
Non-current assets				
Property, plant and equipment	96,748	(2,297)	–	(102)
Goodwill	7,872	–	–	–
Other intangible assets	4,204	(2)	–	–
Investments in jointly controlled entities	12,451	2,088	–	–
Investments in associates	5,488	–	–	–
Other investments	394	–	–	–
Fixed assets	127,157	(211)	–	(102)
Loans	799	–	–	–
Other receivables	429	–	–	–
Derivative financial instruments	898	–	–	–
Prepayments and accrued income	248	–	–	102
Defined benefit pension plan surplus	1,475	–	630	–
	131,006	(211)	630	–
Current assets				
Loans	193	–	–	–
Inventories	15,698	(34)	–	–
Trade and other receivables	37,051	48	–	–
Other investments	328	–	–	–
Derivative financial instruments	5,317	–	–	–
Prepayments and accrued income	1,675	(4)	–	–
Current tax receivable	159	–	–	–
Cash and cash equivalents	1,156	(125)	–	–
	61,577	(115)	–	–
Total assets	192,583	(326)	630	–
Current liabilities				
Trade and other payables	38,820	(280)	–	–
Derivative financial instruments	5,074	–	–	–
Accruals and deferred income	6,316	(13)	–	–
Finance debt	10,184	–	–	–
Current tax payable	4,131	–	–	–
Provisions	715	–	–	–
	65,240	(293)	–	–
Non-current liabilities				
Other payables	3,506	–	–	–
Derivative financial instruments	158	–	–	–
Accruals and deferred income	841	(2)	–	–
Finance debt	12,907	–	–	–
Deferred tax liabilities	15,050	(22)	(1,720)	–
Provisions	8,893	(9)	–	–
Defined benefit pension plan and other post-retirement benefit plan deficits	7,989	–	2,350	–
	49,344	(33)	630	–
Total liabilities	114,584	(326)	630	–
Net assets	77,999	–	–	–
BP shareholders' equity	76,656	–	–	–
Minority interest	1,343	–	–	–
Total equity	77,999	–	–	–

$ million

Liquid resources	Goodwill amortization	Deferred tax	Major maintenance expenditure	Share-based payments	Asset swaps	Dividend accrual	Other	Total IFRS adjustments	IFRS
–	–	159	(1,148)	–	(340)	–	72	(3,656)	93,092
–	2,985	–	–	–	–	–	–	2,985	10,857
–	–	–	–	–	–	–	3	1	4,205
–	–	–	–	–	–	–	17	2,105	14,556
–	–	–	–	–	–	–	(2)	(2)	5,486
–	–	–	–	–	–	–	–	–	394
–	2,985	159	(1,148)	–	(340)	–	90	1,433	128,590
–	–	–	–	–	–	–	12	12	811
–	–	–	–	–	–	–	–	–	429
–	–	–	–	–	–	–	–	–	898
–	–	–	–	–	–	–	4	106	354
–	–	–	–	–	–	–	–	630	2,105
–	2,985	159	(1,148)	–	(340)	–	106	2,181	133,187
–	–	–	–	–	–	–	–	–	193
–	–	–	–	–	–	–	(19)	(53)	15,645
–	–	–	–	–	–	–	–	48	37,099
(328)	–	–	–	–	–	–	–	(328)	–
–	–	–	–	–	–	–	–	–	5,317
–	–	–	–	–	–	–	–	(4)	1,671
–	–	–	–	–	–	–	–	–	159
328	–	–	–	–	–	–	–	203	1,359
–	–	–	–	–	–	–	(19)	(134)	61,443
–	2,985	159	(1,148)	–	(340)	–	87	2,047	194,630
–	–	–	–	–	–	–	–	(280)	38,540
–	–	–	–	–	–	–	–	–	5,074
–	–	–	–	–	–	(1,821)	–	(1,834)	4,482
–	–	–	–	–	–	–	–	–	10,184
–	–	–	–	–	–	–	–	–	4,131
–	–	–	–	–	–	–	–	–	715
–	–	–	–	–	–	(1,821)	–	(2,114)	63,126
–	–	–	–	–	–	–	75	75	3,581
–	–	–	–	–	–	–	–	–	158
–	–	–	–	–	(48)	–	(92)	(142)	699
–	–	–	–	–	–	–	–	–	12,907
–	–	4,145	(354)	(353)	(102)	–	57	1,651	16,701
–	–	–	–	–	–	–	–	(9)	8,884
–	–	–	–	–	–	–	–	2,350	10,339
–	–	4,145	(354)	(353)	(150)	–	40	3,925	53,269
–	–	4,145	(354)	(353)	(150)	(1,821)	40	1,811	116,395
–	2,985	(3,986)	(794)	353	(190)	1,821	47	236	78,235
–	2,985	(3,986)	(794)	353	(190)	1,821	47	236	76,892
–	–	–	–	–	–	–	–	–	1,343
–	2,985	(3,986)	(794)	353	(190)	1,821	47	236	78,235

Notes on financial statements *continued*

50 First-time adoption of International Financial Reporting Standards *continued*

GROUP BALANCE SHEET RECONCILIATION FROM UK GAAP TO IFRS

At 31 December 2003

	UK GAAP in IFRS format	Joint arrangements	Pension reclassification	Leasehold premiums
Non-current assets				
Property, plant and equipment	91,911	(2,089)	–	(205)
Goodwill	9,169	–	–	–
Other intangible assets	4,473	(2)	–	–
Investments in jointly controlled entities	11,009	1,963	–	–
Investments in associates	4,870	–	–	–
Other investments	1,452	–	–	–
Fixed assets	122,884	(128)	–	(205)
Loans	867	–	–	–
Other receivables	495	–	–	–
Derivative financial instruments	534	–	–	–
Prepayments and accrued income	749	–	–	205
Defined benefit pension plan surplus	1,146	–	534	–
	126,675	(128)	534	–
Current assets				
Loans	182	–	–	–
Inventories	11,617	(16)	–	–
Trade and other receivables	27,848	32	–	–
Other investments	185	–	–	–
Derivative financial instruments	1,891	–	–	–
Prepayments and accrued income	1,371	1	–	–
Current tax receivable	92	–	–	–
Cash and cash equivalents	1,947	(76)	–	–
	45,133	(59)	–	–
Total assets	171,808	(187)	534	–
Current liabilities				
Trade and other payables	29,780	(41)	–	–
Derivative financial instruments	4,145	–	–	–
Accruals and deferred income	3,762	(2)	–	–
Finance debt	9,456	–	–	–
Current tax payable	3,441	–	–	–
Provisions	735	–	–	–
	51,319	(43)	–	–
Non-current liabilities				
Other payables	4,769	(140)	–	–
Derivative financial instruments	344	–	–	–
Accruals and deferred income	917	–	–	–
Finance debt	12,869	–	–	–
Deferred tax liabilities	14,371	(4)	(1,653)	–
Provisions	7,864	–	–	–
Defined benefit pension plan and other post-retirement benefit plan deficits	7,635	–	2,187	–
	48,769	(144)	534	–
Total liabilities	100,088	(187)	534	–
Net assets	71,720	–	–	–
BP shareholders' equity	70,595	–	–	–
Minority interest	1,125	–	–	–
Total equity	71,720	–	–	–

$ million

Liquid resources	Goodwill amortization	Deferred tax	Major maintenance expenditure	Share-based payments	Asset swaps	Dividend accrual	Other	Total IFRS adjustments	IFRS
–	–	–	(818)	–	(269)	–	77	(3,304)	88,607
–	1,421	–	–	–	–	–	2	1,423	10,592
–	–	–	–	–	–	–	–	(2)	4,471
–	–	–	–	–	–	–	(63)	1,900	12,909
–	–	–	–	–	–	–	(2)	(2)	4,868
–	–	–	–	–	–	–	–	–	1,452
–	1,421	–	(818)	–	(269)	–	14	15	122,899
–	–	–	–	–	–	–	(15)	(15)	852
–	–	–	–	–	–	–	–	–	495
–	–	–	–	–	–	–	–	–	534
–	–	–	–	–	–	–	3	208	957
–	–	–	–	–	–	–	–	534	1,680
–	1,421	–	(818)	–	(269)	–	2	742	127,417
–	–	–	–	–	–	–	–	–	182
–	–	–	–	–	–	–	(4)	(20)	11,597
–	–	–	–	–	–	–	1	33	27,881
(185)	–	–	–	–	–	–	–	(185)	–
–	–	–	–	–	–	–	–	–	1,891
–	–	–	–	–	–	–	3	4	1,375
–	–	–	–	–	–	–	–	–	92
185	–	–	–	–	–	–	–	109	2,056
–	–	–	–	–	–	–	–	(59)	45,074
–	1,421	–	(818)	–	(269)	–	2	683	172,491
–	–	–	–	–	–	–	1	(40)	29,740
–	–	–	–	–	–	–	–	–	4,145
–	–	–	–	–	–	(1,494)	–	(1,496)	2,266
–	–	–	–	–	–	–	–	–	9,456
–	–	–	–	–	–	–	–	–	3,441
–	–	–	–	–	–	–	–	–	735
–	–	–	–	–	–	(1,494)	1	(1,536)	49,783
–	–	–	–	–	–	–	1	(139)	4,630
–	–	–	–	–	–	–	–	–	344
–	–	–	–	–	(53)	–	–	(53)	864
–	–	–	–	–	–	–	–	–	12,869
–	–	3,844	(273)	(235)	(76)	–	77	1,680	16,051
–	–	–	–	–	–	–	–	–	7,864
–	–	–	–	–	–	–	–	2,187	9,822
–	–	3,844	(273)	(235)	(129)	–	78	3,675	52,444
–	–	3,844	(273)	(235)	(129)	(1,494)	79	2,139	102,227
–	1,421	(3,844)	(545)	235	(140)	1,494	(77)	(1,456)	70,264
–	1,421	(3,844)	(545)	235	(140)	1,494	(77)	(1,456)	69,139
–	–	–	–	–	–	–	–	–	1,125
–	1,421	(3,844)	(545)	235	(140)	1,494	(77)	(1,456)	70,264

50 First-time adoption of International Financial Reporting Standards *continued*

GROUP BALANCE SHEET RECONCILIATION FROM UK GAAP TO IFRS

At 1 January 2003

	UK GAAP in IFRS format	Joint arrangements	Pension reclassification	Leasehold premiums
Non-current assets				
Property, plant and equipment	87,682	(1,760)	–	(199)
Goodwill	10,438	–	–	–
Other intangible assets	5,128	(1)	–	–
Investments in jointly controlled entities	4,031	1,565	–	–
Investments in associates	4,626	–	–	–
Other investments	1,995	–	–	–
Fixed assets	113,900	(196)	–	(199)
Loans	833	–	–	–
Other receivables	1,006	–	–	–
Derivative financial instruments	46	–	–	–
Prepayments and accrued income	461	–	–	199
Defined benefit pension plan surplus	388	–	166	–
	116,634	(196)	166	–
Current assets				
Loans	165	–	–	–
Inventories	10,181	(8)	–	–
Trade and other receivables	24,095	(22)	–	–
Other investments	215	–	–	–
Derivative financial instruments	995	–	–	–
Prepayments and accrued income	1,556	–	–	–
Current tax receivable	94	–	–	–
Cash and cash equivalents	1,520	(19)	–	–
	38,821	(49)	–	–
Total assets	155,455	(245)	166	–
Current liabilities				
Trade and other payables	25,853	(245)	–	–
Derivative financial instruments	1,415	–	–	–
Accruals and deferred income	5,527	–	–	–
Finance debt	10,086	–	–	–
Current tax payable	3,420	–	–	–
Provisions	716	–	–	–
	47,017	(245)	–	–
Non-current liabilities				
Other payables	2,410	–	–	–
Derivative financial instruments	–	–	–	–
Accruals and deferred income	1,002	–	–	–
Finance debt	11,922	–	–	–
Deferred tax liabilities	13,514	–	(2,620)	–
Provisions	7,120	–	–	–
Defined benefit pension plan and other post-retirement benefit plan deficits	7,998	–	2,786	–
	43,966	–	166	–
Total liabilities	90,983	(245)	166	–
Net assets	64,472	–	–	–
BP shareholders' equity	63,834	–	–	–
Minority interest	638	–	–	–
Total equity	64,472	–	–	–

$ million

Liquid resources	Goodwill amortization	Deferred tax	Major maintenance expenditure	Share-based payments	Asset swaps	Dividend accrual	Other	Total IFRS adjustments	IFRS
–	–	–	(577)	–	(280)	–	77	(2,739)	84,943
–	–	–	–	–	–	–	2	2	10,440
–	–	–	–	–	–	–	–	(1)	5,127
–	–	–	–	–	–	–	–	1,565	5,596
–	–	–	–	–	–	–	(112)	(112)	4,514
–	–	–	–	–	–	–	–	–	1,995
–	–	–	(577)	–	(280)	–	(33)	(1,285)	112,615
–	–	–	–	–	–	–	–	–	833
–	–	–	–	–	–	–	–	–	1,006
–	–	–	–	–	–	–	–	–	46
–	–	–	–	–	–	–	3	202	663
–	–	–	–	–	–	–	–	166	554
–	–	–	(577)	–	(280)	–	(30)	(917)	115,717
–	–	–	–	–	–	–	–	–	165
–	–	–	–	–	–	–	(18)	(26)	10,155
–	–	–	–	–	–	–	–	(22)	24,073
(215)	–	–	–	–	–	–	–	(215)	–
–	–	–	–	–	–	–	–	–	995
–	–	–	–	–	–	–	4	4	1,560
–	–	–	–	–	–	–	–	–	94
215	–	–	–	–	–	–	–	196	1,716
–	–	–	–	–	–	–	(14)	(63)	38,758
–	–	–	(577)	–	(280)	–	(44)	(980)	154,475
–	–	–	–	–	–	–	1	(244)	25,609
–	–	–	–	–	–	–	–	–	1,415
–	–	–	–	–	–	(1,397)	–	(1,397)	4,130
–	–	–	–	–	–	–	–	–	10,086
–	–	–	–	–	–	–	–	–	3,420
–	–	–	–	–	–	–	–	–	716
–	–	–	–	–	–	(1,397)	1	(1,641)	45,376
–	–	–	–	–	–	–	1	1	2,411
	–	–	–	–	–	–	–	–	–
–	–	–	–	–	(52)	–	–	(52)	950
–	–	–	–	–	–	–	–	–	11,922
–	–	4,523	(183)	(179)	(80)	–	70	1,531	15,045
–	–	–	–	–	–	–	–	–	7,120
–	–	–	–	–	–	–	–	2,786	10,784
–	–	4,523	(183)	(179)	(132)	–	71	4,266	48,232
–	–	4,523	(183)	(179)	(132)	(1,397)	72	2,625	93,608
–	–	(4,523)	(394)	179	(148)	1,397	(116)	(3,605)	60,867
–	–	(4,523)	(394)	179	(148)	1,397	(116)	(3,605)	60,229
–	–	–	–	–	–	–	–	–	638
–	–	(4,523)	(394)	179	(148)	1,397	(116)	(3,605)	60,867

50 First-time adoption of International Financial Reporting Standards *continued*

GROUP CASH FLOW RECONCILIATION FROM UK GAAP TO IFRS

For the year ended 31 December 2004

	UK GAAP in IFRS format	Joint arrangements
Operating activities		
Profit before taxation	24,243	(16)
Adjustments to reconcile profit before taxation to net cash provided by operating activities		
Exploration expenditure written off	274	–
Depreciation, depletion and amortization	10,840	(110)
Impairment and (gain) loss on sale of businesses and fixed assets	928	–
Earnings from jointly controlled entities and associates	(3,577)	(34)
Dividends received from jointly controlled entities and associates	2,199	–
Interest receivable	(272)	(12)
Interest received	332	12
Finance costs	642	–
Interest paid	(694)	–
Other finance expense	357	–
Share-based payments	138	–
Net operating charge for pensions and other post-retirement benefits, less contributions	(67)	–
Net charge for provisions, less payments	(110)	–
(Increase) decrease in inventories	(3,595)	16
(Increase) decrease in other current and non-current assets	(10,920)	(10)
Increase (decrease) in other current and non-current liabilities	9,726	60
Income taxes paid	(6,378)	(3)
Net cash provided by operating activities	24,066	(97)
Investing activities		
Capital expenditure	(13,035)	158
Acquisitions, net of cash acquired	(1,503)	–
Investment in jointly controlled entities	(1,522)	(126)
Investment in associates	(942)	–
Proceeds from disposal of property, plant and equipment	4,236	–
Proceeds from disposal of businesses	725	–
Proceeds from loan repayments	87	–
Net cash used in investing activities	(11,954)	32
Financing activities		
Net repurchase of shares	(7,208)	–
Proceeds from long-term financing	2,675	–
Repayments of long-term financing	(2,204)	–
Net (decrease) increase in short-term debt	(40)	16
Dividends paid		
BP shareholders	(6,041)	–
Minority interest	(33)	–
Net cash used in financing activities	(12,851)	16
Currency translation differences relating to cash and cash equivalents	91	–
(Decrease) increase in cash and cash equivalents	(648)	(49)
Cash and cash equivalents at beginning of year	2,132	(76)
Cash and cash equivalents at end of year	1,484	(125)

$ million

Net equity accounting	Goodwill amortization	Deferred tax	Major maintenance expenditure	Share-based payments	Asset swaps	Recycling foreign exchange on disposal	Other	Total IFRS adjustments	IFRS
(1,216)	1,489	(25)	(290)	(86)	12	78	46	(8)	24,235
–	–	–	–	–	–	–	–	–	274
–	(1,428)	–	(296)	–	(12)	–	18	(1,828)	9,012
–	(61)	25	–	–	–	(78)	3	(111)	817
1,422	–	–	–	–	–	–	(79)	1,309	(2,268)
–	–	–	–	–	–	–	–	–	2,199
–	–	–	–	–	–	–	–	(12)	(284)
–	–	–	–	–	–	–	–	12	344
(206)	–	–	–	–	–	–	4	(202)	440
–	–	–	–	–	–	–	(4)	(4)	(698)
–	–	–	–	–	–	–	–	–	357
–	–	–	–	86	–	–	–	86	224
–	–	–	–	–	–	–	–	–	(67)
–	–	–	–	–	–	–	–	–	(110)
–	–	–	–	–	–	–	14	30	(3,565)
–	–	–	–	–	–	–	(7)	(17)	(10,937)
–	–	–	–	–	–	–	–	60	9,786
–	–	–	–	–	–	–	–	(3)	(6,381)
–	–	–	(586)	–	–	–	(5)	(688)	23,378
–	–	–	586	–	–	–	5	749	(12,286)
–	–	–	–	–	–	–	–	–	(1,503)
–	–	–	–	–	–	–	–	(126)	(1,648)
–	–	–	–	–	–	–	–	–	(942)
–	–	–	–	–	–	–	–	–	4,236
–	–	–	–	–	–	–	–	–	725
–	–	–	–	–	–	–	–	–	87
–	–	–	586	–	–	–	5	623	(11,331)
–	–	–	–	–	–	–	–	–	(7,208)
–	–	–	–	–	–	–	–	–	2,675
–	–	–	–	–	–	–	–	–	(2,204)
–	–	–	–	–	–	–	–	16	(24)
–	–	–	–	–	–	–	–	–	(6,041)
–	–	–	–	–	–	–	–	–	(33)
–	–	–	–	–	–	–	–	16	(12,835)
–	–	–	–	–	–	–	–	–	91
–	–	–	–	–	–	–	–	(49)	(697)
–	–	–	–	–	–	–	–	(76)	2,056
–	–	–	–	–	–	–	–	(125)	1,359

Notes on financial statements *continued*

50 First-time adoption of International Financial Reporting Standards *continued*

GROUP CASH FLOW RECONCILIATION FROM UK GAAP TO IFRS

For the year ended 31 December 2003

	UK GAAP in IFRS format
Operating activities	
Profit before taxation	16,763
Adjustments to reconcile profit before taxation to net cash provided by operating activities	
Exploration expenditure written off	297
Depreciation, depletion and amortization	10,202
Impairment and (gain) loss on sale of businesses and fixed assets	(93)
Earnings from jointly controlled entities and associates	(1,438)
Dividends received from jointly controlled entities and associates	548
Interest receivable	(201)
Interest received	175
Finance costs	644
Interest paid	(1,006)
Other finance expense	547
Share-based payments	113
Net operating charge for pensions and other post-retirement benefits, less contributions	(2,913)
Net charge for provisions, less payments	66
(Increase) decrease in inventories	(841)
(Increase) decrease in other current and non-current assets	(3,042)
Increase (decrease) in other current and non-current liabilities	1,734
Income taxes paid	(4,804)
Net cash provided by operating activities	16,751
Investing activities	
Capital expenditure	(12,377)
Acquisitions, net of cash acquired	(211)
Investment in jointly controlled entities	(2,529)
Investment in associates	(987)
Proceeds from disposal of property, plant and equipment	6,177
Proceeds from disposal of businesses	179
Proceeds from loan repayments	76
Other	–
Net cash used in investing activities	(9,672)
Financing activities	
Net repurchase of shares	(1,889)
Proceeds from long-term financing	4,322
Repayments of long-term financing	(3,560)
Net (decrease) increase in short-term debt	(2)
Dividends paid	
BP shareholders	(5,654)
Minority interest	(20)
Net cash used in financing activities	(6,803)
Currency translation differences relating to cash and cash equivalents	121
Increase (decrease) in cash and cash equivalents	397
Cash and cash equivalents at beginning of year	1,735
Cash and cash equivalents at end of year	2,132

$ million

Joint arrangements	Net equity accounting	Goodwill amortization	Major maintenance expenditure	Share-based payments	Asset swaps	Recycling foreign exchange on disposal	Other	Total IFRS adjustments	IFRS
(4)	(224)	1,376	(201)	(95)	5	–	48	905	17,668
–	–	–	–	–	–	–	–	–	297
(11)	–	(1,376)	(216)	–	(5)	–	11	(1,597)	8,605
–	–	–	–	–	–	–	(1)	(1)	(94)
(72)	358	–	–	–	–	–	(47)	239	(1,199)
–	–	–	–	–	–	–	–	–	548
(11)	–	–	–	–	–	–	–	(11)	(212)
11	–	–	–	–	–	–	–	11	186
2	(134)	–	–	–	–	–	1	(131)	513
(1)	–	–	–	–	–	–	–	(1)	(1,007)
–	–	–	–	–	–	–	–	–	547
–	–	–	–	95	–	–	–	95	208
–	–	–	–	–	–	–	–	–	(2,913)
–	–	–	–	–	–	–	–	–	66
2	–	–	–	–	–	–	(14)	(12)	(853)
(33)	–	–	–	–	–	–	–	(33)	(3,075)
87	–	–	–	–	–	–	1	88	1,822
–	–	–	–	–	–	–	–	–	(4,804)
(30)	–	–	(417)	–	–	–	(1)	(448)	16,303
74	–	–	417	–	–	–	1	492	(11,885)
–	–	–	–	–	–	–	–	–	(211)
(101)	–	–	–	–	–	–	–	(101)	(2,630)
–	–	–	–	–	–	–	–	–	(987)
–	–	–	–	–	–	–	–	–	6,177
–	–	–	–	–	–	–	–	–	179
–	–	–	–	–	–	–	–	–	76
–	–	–	–	–	–	–	–	–	–
(27)	–	–	417	–	–	–	1	391	(9,281)
–	–	–	–	–	–	–	–	–	(1,889)
–	–	–	–	–	–	–	–	–	4,322
–	–	–	–	–	–	–	–	–	(3,560)
–	–	–	–	–	–	–	–	–	(2)
–	–	–	–	–	–	–	–	–	(5,654)
–	–	–	–	–	–	–	–	–	(20)
–	–	–	–	–	–	–	–	–	(6,803)
–	–	–	–	–	–	–	–	–	121
(57)	–	–	–	–	–	–	–	(57)	340
(19)	–	–	–	–	–	–	–	(19)	1,716
(76)	–	–	–	–	–	–	–	(76)	2,056

50 First-time adoption of International Financial Reporting Standards *continued*

DIFFERENCES BETWEEN UK GAAP AND IFRS PRESENTATION THAT HAVE NO IMPACT ON BP'S REPORTED INCOME OR TOTAL EQUITY

Accounting for joint arrangements Under UK GAAP, certain of the group's activities were conducted through joint arrangements and were included in the consolidated financial statements in proportion to the group's share of the income, expenses, assets and liabilities of these joint arrangements. However, IFRS requires that, if such joint arrangements comprise a legal entity, they be treated as jointly controlled entities. The group has chosen to account for jointly controlled entities under the equity method. The entities affected include Atlantic LNG Trains 2 and 3, a group of German refineries and chemicals operations, the South Caucasus Pipeline Company and other minor operations.

Increase (decrease) in caption heading		$ million
	Years ended 31 December	
	2004	2003
Sales and other operating revenues	(274)	(185)
Earnings from jointly controlled entities – after interest and tax	34	72
Interest and other revenues	(3)	(2)
Purchases	(82)	(93)
Production and manufacturing expenses	(44)	(7)
Depreciation, depletion and amortization	(110)	(11)
Distribution and administration expenses	9	–
Taxation	(16)	(4)
Profit for the year	–	–

			$ million
	At 31 December		1 January
	2004	2003	2003
Property, plant and equipment	(2,297)	(2,089)	(1,760)
Intangible assets	(2)	(2)	(1)
Investments in jointly controlled entities	2,088	1,963	1,565
Inventories	(34)	(16)	(8)
Trade and other receivables	48	32	(22)
Current assets – prepayments and accrued income	(4)	1	–
Cash and cash equivalents	(125)	(76)	(19)
Trade and other payables	(280)	(41)	(245)
Current liabilities – accruals and deferred income	(13)	(2)	–
Other payables	–	(140)	–
Non-current liabilities – accruals and deferred income	(2)	–	–
Deferred tax liabilities	(22)	(4)	–
Provisions	(9)	–	–
Total equity	–	–	–

Presentation of results of equity-accounted entities UK practice in respect of equity accounting is to present the group's share of the profit before interest and tax, finance costs, other finance expense, and tax charge of jointly controlled entities and associates in the corresponding line of the group's income statement. IFRS requires the presentation of equity-accounted results as a single net profit item in the income statement. Consequently, the group's share of all the individual equity-accounted items has been removed from the relevant lines in the income statement and offset against the results of equity-accounted entities to present them on a net-of-tax basis.

Increase (decrease) in caption heading		$ million
	Years ended 31 December	
	2004	2003
Earnings from jointly controlled entities – after interest and tax	(1,251)	(233)
Earnings from associates – after interest and tax	(171)	(125)
Finance costs	(206)	(134)
Taxation	(1,173)	(224)
Minority interest	(43)	–
Profit for the year	–	–

			$ million
	At 31 December		1 January
	2004	2003	2003
Total equity	–	–	–

50 First-time adoption of International Financial Reporting Standards *continued*

Presentation of pensions and other post-retirement benefit obligations BP adopted the UK standard on retirement benefits, FRS 17, in 2004. Under this standard, retirement benefit obligations and assets are presented on a net-of-tax basis in the balance sheet. IFRS, however, requires that these assets and liabilities be shown gross, with the related deferred tax effects included within the deferred tax captions in the balance sheet. An adjustment has therefore been made to reclassify the deferred tax balances.

Increase (decrease) in caption heading		$ million
	Years ended 31 December	
	2004	2003
Profit for the year	–	–

			$ million
	At 31 December		1 January
	2004	2003	2003
Defined benefit pension plan surplus	630	534	166
Deferred tax liabilities	(1,720)	(1,653)	(2,620)
Defined benefit pension plan and other post-retirement benefit plan deficits	2,350	2,187	2,786
Total equity	–	–	–

Reclassification of leasehold premiums In accordance with UK practice, BP included leasehold premiums paid within property, plant and equipment. Under IFRS, the premiums paid on operating leases represent prepaid lease payments and have therefore been reclassified within loans and other receivables as prepayments.

Increase (decrease) in caption heading		$ million
	Years ended 31 December	
	2004	2003
Profit for the year	–	–

			$ million
	At 31 December		1 January
	2004	2003	2003
Property, plant and equipment	(102)	(205)	(199)
Non-current assets – prepayments and accrued income	102	205	199
Total equity	–	–	–

Liquid resources Short-term investments have been reclassified as cash and cash equivalents under IFRS.

Increase (decrease) in caption heading		$ million
	Years ended 31 December	
	2004	2003
Profit for the year	–	–

			$ million
	At 31 December		1 January
	2004	2003	2003
Other investments	(328)	(185)	(215)
Cash and cash equivalents	328	185	215
Total equity	–	–	–

50 First-time adoption of International Financial Reporting Standards *continued*

DIFFERENCES BETWEEN UK GAAP AND IFRS THAT AFFECT BP'S REPORTED INCOME OR TOTAL EQUITY

Goodwill amortization Under UK GAAP, BP capitalized goodwill and amortized it over its estimated useful economic life, which was usually 10 years. Under IFRS, however, goodwill is not amortized but is subject to an annual impairment review. In accordance with IFRS 1, an impairment test was carried out at the date of transition (DoT). No impairment was identified and no other adjustments to the value of goodwill were made. This adjustment reverses the amortization of goodwill charged under UK GAAP after the DoT to IFRS.

Increase (decrease) in caption heading

		$ million
	Years ended 31 December	
	2004	2003
Depreciation, depletion and amortization	(1,428)	(1,376)
Impairment and losses on sale of businesses and fixed assets	(61)	–
Profit for the year	1,489	1,376

			$ million
	At 31 December		1 January
	2004	2003	2003
Goodwill	2,985	1,421	–
Total equity	2,985	1,421	–

Deferred tax adjustments Under UK GAAP, deferred tax is provided on timing differences, whereas IFRS requires provision to be made for temporary differences between carrying values and the related tax base. As a result, deferred tax needs to be recognized under IFRS in respect of a number of differences for which no deferred tax was recognized under UK GAAP. The major areas affected by this are described below.

In accordance with the requirements of IFRS, additional deferred tax has been provided on the temporary difference created by the allocation of fair values to the non-current assets acquired in a business combination. The consequent increase in the difference between the carrying value of non-current assets and the tax base is not considered to be a timing difference under UK GAAP, but is regarded as a temporary difference for IFRS. An adjustment is therefore required to reflect the increase in the deferred tax liability at the DoT. The resulting deferred tax liability changes due to the depreciation or impairment of the underlying fixed asset.

Increase (decrease) in caption heading

		$ million
	Years ended 31 December	
	2004	2003
Impairment and losses on sale of businesses and fixed assets	25	–
Taxation	(418)	(873)
Profit for the year	393	873

			$ million
	At 31 December		1 January
	2004	2003	2003
Property, plant and equipment	159	–	–
Deferred tax liabilities	2,591	2,764	3,608
Total equity	(2,432)	(2,764)	(3,608)

50 First-time adoption of International Financial Reporting Standards *continued*

Certain subsidiaries, principally in the US, have inventories valued on the last-in first-out (LIFO) basis for tax purposes. The difference between the book and tax valuation is not a timing difference for UK GAAP but is a temporary difference for IFRS.

Increase (decrease) in caption heading

		$ million
	Years ended 31 December	
	2004	2003
Taxation	438	165
Profit for the year	(438)	(165)

			$ million
	At 31 December		1 January
	2004	2003	2003
Deferred tax liabilities	1,340	894	729
Total equity	(1,340)	(894)	(729)

Under UK GAAP, a deferred tax provision is made for tax that would arise on the remittance of the retained earnings of overseas subsidiaries, joint ventures and associated undertakings, only to the extent that dividends have been accrued as receivable. For IFRS, deferred tax is recognized for all retained earnings whose distribution is not within the control of the group or whose distribution is likely in the foreseeable future, irrespective of whether dividends have actually been accrued or declared.

Increase (decrease) in caption heading

		$ million
	Years ended 31 December	
	2004	2003
Taxation	29	–
Profit for the year	(29)	–

			$ million
	At 31 December		1 January
	2004	2003	2003
Deferred tax liabilities	214	186	186
Total equity	(214)	(186)	(186)

Major maintenance expenditure Under UK GAAP, the group capitalized expenditure on major maintenance, refits or repairs where it enhanced or restored the performance of an asset, or replaced an asset or part of an asset that was separately depreciated. Under IFRS, the group will continue to capitalize expenditure where it enhances the performance of an asset or replaces an asset or part of an asset that meets the group's definition of a part of an asset in accordance with IAS 16 'Property, Plant and Equipment'. Other elements of expenditure incurred during major plant maintenance shutdowns, such as overhaul costs, are not permitted to be capitalized under IFRS. There is therefore a reduction in the carrying value of property, plant and equipment to reflect this change for expensing overhaul costs that no longer qualify for capitalization.

Increase (decrease) in caption heading

		$ million
	Years ended 31 December	
	2004	2003
Production and manufacturing expenses	586	417
Depreciation, depletion and amortization	(296)	(216)
Taxation	(73)	(81)
Profit for the year	(217)	(120)

			$ million
	At 31 December		1 January
	2004	2003	2003
Property, plant and equipment	(1,148)	(818)	(577)
Deferred tax liabilities	(354)	(273)	(183)
Total equity	(794)	(545)	(394)

50 First-time adoption of International Financial Reporting Standards continued

Share-based payments Under UK GAAP, BP recognized as an expense the costs of the potential awards for the long-term incentive plans (Executive Directors' Incentive Plan and the Long Term Performance Plan) and certain other share-based schemes. The costs of awards under the long-term incentive plans were accrued over the performance period of each plan, based on the estimated actual cost of shares, and an adjustment was made to reflect the actual cost when the final award was confirmed. The cost of other share-based schemes was based on the fair value of the awards.

IFRS requires the fair value of the option and share awards that ultimately vest to be charged to the income statement over the vesting or performance period. The fair value is determined at the date of the grant using an appropriate pricing model (i.e. a binomial model). If an award fails to vest as the result of certain types of performance condition not being satisfied, the charge to the income statement will be adjusted to reflect this.

BP has developed a binomial (or lattice-type) pricing model, which has been used to arrive at the fair value at the grant date of the share option schemes and part of the award under the long-term incentive plans. The other part of the long-term incentive plans is based on market conditions and has been valued using a Monte Carlo model.

Although IFRS 1 allows entities to restrict the recognition of the expense of share-based payments to those schemes granted after 7 November 2002 that have not vested as of 1 January 2005, BP has elected to apply IFRS 2 'Share-based Payment' fully retrospectively.

Increase (decrease) in caption heading		$ million
	Years ended 31 December	
	2004	2003
Production and manufacturing expenses	28	25
Distribution and administration expenses	58	70
Taxation	(62)	(56)
Profit for the year	(24)	(39)

			$ million
	At 31 December		1 January
	2004	2003	2003
Deferred tax liabilities	(353)	(235)	(179)
Total equity	353	235	179

Asset swaps and fair value adjustment Under UK GAAP asset swaps are generally treated as exchanges of assets at net book value, with no gain or loss resulting from them. IFRS requires assets acquired in asset exchanges to be accounted for at fair value at the date of the transaction, with any gain or loss recognized in income.

In 2000, BP agreed to a transaction with its partners in the Prudhoe Bay field in Alaska whereby it received an increase in its natural gas interest in return for a reduction in its share of liquids production.

In 2001, BP undertook a transaction with Solvay that led to the exchange of businesses for an interest in a joint venture and an associated undertaking. The transaction has been recorded at fair value for IFRS. On 1 November 2004 BP acquired Solvay's interests in these ventures and has accounted for this as a business combination.

Increase (decrease) in caption heading		$ million
	Years ended 31 December	
	2004	2003
Depreciation, depletion and amortization	(12)	(5)
Taxation	(27)	3
Profit for the year	39	2

			$ million
	At 31 December		1 January
	2004	2003	2003
Property, plant and equipment	(340)	(269)	(280)
Non-current liabilities – accruals and deferred income	(48)	(53)	(52)
Deferred tax liabilities	(102)	(76)	(80)
Total equity	(190)	(140)	(148)

50 First-time adoption of International Financial Reporting Standards *continued*

Dividend accrual The UK GAAP approach to the recognition of proposed dividends was to account for the dividend in the period to which it related, e.g. the dividend proposed in February 2005 in respect of the final quarter of 2004 was accrued for in 2004. Under IFRS, the proposed dividend can be recognized only in the period in which it is properly authorized or paid, which, in the case of BP, is the quarter following that to which the dividend relates, i.e. the dividend proposed in February 2005 in respect of the fourth quarter of 2004 can be accounted for only in the first quarter of 2005. Therefore each balance sheet is adjusted to derecognize the dividend declared after the balance sheet date.

Increase (decrease) in caption heading			$ million
	At 31 December		1 January
	2004	2003	2003
Current liabilities – accruals and deferred income	(1,821)	(1,494)	(1,397)
Total equity	1,821	1,494	1,397

Recycling of cumulative currency translation differences on disposal of net investment in foreign operations The consolidation of entities with a non-US dollar functional currency results in currency translation differences that are taken directly to equity, where they are accumulated. Under UK GAAP these cumulative currency translation differences remained in equity. IFRS requires that, when an entity is wholly or partially disposed of, such cumulative translation differences be recycled to the income statement as part of the gain or loss on disposal. In addition, there is a requirement to maintain such differences as a separate component of equity. In accordance with one of the exemptions in IFRS 1, the amount of this component has been deemed by BP to be zero at the DoT. Consequently, only those translation differences that arise after the DoT will be recycled upon disposal of a foreign operation.

Increase (decrease) in caption heading		$ million
		Years ended 31 December
	2004	2003
Gains on sale of businesses and fixed assets	78	–
Profit for the year	78	–

			$ million
	At 31 December		1 January
	2004	2003	2003
Total equity	–	–	–

Other This adjustment includes the IFRS adjustments made to equity-accounted entities.

50 First-time adoption of International Financial Reporting Standards *continued*

GROUP BALANCE SHEET RECONCILIATION FROM UK GAAP TO IFRS

At 1 January 2005

	IFRS at 31 December 2004
Non-current assets	
Property, plant and equipment	93,092
Goodwill	10,857
Intangible assets	4,205
Investments in jointly controlled entities	14,556
Investments in associates	5,486
Other investments	394
Fixed assets	128,590
Loans	811
Other receivables	429
Derivative financial instruments	898
Prepayments and accrued income	354
Defined benefit pension plan surplus	2,105
	133,187
Current assets	
Loans	193
Inventories	15,645
Trade and other receivables	37,099
Derivative financial instruments	5,317
Prepayments and accrued income	1,671
Current tax receivable	159
Cash and cash equivalents	1,359
	61,443
Total assets	194,630
Current liabilities	
Trade and other payables	38,540
Derivative financial instruments	5,074
Accruals and deferred income	4,482
Finance debt	10,184
Current tax payable	4,131
Provisions	715
	63,126
Non-current liabilities	
Other payables	3,581
Derivative financial instruments	158
Accruals and deferred income	699
Finance debt	12,907
Deferred tax liabilities	16,701
Provisions	8,884
Defined benefit pension plan and other post-retirement benefit plan deficits	10,339
	53,269
Total liabilities	116,395
Net assets	78,235
BP shareholders' equity	76,892
Minority interest	1,343
Total equity	78,235

$ million

Fair value hedges	Cash flow hedges	Non-qualifying hedge derivatives	Other non-financial contracts at fair value	Other non-financial contracts no longer at fair value	Available-for-sale financial assets	Embedded derivatives	Elimination of deferred gains/losses	Total IAS 39 adjustments	IFRS at 1 January 2005
–	–	–	–	–	–	–	–	–	93,092
–	–	–	–	–	–	–	–	–	10,857
–	–	–	–	–	–	–	–	–	4,205
–	–	–	–	–	–	–	–	–	14,556
–	–	–	–	–	–	–	–	–	5,486
–	–	–	–	–	344	–	–	344	738
–	–	–	–	–	344	–	–	344	128,934
–	–	–	–	–	–	–	–	–	811
–	–	–	–	–	–	–	–	–	429
112	79	8	110	(34)	–	–	(147)	128	1,026
–	–	–	–	–	–	599	–	599	953
–	–	–	–	–	–	–	–	–	2,105
112	79	8	110	(34)	344	599	(147)	1,071	134,258
–	–	–	–	–	–	–	–	–	193
–	–	–	–	–	–	–	–	–	15,645
–	(2)	–	–	–	–	–	–	(2)	37,097
–	141	178	34	47	–	–	–	400	5,717
–	–	–	–	–	–	278	–	278	1,949
–	–	–	–	–	–	–	–	–	159
–	–	–	–	–	–	–	–	–	1,359
–	139	178	34	47	–	278	–	676	62,119
112	218	186	144	13	344	877	(147)	1,747	196,377
–	–	–	–	–	–	–	–	–	38,540
–	16	210	14	–	–	–	–	240	5,314
–	–	–	–	–	–	402	–	402	4,884
–	–	–	–	–	–	–	–	–	10,184
–	–	–	–	–	–	–	–	–	4,131
–	–	–	–	–	–	–	–	–	715
–	16	210	14	–	–	402	–	642	63,768
–	–	–	–	–	–	–	–	–	3,581
129	4	17	12		–	–	–	162	320
–	–	–	–	–	–	1,151	–	1,151	1,850
(17)	–	–	–	–	–	–	164	147	13,054
–	60	(13)	44	5	114	(267)	(55)	(112)	16,589
–	–	–	–	–	–	–	–	–	8,884
–	–	–	–	–	–	–	–	–	10,339
112	64	4	56	5	114	884	109	1,348	54,617
112	80	214	70	5	114	1,286	109	1,990	118,385
–	138	(28)	74	8	230	(409)	(256)	(243)	77,992
–	138	(28)	74	8	230	(409)	(256)	(243)	76,649
–	–	–	–	–	–	–	–	–	1,343
–	138	(28)	74	8	230	(409)	(256)	(243)	77,992

50 First-time adoption of International Financial Reporting Standards *continued*

ADJUSTMENTS REQUIRED TO THE BALANCE SHEET AS AT 1 JANUARY 2005 FOR THE ADOPTION OF IAS 32 AND IAS 39

Under UK GAAP, all derivatives used for trading purposes were recognized on the balance sheet at fair value. However, derivative financial instruments used for hedging purposes were recognized by applying either the accrual method or the deferral method. Under the accrual method, amounts payable or receivable in respect of derivatives are recognized ratably in earnings over the period of the contracts. Changes in the derivatives and fair values are not recognized. On the deferral method, gains and losses from derivatives are deferred and recognized in earnings or as adjustments to carrying amounts as the underlying hedged transaction matures or occurs.

For IFRS, all financial assets and financial liabilities have to be recognized initially at fair value. In subsequent periods the measurement of these financial instruments depends on their classification into one of the following measurement categories: i) financial assets or financial liabilities at-fair-value-through-profit-and-loss (such as those used for trading purposes, and all derivatives which do not qualify for hedge accounting); ii) loans and receivables; and iii) available-for-sale financial assets (including certain investments held for the long term).

Fair value hedges Where fair value hedge accounting was applied to transactions that hedge the group's exposure to the changes in the fair value of a firm commitment or a recognized asset or liability that are attributable to a specific risk the derivatives designated as hedging instruments are recorded at their fair value in the group's balance sheet and changes in their fair value are recognized in the income statement. Any gain or loss on the hedged item attributable to the hedged risk is adjusted against the carrying amount of the hedged item and recognized in the income statement.

The 'pay floating' interest rate swaps and currency swaps hedging the debt book in place on 1 January 2005 were highly effective and consequently qualify as fair value hedges for hedge accounting. The full fair value of the swaps was recognized on the balance sheet and the carrying value of debt was adjusted.

Increase (decrease) in caption heading	$ million
	At 1 January
	2005
Non-current assets – derivative financial instruments	112
Non-current liabilities – derivative financial instruments	129
Finance debt	(17)
Total equity	–

Cash flow hedges The group uses currency derivatives to hedge its exposure to variability in cash flows arising either from a recognized asset or liability or a forecast transaction. The hedged instrument is recognized at fair value on the balance sheet. At maturity of the hedged item, the element deferred in equity is treated in accordance with the nature of the hedged exposure, for example, capitalized into the cost of an item of property, plant and equipment, or expensed in the case of a hedge of a tax payment.

Increase (decrease) in caption heading	$ million
	At 1 January
	2005
Non-current assets – derivative financial instruments	79
Trade and other receivables	(2)
Current assets – derivative financial instruments	141
Current liabilities – derivative financial instruments	16
Non-current liabilities – derivative financial instruments	4
Deferred tax liabilities	60
Total equity	138

Non-qualifying hedge derivatives Under IAS 39, there are strict criteria that need to be met in order for hedge accounting to be applied. This adjustment records the impact of those derivatives, or elements thereof, held by the group that do not qualify for hedge accounting, or hedges for which hedge accounting has not been claimed under IAS 39.

From 1 January 2005, these positions will be fair valued ('marked to market') and the change in fair value taken to income.

Increase (decrease) in caption heading	$ million
	At 1 January
	2005
Non-current assets – derivative financial instruments	8
Current assets – derivative financial instruments	178
Current liabilities – derivative financial instruments	210
Non-current liabilities – derivative financial instruments	17
Deferred tax liabilities	(13)
Total equity	(28)

50 First-time adoption of International Financial Reporting Standards *continued*

Other non-financial contracts at fair value Certain net-settled non-financial contracts are deemed to meet the definition of financial instruments under IAS 39 and, as such, need to be recorded on the balance sheet at fair value.

Increase (decrease) in caption heading	$ million
	At 1 January
	2005
Non-current assets – derivative financial instruments	110
Current assets – derivative financial instruments	34
Current liabilities – derivative financial instruments	14
Non-current liabilities – derivative financial instruments	12
Deferred tax liabilities	44
Total equity	74

Other non-financial contracts no longer at fair value Certain non-financial contracts held for trading purposes were marked to market under UK GAAP. However, under IFRS they could no longer be recorded at fair value as they did not meet the definition of financial assets or financial liabilities. These contracts are accounted for on an accruals basis.

Increase (decrease) in caption heading	$ million
	At 1 January
	2005
Non-current assets – derivative financial instruments	(34)
Current assets – derivative financial instruments	47
Deferred tax liabilities	5
Total equity	8

Available-for-sale financial assets Under UK GAAP, the group's investments other than subsidiaries, jointly controlled entities and associates were stated at cost less accumulated impairment losses.

For IFRS, these investments are classified as available-for-sale financial assets, and as such need to be recorded at fair value with the gain or loss arising as a result of the change in fair value being recorded directly in equity.

The transition adjustment relates to the fair value of listed investments held by the group. In accordance with IAS 39, all future fair value adjustments will be booked directly in equity until disposal of the investment, when the cumulative associated gains/losses are recycled through the income statement. At this point, the gain or loss on disposal under IFRS will be identical to that which would result using historical cost accounting.

Increase (decrease) in caption heading	$ million
	At 1 January
	2005
Other investments	344
Deferred tax liabilities	114
Total equity	230

Embedded derivatives Embedded derivatives are required to be separated from their host contracts and separately recorded at fair value, with any resulting change in gain or loss in the period being recognized in the income statement.

Certain contracts have been determined to contain embedded derivatives. These embedded derivatives will be fair valued at each period end with the resulting gains or losses taken to the income statement.

Increase (decrease) in caption heading	$ million
	At 1 January
	2005
Non-current assets – prepayments and accrued income	599
Current assets – prepayments and accrued income	278
Current liabilities – accruals and deferred income	402
Non-current liabilities – accruals and deferred income	1,151
Deferred tax liabilities	(267)
Total equity	(409)

50 First-time adoption of International Financial Reporting Standards *continued*

Elimination of currently deferred gains and losses from derivatives Under UK GAAP, gains and losses from derivatives are deferred and recognized in earnings or as adjustments to carrying amounts, as appropriate, when the underlying debt matures or the hedged transaction occurs. Where derivatives that are used to manage interest rate risk, to convert non-US dollar debt or to hedge other anticipated cash flows are terminated before the underlying debt matures or the hedged transaction occurs, the resulting gain or loss is recognized on a basis that matches the timing and accounting treatment of the underlying debt or hedged transaction.

On transition to IFRS, only assets and liabilities that qualify as such can continue to be recognized. Consequently, all gains and losses that were generated by derivatives used for hedging purposes and deferred in the balance sheet as if they were assets or liabilities must be eliminated from the transitional balance sheet. This is achieved by transferring gains and losses arising from cash flow hedges to equity, pending recycling to income at a later date, and by transferring gains and losses arising from fair value hedges to adjust the carrying value of the hedged item, in this case, finance debt.

Increase (decrease) in caption heading	$ million
	At 1 January
	2005
Non-current assets – prepayments and accrued income	(147)
Finance debt	164
Deferred tax liabilities	(55)
Total equity	(256)

51 Subsidiaries, jointly controlled entities and associates

The more important subsidiaries, jointly controlled entities and associates of the group at 31 December 2005 and the group percentage of ordinary share capital or joint venture interest (to nearest whole number) are set out below. The principal country of operation is generally indicated by the company's country of incorporation or by its name. Those held directly by the parent company are marked with an asterisk (*), the percentage owned being that of the group unless otherwise indicated. A complete list of investments in subsidiaries, jointly controlled entities and associates will be attached to the parent company's annual return made to the Registrar of Companies. Advantage has been taken of the exemption conferred by regulation 7 of The Partnerships and Unlimited Companies (Accounts) Regulations 1993 from the requirements to deliver to the Registrar of Companies and publish the annual accounts of the CaTO Finance V Limited Partnership.

Subsidiaries	%	Country of incorporation	Principal activities
International			
BP Chemicals Investments	100	England	Petrochemicals
BP Exploration Op. Co.	100	England	Exploration and production
*BP Global Investments	100	England	Investment holding
*BP International	100	England	Integrated oil operations
BP Oil International	100	England	Integrated oil operations
*BP Shipping	100	England	Shipping
*Burmah Castrol	100	Scotland	Lubricants
Algeria			
BP Amoco Exploration (In Amenas)	100	Scotland	Exploration and production
BP Exploration (El Djazair)	100	Bahamas	Exploration and production
Angola			
BP Exploration (Angola)	100	England	Exploration and production
Australia			
BP Oil Australia	100	Australia	Integrated oil operations
BP Australia Capital Markets	100	Australia	Finance
BP Developments Australia	100	Australia	Exploration and production
BP Finance Australia	100	Australia	Finance
Azerbaijan			
Amoco Caspian Sea Petroleum	100	British Virgin Islands	Exploration and production
BP Exploration (Caspian Sea)	100	England	Exploration and production
Canada			
BP Canada Energy	100	Canada	Exploration and production
BP Canada Finance	100	Canada	Finance
Egypt			
BP Egypt Co.	100	US	Exploration and production
BP Egypt Gas Co.	100	US	Exploration and production
France			
BP France	100	France	Refining and marketing and petrochemicals
Germany			
Deutsche BP	100	Germany	Refining and marketing and petrochemicals
Netherlands			
BP Capital	100	Netherlands	Finance
BP Nederland	100	Netherlands	Refining and marketing
New Zealand			
BP Oil New Zealand	100	New Zealand	Marketing
Norway			
BP Norge	100	Norway	Exploration and production
Spain			
BP España	100	Spain	Refining and marketing
South Africa			
*BP Southern Africa	75	South Africa	Refining and marketing
Trinidad			
BP Trinidad (LNG)	100	Netherlands	Exploration and production
BP Trinidad and Tobago	70	US	Exploration and production
UK			
BP Capital Markets	100	England	Finance
BP Chemicals	100	England	Petrochemicals
BP Oil UK	100	England	Refining and marketing
Britoil	100	Scotland	Exploration and production
Jupiter Insurance	100	Guernsey	Insurance
US			
Atlantic Richfield Co.	100	US	Exploration and production, gas, power and renewables, refining and marketing, pipelines and petrochemicals
*BP America	100	US	Exploration and production, gas, power and renewables, refining and marketing, pipelines and petrochemicals
BP America Production Company	100	US	Exploration and production, gas, power and renewables, refining and marketing, pipelines and petrochemicals
BP Amoco Chemical Company	100	US	Exploration and production, gas, power and renewables, refining and marketing, pipelines and petrochemicals
BP Company North America	100	US	Exploration and production, gas, power and renewables, refining and marketing, pipelines and petrochemicals
BP Corporation North America	100	US	Exploration and production, gas, power and renewables, refining and marketing, pipelines and petrochemicals
BP Products North America	100	US	Exploration and production, gas, power and renewables, refining and marketing, pipelines and petrochemicals
BP West Coast Products	100	US	Exploration and production, gas, power and renewables, refining and marketing, pipelines and petrochemicals
Standard Oil Co.	100	US	Exploration and production, gas, power and renewables, refining and marketing, pipelines and petrochemicals
BP Capital Markets America	100	US	Finance

Jointly controlled entities	%	Country of incorporation or registration	Principal activities
CaTO Finance V Limited Partnership	50	England	Finance
Lukarco	46	Netherlands	Exploration and production, pipelines
Pan American Energy	60	US	Exploration and production
Ruhr Oel	50	Germany	Refining and marketing and petrochemicals
Shanghai Secco Petrochemical Co.	50	China	Petrochemicals
TNK-BP	50	British Virgin Islands	Integrated oil operations
Unimar LLC	50	US	Exploration and production
Watson Cogeneration	51	US	Power generation

Associates	%	Country of incorporation	Principal activities
Abu Dhabi			
Abu Dhabi Marine Areas	37	England	Crude oil production
Abu Dhabi Petroleum Co.	24	England	Crude oil production
Azerbaijan			
The Baku-Tbilisi-Ceyhan Pipeline Co.	30	Cayman Islands	Pipelines
Korea			
Samsung Petrochemical Co.	47	England	Petrochemicals
Taiwan			
China American Petrochemical Co.	61	Taiwan	Petrochemicals
Trinidad and Tobago			
Atlantic LNG Company of Trinidad and Tobago	34	Trinidad and Tobago	LNG manufacture
Atlantic LNG 2/3 Company of Trinidad and Tobago	43	Trinidad and Tobago	LNG manufacture

52 Oil and natural gas exploration and production activities[a]

$ million

	2005								
	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
CAPITALIZED COSTS AT 31 DECEMBER									
Gross capitalized costs									
Proved properties	28,453	4,608	46,288	9,585	2,922	12,183	–	5,184	109,223
Unproved properties	276	135	1,547	583	1,124	656	185	155	4,661
	28,729	4,743	47,835	10,168	4,046	12,839	185	5,339	113,884
Accumulated depreciation	19,203	2,949	22,016	4,919	1,508	6,112	–	1,200	57,907
Net capitalized costs	9,526	1,794	25,819	5,249	2,538	6,727	185	4,139	55,977

The group's share of jointly controlled entities' and associates' net capitalized costs at 31 December 2005 was $10,670 million.

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
COSTS INCURRED FOR THE YEAR ENDED 31 DECEMBER									
Acquisition of properties									
Proved	–	–	—	–	–	–	–	–	–
Unproved	–	–	29	34	–	–	–	–	63
	–	–	29	34	–	–	–	–	63
Exploration and appraisal costs[b]	51	7	606	133	11	264	126	68	1,266
Development costs	790	188	2,965	681	186	1,691	–	1,177	7,678
Total costs	841	195	3,600	848	197	1,955	126	1,245	9,007

The group's share of jointly controlled entities' and associates' costs incurred in 2005 was $1,205 million.

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
RESULTS OF OPERATIONS FOR THE YEAR ENDED 31 DECEMBER									
Sales and other operating revenues[c]									
Third parties	4,667	635	2,048	2,260	1,045	1,350	–	690	12,695
Sales between businesses	2,458	976	14,842	2,863	782	2,402	–	4,796	29,119
	7,125	1,611	16,890	5,123	1,827	3,752	–	5,486	41,814
Exploration expenditure	32	1	426	84	6	81	37	17	684
Production costs	1,082	118	1,814	578	159	460	–	180	4,391
Production taxes	485	33	610	281	54	–	–	1,536	2,999
Other costs (income)[d]	1,857	(55)	2,200	537	170	98	8	2,042	6,857
Depreciation, depletion and amortization	1,548	220	2,288	675	162	542	–	193	5,628
Impairment and (gains) losses on sale of businesses and fixed assets	44	(1,038)	232	(133)	–	–	2	–	(893)
	5,048	(721)	7,570	2,022	551	1,181	47	3,968	19,666
Profit before taxation[e]	2,077	2,332	9,320	3,101	1,276	2,571	(47)	1,518	22,148
Allocable taxes	405	880	3,377	1,390	447	1,043	(1)	409	7,950
Results of operations	1,672	1,452	5,943	1,711	829	1,528	(46)	1,109	14,198

The group's share of jointly controlled entities' and associates' results of operations in 2005 was a profit of $3,035 million after deducting interest of $226 million, taxation of $1,250 million and minority interest of $104 million.

[a] This note relates to the requirements contained within the UK Statement of Recommended Practice 'Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities'. Mid-stream activities of natural gas gathering and distribution and the operation of the main pipelines and tankers are excluded. The main mid-stream activities are the Alaskan transportation facilities, the Forties Pipeline system and the Central Area Transmission System. The group's share of jointly controlled entities' and associates' activities is excluded from the tables and included in the footnotes, with the exception of the Abu Dhabi operations, which are included in the income and expenditure items above.

[b] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible fixed assets, and geological and geophysical exploration costs, which are charged to income as incurred.

[c] Sales and other operating revenues represents proceeds from the sale of production and other crude oil and gas, including royalty oil sold on behalf of others where royalty is payable in cash.

[d] Includes the value of royalty oil sold on behalf of others where royalty is payable in cash, property taxes, other government take, the fair value loss on embedded derivatives $1,688 million and a $265 million charge incurred on the cancellation of an intragroup gas supply contract. The UK region includes a $530 million charge offset by corresponding gains primarily in the US, relating to the group's self-insurance programme.

[e] The Exploration and Production profit before interest and tax comprises:

$ million

	2005
Exploration and production activities	
Group (as above)	22,148
Jointly controlled entities and associates	3,035
Mid-stream activities	325
Total profit before interest and tax	25,508

52 Oil and natural gas exploration and production activities[a] *continued*

$ million

									2004
	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
CAPITALIZED COSTS AT 31 DECEMBER									
Gross capitalized costs									
Proved properties	27,540	4,691	43,011	10,450	2,892	10,401	–	3,834	102,819
Unproved properties	300	170	1,395	456	1,240	526	119	105	4,311
	27,840	4,861	44,406	10,906	4,132	10,927	119	3,939	107,130
Accumulated depreciation	17,681	2,794	19,713	5,546	1,350	5,573	–	1,014	53,671
Net capitalized costs	10,159	2,067	24,693	5,360	2,782	5,354	119	2,925	53,459

The group's share of jointly controlled entities' and associates' net capitalized costs at 31 December 2004 was $11,013 million.

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
COSTS INCURRED FOR THE YEAR ENDED 31 DECEMBER									
Acquisition of properties									
Proved	–	–	–	–	–	–	–	–	–
Unproved	2	–	58	5	–	13	–	–	78
	2	–	58	5	–	13	–	–	78
Exploration and appraisal costs[b]	51	17	423	199	85	142	113	9	1,039
Development costs	679	262	3,247	527	88	1,460	–	1,007	7,270
Total costs	732	279	3,728	731	173	1,615	113	1,016	8,387

The group's share of jointly controlled entities' and associates' costs incurred in 2004 was $1,102 million.

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
RESULTS OF OPERATIONS FOR THE YEAR ENDED 31 DECEMBER									
Sales and other operating revenues[c]									
Third parties	3,458	626	1,735	1,776	977	492	5	403	9,472
Sales between businesses	2,424	609	11,794	2,556	530	1,439	–	2,912	22,264
	5,882	1,235	13,529	4,332	1,507	1,931	5	3,315	31,736
Exploration expenditure	26	25	361	141	14	45	17	8	637
Production costs	901	117	1,428	535	142	323	–	131	3,577
Production taxes	273	30	477	239	45	–	–	1,023	2,087
Other costs (income)[d]	(211)	38	1,884	458	96	122	(3)	1,380	3,764
Depreciation, depletion and amortization	1,524	172	2,268	611	174	287	–	121	5,157
Impairment and (gains) losses on sale of businesses and fixed assets	21	1	344	(55)	113	48	–	(3)	469
	2,534	383	6,762	1,929	584	825	14	2,660	15,691
Profit before taxation[e]	3,348	852	6,767	2,403	923	1,106	(9)	655	16,045
Allocable taxes	1,242	534	2,103	859	(4)	441	2	150	5,327
Results of operations	2,106	318	4,664	1,544	927	665	(11)	505	10,718

The group's share of jointly controlled entities' and associates' results of operations in 2004 was a profit of $1,816 million after deducting interest of $189 million, taxation of $969 million and minority interest of $43 million.

[a] This note relates to the requirements contained within the UK Statement of Recommended Practice 'Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities'. Mid-stream activities of natural gas gathering and distribution and the operation of the main pipelines and tankers are excluded. The main mid-stream activities are the Alaskan transportation facilities, the Forties Pipeline system and the Central Area Transmission System. The group's share of jointly controlled entities' and associates' activities is excluded from the tables and included in the footnotes, with the exception of the Abu Dhabi operations, which are included in the income and expenditure items above.
[b] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible fixed assets, and geological and geophysical exploration costs, which are charged to income as incurred.
[c] Sales and other operating revenues represents proceeds from the sale of production and other crude oil and gas, including royalty oil sold on behalf of others where royalty is payable in cash.
[d] Includes the value of royalty oil sold on behalf of others where royalty is payable in cash, property taxes and other government take.
[e] The Exploration and Production profit before interest and tax comprises:

$ million

	2004
Exploration and production activities	
Group (as above)	16,045
Jointly controlled entities and associates	1,816
Mid-stream activities	226
Total profit before interest and tax	18,087

52 Oil and natural gas exploration and production activities[a] *continued*

$ million

									2003
	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
CAPITALIZED COSTS AT 31 DECEMBER									
Gross capitalized costs									
Proved properties	21,398	4,421	42,960	10,379	3,659	9,856	1	3,295	95,969
Unproved properties	299	230	1,278	713	1,779	563	51	64	4,977
	21,697	4,651	44,238	11,092	5,438	10,419	52	3,359	100,946
Accumulated depreciation	13,013	2,886	19,658	5,080	2,413	5,642	33	1,246	49,971
Net capitalized costs	8,684	1,765	24,580	6,012	3,025	4,777	19	2,113	50,975

The group's share of jointly controlled entities' and associates' net capitalized costs at 31 December 2003 was $10,222 million.

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
COSTS INCURRED FOR THE YEAR ENDED 31 DECEMBER									
Acquisition of properties									
Proved	–	–	–	–	–	–	–	–	–
Unproved	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–
Exploration and appraisal costs[b]	20	69	288	119	57	205	26	40	824
Development costs	740	236	3,476	512	42	1,614	–	917	7,537
Total costs	760	305	3,764	631	99	1,819	26	957	8,361

The group's share of jointly controlled entities' and associates' costs incurred in 2003 was $468 million.

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
RESULTS OF OPERATIONS FOR THE YEAR ENDED 31 DECEMBER									
Sales and other operating revenues[c]									
Third parties	2,257	441	1,491	1,233	421	444	–	777	7,064
Sales between businesses	2,901	568	10,991	2,589	925	974	–	1,707	20,655
	5,158	1,009	12,482	3,822	1,346	1,418	–	2,484	27,719
Exploration expenditure	17	37	204	164	15	32	21	52	542
Production costs	825	113	1,262	463	166	241	–	135	3,205
Production taxes	233	14	439	189	40	–	–	742	1,657
Other costs (income)[d]	(151)	57	2,019	438	160	38	30	946	3,537
Depreciation, depletion and amortization	1,530	167	2,492	531	197	219	–	134	5,270
Impairment and (gains) losses on sale of businesses and fixed assets	(553)	30	573	(387)	347	(122)	(65)	2	(175)
	1,901	418	6,989	1,398	925	408	(14)	2,011	14,036
Profit before taxation[e]	3,257	591	5,493	2,424	421	1,010	14	473	13,683
Allocable taxes	1,306	305	1,574	847	(52)	438	56	47	4,521
Results of operations	1,951	286	3,919	1,577	473	572	(42)	426	9,162

The group's share of jointly controlled entities' and associates' results of operations in 2003 was a profit of $790 million after deducting interest of $120 million and taxation of $153 million.

[a] This note relates to the requirements contained within the UK Statement of Recommended Practice 'Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities'. Mid-stream activities of natural gas gathering and distribution and the operation of the main pipelines and tankers are excluded. The main mid-stream activities are the Alaskan transportation facilities, the Forties Pipeline system and the Central Area Transmission System. The group's share of jointly controlled entities' and associates' activities is excluded from the tables and included in the footnotes, with the exception of the Abu Dhabi operations, which are included in the income and expenditure items above.

[b] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible fixed assets, and geological and geophysical exploration costs, which are charged to income as incurred.

[c] Sales and other operating revenues represents proceeds from the sale of production and other crude oil and gas, including royalty oil sold on behalf of others where royalty is payable in cash.

[d] Includes the value of royalty oil sold on behalf of others where royalty is payable in cash, property taxes and other government take.

[e] The Exploration and Production profit before interest and tax comprises:

$ million

	2003
Exploration and production activities	
Group (as above)	13,683
Jointly controlled entities and associates	790
Mid-stream activities	611
Total profit before interest and tax	15,084

Supplementary information on oil and natural gas quantities

BP RESERVES GOVERNANCE

BP manages its hydrocarbon resources in three major categories: prospect inventory, non-proved resources and proved reserves. When a discovery is made, volumes 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 within three years. 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. The first PD bookings will occur at the point of first oil or gas production. Major development projects typically take one to four years from the time of initial booking to the start of production. Adjustments may be made to booked reserves owing to production, reservoir performance, commercial factors, acquisition and divestment activity and additional reservoir development activity.

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

The first element is the accountabilities of certain officers of the company, which ensure that there is clear responsibility for review and, where appropriate, endorsement of changes to reserves bookings; that the review is independent of the operating business unit for the integrity and accuracy of the reserve estimates; and that there are effective controls in the reserve approval process and verification that the group's reserve estimates and the related financial impacts are reported in a timely manner.

The second element is the capital allocation processes whereby delegated authority is exercised to commit to capital projects that are consistent with the delivery of the group's business plan. A formal process exists to review that both technical and commercial criteria are met prior to the commitment of capital to projects.

The third element is internal audit, whose role includes systematically examining the effectiveness of the group's financial controls designed to assure the reliability of reporting and safeguarding of assets and examining the group's compliance with laws, regulations and internal standards.

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

The fifth element is the established criteria whereby reserves above certain thresholds require central authorization. Furthermore, the volumes booked under these authorization levels are reviewed on a periodic basis. The frequency of review is determined according to field size and ensures that more than 80% of the BP reserves base undergoes central review every two years and more than 90% is reviewed every four years.

RESERVES REPORTING

Our proved reserves are associated with both concessions (tax and royalty arrangements) and production-sharing agreements (PSAs). In a concession, the consortium of which we are a part is entitled to the reserves that can be produced over the licence period, which may be the life of the field. In a PSA, we are entitled to recover volumes that equate to costs incurred to develop and produce the reserves and an agreed share of the remaining volumes or the economic equivalent. As part of our entitlement is driven by the monetary amount of costs to be recovered, price fluctuations will have an impact on both production volumes and reserves. Twenty per cent of our proved reserves are associated with PSAs. The main countries in which we operate under PSA arrangements are Algeria, Angola, Azerbaijan, Egypt, Indonesia and Vietnam.

As a UK-registered company, BP estimates its proved reserves under UK accounting rules for oil and gas companies contained in the Statement of Recommended Practice, 'Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities' (UK SORP). In estimating its reserves under UK SORP, BP uses long-term planning prices; these are the long-term price assumptions on which the group makes decisions to invest in the development of a field. Using planning prices for estimating proved reserves removes the impact of the volatility inherent in using year-end spot prices on our reserve base and on cash flow expectations over the long term. The group's planning prices for estimating reserves through the end of 2005 were $25 per barrel for oil and $4.00 per mmBtu for natural gas.

In determining 'reasonable certainty' for UK SORP purposes, BP applies a number of additional internally imposed assessment principles, such as the requirement for internal approval and final investment decision (which we refer to as project sanction), or for such project sanction 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 within three years.

On the basis of UK SORP, our total proved reserves for subsidiaries and equity-accounted entities at the end of 2005 were 18,271mmboe, representing a proved reserve replacement ratio (RRR) before acquisitions and divestments of 100%, versus 110% in 2004. Our principal equity-accounted entity is TNK-BP. For subsidiaries only, the RRR is 71% and, for equity-accounted entities only, the RRR is 160%. The proved reserve replacement ratio (also known as the production replacement ratio) is the extent to which production is replaced by proved reserve additions. This ratio is expressed in oil equivalent terms and includes changes resulting from revisions to previous estimates, improved recovery, extensions, discoveries and other additions, excluding the impact of acquisitions and divestments. Natural gas is converted to oil equivalent at 5.8 billion cubic feet (bcf) equals 1 million barrels. 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. The estimated proved oil and natural gas reserves on this basis are shown on pages 133-134.

The US Securities and Exchange Commission (SEC) rules for estimating reserves are different in certain respects from SORP; in particular, the SEC requires the use of year-end prices.

Supplementary information on oil and natural gas quantities *continued*

At 31 December 2005, the marker price for Brent crude was $58.21 per barrel and for Henry Hub gas it was $9.52 per mmBtu.

Applying higher year-end prices to reserve estimates and assuming they apply to the end-of-field life have the effect of increasing proved reserves associated with concessions (tax and royalty arrangements) for which additional development opportunities become economic at higher prices or where higher prices make it more economic to extend the life of a field. On the other hand, applying higher year-end prices to reserves in fields subject to PSAs has the effect of decreasing proved reserves from those fields because higher prices result in lower volume entitlements.

The company's proved reserves estimates on an SEC basis for the year ended 31 December 2005 reflect year-end prices and some adjustments that have been made vis-à-vis individual asset reserve estimates based on different applications of certain SEC interpretations of SEC regulations relating to the use of technology (mainly seismic) to estimate reserves in the reservoir away from wellbores and the reporting of fuel gas (i.e. gas used for fuel in operations on the lease) within proved reserves. On an aggregate basis, the net impact of these changes, comprising some reductions and some additions, is a decrease of 378mmboe compared with our reserves under UK SORP, resulting in total proved reserves of 17,893mmboe (including equity-accounted entities). Excluding equity-accounted entities, our proved reserves on an SEC basis were 14,023mmboe.

The total net movement in subsidiaries and equity-accounted entities comprises a decrease of 397mmboe as a result of using the year-end price, offset by a net increase of 19mmboe in respect of fuel gas and technology interpretations.

Following SEC rules for reserves, our total proved reserves for subsidiaries and equity-accounted entities at the end of 2005 were 17,893mmboe, representing a proved reserve replacement ratio (RRR) before acquisitions and divestments of 95% versus 89% in 2004. For subsidiaries only, the RRR is 68% and, for equity-accounted entities only, the RRR is 151%.

The estimated proved oil and natural gas reserves prepared on an SEC basis are shown on pages 135-136.

Movements in estimated net proved reserves on a UK SORP basis

2005

CRUDE OIL[a]									million barrels
	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
SUBSIDIARY									
At 1 January 2005									
Developed	548	217	1,938	296	70	275	–	79	3,423
Undeveloped	207	109	1,258	300	86	942	–	1,225	4,127
	755	326	3,196	596	156	1,217	–	1,304	7,550
Changes attributable to									
Revisions of previous estimates	(39)	(10)	15	(20)	19	(193)	–	(144)	(372)
Purchases of reserves-in-place	–	–	2	–	–	–	–	–	2
Extensions, discoveries and other additions	11	–	62	3	11	131	–	–	218
Improved recovery	33	21	240	1	–	2	–	13	310
Production[b]	(101)	(28)	(200)	(52)	(17)	(64)	–	(34)	(496)
Sales of reserves-in-place	–	(15)	(1)	(35)	–	–	–	–	(51)
	(96)	(32)	118	(103)	13	(124)	–	(165)	(389)
AT 31 DECEMBER 2005[c]									
Developed	475	209	1,801	206	73	202	–	94	3,060
Undeveloped	184	85	1,513	287	96	891	–	1,045	4,101
	659	294	3,314	493	169	1,093	–	1,139	7,161
EQUITY-ACCOUNTED ENTITIES (BP SHARE)									
At 1 January 2005									
Developed	–	–	–	204	1	–	1,863	593	2,661
Undeveloped	–	–	–	126	–	–	294	99	519
	–	–	–	330	1	–	2,157	692	3,180
Changes attributable to									
Revisions of previous estimates	–	–	–	–	–	–	368	111	479
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Extensions, discoveries and other additions	–	–	–	2	–	–	–	–	2
Improved recovery	–	–	–	25	–	–	–	–	25
Production	–	–	–	(26)	–	–	(333)	(57)	(416)
Sales of reserves-in-place	–	–	–	–	–	–	(24)	–	(24)
	–	–	–	1	–	–	11	54	66
AT 31 DECEMBER 2005[d]									
Developed	–	–	–	207	1	–	1,682	582	2,472
Undeveloped	–	–	–	124	–	–	486	164	774
	–	–	–	331	1	–	2,168	746	3,246
TOTAL GROUP AND BP SHARE OF EQUITY-ACCOUNTED ENTITIES	659	294	3,314	824	170	1,093	2,168	1,885	10,407

[a] Crude oil includes natural gas liquids (NGLs) and condensate. Net proved reserves of crude oil exclude production royalties due to others, whether royalty is payable in cash or in kind.
[b] Excludes NGLs from processing plants in which an interest is held of 58 thousand barrels a day.
[c] Includes 29 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 97 million barrels of crude oil in respect of the 4.47% minority interest in TNK-BP.

Supplementary information on oil and natural gas quantities *continued*

Movements in estimated net proved reserves on a UK SORP basis *continued*

2005

NATURAL GAS[a]									billion cubic feet
	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
SUBSIDIARY									
At 1 January 2005									
Developed	2,079	216	10,207	3,981	1,578	1,054	–	257	19,372
Undeveloped	923	1,183	2,553	10,824	5,278	1,677	–	1,112	23,550
	3,002	1,399	12,760	14,805	6,856	2,731	–	1,369	42,922
Changes attributable to									
Revisions of previous estimates	(15)	(12)	(2)	122	140	301	–	125	659
Purchases of reserves-in-place	–	–	66	2	–	–	–	–	68
Extensions, discoveries and other additions	17	17	62	225	201	18	–	–	540
Improved recovery	124	18	1,730	83	–	–	–	9	1,964
Production	(395)	(39)	(1,006)[b]	(870)	(274)	(154)	–	(77)	(2,815)
Sales of reserves-in-place	–	(1,153)	(16)	(203)	–	–	–	–	(1,372)
	(269)	(1,169)	834	(641)	67	165	–	57	(956)
AT 31 DECEMBER 2005[c]									
Developed	1,962	184	9,916	3,433	1,423	987	–	242	18,147
Undeveloped	771	46	3,678	10,731	5,500	1,909	–	1,184	23,819
	2,733	230	13,594	14,164	6,923	2,896	–	1,426	41,966
EQUITY-ACCOUNTED ENTITIES (BP SHARE)									
At 1 January 2005									
Developed	–	–	–	1,318	103	–	151	60	1,632
Undeveloped	–	–	–	904	69	–	–	23	996
	–	–	–	2,222	172	–	151	83	2,628
Changes attributable to									
Revisions of previous estimates	–	–	–	21	(77)	–	1,340	103	1,387
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Extensions, discoveries and other additions	–	–	–	27	–	–	–	–	27
Improved recovery	–	–	–	53	–	–	–	–	53
Production	–	–	–	(137)	(17)	–	(176)	(3)	(333)
Sales of reserves-in-place	–	–	–	–	–	–	(119)	–	(119)
	–	–	–	(36)	(94)	–	1,045	100	1,015
AT 31 DECEMBER 2005[d]									
Developed	–	–	–	1,403	50	–	1,019	131	2,603
Undeveloped	–	–	–	783	28	–	177	52	1,040
	–	–	–	2,186	78	–	1,196	183	3,643
TOTAL GROUP AND BP SHARE OF EQUITY-ACCOUNTED ENTITIES	2,733	230	13,594	16,350	7,001	2,896	1,196	1,609	45,609

[a] Net proved reserves of natural gas exclude production royalties due to others, whether royalty is payable in cash or in kind.
[b] Includes 64 billion cubic feet of natural gas consumed in operations.
[c] Includes 3,872 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 54 billion cubic feet of natural gas in respect of the 4.47% minority interest in TNK-BP.

Movements in estimated net proved reserves on an SEC basis

2005

CRUDE OIL[a]

million barrels

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
SUBSIDIARY									
At 1 January 2005									
Developed	559	231	2,041	311	65	204	–	62	3,473
Undeveloped	210	109	1,211	299	85	643	–	725	3,282
	769	340	3,252	610	150	847	–	787	6,755
Changes attributable to									
Revisions of previous estimates	(31)	(8)	103	(21)	21	(190)	–	(148)	(274)
Purchases of reserves-in-place	–	–	2	–	–	–	–	–	2
Extensions, discoveries and other additions	11	–	40	3	11	83	–	–	148
Improved recovery	32	21	217	1	–	2	–	7	280
Production[b]	(101)	(27)	(200)	(53)	(17)	(64)	–	(34)	(496)
Sales of reserves-in-place	–	(15)	(1)	(39)	–	–	–	–	(55)
	(89)	(29)	161	(109)	15	(169)	–	(175)	(395)
AT 31 DECEMBER 2005[c]									
Developed	496	225	1,984	215	70	142	–	69	3,201
Undeveloped	184	86	1,429	286	95	536	–	543	3,159
	680	311	3,413	501	165	678	–	612	6,360
EQUITY-ACCOUNTED ENTITIES (BP SHARE)									
At 1 January 2005									
Developed	–	–	–	204	1	–	1,863	592	2,660
Undeveloped	–	–	–	125	–	–	294	100	519
	–	–	–	329	1	–	2,157	692	3,179
Changes attributable to									
Revisions of previous estimates	–	–	–	1	–	–	319	119	439
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Extensions, discoveries and other additions	–	–	–	2	–	–	–	–	2
Improved recovery	–	–	–	25	–	–	–	–	25
Production	–	–	–	(26)	–	–	(333)	(57)	(416)
Sales of reserves-in-place	–	–	–	–	–	–	(24)	–	(24)
	–	–	–	2	–	–	(38)	62	26
AT 31 DECEMBER 2005[d]									
Developed	–	–	–	207	1	–	1,688	590	2,486
Undeveloped	–	–	–	124	–	–	431	164	719
	–	–	–	331	1	–	2,119	754	3,205

[a]Crude oil includes natural gas liquids (NGLs) and condensate. Net proved reserves of crude oil exclude production royalties due to others, whether royalty is payable in cash or in kind.
[b]Excludes NGLs from processing plants in which an interest is held of 58 thousand barrels a day.
[c]Includes 29 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d]Includes 95 million barrels of crude oil in respect of the 4.47% minority interest in TNK-BP.

Movements in estimated net proved reserves on an SEC basis *continued*

2005

NATURAL GAS[a]									billion cubic feet
	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
SUBSIDIARY									
At 1 January 2005									
Developed	2,498	248	10,811	4,101	1,624	1,015	–	282	20,579
Undeveloped	1,183	1,254	3,270	10,663	5,419	1,886	–	1,396	25,071
	3,681	1,502	14,081	14,764	7,043	2,901	–	1,678	45,650
Changes attributable to									
Revisions of previous estimates	(102)	11	447	104	(133)	152	–	15	494
Purchases of reserves-in-place	–	–	66	2	–	–	–	–	68
Extensions, discoveries and other additions	21	19	47	225	204	44	–	–	560
Improved recovery	111	19	1,773	87	–	–	–	10	2,000
Production[b]	(425)	(44)	(1,018)	(888)	(280)	(163)	–	(80)	(2,898)
Sales of reserves-in-place	–	(1,182)	(14)	(230)	–	–	–	–	(1,426)
	(395)	(1,177)	1,301	(700)	(209)	33	–	(55)	(1,202)
AT 31 DECEMBER 2005[c]									
Developed	2,382	245	11,184	3,560	1,459	934	–	281	20,045
Undeveloped	904	80	4,198	10,504	5,375	2,000	–	1,342	24,403
	3,286	325	15,382	14,064	6,834	2,934	–	1,623	44,448
EQUITY-ACCOUNTED ENTITIES (BP SHARE)									
At 1 January 2005									
Developed	–	–	–	1,397	107	–	214	60	1,778
Undeveloped	–	–	–	977	69	–	10	23	1,079
	–	–	–	2,374	176	–	224	83	2,857
Changes attributable to									
Revisions of previous estimates	–	–	–	26	(81)	–	1,337	102	1,384
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Extensions, discoveries and other additions	–	–	–	28	–	–	–	–	28
Improved recovery	–	–	–	66	–	–	–	–	66
Production[b]	–	–	–	(154)	(19)	–	(184)	(3)	(360)
Sales of reserves-in-place	–	–	–	–	–	–	(119)	–	(119)
	–	–	–	(34)	(100)	–	1,034	99	999
AT 31 DECEMBER 2005[d]									
Developed	–	–	–	1,492	50	–	1,089	130	2,761
Undeveloped	–	–	–	848	26	–	169	52	1,095
	–	–	–	2,340	76	–	1,258	182	3,856

[a] Net proved reserves of natural gas exclude production royalties due to others, whether royalty is payable in cash or in kind.
[b] Includes 174 billion cubic feet of natural gas consumed in operations (147 bcf in subsidiaries, 27 bcf in equity-accounted entities).
[c] Includes 3,812 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 57 billion cubic feet of natural gas in respect of the 4.47% minority interest in TNK-BP.

Group production interests – oil (includes NGLs and condensate)

BP net share of production thousand barrels a day[a]

		Field	Interest %	2005	2004	2003
UK	Offshore	ETAP[b]	Various	49	55	56
		Foinaven[c]	Various	39	48	55
		Magnus[c]	85.0	30	34	39
		Schiehallion/Loyal[c]	Various	28	39	42
		Harding[c]	70.0	22	27	34
		Andrew[c]	62.8	12	12	17
		Other	Various	75	89	105
	Onshore	Wytch Farm[c]	67.8	22	26	29
				277	330	377
Rest of Europe	Netherlands	Various	Various	1	1	1
	Norway	Valhall[c]	28.1	25	25	21
		Draugen	18.4	20	27	25
		Ula[c]	80.0	17	16	16
		Other	Various	12	8	21
				75	77	84
USA	Alaska	Prudhoe Bay[c]	26.4	89	97	105
		Kuparuk	39.2	62	68	73
		Northstar[c]	98.6	46	49	46
		Milne Point[c]	100.0	37	44	44
		Other	Various	34	37	43
	Lower 48 onshore	Various	Various	130	142	160
	Gulf of Mexico	Na Kika[c]	50.0	44	27	–
		Horn Mountain[c]	66.6	26	41	42
		King[c]	100.0	24	26	31
		Mars	28.5	21	35	43
		Ursa	22.7	19	29	17
		Other	Various	80	71	122
				612	666	726
Rest of World	Angola	Kizomba A	26.7	56	16	–
		Girassol	16.7	34	31	33
		Xikomba	26.7	10	18	2
		Other	Various	28	6	–
	Australia	Various	15.8	36	36	40
	Azerbaijan	ACG (Chirag)[c]	34.1	76	39	38
	Canada	Various	Various	10	11	13
	Colombia	Various	Various	41	48	53
	Egypt	Various	Various	47	57	73
	Trinidad & Tobago	Various	100.0	40	59	74
	Venezuela	Various	Various	55	55	53
	Other	Various	Various	26	31	49
				459	407	428
Total group				1,423	1,480	1,615
Equity-accounted entities (BP share)	Abu Dhabi	Various	Various	148	142	138
	Argentina – Pan American Energy	Various	Various	67	64	60
	Russia – TNK-BP	Various	Various	911	831	296
	Other	Various	Various	13	14	12
Total equity-accounted entities				1,139	1,051	506
Total group and BP share of equity-accounted entities[d]				2,562	2,531	2,121

[a] Net of royalty, whether payable in cash or in kind.
[b] Out of nine fields, BP operates six and Shell three.
[c] BP operator.
[d] Includes natural gas liquids (NGLs) from processing plants in which an interest is held of 58 thousand barrels a day (67 thousand barrels a day in 2004 and 70 thousand barrels a day in 2003).

Supplementary information on oil and natural gas quantities *continued*

Group production interests – natural gas

		Field	Interest %	2005	2004	2003
				BP net share of production million cubic feet a day[a]		
UK	Offshore	Braes[b]	Various	165	147	174
		Bruce[c]	37.0	161	163	222
		West Sole[c]	100.0	55	67	73
		Marnock[c]	62.0	47	70	98
		Britannia	9.0	46	54	55
		Shearwater	27.5	37	76	70
		Armada	18.2	30	50	58
		Other	Various	549	547	696
				1,090	1,174	1,446
Rest of Europe	Netherlands	P/18-2[c]	48.7	25	34	30
		Other	Various	37	46	37
	Norway	Various	Various	46	45	52
				108	125	119
USA	Lower 48 onshore	San Juan[c]	Various	753	772	802
		Arkoma	Various	198	183	201
		Hugoton[c]	Various	151	158	182
		Tuscaloosa	Various	111	96	136
		Wamsutter[c]	70.5	110	105	111
		Jonah[c]	65.0	97	114	119
		Other	Various	465	514	558
	Gulf of Mexico	Na Kika[c]	50.0	133	133	–
		Marlin[c]	78.2	52	43	93
		Other	Various	395	553	843
	Alaska	Various	Various	81	78	83
				2,546	2,749	3,128
Rest of World	Australia	Various	15.8	367	308	285
	Canada	Various	Various	307	349	422
	China	Yacheng[c]	34.3	98	99	74
	Egypt	Ha'py[c]	50.0	106	80	83
		Other	Various	83	115	170
	Indonesia	Sanga-Sanga (direct)[c]	26.3	110	137	165
		Other[c]	46.0	128	144	218
	Sharjah	Sajaa[c]	40.0	113	103	101
		Other	40.0	10	14	19
	Trinidad & Tobago	Kapok[c]	100.0	1,005	553	79
		Mahogany[c]	100.0	303	453	503
		Amherstia[c]	100.0	289	408	624
		Parang[c]	100.0	154	137	152
		Immortelle[c]	100.0	132	172	235
		Cassia[c]	100.0	83	85	30
		Other[c]	100.0	21	111	71
	Other	Various	Various	459	308	168
				3,768	3,576	3,399
Total group				7,512	7,624	8,092
Equity-accounted entities (BP share)	Argentina – Pan American Energy	Various	Various	343	317	281
	Russia – TNK-BP	Various	Various	482	458	129
	Other	Various	Various	87	104	111
Total equity-accounted entities				912	879	521
Total group and BP share of equity-accounted entities				8,424	8,503	8,613

[a] Net of royalty, whether payable in cash or in kind.
[b] 2004 includes 11 million cubic feet a day of natural gas received as in-kind tariff payments.
[c] BP operator.

United States accounting principles

The following is a summary of adjustments to profit for the year and to BP shareholders' equity that would be required if generally accepted accounting principles in the United States (US GAAP) had been applied instead of International Financial Reporting Standards.

PROFIT FOR THE YEAR UNDER US GAAP

$ million	2005	2004	2003
Profit for the year as reported	22,341	17,075	12,448
Adjustments			
Deferred taxation/business combinations	(496)	(517)	(588)
Provisions	9	(80)	49
Oil and natural gas reserve differences	11	30	–
Goodwill and intangible assets	–	(61)	–
Derivative financial instruments	87	(337)	(27)
Inventory valuation	(232)	162	39
Gain arising on asset exchange	(12)	(107)	(19)
Pensions and other post-retirement benefits	(486)	(47)	(215)
Impairments	(378)	677	–
Equity-accounted investments	(255)	147	(47)
Major maintenance expenditure	–	217	120
Share-based payments	6	24	39
Other	156	(93)	90
Profit for the year before cumulative effect of accounting changes as adjusted to accord with US GAAP	20,751	17,090	11,889
Cumulative effect of accounting changes			
Major maintenance expenditure	(794)	–	–
Provisions	–	–	1,002
Derivative financial instruments	–	–	50
Profit for the year as adjusted to accord with US GAAP	19,957	17,090	12,941
Dividend requirements on preference shares	2	2	2
Profit for the year applicable to ordinary shares as adjusted to accord with US GAAP	19,955	17,088	12,939
Per ordinary share – cents			
Basic – before cumulative effect of accounting changes	98.22	78.31	53.62
Cumulative effect of accounting changes	(3.76)	–	4.74
	94.46	78.31	58.36
Diluted – before cumulative effect of accounting changes	97.09	76.88	53.10
Cumulative effect of accounting changes	(3.71)	–	4.69
	93.38	76.88	57.79
Per American depositary share – cents[a]			
Basic – before cumulative effect of accounting changes	589.32	469.86	321.72
Cumulative effect of accounting changes	(22.56)	–	28.44
	566.76	469.86	350.16
Diluted – before cumulative effect of accounting changes	582.54	461.28	318.60
Cumulative effect of accounting changes	(22.26)	–	28.14
	560.28	461.28	346.74

BP SHAREHOLDERS' EQUITY UNDER US GAAP

$ million	2005	2004	2003
BP shareholders' equity as reported	79,976	76,892	69,139
Adjustments			
Deferred taxation/business combinations	2,025	2,563	3,009
Provisions	(112)	(77)	(128)
Oil and natural gas reserve differences	41	30	–
Goodwill and intangible assets	171	224	248
Derivative financial instruments	225	(315)	26
Inventory valuation	(167)	65	(98)
Gain arising on asset exchange	239	251	269
Pensions and other post-retirement benefits	3,146	4,089	5,246
Impairments	327	677	–
Equity-accounted investments	(43)	212	65
Investments	–	227	1,251
Major maintenance expenditure	–	794	545
Share-based payments	(334)	(353)	(235)
Other	(32)	(187)	(170)
BP shareholders' equity as adjusted to accord with US GAAP	85,462	85,092	79,167

[a] One American depositary share (ADS) is equivalent to six 25 cent ordinary shares.

Other financial and operating data

Exchange rates

	2005	2004	2003
US dollar/sterling exchange rates			
Average exchange rate for the year	1.82	1.83	1.63
Year end exchange rate	1.73	1.92	1.78
US dollar/euro exchange rates			
Average exchange rate for the year	1.24	1.24	1.13
Year end exchange rate	1.18	1.36	1.25

Ratios

%

	2005	2004	2003
Return on average capital employed (Based on profit after taxation before deducting finance costs)[a]	22.9	18.1	14.8
Return on average BP shareholders' interest (Based on profit after taxation and minority interest)	28.5	23.4	19.2
Payout ratio (Dividend: profit)	32.9	35.4	45.4
Debt to debt-plus-equity ratio (Finance debt: finance debt plus BP and minority interest)	19.2	22.8	24.1
Debt to equity ratio (Finance debt: BP and minority interest)	23.7	29.5	31.8
Net debt to net debt-plus-equity ratio	16.7	21.7	22.4
Net debt to equity ratio (Net debt equals finance debt less cash and cash equivalents)	20.1	27.8	28.8

[a] Before deducting finance costs on a post-tax basis, using a deemed tax rate equal to the US statutory tax rate.

Share prices

pence

ORDINARY SHARE	2005	2004	2003
High	684	557	455
Daily average	592	489	418
Low	504	414	357
End year	619	508	453

$

AMERICAN DEPOSITARY SHARE[a]	2005	2004	2003
High	72.27	61.66	49.35
Daily average	64.38	54.06	41.48
Low	56.61	47.27	35.37
End year	64.22	58.40	49.35

[a] One American depositary share (ADS) is equivalent to six 25 cent ordinary shares.

Statistics

CRUDE OIL, NATURAL GAS AND NATURAL GAS LIQUIDS PRODUCTION (net of royalties)	2005	2004	2003
UK	277	330	377
USA	613	666	726
Other	1,672	1,535	1,018
Crude oil and liquids production (thousand barrels a day)	2,562	2,531	2,121
UK	1,090	1,174	1,446
USA	2,547	2,749	3,128
Other	4,787	4,580	4,039
Natural gas production (million cubic feet a day)	8,424	8,503	8,613
Total production (thousand barrels oil equivalent a day)	4,014	3,997	3,606

REFINERY THROUGHPUTS			thousand barrels a day
Group refinery throughputs[a]	2,399	2,607	2,723

CRUDE OIL AND REFINED PETROLEUM PRODUCT SALES			thousand barrels a day
Crude oil	2,804	2,691	2,836
Refined petroleum products	5,888	6,398	6,688
Total oil sales	8,692	9,089	9,524

ESTIMATED NET PROVED RESERVES OF CRUDE OIL[b]			millions of barrels at 31 December
Developed	3,060	3,423	3,576
Undeveloped	4,101	4,127	3,873
Group companies	7,161	7,550	7,449
Equity-accounted entities (BP share)	3,246	3,180	2,867

ESTIMATED NET PROVED RESERVES OF NATURAL GAS[c]			billions of cubic feet at 31 December
Developed	18,147	19,372	21,073
Undeveloped	23,819	23,550	22,903
Group companies	41,966	42,922	43,976
Equity-accounted entities (BP share)	3,643	2,628	2,553

AVERAGE REALIZATIONS			
BP average liquids realizations ($/bbl)	48.51	35.39	27.25
BP average natural gas realizations ($/mcf)	4.90	3.86	3.39
Brent oil price ($/bbl)	54.48	38.27	28.83
Henry Hub gas price ($/mmBtu)	8.65	6.13	5.37

[a] Includes crude oil and other feedstock input to BP's crude distillation units both for BP and third parties.
[b] Net proved reserves of crude oil exclude production royalties due to others.
[c] Net proved reserves of natural gas exclude production royalties due to others.

Further information is included in *BP Financial and Operating Information 2001-2005.* To obtain a copy see page 177.

Parent company financial statements of BP p.l.c.

Statement of directors' responsibilities in respect of the parent company financial statements

The directors are responsible for preparing the financial statements in accordance with applicable United Kingdom law and United Kingdom generally accepted accounting practice.

Company law requires the directors to prepare financial statements for each financial year that give a true and fair view of the state of affairs of the company. In preparing these financial statements, the directors are required:

- To select suitable accounting policies and then apply them consistently;
- To make judgements and estimates that are reasonable and prudent;
- To state whether applicable accounting standards have been followed, subject to any material departures disclosed and explained in the financial statements;
- To prepare the financial statements on the going concern basis unless it is inappropriate to presume that the company will continue in business.

The directors are responsible for keeping proper accounting records that disclose with reasonable accuracy at any time the financial position of the company and enable them to ensure that the financial statements comply with the Companies Act 1985. They are also responsible for safeguarding the assets of the company and hence for taking reasonable steps for the prevention and detection of fraud and other irregularities.

The directors confirm that they have complied with these requirements, and having a reasonable expectation that the company has adequate resources to continue in operational existence for the foreseeable future, continue to adopt the going concern basis in preparing the financial statements.

Independent auditors' report

We have audited the parent company financial statements of BP p.l.c. for the year ended 31 December 2005 which comprise the balance sheet, cash flow statement, statement of total recognized gains and losses, accounting policies and the related notes 1 to 11. These parent company financial statements have been prepared under the accounting policies set out therein. We have also audited the information in the Directors' Remuneration Report that is described as having been audited.

We have reported separately on the consolidated financial statements of BP p.l.c. for the year ended 31 December 2005.

This report is made solely to the company's members, as a body, in accordance with Section 235 of the Companies Act 1985. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditors' report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for this report or for the opinions we have formed.

RESPECTIVE RESPONSIBILITIES OF DIRECTORS AND AUDITORS

The directors are responsible for preparing the Annual Report, the Directors' Remuneration Report and the parent company financial statements in accordance with applicable United Kingdom law and Accounting Standards (United Kingdom generally accepted accounting practice) as set out in the Statement of Directors' Responsibilities.

Our responsibility is to audit the parent company financial statements and the part of the Directors' Remuneration Report to be audited in accordance with relevant legal and regulatory requirements and International Standards on Auditing (UK and Ireland).

We report to you our opinion as to whether the parent company financial statements give a true and fair view and whether the parent company financial statements and the part of the Directors' Remuneration Report to be audited have been properly prepared in accordance with the Companies Act 1985. We also report to you if, in our opinion, the Directors' Report is not consistent with the parent company financial statements, if the company has not kept proper accounting records, if we have not received all the information and explanations we require for our audit or if information specified by law regarding directors' remuneration and other transactions is not disclosed.

We read other information contained in the Annual Report and consider whether it is consistent with the audited parent company financial statements. The other information comprises the United States accounting principles, the supplementary information on oil and natural gas quantities, the other financial and operating data, the Directors' Report, the Chairman's letter, and Governance: board performance report. We consider the implications for our report if we become aware of any apparent misstatements or material inconsistencies with the parent company financial statements. Our responsibilities do not extend to any other information.

BASIS OF AUDIT OPINION

We conducted our audit in accordance with International Standards on Auditing (UK and Ireland) issued by the Auditing Practices Board. An audit includes examination, on a test basis, of evidence relevant to the amounts and disclosures in the parent company financial statements and the part of the Directors' Remuneration Report to be audited. It also includes an assessment of the significant estimates and judgements made by the directors in the preparation of the parent company financial statements and of whether the accounting policies are appropriate to the company's circumstances, consistently applied and adequately disclosed.

We planned and performed our audit so as to obtain all the information and explanations that we considered necessary in order to provide us with sufficient evidence to give reasonable assurance that the parent company financial statements and the part of the Directors' Remuneration Report to be audited are free from material misstatement, whether caused by fraud or other irregularity or error. In forming our opinion we also evaluated the overall adequacy of the presentation of information in the parent company financial statements and the part of the Directors' Remuneration Report to be audited.

OPINION

In our opinion:

- the parent company financial statements give a true and fair view, in accordance with United Kingdom generally accepted accounting practice, of the state of the company's affairs as at 31 December 2005; and
- the parent company financial statements and the part of the Directors' Remuneration Report to be audited have been properly prepared in accordance with the Companies Act 1985.

Ernst & Young LLP
Registered auditor
London
6 February 2006

Accounting policies

ACCOUNTING STANDARDS

These accounts are prepared in accordance with applicable UK accounting standards. In preparing the financial statements for the current year, the company has adopted Financial Reporting Standards No. 20 'Share-based Payment' (FRS 20), No. 21 'Events after the Balance Sheet Date' (FRS 21), No. 22 'Earnings per share', No. 23 'The Effects of Changes in Foreign Exchange Rates', No. 24 'Financial Reporting in Hyperinflationary Economies', No. 25 'Financial Instruments: Disclosure and Presentation', No. 26 'Financial Instruments: Measurement', No. 27 'Life Assurance' and No. 28 'Corresponding Amounts'.

The adoption of FRS 20 has resulted in changes in accounting policy for share-based payment transactions and the adoption of FRS 21 has resulted in changes in accounting policy for dividends. FRS 20 requires that the fair value of options and shares awarded to employees is charged to the income statement over the vesting period. Under UK GAAP, no charge was made in respect of share options. Dividends proposed or declared on equity instruments after the balance sheet date are no longer recognized as a liability at the balance sheet date. These changes in accounting policy have resulted in a prior year adjustment. Shareholders' interest at 1 January 2004 has been increased by $1,750 million and profit for the years ended 31 December 2004 and 2003 reduced by $64 million and $47 million respectively. The statement of total recognized gains and losses includes a prior year adjustment representing deferred taxation on share-based payments. Profit for the current year has been reduced by approximately $86 million as a result of the changes in accounting policy.

ACCOUNTING CONVENTION

The accounts are prepared under the historical cost convention.

FOREIGN CURRENCY TRANSACTIONS

Foreign currency transactions are booked in the functional currency at the exchange rate ruling on the date of transaction. Foreign currency monetary assets and liabilities are translated into the functional currency at rates of exchange ruling at the balance sheet date. Exchange differences are included in profit for the year.

INVESTMENTS

Investments in subsidiary and associated undertakings are held at cost. The company assesses investments for impairment whenever events or changes in circumstances indicate that the carrying value of an investment may not be recoverable. If any such indication of impairment exists, the company makes an estimate of its recoverable amount. Where the carrying amount of an investment exceeds its recoverable amount, the investment is considered impaired and is written down to its recoverable amount.

SHARE-BASED PAYMENTS

Equity-settled transactions The cost of equity-settled transactions with employees is measured by reference to the fair value at the date at which they are granted and is recognized as an expense over the vesting period, which ends on the date on which the relevant employees become fully entitled to the award. Fair value is determined by using an appropriate valuation model. In valuing equity-settled transactions, no account is taken of any vesting conditions other than conditions linked to the price of the shares of the company (market conditions).

No expense is recognized for awards that do not ultimately vest, except for awards where vesting is conditional upon a market condition, which are treated as vesting irrespective of whether or not the market condition is satisfied, provided that all other performance conditions are satisfied.

At each balance sheet date before vesting, the cumulative expense is calculated, representing the extent to which the vesting period has expired and management's best estimate of the achievement or otherwise of non-market conditions and number of equity instruments that will ultimately vest or in the case of an instrument subject to a market condition, be treated as vesting as described above. The movement in cumulative expense since the previous balance sheet date is recognized in the income statement, with a corresponding entry in equity.

Where the terms of an equity-settled award are modified or a new award is designated as replacing a cancelled or settled award, the cost based on the original award terms continues to be recognized over the original vesting period. In addition, an expense is recognized over the remainder of the new vesting period for the incremental fair value of any modification, based on the difference between the fair value of the original award and the fair value of the modified award, both as measured on the date of the modification. No reduction is recognized if this difference is negative.

Where an equity-settled award is cancelled, it is treated as if it had vested on the date of cancellation, and any cost not yet recognized in the income statement for the award is expensed immediately. Any compensation paid up to the fair value of the award at the cancellation or settlement date is deducted from equity, with any excess over fair value being treated as an expense in the income statement.

Cash-settled transactions The cost of cash-settled transactions is measured at fair value using an appropriate option valuation model.

Fair value is established initially at the grant date and at each balance sheet date thereafter until the awards are settled. During the vesting period, a liability is recognized representing the product of the fair value of the award and the portion of the vesting period expired as at the balance sheet date. From the end of the vesting period until settlement, the liability represents the full fair value of the award as at the balance sheet date. Changes in the carrying amount for the liability are recognized in profit or loss for the period.

PENSIONS AND OTHER POST-RETIREMENT BENEFITS

For defined benefit pension and other post-retirement benefit schemes, scheme assets are measured at fair value and scheme liabilities are measured on an actuarial basis using the projected unit method and discounted at an interest rate equivalent to the current rate of return on a high-quality corporate bond of equivalent currency and term to the scheme liabilities. Full actuarial valuations are obtained at least every three years and are updated at each balance sheet date. The resulting surplus or deficit, net of taxation thereon, is presented separately above the total for net assets on the face of the balance sheet.

The service cost of providing pension and other post-retirement benefits to employees for the year is charged to the income statement. The cost of making improvements to pension and other post-retirement benefits is recognized in the income statement on a straight-line basis over the period during which the increase in benefits vests. To the extent that the improvements in benefits vest immediately, the cost is recognized immediately.

A charge representing the unwinding of the discount on the scheme liabilities during the year is included within other finance expense.

Accounting policies *continued*

A credit representing the expected return on the scheme assets during the year is included within other finance expense. This credit is based on the market value of the scheme assets and expected rates of return at the beginning of the year.

Actuarial gains and losses may result from differences between the expected return and the actual return on scheme assets; differences between the actuarial assumptions underlying the scheme liabilities and actual experience during the year; or changes in the actuarial assumptions used in the valuation of the scheme liabilities. Actuarial gains and losses, and taxation thereon, are recognized in the statement of total recognized gains and losses.

DEFERRED TAXATION

Deferred tax is recognized in respect of all timing differences that have originated but not reversed at the balance sheet date where transactions or events have occurred at that date that will result in an obligation to pay more, or a right to pay less, tax in the future.

In particular:

- Provision is made for tax on gains arising from the disposal of fixed assets that have been rolled over into replacement assets, only to the extent that, at the balance sheet date, there is a binding agreement to dispose of the replacement assets concerned. However, no provision is made where, on the basis of all available evidence at the balance sheet date, it is more likely than not that the taxable gain will be rolled over into replacement assets and charged to tax only where the replacement assets are sold.
- Provision is made for deferred tax that would arise on remittance of the retained earnings of overseas subsidiaries, joint ventures and associated undertakings only to the extent that, at the balance sheet date, dividends have been accrued as receivable.

Deferred tax assets are recognized only to the extent that it is considered more likely than not that there will be suitable taxable profits from which the underlying timing differences can be deducted.

Deferred tax is measured on an undiscounted basis at the tax rates that are expected to apply in the periods in which timing differences reverse, based on tax rates and laws enacted or substantively enacted at the balance sheet date.

USE OF ESTIMATES

The preparation of accounts in conformity with generally accepted accounting practice requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the accounts and the reported amounts of revenues and expenses during the reporting period. Actual outcomes could differ from these estimates.

Company balance sheet

At 31 December				$ million
	Note	2005	2004	2003
Fixed assets				
Investments				
Subsidiary undertakings	3	89,738	87,328	55,908
Associated undertakings	3	2	2	2
Total fixed assets		89,740	87,330	55,910
Current assets				
Debtors – amounts falling due				
Within one year	4	1,211	791	864
After more than one year	4	1,434	1,451	23,752
Deferred taxation	2	436	362	256
Cash at bank and in hand		3	4	3
		3,084	2,608	24,875
Creditors – amounts falling due within one year				
Other creditors	5	6,719	7,686	5,308
Net current assets (liabilities)		(3,635)	(5,078)	19,567
Total assets less current liabilities		86,105	82,252	75,477
Creditors – amounts falling due after more than one year	5	27	60	50
Net assets excluding pension surplus		86,078	82,192	75,427
Defined benefit pension plan surplus	6	2,258	1,465	1,093
Net assets		88,336	83,657	76,520
Represented by				
Capital and reserves				
Called up share capital	7	5,185	5,403	5,552
Share premium account	8	7,371	5,636	3,957
Capital redemption reserve	8	749	730	523
Merger reserve	8	26,493	26,465	26,380
Other reserves	8	16	44	129
Shares held by ESOP trusts	8	(140)	(82)	(96)
Treasury shares	8	(10,598)	–	–
Profit and loss account	8	59,260	45,461	40,075
		88,336	83,657	76,520

The accounts on pages 144-157 were approved by a duly appointed and authorized committee of the board of directors on 6 February 2006 and were signed on its behalf by:

Peter Sutherland, Chairman
The Lord Browne of Madingley, Group Chief Executive

Company cash flow statement

For the year ended 31 December

	Note	2005	2004	2003
				$ million
Profit before interest and tax		20,674	18,313	28,639
Depreciation and amounts provided		–	12	–
Net operating charge for pensions less contributions		186	168	119
Dividends, interest and other income		(21,197)	(19,626)	(28,622)
Share-based payments		278	224	210
(Increase) decrease in debtors		(368)	22,374	(13,550)
Increase (decrease) in creditors		(681)	2,448	(3,632)
Net cash (outflow) inflow from operating activities		(1,108)	23,913	(16,836)
Servicing of finance and returns on investments				
Interest received		110	1,137	708
Interest paid		(249)	(104)	(130)
Dividends received		21,087	18,489	27,914
Other finance income		–	–	–
Net cash inflow from servicing of finance and returns on investments		20,948	19,522	28,492
Tax paid		(8)	(3)	(6)
Capital expenditure and financial investment				
Payments for fixed assets – investments	3	(2,929)	(31,517)	(4,125)
Proceeds from the sale of fixed assets		–	–	2
Net cash outflow for capital expenditure and financial investment		(2,929)	(31,517)	(4,123)
Acquisitions and disposals				
Proceeds from the sale of businesses	3	519	85	17
Net cash outflow for acquisitions and disposals		519	85	17
Equity dividends paid		(7,359)	(6,041)	(5,654)
Net cash inflow		10,063	5,959	1,890
Financing		10,064	5,958	1,889
Increase (decrease) in cash		(1)	1	1
		10,063	5,959	1,890

Financing

	2005	2004	2003
			$ million
Issue of ordinary share capital	(1,784)	(1,737)	(173)
Purchase of shares by ESOP trusts	251	147	63
Repurchase of ordinary share capital	11,597	7,548	1,999
Net cash outflow	10,064	5,958	1,889

Statement of total recognized gains and losses

For the year ended 31 December

	2005	2004	2003
			$ million
Profit for the year	20,858	18,613	28,726
Actuarial gain relating to pensions	1,159	197	841
Tax on actuarial gain relating to pensions	(348)	(59)	(252)
Total recognized gains and losses relating to the year	21,669	18,751	29,315
Prior year adjustment – change in accounting policy	362		
Total recognized gains and losses since last annual accounts	22,031		

Notes on financial statements

1 Auditors' remuneration

Audit fees were $6 million (2004 $4 million and 2003 $2 million).

2 Taxation

$ million

TAX INCLUDED IN STATEMENT OF TOTAL RECOGNIZED GAINS AND LOSSES	2005	2004	2003
Deferred tax			
Origination and reversal of temporary differences in the current year	348	59	252
Tax included in statement of total recognized gains and losses	348	59	252
This comprises			
Actuarial gain relating to pensions	348	59	252
Tax included in statement of total recognized gains and losses	348	59	252

DEFERRED TAX

$ million

	Balance sheet		
	2005	2004	2003
Deferred tax liability			
Pensions	968	628	469
	968	628	469
Deferred tax asset			
Other taxable temporary differences	436	362	256
	436	362	256
Net deferred tax liability	532	266	213

Analysis of movements during the year			
At 1 January	265	213	(40)
Exchange adjustments	(87)	41	(5)
Charge for the year on ordinary activities	6	(47)	6
Charge for the year in the statement of total recognized gains and losses	348	59	252
At 31 December	532	266	213

3 Fixed assets – investments

$ million

	Subsidiary undertakings	Associated undertakings		
	Shares	Shares	Loans	Total
Cost				
At 1 January 2005	87,345	2	2	87,349
Additions	2,929	–	–	2,929
Deletions	(519)	–	–	(519)
At 31 December 2005	89,755	2	2	89,759
Amounts provided				
At 1 January 2005	17	–	2	19
At 31 December 2005	17	–	2	19
Cost				
At 1 January 2004	55,913	2	2	55,917
Additions	31,517	–	–	31,517
Deletions	(85)	–	–	(85)
At 31 December 2004	87,345	2	2	87,349
Amounts provided				
At 1 January 2004	5	–	2	7
Provided in the year	12	–	–	12
At 31 December 2004	17	–	2	19
Net book amount				
At 31 December 2005	89,738	2	–	89,740
At 31 December 2004	87,328	2	–	87,330
At 31 December 2003	55,908	2	–	55,910

The more important subsidiary undertakings of the company at 31 December 2005 and the percentage holding of ordinary share capital (to the nearest whole number) are set out below. The principal country of operation is generally indicated by the company's country of incorporation or by its name. A complete list of investments in subsidiary undertakings, joint ventures and associated undertakings will be attached to the company's annual return made to the Registrar of Companies.

Subsidiary undertakings	%	Country of incorporation	Principal activities
International			
BP Global Investments	100	England	Investment holding
BP International	100	England	Integrated oil operations
BP Shipping	100	England	Shipping
Burmah Castrol	100	Scotland	Lubricants
South Africa			
BP Southern Africa	75	South Africa	Refining and marketing
US			
BP America	100	US	Investment holding

4 Debtors

$ million

	2005		2004		2003	
	Within 1 year	After 1 year	Within 1 year	After 1 year	Within 1 year	After 1 year
Group undertakings	1,084	1,396	647	1,411	774	23,716
Prepayments and accrued income	–	–	–	–	5	–
Other	127	38	144	40	85	36
	1,211	1,434	791	1,451	864	23,752

5 Creditors

$ million

	2005		2004		2003	
	Within 1 year	After 1 year	Within 1 year	After 1 year	Within 1 year	After 1 year
Group undertakings	6,513	–	7,449	–	5,061	–
Social security	15	–	57	–	46	–
Accruals and deferred income	8	27	7	60	22	50
Dividends	1	–	1	–	1	–
Other	182	–	172	–	178	–
	6,719	27	7,686	60	5,308	50

The profile of the maturity of the financial liabilities included in the balance sheet at 31 December is shown in the table below. These amounts are included within Creditors – amounts falling due after more than one year, and are denominated in US dollars.

$ million

	2005	2004	2003
Due within			
1 to 2 years	5	5	5
2 to 5 years	22	55	45
	27	60	50

6 Pensions

The material financial assumptions used for estimating the benefit obligations of the plans are set out below. The assumptions used to evaluate accrued pension benefits at 31 December in any year are used to determine pension expense for the following year, that is, the assumptions at 31 December 2005 are used to determine the pension liabilities at that date and the pension cost for 2006.

%

	2005	2004	2003
Expected long-term rate of return	7.0	7.0	7.0
Discount rate for plan liabilities	4.75	5.25	5.5
Rate of increase in salaries	4.25	4.0	4.0
Rate of increase for pensions in payment	2.5	2.5	2.5
Rate of increase in deferred pensions	2.5	2.5	2.5
Inflation	2.5	2.5	2.5

The market values of the various categories of asset held by the pension plan at 31 December are set out below.

$ million

	2005	2004	2003
UK plans			
Equities	17,796	16,263	13,815
Bonds	2,291	2,396	2,092
Property	1,114	1,645	1,325
Cash	919	402	618
	22,120	20,706	17,850
Present value of plan liabilities	18,894	18,613	16,288
Surplus in the plan	3,226	2,093	1,562
Deferred tax	(968)	(628)	(469)
At 31 December	2,258	1,465	1,093

6 Pensions *continued*

ANALYSIS OF THE AMOUNT CHARGED TO OPERATING PROFIT	2005	2004	2003
			$ million
Current service cost	360	341	261
Past service cost	4	5	–
Settlement, curtailment and special termination benefits	36	36	–
Total operating charge	400	382	261
ANALYSIS OF THE AMOUNT CREDITED (CHARGED) TO OTHER FINANCE INCOME			
Expected return on pension plan assets	1,357	1,257	983
Interest on pension plan liabilities	(914)	(899)	(779)
Other finance income	443	358	204
ANALYSIS OF THE AMOUNT RECOGNIZED IN THE STATEMENT OF TOTAL RECOGNIZED GAINS AND LOSSES			
Actual return less expected return on pension plan assets	2,946	750	1,526
Experience gains and losses arising on the plan liabilities	(66)	157	621
Change in assumptions underlying the present value of the plan liabilities	(1,721)	(710)	(1,306)
Actuarial gain (loss) recognized in statement of total recognized gains and losses	1,159	197	841
MOVEMENT IN SURPLUS DURING THE YEAR			
Surplus in scheme at 1 January	2,093	1,562	497
Movement in year			
Current service cost	(360)	(341)	(261)
Past service cost	(4)	(5)	–
Settlement, curtailment and special termination benefits	(36)	(36)	–
Other finance income	443	358	204
Actuarial gain (loss)	1,159	197	841
Employers' contributions	214	214	142
Exchange adjustments	(283)	144	139
Surplus in plan at 31 December	3,226	2,093	1,562

HISTORY OF EXPERIENCE GAINS AND LOSSES	2005	2004	2003
Difference between the expected and actual return on plan assets			
Amount ($ million)	2,946	750	1,526
Percentage of plan assets	14%	4%	9%
Experience gains and losses on plan liabilities			
Amount ($ million)	(66)	157	621
Percentage of the present value of plan liabilities	0%	1%	4%
Total amount recognized in statement of total recognized gains and losses			
Amount ($ million)	1,159	197	841
Percentage of the present value of plan liabilities	6%	1%	5%

7 Called up share capital

The company's authorized ordinary share capital remains unchanged at 36 billion shares of 25 cents each, amounting to $9 billion. In addition, the company has authorized preference share capital of 12,750,000 shares of £1 each ($21 million).

The allotted, called up and fully paid share capital at 31 December was as follows:

	2005		2004		2003	
Issued	shares (thousand)	$ million	shares (thousand)	$ million	shares (thousand)	$ million
8% cumulative first preference shares of £1 each	7,233	12	7,233	12	7,233	12
9% cumulative second preference shares of £1 each	5,473	9	5,473	9	5,473	9
		21		21		21
Ordinary shares of 25 cents each						
1 January	21,525,978	5,382	22,122,610	5,531	22,378,651	5,595
Employee share schemes	68,500	17	62,224	16	32,889	8
Atlantic Richfield	13,644	3	29,288	7	9,786	2
Issue of ordinary share capital for TNK-BP	108,629	27	139,096	35	–	–
Repurchase of ordinary share capital	(1,059,706)	(265)	(827,240)	(207)	(298,716)	(74)
31 December	20,657,045	5,164	21,525,978	5,382	22,122,610	5,531
		5,185		5,403		5,552
Authorized						
8% cumulative first preference shares of £1 each	7,250		7,250		7,250	
9% cumulative second preference shares of £1 each	5,500		5,500		5,500	
Ordinary shares of 25 cents each	36,000,000		36,000,000		36,000,000	

Voting on substantive resolutions tabled at a general meeting is on a poll. On a poll, shareholders present in person or by proxy have two votes for every £5 in nominal amount of the first and second preference shares held and one vote for every ordinary share held. On a show-of-hands vote on other resolutions (procedural matters) at a general meeting, shareholders present in person or by proxy have one vote each.

In the event of the winding up of the company, preference shareholders would be entitled to a sum equal to the capital paid up on the preference shares plus an amount in respect of accrued and unpaid dividends and a premium equal to the higher of (i) 10% of the capital paid up on the preference shares and (ii) the excess of the average market price of such shares on the London Stock Exchange during the previous six months over par value.

EMPLOYEE SHARE SCHEMES

During the year 68,499,852 ordinary shares (2004 62,224,092 and 2003 32,889,234 ordinary shares) were issued under the BP, Amoco and Burmah Castrol employee share schemes.

ATLANTIC RICHFIELD

13,644,462 ordinary shares (2004 29,288,178 and 2003 9,786,396 ordinary shares) were issued in respect of Atlantic Richfield employee share option schemes.

REPURCHASE OF ORDINARY SHARE CAPITAL

The company purchased 1,059,706,481 ordinary shares (2004 827,240,360 and 2003 298,716,391 ordinary shares) for a total consideration of $11,597 million (2004 $7,548 million and 2003 $1,999 million), of which 76,800,000 were cancelled and 982,906,481 were retained in treasury. All the shares repurchased in 2004 and 2003 were cancelled. At 31 December 2005, 982,624,971 shares of nominal value $246 million were held in treasury. Transaction costs of share repurchases amounted to $63 million (2004 $43 million and 2003 $11 million).

8 Capital and reserves

$ million

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Other reserves	Own shares	Treasury shares	Profit and loss account	Total
At 1 January 2005	5,403	5,636	730	26,465	44	(82)	–	45,461	83,657
Currency translation differences	–	–	–	–	–	12	–	–	12
Actuarial gain (loss) (net of tax)	–	–	–	–	–	–	–	811	811
Employee share schemes	17	436	–	–	–	–	3	(1)	455
Atlantic Richfield	3	76	–	28	(28)	–	–	–	79
Issue of ordinary share capital for TNK-BP	27	1,223	–	–	–	–	–	–	1,250
Purchase of shares by ESOP trusts	–	–	–	–	–	(251)	–	–	(251)
Share-based payments (net of tax)	–	–	–	–	–	181	–	240	421
Repurchase of ordinary share capital	(265)	–	19	–	–	–	(10,601)	(750)	(11,597)
Profit for the year	–	–	–	–	–	–	–	20,858	20,858
Dividends	–	–	–	–	–	–	–	(7,359)	(7,359)
At 31 December 2005	5,185	7,371	749	26,493	16	(140)	(10,598)	59,260	88,336
At 1 January 2004	5,552	3,957	523	26,380	129	(96)	–	38,325	74,770
Prior year adjustment – change in accounting policy	–	–	–	–	–	–	–	1,750	1,750
Restated	5,552	3,957	523	26,380	129	(96)	–	40,075	76,520
Currency translation differences	–	–	–	–	–	(7)	–	–	(7)
Actuarial gain (loss) (net of tax)	–	–	–	–	–	–	–	138	138
Employee share schemes	16	311	–	–	–	–	–	–	327
Atlantic Richfield	7	153	–	85	(85)	–	–	–	160
Issue of ordinary share capital for TNK-BP	35	1,215	–	–	–	–	–	–	1,250
Purchase of shares by ESOP trusts	–	–	–	–	–	(147)	–	–	(147)
Repurchase of ordinary share capital	(207)	–	207	–	–	–	–	(7,548)	(7,548)
Share-based payments (net of tax)	–	–	–	–	–	168	–	224	392
Profit for the year	–	–	–	–	–	–	–	18,613	18,613
Dividends	–	–	–	–	–	–	–	(6,041)	(6,041)
At 31 December 2004	5,403	5,636	730	26,465	44	(82)	–	45,461	83,657

$ million

Prior year adjustment	Profit and loss account
Dividend accrual reversal	1,494
Share-based payments	256
At 1 January 2004	1,750

As a consolidated income statement is presented, a separate income statement for the parent company is not required to be published.

The profit and loss account reserve includes $27,391 million (2004 $25,026 million and 2003 $24,107 million), the distribution of which is limited by statutory or other restrictions.

9 Contingent liabilities

The parent company has issued guarantees under which amounts outstanding at 31 December 2005 were $16,846 million (2004 $21,106 million and 2003 $20,903 million), including $16,822 million (2004 $21,050 million and 2003 $20,847million) in respect of borrowings by its subsidiary undertakings and $24 million (2004 $56 million and 2003 $56 million) in respect of liabilities of other third parties.

10 Share-based payments

EFFECT OF SHARE-BASED PAYMENT TRANSACTIONS ON THE GROUP'S RESULT AND FINANCIAL POSITION

	2005	2004	2003
			$ million
Total expense recognized for equity-settled share-based payment transactions	348	289	268
Total expense recognized for cash-settled share-based payment transactions	20	36	25
Total expense recognized for share-based payment transactions	368	325	293
Closing balance of liability for cash-settled share-based transactions	48	59	51
Total intrinsic value for vested cash-settled share-based payment transactions	41	53	50

For ease of presentation, option and share holdings detailed in the tables within this note are stated as UK ordinary share equivalents in US dollars. US employees are granted American Depositary Shares (ADSs) or options over the company's ADSs (one ADS is equivalent to six ordinary shares). The share-based payment plans that existed during the year are detailed below. All plans are ongoing unless otherwise stated.

PLANS FOR EXECUTIVE DIRECTORS

Executive Directors' Incentive Plan (EDIP) – share element (2005 onwards) An equity-settled incentive share plan for executive directors driven by one performance measure over a three-year performance period. The award of shares is determined by comparing BP's total shareholder return (TSR) against the other oil majors. In addition, for the group chief executive, 27% of the grant is based on long-term leadership (LTL) measures. After the performance period, the shares that vest (net of tax) are then subject to a three-year retention period. The directors' remuneration report on pages 164-173 includes full details of this plan.

Executive Directors' Incentive Plan (EDIP) – share element (pre-2005) An equity-settled incentive share plan for executive directors driven by three performance measures over a three-year performance period. The primary measure is BP's shareholder return against the market (SHRAM) versus that of the companies within the FTSE All World Oil & Gas Index. This accounts for nearly two-thirds of the potential total award, with the remainder being assessed on BP's relative return on average capital employed (ROACE) and earnings per share (EPS) growth compared with the other oil majors. After the performance period, the shares that vest (net of tax) are then subject to a three-year retention period. The directors' remuneration report on pages 164-173 includes full details of this plan. For 2005 and subsequent years the share element of EDIP was amended as described above.

Executive Directors' Incentive Plan (EDIP) – share option element (pre-2005) An equity-settled share option plan for executive directors that permits options to be granted at an exercise price no lower than the market price of a share on the date that the option is granted. Options vest over three years (one-third each after one, two and three years respectively) and must be exercised within seven years of the date of grant. Last grants were made in 2004. For 2005 onwards the remuneration committee's policy is not to make further grants of share options to executive directors.

PLANS FOR SENIOR EMPLOYEES

Medium Term Performance Plan (MTPP) (2005 onwards) An equity-settled incentive share plan for senior employees driven by two performance measures over a three-year performance period. The award of shares is determined by comparing BP's TSR against the other oil majors and, additionally, by comparing free cash flow (FCF) against a threshold established for the period. For a small group of particularly senior employees, only the TSR measure is applicable in determining the award. The number of shares awarded is increased to take account of the net dividends that would have been received during the performance period, assuming that such dividends had been reinvested. With regard to leaver provisions, the general rule is that leaving employment during the performance period will preclude an award of shares. However, special arrangements apply where the participant leaves for a qualifying reason and employment ceases after completion of the first year of the performance period.

Long Term Performance Plan (LTPP) (pre-2005) An equity-settled incentive share plan for senior employees driven by three performance measures over a three-year performance period. The primary measure is BP's SHRAM versus that of the companies within the FTSE All World Oil & Gas Index. This accounts for nearly two-thirds of the potential total award, with the remainder being assessed on BP's relative ROACE and EPS growth compared with the other oil majors. Shares are awarded at the end of the performance period and are then subject to a three-year restriction period. With regard to leaver provisions, the general rule is that leaving during the performance period will preclude an award of shares. However, special arrangements apply where the participant leaves for a qualifying reason and employment ceases after completion of the first year of the performance period. This plan was replaced by the MTPP for 2005 onwards.

10 Share-based payments *continued*

Deferred Annual Bonus Plan (DAB) An equity-settled restricted share plan for senior employees. The award value is equal to 50% of the annual cash bonus awarded for the preceding performance year (the 'performance period'). The shares are restricted for a period of three years (the 'restriction period'). Shares accrue dividends during the restriction period and these are reinvested. With regard to leaver provisions, if a participant ceases to be employed by BP prior to the end of the performance period, then the general rule is that this will preclude an award of shares. However, special arrangements apply where the participant leaves for a qualifying reason. Similarly, if a participant ceases to be employed by BP prior to the end of the restriction period, the general rule is that the restricted shares will be forfeited. Special arrangements apply where the participant leaves for a qualifying reason.

Restricted Share Plan (RSP) An equity-settled restricted share plan used predominantly for senior employees for special circumstances (such as recruitment and retention). There are no performance conditions but the shares are subject to a three-year restriction period. During the restriction period, shares accrue dividends, which are reinvested. With regard to leaver provisions, the general rule is that ceasing employment during the restriction period will result in the forfeit of shares. However, special arrangements apply where the participant leaves for a qualifying reason.

BP Share Option Plan (BPSOP) An equity-settled share option plan that applies to certain categories of employees. Participants are granted share options with an exercise price no lower than market price of a share immediately preceding the date of grant. There are no performance conditions and the options are exercisable between the third and 10th anniversaries of the grant date. The general rule is that the options will lapse if the participant leaves employment before the end of the third calendar year from the date of grant (and that vested options are exercisable within 3½ years from the date of leaving). However, special arrangements apply where the participant leaves for a qualifying reason and employment ceases after the end of the calendar year of the date of grant. Share options are no longer offered to the most senior employees.

SAVINGS AND MATCHING PLANS

BP ShareSave Plan A savings-related share option plan, under which employees save on a monthly basis, over a three- or five-year period, towards the purchase of shares at a fixed price determined when the option is granted. This price is usually set at a 20% discount to the market price at the time of grant. The option must be exercised within six months of maturity of the savings contract; otherwise it lapses. The plan is run in the UK and options are granted annually, usually in June. Until 2003, a three-year savings plan was also run in a small number of other countries. Options will remain outstanding in respect of these countries until the end of June 2007. Participants leaving for a qualifying reason will have six months in which to use their savings to exercise their options on a pro-rated basis.

BP ShareMatch Plans Matching share plans, under which BP matches employees' own contributions of shares up to a predetermined limit. The plans are run in the UK and in over 70 other countries. The UK plan is run on a monthly basis with shares being held in trust for five years before they can be released free of any income tax and national insurance liability. In other countries, the plan is run on an annual basis with shares being held in trust for three years. The plan is operated on a cash basis in those countries where there are regulatory restrictions preventing the holding of BP shares. When the employee leaves BP, all shares must be removed from trust and units under the plan operated on a cash basis must be encashed.

CASH PLANS

Cash Options/Stock Appreciation Rights (SARs) These are cash-settled share-based payments available to certain employees that require the group to pay the intrinsic value of the cash option/SAR to the employee at the date of exercise. There are no performance conditions; however, participants must continue in employment with BP for the first three calendar years of the plan for the options/SARs to vest. Special arrangements may apply for qualifying leavers. The options/SARs are exercisable between the third and 10th anniversaries of the grant date.

EMPLOYEE SHARE OWNERSHIP PLANS (ESOPS)

ESOPs have been established to acquire BP shares to satisfy any awards made to participants under EDIP, LTPP, MTPP, DAB and the BP ShareMatch Plans. The ESOPs have waived their rights to dividends on shares held for future awards and are funded by the company. Until such time as the company's own shares held by the ESOP trusts vest unconditionally in employees, the amount paid for those shares is deducted in arriving at shareholders' interest. See Note 8. Assets and liabilities of the ESOPs are recognized as assets and liabilities of the company.
At 31 December 2005, the ESOPs held 14,560,003 shares (2004 8,621,219 shares and 2003 11,930,379 shares) for potential future awards, which had a market value of $156 million (2004 $84 million and 2003 $96 million).

Share option transactions	2005		2004		2003	
	Number of options	Weighted average exercise price ($)	Number of options	Weighted average exercise price ($)	Number of options	Weighted average exercise price ($)
Outstanding at beginning of the period	470,263,808	7.16	461,885,881	6.76	410,986,179	6.70
Granted during the period	54,482,053	10.24	80,394,760	7.93	104,758,602	6.22
Forfeited during the period	(4,844,827)	8.30	(7,043,911)	6.77	(20,412,529)	7.11
Exercised during the period	(68,687,976)	6.40	(62,625,182)	5.18	(32,988,942)	4.11
Expired during the period	(759,556)	6.75	(2,347,740)	7.55	(457,429)	6.40
Outstanding at end of the period	450,453,502	7.64	470,263,808	7.16	461,885,881	6.76
Exercisable at the end of the period	222,729,398	7.54	224,627,758	7.00	229,198,494	6.21

10 Share-based payments *continued*

As share options are exercised continuously throughout the year, the weighted average share price during the year of $10.77 (2004 $8.95 and 2003 $6.81) is representative of the weighted average share price at the date of exercise. For the options outstanding at 31 December 2005, the exercise price ranges and weighted average remaining contractual lives are shown below.

	Options outstanding			Options exercisable	
Range of exercise prices	Number of shares	Weighted average remaining life (yrs)	Weighted average exercise price ($)	Number of shares	Weighted average exercise price ($)
$4.22–$6.14	74,255,790	1.88	5.51	52,734,810	5.44
$6.15–$8.06	151,161,264	6.15	7.02	36,840,758	7.70
$8.07–$9.99	176,892,928	5.95	8.29	133,128,330	8.32
$10.00–$11.92	48,143,520	9.19	10.45	25,500	10.53
	450,453,502	5.69	7.64	222,729,398	7.54

FAIR VALUES AND ASSOCIATED DETAILS FOR OPTIONS AND SHARES GRANTED

Options granted in 2005	BPSOP	ShareSave 3 year	ShareSave 5 year
Option pricing model used	Binomial	Binomial	Binomial
Weighted average fair value	$2.34	$2.76	$2.94
Weighted average share price	$10.85	$10.49	$10.49
Weighted average exercise price	$10.63	$7.96	$7.96
Expected volatility	18%	18%	18%
Option life	10 years	3.5 years	5.5 years
Expected dividends	2.72%	3.00%	3.00%
Risk free interest rate	4.25%	4.00%	4.25%
Expected exercise behaviour	5% years 4-9 70% year 10	100% year 4	100% year 6

Options granted in 2004	EDIP Options	BPSOP	ShareSave 3 year	ShareSave 5 year
Option pricing model used	Binomial	Binomial	Binomial	Binomial
Weighted average fair value	$1.34	$1.55	$1.94	$2.13
Weighted average share price	$8.09	$8.12	$8.75	$8.75
Weighted average exercise price	$8.09	$8.09	$7.00	$7.00
Expected volatility	22%	22%	22%	22%
Option life	7 years	10 years	3.5 years	5.5 years
Expected dividends	3.75%	3.75%	3.75%	3.75%
Risk free interest rate	3.50%	4.00%	3.00%	3.75%
Expected exercise behaviour	5% years 2-6 75% year 7	5% years 4-9 70% year 10	100% year 4	100% year 6

Options granted in 2003	EDIP Options	BPSOP	ShareSave 3 year	ShareSave 5 year
Option pricing model used	Binomial	Binomial	Binomial	Binomial
Weighted average fair value	$1.37	$1.50	$1.91	$2.02
Weighted average share price	$6.29	$6.43	$7.23	$7.23
Weighted average exercise price	$6.29	$6.35	$5.79	$5.79
Expected volatility	30%	30%	30%	30%
Option life	7 years	10 years	3.5 years	5.5 years
Expected dividends	4.00%	4.00%	4.00%	4.00%
Risk free interest rate	3.50%	3.50%	3.50%	3.50%
Expected exercise behaviour	5% years 2-6 75% year 7	5% years 4-9 70% year 10	100% year 4	100% year 6

The group uses a third-party estimate of expected volatility of US ADSs for the quarter within which the grant date of the relevant plan falls. This estimate takes into account the volatility implied by options in the market.

Shares granted in 2005	MTPP – TSR	MTPP – FCF	EDIP – TSR	EDIP – LTL	RSP
Number of equity instruments granted (million)	9.3	8.4	3.7	0.5	0.3
Weighted average fair value	$5.72	$11.04	$3.87	$10.13	$11.04
Fair value measurement basis	Monte Carlo	Market value	Monte Carlo	Market value	Market value

10 Share-based payments *continued*

The group used a Monte Carlo simulation to fair value the TSR element of the 2005 MTPP and EDIP plans. In accordance with the rules of the plans the model simulates BP's TSR and compares it against our principal strategic competitors over the three-year period of the plans. The model takes into account the historic dividends, share price volatilities and covariances of BP and each comparator company to produce a predicted distribution of relative share performance. This is applied to the reward criteria to give an expected value of the TSR element.

Shares granted in 2004	LTPP – SHRAM	LTPP – EPS/ROACE	EDIP – SHRAM	EDIP – EPS/ROACE	RSP
Number of equity instruments granted (million)	6.8	4.1	0.9	0.5	0.1
Weighted average fair value	$4.06	$7.21	$4.06	$7.21	$8.12
Fair value measurement basis	Monte Carlo	Market value	Monte Carlo	Market value	Market value

Shares granted in 2003	LTPP – SHRAM	LTPP – EPS/ROACE	EDIP – SHRAM	EDIP – EPS/ROACE	RSP
Number of equity instruments granted (million)	6.8	4.1	1.1	0.6	0.1
Weighted average fair value	$3.53	$5.65	$3.53	$5.65	$6.43
Fair value measurement basis	Monte Carlo	Market value	Monte Carlo	Market value	Market value

The group used a Monte Carlo simulation to fair value the SHRAM element of the 2003 and 2004 LTPP and EDIP plans. In accordance with the rules of the plans, the model simulates BP's SHRAM and compares it with the comparator companies (all companies in the FTSE World Oil and Gas Index) and compares it to the comparator companies over the three-year period of the plans. The SHRAMs of the comparator companies have been determined from market data over the preceding three-year period. The model takes into account the historic dividend yields, share price volatilities and covariances of BP and each comparator company to produce a predicted distribution of relative share performance. This is applied to the reward criteria to give an expected value of the SHRAM element.

Accounting expense does not necessarily represent the actual value of share-based payments made to recipients which are determined by the Remuneration Committee according to established criteria.

11 Directors' remuneration

$ million

	2005	2004	2003
Total for all directors			
Emoluments	18	19	17
Ex-gratia payments to executive directors retiring in the year	–	–	1
Gains made on the exercise of share options	–	3	1
Amounts awarded under incentive schemes	8	6	4

Emoluments These amounts comprise fees paid to the non-executive chairman and the non-executive directors and, for executive directors, salary and benefits earned during the relevant financial year, plus bonuses awarded for the year.

Pension contributions Five executive directors participated in a non-contributory pension scheme established for UK staff by a separate trust fund to which contributions are made by BP based on actuarial advice. One US executive director participated in the US BP Retirement Accumulation Plan during 2005.

Office facilities for former chairmen and deputy chairmen It is customary for the company to make available to former chairmen and deputy chairmen, who were previously employed executives, the use of office and basic secretarial facilities following their retirement. The cost involved in doing so is not significant.

Further information Full details of individual directors' remuneration are given in the directors' remuneration report on pages 164-173.

Governance: board performance report

GOVERNANCE AND THE ROLE OF OUR BOARD

The governance of companies continues to be under scrutiny. Regulators and commentators maintain their focus on structural elements. We believe too little attention is paid to the underlying purpose of governance. Governance lies at the heart of all the board does and it is the task our owners entrust to the board.

Governance is not an exercise in compliance nor is it a higher form of management. Governance is a more powerful concept. It has a clear objective: ensuring the pursuit of the company's purpose. The board's activity is focused on this task, which is unique to it as the representative of BP's owners. This task is discharged by the board through undertaking such activities as are necessary for the effective promotion of long-term shareholder interest. In promoting the long-term interest of shareholders, the board has to ensure that the business is responsive to the views of those with whom it comes into contact. This can include gaining an understanding of the environmental and social consequences of the company's actions. However, it remains a matter of business judgement as to how these consequences are properly taken into account in maximizing shareholder value.

Governance is the system by which the company's owners and their representatives on the board ensure that it pursues, does not deviate from and only allocates resources to its defined purpose.

As a company, we recognize the importance of good governance and that it is a discrete task from management. Clarity of roles is key to our approach. Policies and processes depend on the people who operate them. Governance requires distinct skills and processes. Governance is overseen by the BP board, while management is delegated to the group chief executive by means of the board governance policies.

Our board governance policies use a coherent, principles-based approach, which anticipated many developments in UK governance regulation. These policies ensure that our board and management operate within a clear and efficient governance framework that places long-term shareholder interest at the heart of all we do.

To that end, our board exercises judgement in carrying out its work in policy-making, in monitoring executive action and in its active consideration of group strategy. The board's judgements seek to maximize the expected value of shareholders' interest in the company, rather than eliminate the possibility of any adverse outcomes.

ACCOUNTABILITY TO SHAREHOLDERS

Our board is accountable in a variety of ways. It is required to be proactive in obtaining an understanding of shareholder preferences and to evaluate systematically the economic, social, environmental and ethical matters that may influence or affect the interests of our shareholders.

Reporting A number of formal communication channels are used to account to shareholders for the performance of the company. These include the Annual Report and Accounts, the Annual Review, the Annual Report on Form 20-F, quarterly Forms 6-K and announcements made through stock exchanges on which BP shares are listed, as well as through the annual general meeting (AGM). BP is keen to promote the use of electronic platforms in the reporting arena.

Dialogue with directors Presentations given at appropriate intervals to representatives of the investment community are available to all shareholders by internet broadcast or open conference call, details of which are given on *www.bp.com*. Less formal processes include contacts with institutional shareholders by the chairman and other directors. This is supported by the dialogue with shareholders concerning the governance and operation of the group maintained by the company secretary's office, investor relations and other BP teams, which meet with investors and shareholder groups representing both large and small investors.

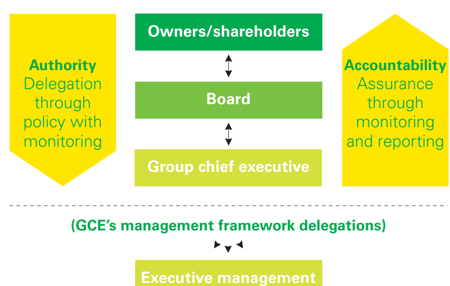
Our board is accountable to shareholders for the performance and activities of the entire BP group. It embeds shareholder interest in the goals established for the company.

AGM and voting The chairman and board committee chairmen were present at the 2005 AGM to answer shareholders' questions and hear their views during the meeting. Members of the board met informally with shareholders afterwards. Given the size and geographical diversity of our shareholder base, we recognize that opportunities for shareholder interaction at the AGM are limited. However, all votes at shareholder meetings, whether by proxy or in person, are counted, since votes on all matters, except procedural issues, are taken by way of a poll. In 2005, we were pleased to note that voting levels increased to 62%, with more than 98% of votes being cast in line with the board's recommendations.

Directors' elections Directors stand for re-election each year. New directors are subject to election at the first opportunity following their appointment. All names submitted to shareholders for election are accompanied by biographies. Voting levels demonstrate continued support for all our directors and affirm the board's assertion of the independence of all our non-executive directors.

HOW OUR BOARD GOVERNS THE COMPANY

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



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

Recognizing that as a group its capacity is limited, our board reserves to itself the making of broad policy decisions. It delegates more detailed considerations involved in meeting its stated requirements either to board committees and officers (in the case of its own processes) or to the group chief executive (in the case of the management of the company's business activities). The board governs BP through setting general policy for the conduct of business (and, critically, by clearly articulating its goals) and by monitoring its implementation by the group chief executive.

To discharge its governance function in the most effective manner, our board has laid down rules for its own activities in a *governance process policy*. The process policy covers:

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

The responsibility for implementation of this policy is placed on the chairman.

The *board-executive linkage policy* sets out how the board delegates authority to the group chief executive and the extent of that authority. In its *board goals policy*, the board states what it expects the group chief executive to deliver.

The restrictions on the manner in which the group chief executive may achieve the required results are set out in the *executive limitations policy*. This policy sets boundaries on executive action, requiring due consideration of internal controls, risk preferences, financing, ethical behaviour, health, safety, the environment, treatment of employees and political considerations in any and all action taken in the course of our business. Through the goals and executive limitations policies, the board shapes BP's values and standards.

ACCOUNTABILITY IN OUR BUSINESS

Our group chief executive outlines how he intends to deliver the required outcome in annual and medium-term plans, which also address a comprehensive assessment of the group's risks. Progress towards the expected outcome forms the basis of regular reports to the board that cover actual results and a forecast of results for the current year. The board considers annual and five-year plans for the group and, in doing so, reviews the major influences and risks affecting the group's business.

The group chief executive is obliged through dialogue and systematic review to discuss with the board all material matters currently or prospectively affecting the company and its performance and all strategic projects or developments. This key dialogue specifically includes any materially under-performing business activities and actions that breach the executive limitations policy and material matters of a social, environmental and ethical nature.

The board-executive linkage policy also sets out how the group chief executive's performance will be monitored and recognizes that, in the multitude of changing circumstances, judgement is always involved. The systems set out in the board-executive linkage policy are designed to manage, rather than to eliminate, the risk of failure to achieve the goals or observe the executive limitations policy. They provide reasonable, not absolute, assurance against material misstatement or loss.

WHO IS ON THE BOARD?

The board is composed of the chairman, 11 non-executive and six executive directors. In total, five nationalities are represented on the board. Directors' biographies are set out on pages 174-175.

Governance policies and processes depend on the quality and commitment of the people who operate them.

As reported last year, the board is actively engaged in succession planning issues for both executive and non-executive roles. We reported in the past two years on our pursuit of an orderly process of evolution to refresh the composition of the board without compromising its continued effectiveness. To that end, we were delighted to welcome Mr Douglas Flint to the board in January 2005. At the AGM in April 2005, Sir Robin Nicholson and Mr Charles (Chuck) Knight retired. Mr Michael Miles will stand down at the 2006 AGM. The chairmanships of the principal board committees were also reviewed during 2005; Dr Julius became chairman of the remuneration committee, succeeding Sir Robin Nicholson. The board committee reports on pages 161-163 provide details on the chairmen and composition of these committees.

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

BOARD INDEPENDENCE

The qualification for board membership includes a requirement that all our non-executive directors be free from any relationship with the executive management of the company that could materially interfere with the exercise of their independent judgement. In the board's view, all our non-executive directors fulfil this requirement. It determined all non-executive directors who served during 2005 to be independent. All have received overwhelming endorsement at successive AGMs, at which they are now subject to annual election.

Mr Knight and Sir Robin Nicholson were appointed to the BP board in 1987 and Mr Miles was appointed in 1994. The length of their respective service on the board exceeds the nine years referred to in the Combined Code. The board considers that the experience and long-term perspective of each of these directors on BP's business during its recent period of growth has provided a valuable contribution to the board, given the long-term nature of our business. The integrity and independence of character of these directors are beyond doubt. Both Mr Knight and Sir Robin retired at the 2005 AGM. Mr Miles will retire in 2006.

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

Annual elections for all directors and the provision of independent support to our board and board committees underscore our commitment to good governance practice.

The board has satisfied itself that there is no compromise to the independence of those directors who serve together as directors on the boards of outside entities (or who have other appointments in outside entities). Where necessary, our board ensures appropriate processes are in place to manage any possible conflict of interest.

Sir Robin Nicholson received fees during 2005 for representing the board on the BP technology advisory council. Since these fees relate to board representation, they did not compromise Sir Robin's independence. Full details of these fees are disclosed on page 173.

DIRECTORS' APPOINTMENTS, RETIREMENT POLICIES AND INSURANCE

The chairman and non-executive directors of BP are elected each year and, subject to BP's Articles of Association, serve on the basis of letters of appointment. Executive directors of BP have service contracts with the company. Details of all payments to directors are reviewed in the directors' remuneration report on pages 164-173.

BP's policy on directors' retirement is as follows: executive directors retire at age 60, while non-executive directors ordinarily retire at the AGM following their 70th birthday. It is the board's policy that non-executive directors are not generally expected to hold office for more than 10 years.

In accordance with BP's Articles of Association, directors are granted an indemnity from the company in respect of liabilities incurred as a result of their office, to the extent permitted by law. In respect of those liabilities for which directors may not be indemnified, the company purchased and maintained a directors' and officers' liability insurance policy throughout 2005. This insurance cover was renewed at the beginning of 2006. Although their defence costs may be met, neither the company's indemnity nor insurance provides cover in the event that the director is proved to have acted fraudulently or dishonestly.

BOARD AND COMMITTEES: MEETINGS AND ATTENDANCE

In addition to the AGM (which 17 directors attended), the board met seven times during 2005: four times in the UK, twice in the US and once in China. Two of these meetings were two-day strategy discussions. 2005 saw a continued high number of committee meetings, a trend we expect to continue.

The board requires all members to devote sufficient time to the work of the board to discharge the office of director and to use their best endeavours to attend meetings. Directors' attendance at board and committee meetings is set out below.

SERVING AS A DIRECTOR: INDUCTION, TRAINING AND EVALUATION

Induction Directors receive induction on their appointment to the board as appropriate, covering matters such as the operation and activities of the group (including key financial, business, social and environmental risks to the group's activities), the role of the board and the matters reserved for its decision, the tasks and membership of the principal board committees, the powers delegated to those committees, the board's governance policies and practices, and the latest financial information about the group. The chairman is accountable for the induction of new board members.

Training Our directors are updated on BP's business, the environment in which it operates and other matters throughout their period in office. Our directors are advised on their appointment of the legal and other duties and obligations they have as directors of a listed company. The board regularly considers the implications of these duties under the board governance policies. Our non-executive directors also receive training specific to the tasks of the particular board committees on which they serve.

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

Directors' attendance

	Board meetings		Audit committee meetings		EEAC meetings		Chairman's committee meetings		Remuneration committee meetings		Nomination committee meetings	
	Attended	Possible	Attended	Possible	Attended	Possible	Attended	Possible	Attended	Possible	Attended	Possible
P D Sutherland	7	7	–	–	–	–	4	4	6[a]	6[a]	2	2
Sir Ian Prosser	7	7	12	12	–	–	4	4	6	6	2	2
J H Bryan	7	7	11	12	–	–	4	4	6	6	–	–
A Burgmans	7	7	–	–	5	7	4	4	–	–	–	–
E B Davis, Jr	7	7	12	12	–	–	4	4	5	6	–	–
D J Flint	7	7	7	9	–	–	4	4	–	–	–	–
Dr D S Julius	7	7	–	–	–	–	4	4	6	6	1	1
C F Knight	1	2	–	–	–	–	1	1	1	3	–	–
Sir Tom McKillop	6	7	–	–	–	–	3	4	6	6	–	–
Dr W E Massey	7	7	–	–	7	7	3	4	–	–	2	2
H M P Miles	7	7	11	12	6	7	4	4	–	–	–	–
Sir Robin Nicholson	1	2	–	–	–	–	1	1	2	3	1	1
M H Wilson	7	7	12	12	7	7	4	4	–	–	–	–
Lord Browne	7	7	–	–	–	–	–	–	–	–	–	–
Dr D C Allen	7	7	–	–	–	–	–	–	–	–	–	–
I C Conn	7	7	–	–	–	–	–	–	–	–	–	–
Dr B E Grote	7	7	–	–	–	–	–	–	–	–	–	–
Dr A B Hayward	7	7	–	–	–	–	–	–	–	–	–	–
J A Manzoni	7	7	–	–	–	–	–	–	–	–	–	–

[a] Attended all remuneration committee meetings as chairman of the board.

demonstrate the requisite commitment to discharge effectively their duties to BP. The nomination committee keeps the extent of directors' other interests under review to ensure that the effectiveness of our board is not compromised. The board attendance table on page 160 illustrates our directors' commitment to the work of the board.

Evaluation The board continued its ongoing evaluation processes to assess its performance and identify areas in which its effectiveness, policies or processes might be enhanced. A formal evaluation of board process and effectiveness was undertaken, drawing on internal resources. Individual questionnaires and interviews were completed; no individual performance problems were identified. The results showed an improvement from the previous evaluation, particularly in board committee process and activities, while also identifying areas for further improvement.

Regular evaluation of board effectiveness underpins our confidence in BP's governance policies and processes and affords opportunity for their development.

Separate evaluations of the remuneration, ethics and environment and audit assurance committees took place during the year. The use of external providers in the context of board evaluation is being kept under review.

THE CHAIRMAN AND SENIOR INDEPENDENT DIRECTOR

BP's board governance policies require that neither the *chairman* nor *deputy chairman* are to be employed executives of the group; throughout 2005 the posts were held by Mr Sutherland and Sir Ian Prosser respectively. Sir Ian also acts as our *senior independent director* and is the director whom shareholders may contact if they feel their concerns are not being addressed through normal channels.

Between board meetings, the chairman has responsibility for ensuring the integrity and effectiveness of the board/executive relationship. This requires his interaction with the group chief executive between board meetings, as well as his contact with other board members and shareholders. The chairman represents the views of the board to shareholders on key issues, not least in succession planning issues for both executive and non-executive appointments. The chairman and all the non-executive directors meet periodically as the *chairman's committee (see report on pages 162-163)*. The performance of the chairman is evaluated each year at a meeting of the chairman's committee, for which item of business he is not present. The company secretary reports to the chairman and has no executive functions.

BOARD COMMITTEES

The governance process policy allocates the tasks of monitoring executive actions and assessing performance to certain board committees. These tasks, rather than any terms of reference, prescribe the authority and the role of the board committees. Reports for each of the committees for 2005 appear below. In common with the board, each committee has access to independent advice and counsel as required and each is supported by the company secretary's office, which is demonstrably independent of the executive management of the group.

AUDIT COMMITTEE REPORT

Schedule and composition The committee met 12 times during 2005 and comprised the following directors: *Sir Ian Prosser (chairman), J H Bryan, E B Davis, Jr, D J Flint, H M P Miles, M H Wilson.*

All members of the audit committee are independent non-executive directors. Together, the audit committee members continue to have the recent and relevant financial experience required to discharge the committee's duties. Following his appointment to the committee this year, the board satisfied itself that Mr Flint as an individual possesses the financial experience identified in the Combined Code guidance.

The external auditors' lead partner, the BP general auditor (head of internal audit), together with the group chief financial officer, the chief accounting officer and the group controller, attend each meeting at the request of the committee chairman. During the year, the committee meets with the external auditor, without the executive management being present, and also meets in private session with the BP general auditor.

Role and authority The audit committee's tasks are considered by the committee to be broader than those envisaged under Combined Code Provision C.3.2. The committee is satisfied that it addresses each of those matters identified as properly falling within an audit committee's purview. The committee has full delegated authority from the board to address those tasks assigned to it. In common with the board and all committees, it may request any information from the executive management necessary to discharge its functions and may, where it considers it necessary, seek independent advice and counsel.

Process The committee structures its work programme so as to discharge its tasks, which include systematic monitoring and obtaining assurance that the legally required standards of disclosure are being fully and fairly observed and that the executive limitations relating to financial matters are being observed. Forward agendas are set each year to meet these requirements and to allow the committee to monitor (and seek assurance on) the management of the financial risks identified in the company's annual business plan. The committee chairman reports on the committee's activities to the board meeting immediately following a committee meeting. Between meetings, the committee chairman reviews emerging issues as appropriate with the group chief financial officer, the external auditor and the BP general auditor. He is supported in this task by the company secretary's office. During the year, external specialist legal and regulatory advice has also been provided to the committee by Sullivan & Cromwell LLP.

Activities in 2005 *Financial reports* During the year, the committee reviewed all annual and quarterly financial reports before recommending their publication on behalf of the board. In particular, the committee reviewed the implementation of International Financial Reporting Standards and their impact on the group's financial results and the restatement of comparative information. The committee discussed and constructively challenged judgements related to critical accounting policies and estimates drawing on prepared reports, presentations and independent advice from the external auditors.

Internal control and risk management During the year, specific reports on risk management and internal control were reviewed for the exploration and production, refining and marketing, and gas, power and renewables segments, along with the controls and systems underpinning the trading functions that service all BP's businesses. Reviews were undertaken of the reporting interface between the group and TNK-BP and of the planned disposal of the Innovene petrochemicals business. On a quarterly basis, the committee also monitored the company's progress in evaluating its internal controls in response to applicable requirements of Section 404 of the US Sarbanes-Oxley Act of 2002. Regular advice was also provided by the internal audit function, including an annual assessment of the effectiveness of the company's enterprise level controls.

Special topics considered during the year included capital project selection processes, the assessment of environmental and litigation provisions and accounting for long-term contractual commitments.

Employee concerns reporting/whistleblowing The committee received regular reports of the matters raised through the employee concerns programme, OpenTalk, and, through this process, together with the receipt of quarterly fraud reports from internal audit, was alerted to instances of actual or potential concern related to the finances and financial accounting of the group.

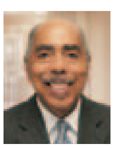
External auditors In addition to the lead partner's attendance at all meetings, the committee regularly invited other relevant audit partners to participate during business segment reviews. Private meetings were held without executive management present.

The committee evaluated the performance of the external auditors and enquired into their independence, objectivity and viability. Independence was safeguarded by limiting non-audit services provided by the auditor to defined audit-related work and tax services that fall within specific categories. All such services were pre-approved by the committee and monitored quarterly. A new lead audit partner is appointed every five years, with other senior audit staff rotating every seven years; no senior staff connected with the BP audit may transfer to the company.

After review of the audit engagement terms and proposed fees, the committee advised the board of its assessment and recommended that reappointment of the auditors be proposed to shareholders at the 2005 AGM.

Internal audit The committee agreed with the BP general auditor the programme to be undertaken during the year and the resources required. Twice-yearly reports of audit findings and management responses were reviewed in detail. Discussions of these reports contributed to the committee's view of the effectiveness of the company's system of internal controls and hence its advice to the board on this matter. The committee also met privately with the BP general auditor, without the presence of executive management, and evaluated the performance of the function.

Performance evaluation On an annual basis, the committee conducts a review of its process and performance. The form of review varies to encourage fresh thinking and this year involved face-to-face interviews with individual members and with others in regular attendance. Outcomes were discussed at the committee's November meeting. The committee concluded that few substantive changes were required but used the discussion to help shape the 2006 forward agenda and in particular to increase the frequency of the committee's private meetings.



ETHICS AND ENVIRONMENT ASSURANCE COMMITTEE REPORT

Schedule and composition The committee met seven times during 2005 and comprised the following directors: *Dr W E Massey (chairman), A Burgmans, H M P Miles, M H Wilson.*

All members of the ethics and environment assurance committee are independent non-executive directors. The external auditors' lead partner and the BP general auditor (head of internal audit) attend each meeting at the request of the committee chairman.

Role and authority The task of the committee is to monitor on behalf of the board matters relating to the executive management's processes to address environmental, health and safety, security and ethical behaviour issues. The committee monitors the observance of the executive limitations relating to non-financial risks to the group. Just as for the audit committee, it has the right to request any information from the executive management that it considers necessary to discharge its functions. The committee chairman reports on the committee's activities to the board meeting immediately following a committee meeting.

Process and activities in 2005 This committee has a broad remit because it covers all non-financial risks and must necessarily be selective in setting its agendas. These are focused on regular reports – such as health, safety and environment (HSE) reviews and compliance and ethics certification reports – that allow the committee to monitor and assess the observance of the executive limitations. In addition, the committee reviews specific risks that are identified in the company's annual plan and developments in business and functional areas that may emerge during the year. During 2005, the committee met specially to consider the incident at the Texas City refinery. It reviewed the causes of the accident and the implications for the group of the lessons to be learned. The committee continues to monitor the executive management's response and the strengthening of its safety and operational capability.

Other areas of specific focus during the year included:

Business continuity and crisis management The committee received reports and reviewed the group's enhanced focus on bringing more consistency and resilience to these linked topics across all business segments and functions.

Health, safety and environmental performance While overshadowed by events at Texas City, the progress in addressing road safety, employee health, greenhouse gas emissions, oil spills and plant integrity was considered during 2005. Specific attention was given to the progress made by TNK-BP in improving HSE standards in its operations in Russia.

Regional reviews Most board-level monitoring is conducted through a business segment or functional dimension, but the committee also examines risks that require management at regional or country level. In 2005, risk reviews were undertaken for Africa, the Middle East and Alaska.

Digital security The committee considered the company's response to the increasing international threats to communications and computing, threats heightened by the convergence and increased interconnectivity of technology infrastructure.

REMUNERATION COMMITTEE REPORT

Schedule and composition The committee met six times during 2005 and comprised the following directors: *Dr D S Julius (chairman), J H Bryan, E B Davis, Jr, Sir Tom McKillop, Sir Ian Prosser, Sir Robin Nicholson (retired at the AGM), C F Knight (retired at the AGM).*

All members of the remuneration committee are non-executive directors and are considered by the board to be independent. The chairman of the board also attends committee meetings. The committee is independently advised.

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

Process and activities in 2005 Full details of the committee's remit and work are set out in the directors' remuneration report on pages 164-173, which is the subject of a vote by shareholders at the 2006 AGM.

CHAIRMAN'S COMMITTEE REPORT

Schedule and composition The chairman's committee met four times during 2005 and comprised all the non-executive directors.

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

Process and activities in 2005 At its various meetings, the committee evaluated the performance of the chairman and the group chief executive, considered the plan for executive succession and considered a number of other broad matters of governance, including issues that spanned the remit of the other principal committees. Additionally, the committee addressed non-executive succession planning issues in co-ordination with the nomination committee.

NOMINATION COMMITTEE REPORT

Schedule and composition The committee met twice during 2005 and comprised the following directors: *P D Sutherland (chairman), Dr D S Julius (from the AGM), Dr W E Massey, Sir Robin Nicholson (retired at the AGM), Sir Ian Prosser.*

All members of the nomination committee are considered by the board to be independent.

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

Process During the year, the nomination committee carried out a detailed review of the skills and expertise of the non-executive directors as part of the board succession planning described earlier. The committee receives external assistance as required. The committee consults with the group chief executive concerning the identification and appointment of new executive directors. External search consultants are retained in the UK/Europe and in the US to assist the committee to identify potential candidates as non-executive directors.

Activities in 2005 The committee considered the composition of the board and board committees in the context of forthcoming work programmes, BP's strategy and business activities and retirements from the board. In its succession planning for both executive and non-executive directors, the committee is mindful of the requirements of the group's strategy and five-year plan. Board and committee evaluation processes informed its work in identifying the skills and experiences sought from potential candidates. Evaluations of the balance of skills and experience on the board are carried out in conjunction with the chairman's committee. The committee keeps under review contingency planning for key executive and non-executive director roles. The nomination committee recommended to the board that 17 incumbent directors be proposed for re-election at the AGM.

COMBINED CODE COMPLIANCE

BP complied throughout 2005 with the provisions of the Combined Code Principles of Good Governance and Code of Best Practice, except in the following aspects:

A.4.4 Letters of appointment do not set out fixed time commitments since the schedule of board and committee meetings is subject to change according to the exigencies of the business. All directors are expected to demonstrate their commitment to the work of the board on an ongoing basis. This is reviewed by the nomination committee in recommending candidates for annual re-election.

B.1.4 The amount of fees received by executive directors in respect of their service on outside boards is not disclosed since this information is not considered relevant to BP.

B.2.2 The remuneration of the chairman is fixed by the board as a whole (rather than the remuneration committee) within the limits set by shareholders, since the chairman's performance is a matter for the whole board.

INTERNAL CONTROL REVIEW

The board governance policies include a process for the board to review regularly the effectiveness of the system of internal control as required by Code provision C.2.1. As part of this process, the board and the audit and ethics and environment assurance committees requested, received and reviewed reports from executive management, including management of the principal business segments, at their regular meetings. That enabled them to assess the effectiveness of the system of internal control in operation for managing significant risks, including social, environmental and ethical risks, throughout the year. This process did not extend to joint ventures or associates.

The BP general auditor presented reports to the January 2006 meetings of both the audit and ethics and environment assurance committees to support the board in its annual assessment of internal control. The reports described how significant risks were identified and embedded within business segment and function plans across the group; the effectiveness of executive management's controls; and the continuing development of the systems in place to identify, address and manage risks. The reports also highlighted future potentially significant risks that had been reviewed by the board as part of the company's planning process. The two committees engage with executive management regularly to monitor the management of risks. Significant incidents that occurred and management's response to them were considered by the committees during the year.

In the board's view, the information it received was sufficient to enable it to review the effectiveness of the company's system of internal control in accordance with the Internal Control Revised Guidance for Directors on the Combined Code (Turnbull).

DIRECTORS' INTERESTS

in BP ordinary shares or calculated equivalents

	At 31 Dec 2005	At 1 Jan 2005	Change from 31 Dec 2005-7 Feb 2006
Current directors			
Dr D C Allen	443,742[a]	408,342	–
Lord Browne	2,242,954[b]	2,031,279	–
J H Bryan	158,760[c]	158,760	–
A Burgmans	10,000	10,000	–
I C Conn	156,349[d]	121,187	54
E B Davis, Jr	67,610[c]	66,349	–
D J Flint	15,000	–	–
Dr B E Grote	988,812[c]	888,213	–
Dr A B Hayward	305,543	206,084	54
Dr D S Julius	15,000	15,000	–
Sir Tom McKillop	20,000	20,000	–
J A Manzoni	275,743	196,336	51
Dr W E Massey	49,722[c]	49,722	–
H M P Miles	22,145	22,145	–
Sir Ian Prosser	16,301	16,301	–
P D Sutherland	30,079	30,079	–
M H Wilson	60,000[c]	60,000	–

	At retirement	At 1 Jan 2005
Directors leaving the board in 2005		
C F Knight	98,782[c]	98,578
Sir Robin Nicholson	4,052	4,020

[a] Includes 25,368 shares held as ADSs.
[b] Includes 58,713 shares held as ADSs.
[c] Held as ADSs.
[d] Includes 38,836 shares held as ADSs.

The above figures indicate and include all the beneficial and non-beneficial interests of each director of the company in shares of the company (or calculated equivalents) that have been disclosed to the company under the Companies Act 1985 as at the applicable dates. In making these disclosures, the directors did not distinguish between beneficial and non-beneficial interests.

Executive directors are also deemed to have an interest in such shares of the company held from time to time by The BP Employee Share Ownership Plan (No. 2) to facilitate the operation of the company's option schemes.

No director has any interest in the preference shares or debentures of the company, or in the shares or loan stock of any subsidiary company.

Directors' remuneration report

The directors' remuneration report covers all directors, both executive and non-executive, and is set out on pages 164-173.

It is divided into two parts. Executive directors' remuneration is in the first part, which was prepared by the remuneration committee. Non-executive directors' remuneration is in the second part, which 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. This report is subject to the approval of shareholders at the annual general meeting (AGM).

Part 1 – Executive directors' remuneration

DEAR SHAREHOLDER As described in this Annual Report, 2005 was a year of strong financial performance for the group set against a background of a number of significant events – both positive and negative. It was also a year in which you, our shareholders, approved the renewal of the long-term incentive plan for the executive directors.

I am pleased to report that this plan has been implemented and is a key part of our policy on remuneration. This revised policy has provided an effective framework against which to evaluate the performance of the executive directors. In a performance-driven organization, the measurement of that performance is critical. We believe that we have an appropriate balance of quantitative and qualitative measures. Equally, the policy allows the remuneration committee to exercise judgement when it is appropriate to do so.

During the year, the executive team demonstrated strong leadership and delivery against a demanding set of targets. They managed events well and group performance was also strong. Against this backdrop, the significant events of the year were also taken into account in the committee's overall judgement of results.

Full details of executive directors' remuneration are set out in the pages that follow. I am confident that the committee's approach aligns executive remuneration with the interests of shareholders as well as rewarding and engaging the world-class team of people that we have leading this company.

Dr D S Julius
Chairman, Remuneration Committee
6 February 2006

THE REMUNERATION COMMITTEE

Tasks The committee's tasks are:

- To determine, on behalf of the board, the terms of engagement and remuneration of the group chief executive and the executive directors and to report on those to the shareholders.
- To determine, on behalf of the board, matters of policy over which the company has authority relating to the establishment or operation of the company's pension scheme of which the executive directors are members.
- To nominate, on behalf of the board, any trustees (or directors of corporate trustees) of such scheme.
- To monitor the policies being applied by the group chief executive in remunerating senior executives other than executive directors.

Constitution and operation The committee members are all non-executive directors. Dr Julius (chairman), Mr Bryan, Mr Davis, Sir Tom McKillop and Sir Ian Prosser were members of the committee throughout the year. Sir Robin Nicholson and Mr Knight retired from the committee at the 2005 AGM. Each member is now subject to annual re-election as a director of the company. The board considers all committee members to be independent *(see pages 159-160).* They have no personal financial interest, other than as shareholders, in the committee's decisions. The committee met six times in the period under review. There was a full attendance record, except for Mr Davis and Sir Robin Nicholson who were each unable to attend one meeting and Mr Knight who was unable to attend two meetings. Mr Sutherland, as chairman of the board, attended all committee meetings.

The committee is accountable to shareholders through its annual report on executive directors' remuneration. It will consider the outcome of the vote at the AGM on the directors' remuneration report and take into account the views of shareholders in its future decisions. The committee values its dialogue with major shareholders on remuneration matters.

Advice Advice is provided to the committee by the company secretary's office, which is independent of executive management and reports to the chairman of the board. Mr Aronson, an independent consultant, is the committee's secretary and special adviser. Advice was also received from Mr Jackson (company secretary) and Mrs Martin (senior counsel, company secretary's office).

The committee also appoints external professional advisers to provide specialist advice and services on particular remuneration matters. The independence of advice is subject to annual review.

The committee continued the engagement of Towers Perrin as its principal external adviser during 2005. Towers Perrin also provided limited ad hoc remuneration and benefits advice to parts of the group, mainly comprising pensions advice in Canada, as well as providing some market information on pay structures. The committee also continued the engagement of Kepler Associates to advise on performance measurement. Kepler Associates also provided performance data and limited ad hoc advice on performance measurement to the group.

Freshfields Bruckhaus Deringer provided legal advice on specific matters to the committee as well as providing some legal advice to the group.

Ernst & Young reviewed the calculations in respect of financial-based targets that form the basis of the performance-related pay for the executive directors. They also provided audit, audit-related and taxation services to the group.

Lord Browne (group chief executive) was consulted on matters relating to the other executive directors who report to him and on matters relating to the performance of the company. He was not present when matters affecting his own remuneration were considered.

POLICY ON EXECUTIVE DIRECTORS' REMUNERATION

During 2004, the committee carried out a comprehensive and independent review of all elements of remuneration policy for executive directors, culminating in a shareholder resolution at the 2005 AGM approving the renewal of the Executive Directors' Incentive Plan (EDIP). The committee seeks to ensure that, in determining remuneration policy, there is a clear link between the company's purpose, the business plans and executive reward. The following key principles guide its policy:

- Policy for the remuneration of executive directors will be determined and regularly reviewed independently of executive management and will set the tone for the remuneration of other senior executives.
- The remuneration structure will support and reflect BP's stated purpose to maximize long-term shareholder value.
- The remuneration structure will reflect a just system of rewards for the participants.
- The overall quantum of all potential remuneration components will be determined by the exercise of informed judgement of the independent remuneration committee, taking into account the success of BP and the competitive global market.
- The majority of the remuneration will be linked to the achievement of demanding performance targets that are independently set and reflect the creation of long-term shareholder value.
- A significant personal shareholding will be developed in order to align executive and shareholder interests.
- Assessment of performance will be quantitative and qualitative and will include exercise of informed judgement by the remuneration committee within a framework that takes account of sector characteristics and is approved by shareholders.
- The committee will be proactive in obtaining an understanding of shareholder preferences.
- Remuneration policy and practices will be as transparent as possible, both for participants and shareholders.
- The wider scene, including pay and employment conditions elsewhere in the group, will be taken into account, especially when determining annual salary increases.

Elements of remuneration The executive directors' total remuneration will consist of salary, annual bonus, long-term incentives, pensions and other benefits. This reward structure will be regularly reviewed by the committee to ensure that it is achieving its objectives.
In 2006, over three-quarters of executive directors' potential direct remuneration will again be performance-related *(see illustrative chart below).*

This chart reflects on-target values for annual bonus and share element.

Salary The committee expects to review salaries in 2006. In doing so, the committee considers both top Europe-based global companies and the US oil and gas sector; each of these groups is defined and analysed by the committee's independent external remuneration advisers. The committee then assesses the market information and advice and applies its judgement in setting the salary levels.

Annual bonus Each executive director is eligible to participate in an annual performance-based bonus scheme. The committee reviews and sets bonus targets and levels of eligibility annually.

For 2006, the target level is 120% of base salary (except for Lord Browne, for whom, as group chief executive, it is considered appropriate to have a target of 130%). In normal circumstances, the maximum payment level for substantially exceeding targets will continue to be 150% (165% for the group chief executive) of base salary. In exceptional circumstances, outstanding performance may be recognized by bonus payments moderately above the 150% (and 165%) levels at the discretion of the remuneration committee. Similarly, bonuses may be reduced where the committee considers that this is warranted and, in exceptional circumstances, bonuses can be reduced to zero.

The committee recognizes that it is responsible to shareholders to use its discretion in a reasonable and informed manner in the best interests of the company and that it has a corresponding duty to be accountable and transparent as to the manner in which it exercises its discretion. The committee will explain any significant exercise of discretion in the subsequent directors' remuneration report.

Executive directors' annual bonus awards for 2006 will be based on a mix of demanding financial targets, based on the company's annual plan and leadership objectives established at the beginning of the year, in accordance with the following weightings:

- 50% financial and operational metrics from the annual plan, principally earnings before interest, tax, depreciation and amortization (EBITDA) and return on average capital employed (ROACE).
- 30% annual strategic milestones taken from the five-year group business plan, including those relating to technology, operational actions and business development.
- 20% individual performance against leadership objectives and living the values of the group, which incorporates BP's code of conduct.

In assessing the final outcome of the individual bonuses each year, the committee will also carefully review the underlying performance of the group in the context of the five-year group business plan, as well as looking at competitor results, analysts' reports and the views from the chairmen of other BP board committees. All the calculations are reviewed by Ernst & Young.

Long-term incentives Long-term incentives will continue to be provided under the EDIP. It has three elements within its framework:

a share element, a share option element and a cash element. The committee does not currently intend to use either the share option or cash elements but, in exceptional circumstances, may do so.

Each executive director participates in the EDIP. The committee's policy, subject to unforeseen circumstances, is that this should continue until the EDIP expires or is renewed in 2010.

The committee's policy continues to be that each executive director should hold shares equivalent in value to 5 x the director's base salary within five years of being appointed an executive director. This policy is reflected in the terms of the EDIP, as shares awarded under the share element will only be released at the end of the three-year retention period *(as described below)* if the minimum shareholding guidelines have been met.

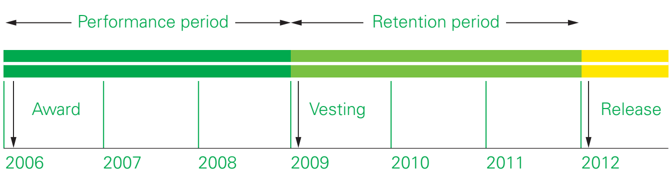
1. Share element The committee may make conditional share awards (performance shares) to executive directors, which will only vest to the extent that a demanding performance condition imposed by the committee is met at the end of a three-year performance period.

The maximum number of performance shares that may be awarded to an executive director in any one year will be determined at the discretion of the remuneration committee and will not normally exceed 5.5 x base salary and, in the case of the group chief executive, 7.5 x base salary.

In addition to the performance condition described below, the committee will have an overriding discretion, in exceptional circumstances, to reduce the number of shares that vest (or to provide that no shares vest).

The shares that vest will normally be subject to a compulsory retention period determined by the committee, which will not normally be less than three years. This gives executive directors a six-year incentive structure and is designed to ensure that their interests are aligned with those of shareholders. Where shares vest under awards made in 2005 and future years, the executive director will receive additional shares representing the value of reinvested dividends on these shares.

TIMELINE FOR 2006-2008 EDIP SHARE ELEMENT



For share element awards in 2006, the performance condition will (as in 2005) relate to BP's total shareholder return (TSR) performance against the other oil majors (ExxonMobil, Shell, Total and Chevron) over a three-year period. The committee will have the discretion to amend this peer group in appropriate circumstances, for example, in the case of any significant consolidations in the industry. TSR is calculated by taking the share price performance of a company over the period, assuming dividends to be reinvested in the company's shares. All share prices will be averaged over the three months before the beginning and end of the performance period and will be measured in US dollars. At the end of the performance period, the TSR performance of each of the companies will be ranked to establish the relative total return to shareholders over the period. Shares under the award will vest as to 100%, 70% and 35% if BP achieves first, second or third place respectively; no shares will vest if BP achieves fourth or fifth place.

The committee considers that relative TSR is the most appropriate measure of performance for BP's long-term incentives for executive directors as it best reflects the creation of long-term shareholder value. Relative performance of the peer group is particularly key in order to minimize the influence of sector-specific effects, including oil price.

The committee is mindful of the possibility that a simple ranking system may in some circumstances give rise to distorted results in view of the broad similarity of the oil majors' underlying businesses, the small size of the comparator group and inherent imperfections in measurement. To counter this, the committee will have the ability to exercise discretion in a reasonable and informed manner to adjust (upwards or downwards) the vesting level derived from the ranking if it considers that the ranking does not fairly reflect BP's underlying business performance relative to the comparator group.

The exercise of this discretion would be made after a broad analysis of the underlying health of BP's business relative to competitors, as shown by a range of other measures including, but not limited to, ROACE, earnings per share (EPS) growth, reserves replacement and cash flow. This will enable a more comprehensive review of long-term performance, with the aims of tempering anomalies created by relying solely on a formula-based approach and ensuring that the objectives of the plan are met.

It is anticipated that the need to use discretion is most likely to arise where the TSR performance of some companies is clustered, so that a relatively small difference in TSR performance would produce a major difference in vesting levels. In these circumstances, the committee will have power to adjust the vesting level, normally by determining an average vesting level for the companies affected by the clustering.

In line with its policy on transparency, the committee will explain any adjustment to the relative TSR ranking in the next directors' remuneration report following the vesting.

The committee may amend the performance conditions if events occur that would make the amended condition a fairer measure of performance and provided that any amended condition is no easier to satisfy.

For 2006, all executive directors will receive performance share awards on the above basis, over a maximum number of shares set by reference to 5.5 x base salary. For awards under the share element in future years, the committee may continue with the same performance condition or may impose a different condition, which it considers to be no less demanding.

As group chief executive, Lord Browne is eligible for performance share awards of up to 7.5 x base salary. The committee has determined that, while the largest part of this should relate to the TSR measure described above, it continues to be appropriate that a specific part (up to 2 x base salary) should be based on long-term leadership measures. These will focus on sustaining BP's financial, strategic and organizational health and will include, but not be limited to, maintenance of BP's performance culture and the continued development of BP's business strategy, executive talent and internal organization. As with the TSR part of his award, this part will be measured over a three-year performance period.

Share element awards made in previous years Awards for the period 2005-2007 were made on the same basis as described above. For outstanding awards of performance units made under the plans for the periods 2003-2005 and 2004-2006, the previous performance conditions will apply for the three-year performance periods in each of the plans. The primary measure is BP's shareholder return against the market (SHRAM), which accounts for nearly two-thirds of the potential total award, the remainder being assessed on BP's relative ROACE and EPS growth.

BP's SHRAM is measured against the companies in the FTSE All World Oil & Gas Index. Companies within the index are weighted according to their market capitalization at the beginning of each three-year period in order to give greatest emphasis to oil majors. BP's ROACE and EPS growth are measured against ExxonMobil, Shell, Total and Chevron. All calculations are reviewed by Ernst & Young to ensure that they meet an independent objective standard. The relative position of the company within the comparator group determines the number of shares awarded per performance unit, subject to a maximum of two shares per unit.

2. Share option element The share option element of the EDIP permits options to be granted to executive directors at an exercise price no lower than the market value of a share at the date the option is granted. The committee does not currently intend to use this element.

3. Cash element The cash element allows the committee to grant long-term cash-based incentives. This element has not been used since the EDIP was established in 2000 and the committee would only do so in special circumstances.

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

UK directors UK directors are members of the regular BP Pension Scheme. Scheme members' core benefits are non-contributory. They include a pension accrual of 1/60th of basic salary for each year of service, subject to a maximum of two-thirds of final basic salary, and a dependant's benefit of two-thirds of the member's pension. Bonuses are not pensionable for UK directors. The scheme pension is not integrated with state pension benefits.

Normal retirement age is 60, but scheme members who have 30 or more years' pensionable service at age 55 can elect to retire early without an actuarial reduction being applied to their pension.

In accordance with the company's past practice for executive directors who retire from BP on or after age 55 having accrued at least 30 years' service, Lord Browne remains eligible for consideration for a payment from the company of an ex-gratia lump-sum superannuation payment equal to one year's base salary following his retirement. All matters relating to such superannuation payments are considered by the remuneration committee. Any such payment would be additional to his pension entitlements referred to above. No other executive director is eligible for consideration for a superannuation payment on retirement, because the remuneration committee decided in 1996 that appointees to the board after that time should cease to be eligible for consideration for such a payment.

The UK government has made important changes to the operation and taxation of UK pensions, which come into effect from 6 April 2006 and affect all UK employees. The remuneration committee has reviewed and approved proposals by the company that maintain the pension promise for all UK employees but that deliver pension benefits in excess of the new *lifetime allowance* of £1.5 million (or *personal lifetime allowance* as at 6 April 2006 under statute if higher) via an unapproved, unfunded pension arrangement paid by the company direct.

The trustee directors of the BP Pension Scheme have reviewed, in accordance with its statutory obligation, the actuarial basis under which cash equivalent transfer values are payable to all UK employees who participate in that scheme. Consistent with evolving actuarial practice, the trustee directors have resolved to base cash equivalent transfer values on a similar basis to that underlying the company's accounts, including allowance for improving longevity in accordance with standard tables; this has the effect of increasing cash equivalent transfer values for the UK executive directors on average by about 15%. Although the change became effective in January 2006, the table on page 171 shows both 31 December 2004 and 31 December 2005 transfer value figures on the new basis.

US director As a US director, Dr Grote participates in the US BP Retirement Accumulation Plan (US plan), which features a cash balance formula. The current design of the US plan became effective on 1 July 2000.

Consistent with US tax regulations, pension benefits are provided through a combination of tax-qualified and non-qualified benefit restoration plans, 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 (as specified under the qualified arrangement) multiplied by years of service, with 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 an eligible participant under the supplemental plan and his pension accrual for 2005 includes the total amount that may become payable under all plans.

Other benefits

- Benefits and other share schemes: Executive directors are eligible to participate in regular employee benefit plans and in all-employee share schemes and savings plans applying in their home countries. Benefits in kind are not pensionable.
- Resettlement allowance: Expatriates may receive a resettlement allowance for a limited period.

SERVICE CONTRACTS

Director	Contract date	Current salary
Lord Browne	11 Nov 1993	£1,486,400
Dr D C Allen	29 Jan 2003	£441,000
I C Conn	22 Jul 2004	£441,000
Dr B E Grote	7 Aug 2000	$945,000
Dr A B Hayward	29 Jan 2003	£441,000
J A Manzoni	29 Jan 2003	£441,000

The committee's policy is for service contracts to expire at normal retirement date and have a notice period of one year. All contracts comply with this.

The service contracts of Dr Allen, Mr Conn, Dr Hayward and Mr Manzoni may be terminated by the company at any time with immediate effect on payment in lieu of notice equivalent to one year's salary or the amount of salary that would have been paid if the contract had terminated on the expiry of the remainder of the notice period.

Dr Grote's service contract is with BP Exploration (Alaska) Inc. He is seconded to BP p.l.c. under a secondment agreement dated 7 August 2000 that had an unexpired term of two years at 31 December 2005. The secondment may be terminated by one month's notice by either party and terminates automatically on the termination of Dr Grote's service contract.

There are no other provisions for compensation payable on early termination of the above contracts. In the event of early termination under any of the above contracts by the company other than for cause (or under a specific termination payment provision), the relevant director's then current salary and benefits would be taken into account in calculating any liability of the company.

Since January 2003, the committee has included a provision in

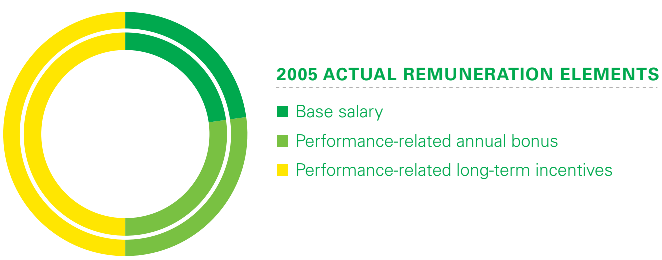
Summary of 2005 remuneration of executive directors

	Annual remuneration								Long-term remuneration				
									Share element of EDIP/LTPPs				
									2002-2004 plan (vested in Feb 2005)		**2003-2005 plan (to vest in Feb 2006)**		2005-2007 plan (awarded in Apr 2005)
	Salary (thousand) 2004	Salary (thousand) 2005	Annual performance bonus (thousand) 2004	Annual performance bonus (thousand) 2005	Non-cash benefits and other emoluments (thousand) 2004	Non-cash benefits and other emoluments (thousand) 2005	Total (thousand) 2004	Total (thousand) **2005**	Actual shares vested	Value[a] (thousand)	Expected shares to vest[b]	Value[c] (thousand)	Potential maximum performance shares[d]
Lord Browne	£1,382	£1,451	£2,280	£1,750	£82	£90	£3,744	**£3,291**	356,667	£1,958	474,384	£3,202	2,006,767
Dr D C Allen	£410	£431	£615	£480	£11	£12	£1,036	**£923**	60,000	£329	147,783	£998	436,623
I C Conn[e]	£200	£421	£300	£450	£42	£43	£542	**£914**	51,750	£284	68,250	£461	415,832
Dr B E Grote	$841	$923	$1,262	$1,100	$0	$0	$2,103	**$2,023**	136,960	$1,419	175,229	$2,077	501,782
Dr A B Hayward	£410	£431	£615	£460	£36	£14	£1,061	**£905**	55,125	£303	147,783	£998	436,623
J A Manzoni	£410	£431	£615	£440	£46	£47	£1,071	**£918**	60,000	£329	147,783	£998	436,623

Amounts shown are in the currency received by executive directors. Annual bonus is shown in the year it was earned.

[a] Based on market price on date of award (£5.49 per share/$62.15 per ADS).
[b] Gross award of shares based on a performance assessment by the remuneration committee and on the other terms of the plan. Sufficient shares are sold to pay for tax applicable. Remaining shares are held in trust for current directors until 2009, when they are released to the individual.
[c] Based on closing price of BP shares on 1 February 2006 (£6.75 per share/$71.12 per ADS).
[d] Maximum potential shares that could vest at the end of the three-year period depending on performance.
[e] 2004 remuneration reflects that received by Mr Conn from his appointment as executive director on 1 July 2004.

new service contracts to allow for severance payments to be phased, where appropriate to do so. It will also consider mitigation to reduce compensation to a departing director, where appropriate to do so.



The chart above reflects the average mix of total remuneration received by executive directors in 2005 and includes actual salary, bonus and share element award.

Salary Base salaries for all executive directors were reviewed relative to top Europe-based global companies and the US oil and gas sector. Having taken account of market movements and performance, the committee awarded a 5% increase in base salaries with effect from 1 July 2005 for all exective directors except Mr Conn, whose increase was slightly higher to bring him to the same level as his peers.

Annual bonus The measures and weightings described earlier form the framework within which the remuneration committee determined the annual bonuses for the executive directors.

The committee made evaluations against each of the measures: financial, metrics and milestones, and individual. The financial measures were taken from the annual plan principally on cash flow. Cash flow was strong. Amounts received from the divestment of non-strategic assets significantly exceeded internal targets (principally due to the Innovene disposal) and these, along with other actions and successes, more than offset reductions in cash flow caused by adverse events. Production rates, allowing for the impact of oil prices on production-sharing contracts and weather-related downtime, were within internal expectations.

Annual strategic metrics and milestones were taken from the five-year group business plan. There is a wide range of measures, including those relating to people, safety, environment, technology and organization as well as operations and business development. The group continued to perform well, developing business in Russia, India and elsewhere. New fields came on stream in the US, Angola, Azerbaijan and Trinidad & Tobago. A new code of conduct was launched and employees were trained in its application. Safety performance was impaired by the incident at Texas City.

Individual performance against leadership objectives was reviewed by the committee, as was the underlying performance of the group in the context of the five-year plan, together with competitor results and positioning. Results are in line with or exceed expectations.

The committee also considered this performance in the light of the significant events during the year, both positive and negative. These included the high prices of oil and gas; the overall financial performance of the group; the disposal of non-strategic assets, principally Innovene; the financial and other consequences of the serious incident at the Texas City refinery and the repairs to the Thunder Horse platform; and the effects of the hurricanes in the Gulf of Mexico. The scale and the impact of all of these events were taken into account in determining the annual bonuses, which are set out in the table above.

SHARE OPTIONS

	Option type	At 1 Jan 2005	Granted	Exercised	At 31 Dec 2005	Option price	Market price at date of exercise	Date from which first exercisable	Expiry date
Lord Browne	SAYE	4,550	–	–	4,550	£3.50		1 Sep 2008	28 Feb 2009
	EDIP	408,522	–	–	408,522	£5.99		15 May 2001	15 May 2007
	EDIP	1,269,843	–	–	1,269,843	£5.67		19 Feb 2002	19 Feb 2008
	EDIP	1,348,032	–	–	1,348,032	£5.72		18 Feb 2003	18 Feb 2009
	EDIP	1,348,032	–	–	1,348,032	£3.88		17 Feb 2004	17 Feb 2010
	EDIP	1,500,000	–	–	1,500,000	£4.22		25 Feb 2005	25 Feb 2011
Dr D C Allen	EXEC	37,000	–	–	37,000	£5.99		15 May 2003	15 May 2010
	EXEC	87,950	–	–	87,950	£5.67		23 Feb 2004	23 Feb 2011
	EXEC	175,000	–	–	175,000	£5.72		18 Feb 2005	18 Feb 2012
	EDIP	220,000	–	–	220,000	£3.88		17 Feb 2004	17 Feb 2010
	EDIP	275,000	–	–	275,000	£4.22		25 Feb 2005	25 Feb 2011
I C Conn	SAYE	1,355	–	1,355	0	£4.98	£6.38	1 Sep 2005	28 Feb 2006
	SAYE	1,456	–	–	1,456	£3.50		1 Sep 2008	28 Feb 2009
	SAYE	1,186	–	–	1,186	£3.86		1 Sep 2009	28 Feb 2010
	SAYE	0	1,498	–	1498	£4.41		1 Sep 2010	28 Feb 2011
	EXEC	72,250	–	–	72,250	£5.67		23 Feb 2004	23 Feb 2011
	EXEC	130,000	–	–	130,000	£5.72		18 Feb 2005	18 Feb 2012
	EXEC	160,000	–	–	160,000	£3.88		17 Feb 2006	17 Feb 2013
	EXEC	126,000	–	–	126,000	£4.22		25 Feb 2007	25 Feb 2014
Dr B E Grote[a]	SAR	35,200	–	–	35,200	$25.27		6 Mar 1999	6 Mar 2006
	SAR	40,000	–	–	40,000	$33.34		28 Feb 2000	28 Feb 2007
	BPA	10,404	–	–	10,404	$53.90		15 Mar 2000	14 Mar 2009
	BPA	12,600	–	–	12,600	$48.94		28 Mar 2001	27 Mar 2010
	EDIP	40,182	–	–	40,182	$49.65		19 Feb 2002	19 Feb 2008
	EDIP	58,173	–	–	58,173	$48.82		18 Feb 2003	18 Feb 2009
	EDIP	58,173	–	–	58,173	$37.76		17 Feb 2004	17 Feb 2010
	EDIP	58,333	–	–	58,333	$48.53		25 Feb 2005	25 Feb 2011
Dr A B Hayward	SAYE	3,302	–	–	3,302	£5.11		1 Sep 2006	28 Feb 2007
	EXEC	34,000	–	–	34,000	£5.99		15 May 2003	15 May 2010
	EXEC	77,400	–	–	77,400	£5.67		23 Feb 2004	23 Feb 2011
	EXEC	160,000	–	–	160,000	£5.72		18 Feb 2005	18 Feb 2012
	EDIP	220,000	–	–	220,000	£3.88		17 Feb 2004	17 Feb 2010
	EDIP	275,000	–	–	275,000	£4.22		25 Feb 2005	25 Feb 2011
J A Manzoni	SAYE	878	–	–	878	£4.52		1 Sep 2007	28 Feb 2008
	SAYE	2,548	–	–	2,548	£3.50		1 Sep 2008	28 Feb 2009
	SAYE	847	–	–	847	£3.86		1 Sep 2009	28 Feb 2010
	EXEC	12,000	–	12,000	0	£2.04	£5.52	28 Feb 1998	28 Feb 2005
	EXEC	34,000	–	–	34,000	£5.99		15 May 2003	15 May 2010
	EXEC	72,250	–	–	72,250	£5.67		23 Feb 2004	23 Feb 2011
	EXEC	175,000	–	–	175,000	£5.72		18 Feb 2005	18 Feb 2012
	EDIP	220,000	–	–	220,000	£3.88		17 Feb 2004	17 Feb 2010
	EDIP	275,000	–	–	275,000	£4.22		25 Feb 2005	25 Feb 2011

The closing market prices of an ordinary share and of an ADS on 31 December 2005 were £6.19 and $64.22 respectively.
During 2005, the highest market prices were £6.84 and $72.27 respectively and the lowest market prices were £5.04 and $56.61 respectively.

EDIP = Executive Directors' Incentive Plan adopted by shareholders in April 2005 as described on pages 165-167.
BPA = BP Amoco share option plan, which applied to US executive directors prior to the adoption of the EDIP.
SAR = Stock Appreciation Rights under BP America Inc. Share Appreciation Plan.
SAYE = Save As You Earn employee share scheme.
EXEC = Executive Share Option Scheme. These options were granted to the relevant individuals prior to their appointments as directors and are not subject to performance conditions.

[a] Numbers shown are ADSs under option. One ADS is equivalent to six ordinary shares.

SHARE ELEMENT OF EDIP AND LONG TERM PERFORMANCE PLANS

Under the share element of the EDIP and the Long Term Performance Plans (LTPPs), performance units were until 2004 granted at the beginning of the three-year period and converted into an award of shares at the end of the period, depending on performance. There is a maximum of two shares per performance unit. For 2005 and future years, grants of performance shares are made, being the maximum number of shares that could vest *(as described on pages 165-167)*. In the table below, performance units that have yet to convert to shares are expressed as the maximum number of shares into which they could convert (based on the maximum 2:1 ratio). This achieves consistency of disclosure between the two periods.

For the 2003-2005 share element of the EDIP and the LTPPs, BP's performance was assessed in terms of SHRAM, ROACE and EPS growth. BP's three-year SHRAM was measured against the companies in the FTSE All World Oil & Gas Index. Companies within the index are weighted according to their market capitalization at the beginning of each three-year period in order to give greatest emphasis to oil majors. BP's ROACE and EPS were measured against ExxonMobil, Shell, Total and Chevron. Based on a performance assessment of 75 points out of 200 (0 for SHRAM, 50 for ROACE and 25 for EPS growth), the committee expects to make awards of shares to executive directors as highlighted in the 2003-2005 lines of the table below.

SHARE ELEMENT OF EDIP AND LTPPs

				Share element/LTPP interests			Interests vested in 2005		
				Potential maximum performance shares[a]					
	Performance period	Date of award of performance shares	Market price of each share at date of award of performance shares £	At 1 Jan 2005	Awarded 2005	At 31 Dec 2005	Number of ordinary shares vested[b]	Vesting date	Market price of each share at vesting date £
Lord Browne	2002–2004	18 Feb 2002	5.73	951,112	–	–	356,667	9 Feb 2005	5.49
	2003–2005	**17 Feb 2003**	**3.96**	**1,265,024**	**–**	**1,265,024**	**74,384**	**expected to vest Feb 2006**	
	2004–2006	25 Feb 2004	4.25	1,268,894	–	1,268,894	–	–	–
	2005–2007	28 April 2005	5.33	–	2,006,767	2,006,767	–	–	–
Dr D C Allen	2002–2004	6 Mar 2002	5.99	160,000	–	–	60,000	9 Feb 2005	5.49
	2003–2005	**17 Feb 2003**	**3.96**	**394,088**	**–**	**394,088**	**147,783**	**expected to vest Feb 2006**	
	2004–2006	25 Feb 2004	4.25	376,470	–	376,470	–	–	–
	2005–2007	28 Apr 2005	5.33	–	436,623	436,623	–	–	–
I C Conn[c]	2002–2004	6 Mar 2002	5.99	138,000	–	–	51,750	9 Feb 2005	5.49
	2003–2005	**17 Feb 2003**	**3.96**	**182,000**	**–**	**182,000**	**68,250**	**expected to vest Feb 2006**	
	2004–2006	25 Feb 2004	4.25	182,000	–	182,000	–	–	–
	2005–2007	28 Apr 2005	5.33	–	415,832	415,832	–	–	–
Dr B E Grote	2002–2004	18 Feb 2002	5.73	365,226	–	–	136,960	9 Feb 2005	5.49
	2003–2005	**17 Feb 2003**	**3.96**	**467,276**	**–**	**467,276**	**175,229**	**expected to vest Feb 2006**	
	2004–2006	25 Feb 2004	4.25	425,338	–	425,338	–	–	–
	2005–2007	28 Apr 2005	5.33	–	501,782	501,782	–	–	–
Dr A B Hayward	2002–2004	6 Mar 2002	5.99	147,000	–	–	55,125	9 Feb 2005	5.49
	2003–2005	**17 Feb 2003**	**3.96**	**394,088**	**–**	**394,088**	**147,783**	**expected to vest Feb 2006**	
	2004–2006	25 Feb 2004	4.25	376,470	–	376,470	–	–	–
	2005–2007	28 Apr 2005	5.33	–	436,623	436,623	–	–	–
J A Manzoni	2002–2004	6 Mar 2002	5.99	160,000	–	–	60,000	9 Feb 2005	5.49
	2003–2005	**17 Feb 2003**	**3.96**	**394,088**	**–**	**394,088**	**147,783**	**expected to vest Feb 2006**	
	2004–2006	25 Feb 2004	4.25	376,470	–	376,470	–	–	–
	2005–2007	28 Apr 2005	5.33	–	436,623	436,623	–	–	–
Former directors									
R L Olver	2002–2004	18 Feb 2002	5.73	392,592	–	–	147,222	9 Feb 2005	5.49
	2003–2005	**17 Feb 2003**	**3.96**	**548,276**	**–**	**548,276**	**205,604**	**expected to vest Feb 2006**	

[a] BP's performance is measured against the oil sector. For the periods 2003-2005 and 2004-2006, the performance measure is SHRAM, which is measured against the FTSE All World Oil & Gas Index, and ROACE and EPS growth, which are measured against ExxonMobil, Shell, Total and Chevron. For the 2005-2007 period, the performance condition is TSR measured against ExxonMobil, Shell, Total and Chevron. Each performance period ends on 31 December of the third year.

[b] Represents awards of shares made, or expected to be made, at the end of the relevant performance period based on performance achieved under rules of the plan.

[c] Mr Conn elected to defer to 2006 the determination of whether LTPP awards should be made for the 2000-2002 performance period. As this period ended prior to his appointment as a director, the expected award is not included in this table.

PENSIONS

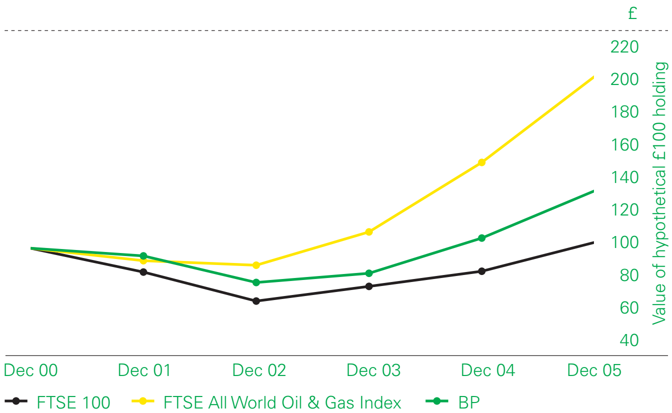
thousand

	Service at 31 Dec 2005	Accrued pension entitlement at 31 Dec 2005	Additional pension earned during the year ended 31 Dec 2005[a]	Transfer value of accrued benefit[b] at 31 Dec 2004 (A)	Transfer value of accrued benefit[b] at 31 Dec 2005 (B)	Amount of B-A less contributions made by the director in 2005
Lord Browne (UK)	39 years	£991	£47	£17,170	£19,979	£2,809
Dr D C Allen (UK)	27 years	£200	£17	£2,754	£3,433	£679
I C Conn (UK)	20 years	£147	£20	£1,542	£2,124	£582
Dr B E Grote (US)	26 years	$570	$105	$5,529	$6,681	$1,152
Dr A B Hayward (UK)	24 years	£207	£19	£2,680	£3,408	£728
J A Manzoni (UK)	22 years	£163	£15	£1,958	£2,518	£560

[a]Additional pension earned during the year includes an inflation increase of 3.5%.
[b]Transfer values have been calculated in accordance with version 8.1 of guidance note GN11 issued by the actuarial profession.

HISTORICAL TSR PERFORMANCE

This graph is included to meet a legislative requirement and shows the growth in the value of a hypothetical £100 holding in BP p.l.c. ordinary shares over five years relative to the FTSE 100 and to the FTSE All World Oil & Gas Index. These are considered to be the most relevant broad equity market indices for this purpose and the company is a constituent of both indices.



PAST DIRECTORS

During 2005, Mr Olver continued as a consultant to BP in relation to its activities in Russia and served as a BP-nominated director of TNK-BP Limited, a joint venture company owned 50% by BP. Under the consultancy agreement, he received £300,000 in fees in 2005 as well as reimbursement of costs and support for his role. He is also entitled to retain fees paid to him by TNK-BP up to a maximum of $120,000 a year for his role as a director, deputy chairman and chairman of the audit committee of TNK-BP Limited.

Part 2 – Non-executive directors' remuneration

POLICY ON NON-EXECUTIVE DIRECTORS' REMUNERATION

The board sets the level of remuneration for all non-executive directors within the limit approved from time to time by shareholders. In line with BP's governance policies, the remuneration of the chairman is set by the board rather than the remuneration committee, since the performance of the chairman is a matter for the board as a whole rather than any one committee.

The board has adopted the following policies to guide its current and future decision-making with regard to non-executive directors' remuneration:

- Within the limits set by the shareholders from time to time, remuneration should be sufficient to attract, motivate and retain world-class non-executive talent.
- Remuneration of non-executive directors is set by the board and should be proportional to their contribution towards the interests of the company.
- Remuneration practice should be consistent with recognized best-practice standards for non-executive directors' remuneration.
- Remuneration should be in the form of cash fees, payable monthly.
- Non-executive directors should not receive share options from the company.
- Non-executive directors should be encouraged to establish a holding in BP shares broadly related to one year's base fee, to be held directly or indirectly in a manner compatible with their personal investment activities, and any applicable legal and regulatory requirements.

ELEMENTS OF REMUNERATION

Non-executive directors' pay comprises cash fees, paid monthly, with increments for positions of additional responsibility, reflecting additional workload and consequent potential liability. For all non-executive directors, except the chairman, a fixed sum allowance is paid for transatlantic travel (or equivalent intercontinental travel) undertaken for the purpose of attending a board or board committee meeting. In addition, non-executive directors receive reimbursement of reasonable travel and related business expenses. No share or share option awards are made to any non-executive director in respect of service on the board.

LETTERS OF APPOINTMENT

Non-executive directors have letters of appointment, which recognize that, subject to the Articles of Association, their service is at the discretion of the shareholders. All directors stand for re-election at each annual general meeting.

NON-EXECUTIVE DIRECTORS' ANNUAL FEE STRUCTURE

The fees paid to non-executive directors are set by the board within the limit set by shareholders in accordance with the Articles. Shareholders approved an increase to this limit in 2004. All fees are fixed and paid in pounds sterling. Fees payable to non-executive directors were reviewed in 2005 by an ad hoc board committee comprising Mr Bryan (chairman), Dr Julius and Mr Burgmans. This ad hoc committee recommended an increase in fees to reflect the increase in director workload as well as increases in global market rates for independent/non-executive directors, since these fees were last reviewed in 2002. The board duly approved the recommended increases with effect from 1 January 2005.

£ thousand

	2005	2004
Chairman[a]	500[a]	390
Deputy chairman[b]	100[b]	85
Board member	75	65
Committee chairmanship fee	20	15
Transatlantic attendance allowance[c]	5	5

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

[b] The deputy chairman receives a £25,000 (2004 £20,000) increment on top of the standard board fee. In addition, he is eligible for committee chairmanship fees and the transatlantic attendance allowance. The deputy chairman is currently chairman of the audit committee.

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

LONG-TERM INCENTIVES (RESIDUAL)

The table on the next page sets out the residual entitlements of non-executive directors who were formerly non-executive directors of Amoco Corporation under the Amoco Non-Employee Directors' Restricted Stock Plan.

Information subject to audit

REMUNERATION OF NON-EXECUTIVE DIRECTORS £ thousand

Current directors	2005	2004
J H Bryan	110	100
A Burgmans	90	53
E B Davis, Jr	110	105
D J Flint[a]	90	n/a
Dr D S Julius	107	75
Sir Tom McKillop	90	38
Dr W E Massey	130	115
H M P Miles	90	75
Sir Ian Prosser	135	110
P D Sutherland	500	390
M H Wilson	105	95
Directors leaving the board in 2005		
C F Knight[b c]	30	90
Sir Robin Nicholson[b d e]	32	90

[a]Appointed on 1 January 2005.
[b]Retired at AGM on 14 April 2005.
[c]Also received a superannuation gratuity of £79,000 following his retirement.
[d]Also received £20,000 each year for serving as the board's representative on the BP technology advisory council.
[e]Also received a superannuation gratuity of £84,000 following his retirement.

AMOCO NON-EMPLOYEE DIRECTORS' RESTRICTED STOCK PLAN

Non-executive directors of Amoco Corporation were allocated restricted stock in the Amoco Non-Employee Directors' Restricted Stock Plan by way of remuneration for their service on the board of Amoco Corporation prior to its merger with BP in 1998. On merger, interests in Amoco shares in the plan were converted into interests in BP ADSs. Under the terms of the plan, the restricted stock will vest on the retirement of the non-executive director having reached age 70 or on earlier retirement at the discretion of the board. Since the merger, no further entitlements have accrued to any director under the plan. These residual interests require disclosure under the directors' remuneration report regulations 2002 as interests in a long-term incentive scheme.

	Interest in BP ADSs at 1 Jan 2005 and 31 Dec 2005[a]	Date on which director reaches age 70[b]
J H Bryan	5,546	5 Oct 2006
E B Davis, Jr	4,490	5 Aug 2014
Dr W E Massey	3,346	5 Apr 2008
M H Wilson	3,170	4 Nov 2007

[a]No awards were granted and no awards lapsed during the year. The awards were granted over Amoco stock prior to the merger but their notional weighted average market value at the date of grant (applying the subsequent merger ratio of 0.66167 of a BP ADS for every Amoco share) was $27.87 per BP ADS.
[b]For the purposes of the regulations, the date on which the director retires from the board at or after the age of 70 is the end of the qualifying period. If the director retires prior to this date, the board may waive the restrictions.

SUPERANNUATION GRATUITIES

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

The board made superannuation gratuity payments during the year to the following former directors: Mr Knight £79,000 and Sir Robin Nicholson £84,000 (who both retired in 2005) and Mr Maljers £18,000 (who retired in 2004). These payments were in line with the policy arrangements agreed in 2002 *(see below)*.

In 2002, the board revised its policy with respect to superannuation gratuities so that: (i) non-executive directors appointed to the board after 1 July 2002 would not be eligible for consideration for such a payment; and (ii) while non-executive directors in service at 1 July 2002 would remain eligible for consideration for a payment, service after that date would not be taken into account by the board in considering the amount of any such payment.

This directors' remuneration report was approved by the board and signed on its behalf by David J Jackson, company secretary, on 6 February 2006.

Board of directors

EXECUTIVE DIRECTORS

1 **The Lord Browne of Madingley, FREng,** Group Chief Executive

Lord Browne (57) joined BP in 1966 and subsequently held a variety of exploration and production and finance posts in the US, UK and Canada. He was appointed an executive director in 1991 and group chief executive in 1995. He is a non-executive director of Intel Corporation and Goldman Sachs Group Inc. He was knighted in 1998 and made a life peer in 2001.

2 **Dr D C Allen,** Group Chief of Staff

David Allen (51) 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 an executive vice president and group chief of staff in 2000 and an executive director of BP in 2003. He is a director of BP Pension Trustees Ltd.

3 **I C Conn,** Group Executive Officer, Strategic Resources

Iain Conn (43) joined BP in 1986. Following a variety of roles in oil trading, commercial refining, marketing, 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 July 2004. He was appointed to the board of Rolls-Royce Group plc in January 2005. He is chairman of BP Pension Trustees Ltd.

4 **Dr B E Grote,** Chief Financial Officer

Byron Grote (57) 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.

5 **Dr A B Hayward,** Chief Executive, Exploration and Production

Tony Hayward (48) joined BP in 1982. He became a director of exploration and production in 1997, the segment in which he had previously held a series of roles. In 2000, he was made group treasurer and an executive vice president in 2002. He was appointed chief operating officer for exploration and production in 2002 and an executive director of BP in 2003. He is a non-executive director of Corus Group.

6 **J A Manzoni,** Chief Executive, Refining and Marketing

John Manzoni (46) joined BP in 1983. He became group vice president for European marketing in 1999 and BP regional president for the eastern US in 2000. In 2001, he became an executive vice president and chief executive for BP's gas and power segment. He was appointed chief executive of the refining and marketing segment in 2002 and an executive director of BP in 2003. He is a non-executive director of SABMiller plc.

NON-EXECUTIVE DIRECTORS

7 **P D Sutherland, KCMG,** Chairman

Peter Sutherland (59) 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 nomination committees

8 **Sir Ian Prosser,** Deputy Chairman

Sir Ian (62) joined BP's board in 1997 and was appointed non-executive deputy chairman in 1999. He retired as chairman of Intercontinental Hotels Group PLC, previously Bass PLC, in 2003. He was a non-executive director of The Boots Company from 1984 to 1996, of Lloyds Bank PLC from 1988 to 1995 and of Lloyds TSB Group PLC from 1995 to 1999. In 2000, he was appointed a non-executive director of GlaxoSmithKline and in 2004 he was appointed a non-executive director of Sara Lee Corporation.

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

9 **J H Bryan**

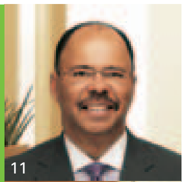
John Bryan (69) joined BP's board in 1998, having previously been a director of Amoco. He serves on the boards of General Motors Corporation and Goldman Sachs Group Inc. He retired as chairman of Sara Lee Corporation in 2001. He is chairman of Millennium Park Inc. in Chicago.

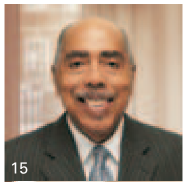
Member of the chairman's, remuneration and audit committees

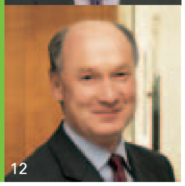
10 **A Burgmans**

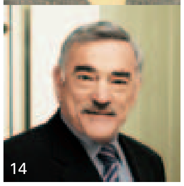
Antony Burgmans (59) joined BP's board in 2004. He was appointed to the board of Unilever in 1991. In 1999, he became chairman of Unilever NV and vice chairman of Unilever PLC. He was appointed non-executive chairman of Unilever NV and Unilever PLC in 2005. He is also a member of the supervisory board of ABN AMRO Bank NV.

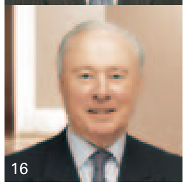
Member of the chairman's and ethics and environment assurance committees











11 **E B Davis, Jr**
Erroll B Davis, Jr (61) 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 July 2005. He continued as chairman of Alliant Energy until 1 February 2006, leaving to become chancellor of the University System of Georgia. He is a non-executive director of PPG Industries, Union Pacific Corporation and the US Olympic Committee.
Member of the chairman's, audit and remuneration committees

12 **D J Flint**
Douglas Flint (50) joined BP's board in January 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 advisory council of the International Accounting Standards Board.
Member of the chairman's and audit committees

13 **Dr D S Julius, CBE**
DeAnne Julius (56) 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 Lloyds TSB Group PLC, Serco and Roche Holdings SA.
Member of the chairman's committee and chairman of the remuneration committee

14 **Sir Tom McKillop**
Sir Tom McKillop (61) 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 31 December 2005. He was a non-executive director of Lloyds TSB Group PLC until 2004 and is deputy chairman of The Royal Bank of Scotland Group.
Member of the chairman's and remuneration committees

15 **Dr W E Massey**
Walter Massey (67) joined BP's board in 1998, having previously been a director of Amoco. He is president of Morehouse College, a non-executive director of Motorola, Bank of America and McDonald's Corporation and a member of President Bush's Council of Advisors on Science and Technology.
Member of the chairman's and nomination committees and chairman of the ethics and environment assurance committee

16 **H M P Miles, OBE**
Michael Miles (69) joined BP's board in 1994. In 1988, he became an executive director of John Swire & Sons Ltd. He was chairman of Swire Pacific between 1984 and 1988. He is chairman of Schroders plc, non-executive chairman of Johnson Matthey Plc and a director of BP Pension Trustees Ltd.
Member of the chairman's, audit and ethics and environment assurance committees

17 **M H Wilson**
Michael Wilson (68) joined BP's board in 1998, having previously been a director of Amoco. He was a member of the Canadian Parliament from 1979 to 1993 and held various ministerial posts, including Finance, Industry, Science, Technology and International Trade. He is chairman of UBS Canada and a non-executive director of Manulife Financial Corporation. He is an Officer of the Order of Canada.
Member of the chairman's, audit and ethics and environment assurance committees

CHANGES TO THE BOARD
Charles Knight and Sir Robin Nicholson retired on 14 April 2005.

COMPANY SECRETARY
David Jackson (53) was appointed company secretary in 2003. A solicitor, he is a director of BP Pension Trustees Ltd, a director of Business in the Community and a member of the Listing Authorities Advisory Committee.

Shareholdings and annual general meeting

REGISTER OF MEMBERS HOLDING BP ORDINARY SHARES AS AT 31 DECEMBER 2005

Range of holdings	Number of shareholders	Percentage of total shareholders	Percentage of total share capital
1 – 200	60,420	18.25	0.02
201 – 1,000	127,158	38.40	0.30
1,001 – 10,000	128,949	38.94	1.81
10,001 – 100,000	12,622	3.81	1.19
100,001 – 1,000,000	1,164	0.35	1.92
Over 1,000,000[a]	818	0.25	94.76
	331,131	100.00	100.00

[a] Includes JPMorgan Chase Bank, holding 31.07% of the total share capital as the approved depositary for ADSs, a breakdown of which is shown in the table below.

REGISTER OF HOLDERS OF AMERICAN DEPOSITARY SHARES AS AT 31 DECEMBER 2005[a]

Range of holdings	Number of ADS holders	Percentage of total ADS holders	Percentage of total ADSs
1 – 200	81,911	52.25	0.44
201 – 1,000	45,386	28.95	1.95
1,001 – 10,000	27,478	17.53	6.73
10,001 – 100,000	1,955	1.24	3.07
100,001 – 1,000,000	29	0.02	0.57
Over 1,000,000[b]	1	0.01	87.24
	156,760	100.00	100.00

[a] One ADS represents six ordinary shares.
[b] One of the holders of ADSs represents some 839,800 preference shareholders.

At 31 December 2005, there were also 1,588 preference shareholders.

SUBSTANTIAL SHAREHOLDINGS

At the date of this report, the company had been notified that JPMorgan Chase Bank, as depositary for American depositary shares (ADSs), holds interests through its nominee, Guaranty Nominees Limited, in 6,723,651,976 ordinary shares (31.07% of the company's ordinary share capital). Legal & General Group plc hold interests in 758,262,602 ordinary shares (3.61% of the company's ordinary share capital).

At the date of this report, the company has been notified of the following interests in preference shares: Co-operative Insurance Society Limited holds interests in 1,550,538 8% 1st preference shares (21.44% of that class) and 1,789,796 9% 2nd preference shares (32.7% of that class); The National Farmers Union Mutual Insurance Society Ltd hold interests in 945,000 8% 1st preference shares (13.07% of that class) and 987,000 9% 2nd preference shares (18.03% of that class); Prudential plc holds interests in 528,150 8% 1st preference shares (7.3% of that class) and 644,450 9% 2nd preference shares (11.77% of that class); Royal & SunAlliance Insurance plc holds interests in 287,500 8% 1st preference shares (3.97% of that class) and 250,000 9% 2nd preference shares (4.57% of that class); Ruffer Limited Liability Partnership holds interests in 750,000 9% 2nd preference shares (13.7% of that class).

It should be noted that the total preference shares in issue comprise only 0.39% of the company's total issued nominal share capital, the rest being ordinary shares.

ANNUAL GENERAL MEETING

The 2006 annual general meeting will be held on Thursday 20 April 2006 at 11.30 a.m. at ExCel London, One Western Gateway, Royal Victoria Dock, London E16 1XL. A separate notice, 'Engaging with us', convening the meeting, is sent to shareholders with this Report, together with an explanation of the items of special business to be considered at the meeting.

All resolutions of which notice has been given will be decided on a poll.

Ernst & Young LLP have expressed their willingness to continue in office as auditors and a resolution for their reappointment is included in the notice of the annual general meeting.

By order of the board
David J Jackson
Secretary
6 February 2006

Further information

ADMINISTRATION

If you have any queries about the administration of shareholdings, such as change of address, change of ownership, dividend payments, the dividend reinvestment plan or the ADS direct access plan, please contact the Registrar or ADS Depositary.

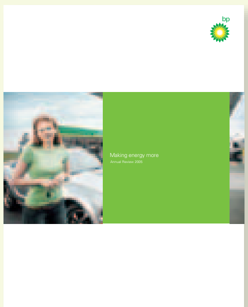
To elect to receive the Directors' Report and Annual Accounts in place of summary financial statements for all future financial years, please write to the Registrar.

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

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

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

PUBLICATIONS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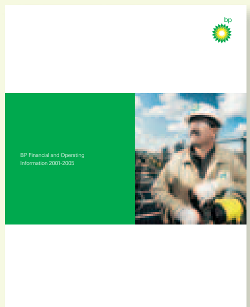
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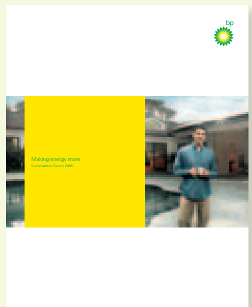
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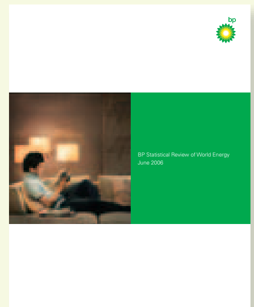
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1 www.bp.com/annualreview
BP Annual Review 2005 highlights our financial and operating performance.

2 www.bp.com/financialandoperating
BP Financial and Operating Information 2001-2005 includes five-year financial and operating data.

3 www.bp.com/sustainabilityreport
BP Sustainability Report 2005 explains our environmental and social commitments and performance.

4 www.bp.com/statisticalreview
BP Statistical Review of World Energy, published in June each year, reports on key global energy trends.

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