BP PLC
Form 20-F
June 28, 2004
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 20-F

(Mark One)

[ ] REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) or (g)

OF THE SECURITIES EXCHANGE ACT OF 1934
OR

[ü] **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)**

OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2003
OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to
Commission file number 1-6262

BP p.l.c.

(Exact name of Registrant as specified in its charter)

ENGLAND and WALES

(Jurisdiction of incorporation or organization)

1 St James s Square

London

SW1Y 4PD

England

(Address of principal executive offices)

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

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

New York Stock Exchange*

Pacific Exchange, Inc.*

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

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

None

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

None

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

Ordinary Shares of 25c each	**22,122,610,104**
Cumulative First Preference Shares of £1 each	**7,232,838**
Cumulative Second Preference Shares of £1 each	**5,473,414**

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

Yes ü No ____

Indicate by check mark which financial statement item the Registrant has elected to follow.

Item 17 ____ Item 18 ü

Table of Contents

TABLE OF CONTENTS

			Page
		Certain Definitions	4
Part I	Item 1	Identity of Directors, Senior Management and Advisors	7
	Item 2	Offer Statistics and Expected Timetable	7
	Item 3	Key Information	7
		Selected Financial Information	7
		Risk Factors	10
		Forward-Looking Statements	12
		Statements Regarding Competitive Position	12
		Special Notice	12
	Item 4	Information on the Company	13
		General	13
		Segmental Information	18
		Exploration and Production	20
		Gas, Power and Renewables	43
		Refining and Marketing	49
		Petrochemicals	58
		Other Businesses and Corporate	65
		Regulation of the Group s Business	67
		Environmental Protection	68
		Property, Plants and Equipment	75
		Organizational Structure	76
	Item 5	Operating and Financial Review and Prospects	78
		Group Operating Results	78
		Liquidity and Capital Resources	92
		Outlook	98
		Prospects	99
		Critical Accounting Policies and New Accounting Standards	120
	Item 6	Directors, Senior Management and Employees	128
		Directors and Senior Management	128
		Compensation	132
		Board Practices	148
		Employees	155
		Share Ownership	156
	Item 7	Major Shareholders and Related Party Transactions	158
		Major Shareholders	158
		Related Party Transactions	158
	Item 8	Financial Information	158
		Consolidated Statements and Other Financial Information	158
		Significant Changes	159
	Item 9	The Offer and Listing	159
	Item 10	Additional Information	161
		Memorandum and Articles of Association	161
		Material Contracts	165
		Exchange Controls and Other Limitations Affecting Security Holders	165
		Taxation	166
		Documents on Display	169
	Item 11	Quantitative and Qualitative Disclosures about Market Risk	170
	Item 12	Description of Securities Other Than Equity Securities	179

Table of Contents

TABLE OF CONTENTS

			Page
Part II	Item 13	Defaults, Dividend Arrearages and Delinquencies	180
	Item 14	Material Modifications to the Rights of Security Holders and Use of Proceeds	180
	Item 15	Controls and Procedures	180
	Item 16A	Audit Committee Financial Expert	181
	Item 16B	Code of Ethics	181
	Item 16C	Principal Accountant Fees and Services	182
	Item 16D	Exemptions from the Listing Standards for Audit Committees	183
	Item 16E	Purchases of Equity Securities by the Issuer and Affiliated Purchasers	183
Part III	Item 17	Financial Statements	184
	Item 18	Financial Statements	184
	Item 19	Exhibits	184

Table of Contents

CERTAIN DEFINITIONS

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

Oil and natural gas reserves

Proved oil and gas reserves Proved reserves are defined by the SEC in Rule 4-10(a) of Regulation S-X, paragraphs (2), (2i), (2ii) and (2iii). Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

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

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

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

(a) oil that may become available from known reservoirs but is classified separately as indicated additional reserves ;

(b) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;

(c) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and

(d) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

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

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

Table of Contents

Miscellaneous terms

ADR American Depositary Receipt.

ADS American Depositary Share.

Amoco The former Amoco Corporation and its subsidiaries.

Atlantic Richfield Atlantic Richfield Company and its subsidiaries.

Associated undertaking An undertaking in which the BP Group has a participating interest and over whose operating and financial policy the BP Group exercises a significant influence (presumed to be the case where 20% or more of the voting rights are held) and which is not a subsidiary undertaking.

Barrel 42 US gallons.

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

Burmah Castrol Burmah Castrol plc and its subsidiaries.

Cent or c One hundredth of the US dollar.

The Company BP p.l.c.

Liquids Crude oil, condensate and natural gas liquids.

Dollar or $ The US dollar.

FSA Financial Services Authority.

Gas Natural Gas.

Hydrocarbons Crude oil and natural gas.

Joint venture an entity in which the Group has a long-term interest and shares control with one or more co-venturers.

LNG Liquefied Natural Gas.

London Stock Exchange or LSE London Stock Exchange Limited.

LPG Liquefied Petroleum Gas.

MTBE Methyl Tertiary Butyl Ether.

NGL Natural Gas Liquid.

Noon Buying Rate The noon buying rate in New York City for cable transfers in pounds as certified for customs purposes by the Federal Reserve Bank of New York.

OECD Organization for Economic Cooperation and Development.

OPEC The Organization of Petroleum Exporting Countries.

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

Table of Contents

Pence or p One hundredth of a pound.

Pound , sterling or £ The pound sterling.

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

Subsidiary undertaking An undertaking in which the BP Group holds a majority of the voting rights.

Tonne 2,204.6 pounds.

UK United Kingdom of Great Britain and Northern Ireland.

UK GAAP Generally Accepted Accounting Practice in the UK.

Undertaking A body corporate, partnership or an unincorporated association, carrying on a trade or business.

US or USA United States of America.

US GAAP Generally Accepted Accounting Principles in the USA.

Table of Contents

PART I

ITEM 1 IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISORS

Not applicable.

ITEM 2 OFFER STATISTICS AND EXPECTED TIMETABLE

Not applicable.

ITEM 3 KEY INFORMATION

SELECTED FINANCIAL INFORMATION

Summary

This information has been extracted or derived from the audited financial statements of the BP Group presented elsewhere herein or otherwise included with BP p.l.c. s Annual Reports on Form 20-F for the relevant years which have been filed with the Securities and Exchange Commission, as reclassified to conform with the accounting presentation adopted in this annual report.

	Years ended December 31,				
	2003	2002	2001	2000	1999
	($ million except per share amounts)				
UK GAAP					
Income statement data					
Turnover	236,045	180,186	175,389	161,826	101,180
Less: joint ventures	3,474	1,465	1,171	13,764	17,614
Group turnover	232,571	178,721	174,218	148,062	83,566
Profit for the year	10,267	6,845	6,556	10,120	4,566
Per ordinary share: (cents)					
Profit for the year:					
Basic	46.30	30.55	29.21	46.77	23.55

Diluted	45.87	30.41	29.04	46.46	23.42
Dividends per share (cents)	26.00	24.00	22.00	20.50	20.00
Dividends per share (pence)	15.517	15.638	15.436	13.791	12.339
Ordinary share data (a)					
Average number outstanding of 25 cents ordinary shares (shares million undiluted)	22,171	22,397	22,436	21,638	19,386
Average number outstanding of 25 cents ordinary shares (shares million diluted)	22,429	22,504	22,574	21,783	19,497
Balance sheet data					
Total assets	177,572	159,125	141,970	144,862	89,481
Net assets	77,063	70,047	65,759	66,152	38,092
Share capital	5,552	5,616	5,629	5,653	4,892
BP shareholders interest	75,938	69,409	65,161	65,584	37,031
Finance debt due after more than one year	12,869	11,922	12,327	14,772	9,644
Debt to borrowed and invested capital (b)	14%	15%	16%	18%	20%

7

Table of Contents

	Years ended December 31,				
	2003	2002	2001	2000	1999
	($ million except per share amounts)				
US GAAP					
Income statement data					
Revenues	232,571	178,721	174,218	148,062	83,566
Profit for the year	13,143	8,397	4,164	10,183	4,596
Comprehensive income	20,088	10,544	2,649	7,730	3,674
Profit per ordinary share: (cents)					
Basic	59.27	37.48	18.55	47.05	23.70
Diluted	58.70	37.30	18.44	46.74	23.56
Profit per American Depositary Share: (cents)					
Basic	355.62	224.88	111.30	282.30	142.20
Diluted	352.20	223.80	110.64	280.44	141.36
Balance sheet data					
Total assets	186,359	164,103	145,990	151,966	90,262
Net assets	80,889	67,759	62,920	66,122	38,899
BP shareholders interest	79,764	67,121	62,322	65,554	37,838

(a) The number of ordinary shares shown have been used to calculate per share amounts for both UK and US GAAP.

(b) Finance debt due after more than one year, as a percentage of such debt plus BP and minority shareholders interests.

8

Table of Contents

Dividends

BP has paid dividends on its ordinary shares in each year since 1917. In 2000 and thereafter, dividends were, and are expected to continue to be, paid quarterly in March, June, September and December. Until their shares have been exchanged for BP ADSs, Amoco and Atlantic Richfield shareholders do not have the right to receive dividends.

BP currently announces dividends for ordinary shares in US dollars and states an equivalent pounds sterling dividend. Dividends on BP ordinary shares will be paid in pounds sterling and on BP ADSs in US dollars. The rate of exchange used to determine the sterling amount equivalent is the average of the forward exchange rate in London over the five business days prior to the announcement date. The directors may choose to declare dividends in any currency provided that a sterling equivalent is announced, but it is not the Company s intention to change its current policy of announcing dividends on ordinary shares in US dollars.

The following table shows dividends announced by the Company per ADS for each of the past five years, together with the refund but before deduction of withholding taxes as described in Item 10 Additional Information Taxation on page 166. Refund means an amount equal to the tax credit available to individual shareholders resident in the UK in respect of such dividend, less a withholding tax equal to 15% (but limited to the amount of the tax credit) of the aggregate of such tax credit and such dividend.

For dividends paid after April 30, 2004, there will be no refund available to shareholders resident in the US. Refer to Item 10 Additional Information Taxation for more information.

		Quarterly				
Dividends per American Depositary Share (a)		First	Second	Third	Fourth	Total
1999	UK pence	20.5	20.8	20.2	20.8	82.3
	US cents	33.3	33.3	33.3	33.4	133.3
	Can. cents	48.7	50.1	48.6	48.5	195.9
2000	UK pence	21.5	22.3	24.0	24.1	91.9
	US cents	33.3	33.3	35.0	35.0	136.6
	Can. cents	49.7	49.8	53.6	53.2	206.3
2001	UK pence	24.4	26.1	25.4	27.0	102.9
	US cents	35.0	36.7	36.7	38.3	146.7
	Can. cents	53.7	56.0	58.5	61.0	229.2
2002	UK pence	27.0	25.8	26.0	25.4	104.2
	US cents	38.3	40.0	40.0	41.7	160.0
	Can. cents	60.1	63.0	62.3	63.8	249.2
2003	UK pence	26.3	26.9	25.7	24.5	103.4
	US cents	41.7	43.3	43.3	45.0	173.3
	Can. cents	60.3	60.0	56.8	59.7	236.8

(a) With effect from October 4, 1999 BP split (or subdivided) its ordinary share capital. As a result, the number of BP ordinary shares held at the close of business on Friday October 1, 1999, doubled, and holders of ADSs received a two-for-one stock split.

A dividend reinvestment plan was introduced with effect from the fourth quarterly 1998 dividend, whereby holders of BP ordinary shares can elect to reinvest the net cash dividend in shares purchased on the London Stock Exchange. This plan is not available to any person resident in the USA or Canada, or in any jurisdiction outside the UK where such an offer requires compliance by the Company with any governmental or regulatory procedures or any similar formalities.

A dividend reinvestment plan is, however, available for holders of ADSs through JPMorgan Chase Bank.

Future dividends will be dependent upon future earnings, the financial condition of the Group, the Risk Factors set out below, and other matters which may affect the business of the Group set out in Item 5 Operating and Financial Review and Prospects on page 78.

Table of Contents

RISK FACTORS

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

External 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 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 BP 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 which could have a significant effect on the BP Group s results of operations in the period in which it occurs.

Regulatory Risks: 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 or cancellation 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. 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. Fluctuation in exchange rates can therefore give rise to foreign exchange exposures.

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.

Table of Contents

Reputational 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 minimum 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.

Operational Risks

Inherent in our operations are hazards which require continual oversight and control. If operational risks materialized it could result in loss of life, damage to the environment or loss of production.

Drilling and Production Risk: Exploration and production require high levels of investment and have particular economic risks and opportunities. 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.

Table of Contents

FORWARD-LOOKING STATEMENTS

In order to utilize the Safe Harbor provisions of the United States Private Securities Litigation Reform Act of 1995, BP is providing the following cautionary statement. This document contains certain forward-looking statements with respect to the financial condition, results of operations and businesses of BP and certain of the plans and objectives of BP with respect to these items. These statements may generally, but not always, be identified by the use of words such as will , expects , is expected to , should , may , is likely to , intends , believes , plan similar expressions. In particular, among other statements, (i) certain statements in Item 4 Information on the Company and Item 5 Operating and Financial Review and Prospects with regard to management aims and objectives, future capital expenditure, future hydrocarbon production volume, date or period(s) in which production is scheduled or expected to come on stream or a project or action is scheduled or expected to be completed, capacity of planned plants or facilities and impact of health, safety and environmental regulations; (ii) the statements in Item 4 Information on the Company with regard to planned expansion, investment or other projects and future regulatory actions; and (iii) the statements in Item 5 Operating and Financial Review and Prospects, including under Liquidity and Capital Resources with regard to future cash flows, future levels of capital expenditure and divestments, working capital, expected payments under contractual and commercial commitments; under Outlook with regard to global and certain regional economies, oil and gas prices and realizations, expectations for supply and demand, refining and marketing margins, petrochemical margins and sales; and under Prospects with regard to the plans and prospects of the Group, forward-looking rules of thumb, changes to BP s financial reporting due to the adoption of FRS 17, operating capital employed/capital in service, cash returns, underlying cash flows, finding and development costs, BP s intentions with respect to shareholder distributions and share buybacks, gearing, opportunities for material acquisitions and costs for providing pension and other postretirement benefits are all forward-looking in nature.

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

STATEMENTS REGARDING COMPETITIVE POSITION

Statements made in Item 4 Information on the Company, referring to BP s competitive position are based on the Company s belief, and in some cases rely on a range of sources, including investment analysts reports, independent market studies and BP s internal assessments of market share based on publicly available information about the financial results and performance of market participants.

SPECIAL NOTICE

The Company has received comments from the Staff of the SEC relating to our Annual Report on Form 20-F for the year ended December 31, 2002, and as of the date of filing this 2003 Form 20-F, the SEC review process is still ongoing.

Table of Contents

ITEM 4 INFORMATION ON THE COMPANY

GENERAL

Unless otherwise indicated, information in this Item reflects 100% of the assets and operations of the Company and its subsidiaries which were consolidated at the date or for the periods indicated, including minority interests. Also, unless otherwise indicated, figures for business turnover include sales between BP businesses.

BP was created on December 31, 1998 by the merger of Amoco Corporation, incorporated in Indiana, USA, in 1889, and The British Petroleum Company p.l.c., registered in 1909 in England and Wales. The resulting company, BP p.l.c. is a public limited company, registered in England and Wales.

BP is one of the world s leading oil companies on the basis of market capitalization and proved reserves. Our worldwide headquarters is located in London, UK. Our registered address is:

BP p.l.c.

1 St James s Square

London SW1Y 4PD

United Kingdom

Tel: +44 (0)20 7496 4000

Internet address: www.bp.com

Our agent in the USA is:

BP America Inc.

4101 Winfield Road

Warrenville, Illinois 60555

Tel: +1 630 821 2222

Overview of the Group

Our operating business segments are Exploration and Production; Gas, Power and Renewables; Refining and Marketing; and Petrochemicals. Exploration and Production s activities include oil and natural gas exploration and field development and production (upstream activities), together with pipeline transportation and natural gas processing (midstream activities). Gas, Power and Renewables activities include marketing and trading of natural gas, NGL, new market development and LNG, and solar and renewables. The activities of Refining and Marketing include oil supply and trading as well as refining and marketing (downstream activities). Petrochemicals activities include manufacturing, marketing and distribution. The Group provides high quality technological support for all its businesses through its research and engineering activities.

These segments fall into two groupings: the Resources Business comprising Exploration and Production; and Customer Facing Businesses comprising Refining and Marketing, Petrochemicals and Gas, Power and Renewables.

The Group s operating business segments are managed on a global basis and not on a regional basis. Geographical information for the Group and segments is given to provide additional information for investors, but does not reflect the way BP manages its activities. Information by geographical area is provided for production and reserves in response to the requirements of Appendix A to Item 4D of Form 20-F.

Table of Contents

We have well established operations in Europe, the USA, Canada, South America, Australasia and parts of Africa. Currently, more than 70% of the Group s capital is invested in Organization for Economic Cooperation and Development (OECD) countries with just under 40% of our fixed assets located in the USA, and just under 30% located in the UK and the Rest of Europe.

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

In Exploration and Production we have upstream interests in 25 countries. In addition to our drive to maximize the value of our existing portfolio we are creating new profit centres. Exploration and Production activities are managed through operating units which are accountable for the day-to-day management of the segment s activities. An operating unit is accountable for one or more fields. Profit centres comprise one or more operating units. Profit centres are, or are expected to become, areas that provide significant production and income for the segment. Our new profit centres are in the Deepwater Gulf of Mexico, Trinidad, Angola, Algeria, Azerbaijan, Russia and Asia Pacific, where we believe we have competitive advantage and which we believe provide the foundation for volume growth and improved margins in the future. We also have significant midstream activities to support our upstream interests.

In Gas, Power and Renewables, we have growing marketing and trading businesses in North America (USA and Canada), the UK and the rest of Europe. Our marketing and trading activities include natural gas, LNG, NGL and power. Our international natural gas monetization activities, which are our efforts to identify and capture worldwide opportunities to sell our upstream natural gas resources, are focused on growing natural gas markets including the USA, Canada, Spain and many of the emerging markets of the Asia Pacific region, notably China. We are involved in power projects in the USA, UK, Spain and South Korea.

In Refining and Marketing we have a strong presence in the USA. We market under the Amoco and BP brands in the Midwest, East, and Southeast, and under the ARCO brand on the West Coast. In Europe we have a strong retail position and increased our presence in 2002 by acquiring Veba Oil (Veba). The Veba transaction expanded our refining position in Germany and our marketing position in Germany and Central Europe. Veba markets gasoline under the Aral brand, which is now our principal retail brand in Germany and in the Czech Republic. We have established or are growing businesses elsewhere in the world under the BP brand.

In Petrochemicals, we are the world s third largest petrochemical company, based on production capacity, with strong manufacturing and marketing bases in the USA and Europe. We are growing in the Asia Pacific region, where we already have interests in a number of production facilities. Our strategy is focused on seven core products, with the aim of providing world-class performance in all aspects of our activities. We are now managing our portfolio in two distinct parts Aromatics and Acetyls (A&A), comprising PTA, PX and acetic acid, and Olefins and Derivatives (O&D) comprising ethylene and related co-products, polypropylene, HDPE and acrylonitrile. On April 27, 2004 we announced our intention to set up a separate corporate entity for the O&D businesses. It is our intention to make a public offering of this new entity at an appropriate time. Based on the estimated lead time required for such a transaction, and depending on market circumstances, we are aiming to make such an offering in the second half of 2005. We intend to retain and grow the A&A businesses, which will be transferred to the Refining and Marketing segment on January 1, 2005.

Acquisitions and Disposals

There were no significant acquisitions in 2001. Disposals in 2001 comprised a number of small transactions, with total proceeds of $2,903 million.

Table of Contents

With effect from February 1, 2002, BP acquired a majority stake in Veba from E.ON. Veba owns Aral, Germany s biggest fuels retailer. BP paid E.ON $1.6 billion in cash and assumed some $1.0 billion of debt in return for 51% and operational control of Veba. Under the terms of the agreement, E.ON had the option to require BP to buy the remaining 49% of Veba.

On June 30, 2002, BP purchased the remaining 49% of Veba from E.ON for $2.4 billion. Separately, E.ON acquired BP s wholly-owned subsidiary Gelsenberg, which held a 25.5% stake in Germany s largest natural gas distributor, Ruhrgas, for $2.3 billion.

As a condition of regulatory approval of the deal, BP was required to dispose of 4% of the combined 26.5% retail market share of BP and Aral in Germany, 45% of its stake in the Bayernoil refinery, two of its three shareholdings in the ARG ethylene pipeline, and to make it possible for a new entrant to supply aviation fuel on competitive terms at Frankfurt airport. During 2003, BP fully complied with the conditions imposed.

Separately, BP and E.ON sold the bulk of Veba s oil and natural gas exploration and production business to Petro-Canada for $1.6 billion in the second quarter of 2002.

In addition to the sale of Veba s exploration and production business, 2002 disposal proceeds of $6,782 million included $2,338 million from the sale of our investment in Ruhrgas, with the balance of the proceeds coming from a number of other transactions.

In August 2003, BP and Alfa Group and Access-Renova (AAR) completed a transaction first announced in February 2003 to create the third largest oil company operating in Russia based on production volume. The company, TNK-BP, is a 50:50 joint venture between BP and AAR, and operates in Russia and the Ukraine. BP s share of the result of the TNK-BP joint venture has been included within the Exploration and Production segment from August 29, 2003.

AAR contributed its holdings in TNK and Sidanco, its share of Rusia Petroleum, its stake in the Rospan gasfield in West Siberia and its interest in the Sakhalin IV and V exploration licence to the joint venture. BP contributed its holding in Sidanco, its stake in Rusia Petroleum and its holding in the BP Moscow retail network. Neither AAR s association with Slavneft, nor BP s interest in LukArco or the Russian elements of BP s international businesses such as lubricants, marine and aviation were included in this transaction.

In addition, BP paid AAR $2.6 billion in cash upon completion of the transaction, which was subsequently reduced by receipt of pre-acquisition dividends net of transaction costs of $0.3 billion, and subject to the terms of its agreement with AAR, will pay three annual tranches of $1.25 billion in BP shares, valued at market prices prior to each annual payment. BP s net investment in TNK-BP following this transaction was $6.7 billion.

In January 2004, BP and AAR completed a subsequent transaction to include AAR s 50% stake in Slavneft within TNK-BP, at which time BP paid $1.35 billion to AAR. Slavneft was previously held equally by AAR and Sibneft. TNK-BP and Sibneft will continue to work together to finalize an agreement to split the main assets of Slavneft between the two companies.

Disposal proceeds in 2003 amounted to $6,432 million, and resulted primarily from the sale of various upstream interests and completion of divestments required as a condition of approval of the Veba acquisition.

On January 13, 2004, BP sold its 2% stake in PetroChina Company Limited (PetroChina) for $1.65 billion. On February 10, 2004 we sold our 2.1% stake in Sinopec for $0.7 billion.

Table of Contents

Financial and Operating Information

The following table summarizes the Group s turnover, profit and capital expenditure for the last five years and total assets at the end of each of those years.

	Years ended December 31,				
	2003	2002	2001	2000	1999
			($ million)		
Turnover	236,045	180,186	175,389	161,826	101,180
Less: joint ventures	3,474	1,465	1,171	13,764	17,614
Group turnover (sales to third parties)	232,571	178,721	174,218	148,062	83,566
Total operating profit (a)	16,429	11,375	14,127	18,407	10,622
Profit for the year*	10,267	6,845	6,556	10,120	4,566
Capital expenditure and acquisitions	20,075 (b)	19,111 (b)	14,124	47,613 (b)	7,345 (c)
Total assets	177,572	159,125	141,970	144,862	89,481

* After minority shareholders interest

(a) Operating profit is a UK GAAP measure of trading performance. It excludes profits and losses on the sale of fixed assets and businesses or termination of operations and fundamental restructuring costs, interest expense and taxation.

(b) Capital expenditure and acquisitions for 2003 includes $5,794 million for the acquisition of our interest in TNK-BP, for 2002 includes $5,038 million for the acquisition of Veba, for 2000 includes $27,506 million for the acquisition of Atlantic Richfield and $8,936 million for other significant one-off cash investments.

(c) Capital expenditure and acquisitions in 1999 reflected reduced investment following the merger of BP and Amoco.

With the exception of the Atlantic Richfield acquisition, which was a share transaction, all capital expenditure and acquisitions during the last five years have been financed from cash flow from operations, disposal proceeds and external financing.

Information for 2003, 2002 and 2001 concerning the profits and assets attributable to the businesses and to the geographical areas in which the Group operates is set forth in Item 18 Financial Statements Note 47 on page F-87.

Table of Contents

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

	Years ended December 31,				
	2003	2002	2001	2000	1999
Total crude oil production (thousand barrels per day) (a)	2,121	2,018	1,931	1,928	2,061
Total natural gas production (million cubic feet per day) (a)	8,613	8,707	8,632	7,609	6,067
Estimated net proved crude oil reserves (million barrels) (b)	7,214	7,762	7,217	6,508	6,535
Estimated net proved natural gas reserves (billion cubic feet) (b)	45,155	45,844	42,959	41,100	33,802
Total estimated net proved crude oil reserves (million barrels) (c)	10,081	9,165	8,376	7,643	7,572
Total estimated net proved natural gas reserves (billion cubic feet) (d)	48,024	48,789	46,175	43,918	35,526

(a) Includes BP s share of equity-accounted entities.

(b) Net proved reserves of crude oil and natural gas exclude production royalties due to others, whether royalty is payable in cash or in kind, and reserves of equity-accounted entities.

(c) Including reserves of equity-accounted entities. Includes 152 million barrels (17 million barrels at December 31, 2002 and 20 million barrels at December 31, 2001) in respect of the 30% minority interest in BP Trinidad and Tobago LLC and the 5.4% minority interest held in subsidiaries of TNK-BP.

(d) Including reserves of equity-accounted entities. Includes 4,505 billion cubic feet of natural gas (1,185 billion cubic feet at December 31, 2002 and 1,258 billion cubic feet at December 31, 2001) in respect of the 30% minority interest in Trinidad and Tobago LLC and the 5.4% minority interest held in subsidiaries of TNK-BP.

During 2003, 1,289 million barrels of oil and natural gas, on an oil equivalent* basis (mmboe), were added to BP s proved reserves (excluding purchases, sales and equity-accounted entities), more than replacing the volume produced. After allowing for production, which amounted to 1,085 mmboe, BP s proved reserves, excluding equity-accounted entities, increased to 14,999 mmboe. These proved reserves are mainly located in the USA (40%), Rest of Americas (23%) and the UK (11%).

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

Table of Contents

SEGMENTAL INFORMATION

The following tables show turnover and profit before interest and tax by business and by geographical area for the years ended December 31, 2003, 2002 and 2001.

Turnover (a)	2003 Total sales	2003 Sales between businesses	2003 Sales to third parties	2002 Total sales	2002 Sales between businesses	2002 Sales to third parties	2001 Total sales	2001 Sales between businesses	2001 Sales to third parties
		($ million)			($ million)			($ million)	
By business									
Exploration and Production	31,341	23,279	8,062	25,753	18,556	7,197	28,229	19,660	8,569
Gas, Power and Renewables	65,445	1,963	63,482	37,357	1,320	36,037	39,442	2,954	36,488
Refining and Marketing	149,477	4,448	145,029	125,836	3,366	122,470	120,233	2,903	117,330
Petrochemicals	16,075	592	15,483	13,064	557	12,507	11,515	233	11,282
Other businesses and corporate	515		515	510		510	549		549
Group turnover	262,853	30,282	232,571	202,520	23,799	178,721	199,968	25,750	174,218
Share of joint venture sales			3,474			1,465			1,171
			236,045			180,186			175,389

	2003 Total sales	2003 Sales between areas	2003 Sales to third parties	2002 Total sales	2002 Sales between areas	2002 Sales to third parties	2001 Total sales	2001 Sales between areas	2001 Sales to third parties
		($ million)			($ million)			($ million)	
By geographical area									
UK (b)	54,971	15,275	39,696	48,748	14,673	34,075	47,618	13,467	34,151
Rest of Europe	50,582	8,672	41,910	46,518	7,980	38,538	36,701	7,603	29,098
USA	108,910	2,169	106,741	80,381	2,099	78,282	84,696	939	83,757
Rest of World	52,498	8,274	44,224	34,401	6,575	27,826	33,911	6,699	27,212
	266,961	34,390	232,571	210,048	31,327	178,721	202,926	28,708	174,218
Share of joint venture sales									
UK			144			129			13
Rest of Europe			290			298			30

USA	177	236	318
Rest of World	2,863	802	810
	3,474	1,465	1,171

(a) Turnover to third parties is stated by origin, which is not materially different from turnover by destination. Transfers between Group companies are made at market prices, taking into account the volumes involved.

(b) UK area includes the UK-based international activities of Refining and Marketing.

Table of Contents

Analysis of profit	Group operating profit (a)	Joint ventures	Associated undertakings	Total operating profit (a)	Exceptional items (b)	Profit before interest and tax
			($ million)			
Year ended December 31, 2003						
By business						
Exploration and Production	12,754	914	272	13,940	913	14,853
Gas, Power & Renewables	481		(3)	478	(6)	472
Refining and Marketing	2,128	29	135	2,292	(213)	2,079
Petrochemicals	550	(19)	92	623	38	661
Other businesses and corporate	(922)		18	(904)	99	(805)
	14,991	924	514	16,429	831	17,260
By geographical area						
UK (c)	2,590	(19)	14	2,585	717	3,302
Rest of Europe	1,966		12	1,978	(151)	1,827
USA	5,485	27	79	5,591	(347)	5,244
Rest of World	4,950	916	409	6,275	612	6,887
	14,991	924	514	16,429	831	17,260
Year ended December 31, 2002						
By business						
Exploration and Production	8,598	343	268	9,209	(726)	8,483
Gas, Power & Renewables	298		107	405	1,551	1,956
Refining and Marketing	1,717	24	180	1,921	613	2,534
Petrochemicals	551	(20)	10	541	(256)	285
Other businesses and corporate	(753)		52	(701)	(14)	(715)
	10,411	347	617	11,375	1,168	12,543
By geographical area						
UK (c)	1,788	(14)	10	1,784	(88)	1,696
Rest of Europe	1,856	(2)	132	1,986	1,817	3,803
USA	3,305	17	136	3,458	(242)	3,216
Rest of World	3,462	346	339	4,147	(319)	3,828
	10,411	347	617	11,375	1,168	12,543
Year ended December 31, 2001						
By business						
Exploration and Production	11,796	373	186	12,355	195	12,550
Gas, Power & Renewables	223		184	407		407
Refining and Marketing	1,712	83	195	1,990	471	2,461
Petrochemicals	(201)	(17)	116	(102)	(297)	(399)
Other businesses and corporate	(598)		75	(523)	166	(357)
	12,932	439	756	14,127	535	14,662

By geographical area						
UK (c)	2,435	(5)	13	2,443	(319)	2,124
Rest of Europe	1,138	(4)	236	1,370	33	1,403
USA	5,619	77	186	5,882	289	6,171
Rest of World	3,740	371	321	4,432	532	4,964
	12,932	439	756	14,127	535	14,662

(a) Group operating profit and total operating profit are before interest expense, which is attributable to the corporate function. Transfers between Group companies are made at market prices taking into account the volumes involved.

(b) Exceptional items comprise profit or loss on the sale of fixed assets and businesses or termination of operations.

(c) UK area includes the UK-based international activities of Refining and Marketing.

Table of Contents

EXPLORATION AND PRODUCTION

The activities of our Exploration and Production business include oil and natural gas exploration and field development and production the upstream activities as well as the management of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities the midstream activities. We have Exploration and Production interests in 25 countries. Areas of activity include the USA, UK, Norway, Canada, South America, Africa, the Middle East and Asia Pacific. Production during 2003 came from 23 countries. Our most significant midstream activities are in three major pipelines the Trans Alaska Pipeline System (TAPS, BP 46.9%); the Forties Pipeline System (FPS, BP 100%) and the Central Area Transmission System pipeline (CATS, BP 29.5%) both in the UK sector of the North Sea; and three major LNG plants the Atlantic LNG plant in Trinidad (BP 34% in Train 1, 42% in Trains 2 and 3, and 38% in Train 4), in Indonesia through our interests in the Sanga-Sanga Production Sharing Agreement (PSA, BP 38%), which supplies natural gas to the Bontang LNG plant and in Australia through our share of LNG from the North West Shelf natural gas development (BP 16.7%).

With effect from January 1, 2004, we have transferred certain of our Natural Gas Liquid processing plants to the Gas, Power and Renewables segment in order to consolidate the management of our global NGL activity. This will have no impact on the Exploration and Production segment s reported production. Our 2003 results have not been restated to reflect this transfer. The impact that this would have had on our 2003 segment results is shown under Transfer of Natural Gas Liquids Activities on page 112 in Item 5 Operating and Financial Review and Prospects Group Operating Results.

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Turnover (a)	31,341	25,753	28,229
Total operating profit	13,940	9,209	12,355
Total assets	79,344	72,801	70,017
Capital expenditure and acquisitions	15,452	9,699	8,861
		($ per barrel)	
Average BP crude oil realizations (b)	28.23	24.06	23.27
Average BP NGL realizations (b)	19.26	12.85	16.27
Average BP liquids realizations (b) (c)	27.25	22.69	22.50
Average West Texas Intermediate oil price	31.06	26.14	25.89
Average Brent oil price	28.83	25.03	24.44
		($ per thousand cubic feet)	
Average BP natural gas realizations (b)	3.39	2.46	3.30
Average BP US natural gas realizations (b)	4.47	2.63	3.99
		($ per mmbtu)	
Average Henry Hub gas price (d)	5.37	3.22	4.26

(a) Excludes BP s share of joint venture turnover of $2,587 million in 2003, $539 million in 2002 and $666 million in 2001.

(b) The Exploration and Production business does not undertake any hedging activity. Consequently, realizations reflect the market price achieved.

(c) Crude oil and natural gas liquids.

(d) Henry Hub First of Month Index.

Table of Contents

Our upstream activities are divided between existing profit centres that is our operations in Alaska, Egypt, Latin America (including Argentina, Brazil, Colombia, Mexico and Venezuela), Middle East (including Abu Dhabi, Sharjah and Pakistan), North America Gas (Onshore US, the Gulf of Mexico Shelf and Canada) and the North Sea (UK, Netherlands and Norway); and new profit centres that is our operations in Asia Pacific (Australia, Vietnam, Indonesia and China), Azerbaijan, Algeria, Angola, Trinidad, Deepwater Gulf of Mexico and Russia.

The Exploration and Production strategy is to:

- create new profit centres by accessing areas with the potential for large oil and natural gas fields; exploring successfully and pursuing only the best projects for development;
- manage the performance of producing assets by investing only in the best available opportunities and optimizing operating efficiency; and
- sell assets that are no longer strategic to us and have greater value to others.

This strategy is underpinned by a focus on investing in a portfolio of large, lower-cost oil and natural gas fields chosen for their potentially strong return on capital employed. We seek to manage those assets safely with maximum capital and operating efficiency. We are currently developing new profit centres in which we have a distinctive position. These new profit centres augment the production assets in our existing profit centres, providing greater reach, investment choice and opportunity for growth.

In support of growth, 2003 capital expenditure and acquisitions was $15.5 billion, including $5.8 billion for the purchase of our interest in TNK-BP. 2002 capital expenditure and acquisitions at $9.7 billion was 9% higher than the 2001 level of $8.9 billion. Excluding acquisitions, capital expenditure in 2003 was $9.7 billion compared with $9.3 billion in 2002 and $8.6 billion in 2001. Development expenditure incurred in 2003, excluding midstream activities, was $7,547 million compared with $7,235 million in 2002 and $6,858 million in 2001. This reflects the investment we have been making in our new profit centres and the development phase on many of our major projects. Capital expenditure excluding acquisitions for 2004 is planned to be approximately $9 billion.

Upstream Activities

Exploration

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

Our exploration and appraisal costs in 2003 were $826 million compared to $1,108 million in 2002. About 34% of 2003 exploration and appraisal capital was directed towards appraisal activity as we delineated the discoveries made during 2000, 2001, and 2002. In 2003, we participated in 74 gross (32 net) exploration and appraisal wells in 19 countries. The principal areas of activity were Angola, Egypt and the USA.

Total exploration expense in 2003 of $542 million (2002, $644 million) includes the write-off of unsuccessful drilling activity in Colombia (Niscota - $62 million) and in Brazil (Reki - $30 million).

In 2003, we obtained upstream rights in several new tracts, which include the following:

In Egypt, BP were awarded six new blocks in the Gulf of Suez and northern Red Sea.

In the Gulf of Mexico, BP was successful in the Outer Continental Shelf Lease Sales 185 and 187 with bids on 80 blocks, of which 58 were won, for an overall success rate of 73%. BP also gained leases in Louisiana state waters where we were 100% successful in purchasing the blocks we bid on.

Table of Contents

In 2003, we were involved in discoveries in Angola, Azerbaijan, Egypt and the USA. In most cases, reserve bookings from these fields will depend on the results of ongoing technical and commercial evaluations, including appraisal drilling. Our 2003 discoveries included the following:

- In Angola, BP made further discoveries in the ultra deep water (greater than 1,500 metres) acreage with the Saturno and Marte wells in Block 31 (BP 26.7% and operator), and in Block 18 (BP 50% and operator) with the Cesio and Chumbo discoveries. Continued success was experienced in the established partner-operated deepwater blocks; in Block 15 (BP 26.7%) the Clochas, Kakocha and Tchihumba discoveries, and in Block 17 (BP 16.7%) the Hortensia and Acacia discoveries.

- In Egypt, BP successfully appraised the 2002 Ruby discovery with the Ruby-2 well in the West Mediterranean Deep Water Concession (BP 80%) in the Nile Delta. In the Gulf of Suez, BP drilled the discovery well Saqqara-1 in the LL87 block. This was the largest oil discovery in the Gulf of Suez in nearly 14 years.

- In the Deepwater Gulf of Mexico, a discovery was made with the Tubular Bells well (BP 50% and operator) in the Mississippi Canyon.

- In Azerbaijan a deeper reservoir was discovered in the Shah Deniz field.

2004 activity has resulted in further discoveries with the Bavuca well in Angola Block 15 (BP 26.7%) and in Egypt with the Raven 1 well in the North Alexandria Concession (BP 60% and operator) and the Taurt well in the Ras El Barr concession (BP 50% and operator).

Reserves and Production

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

BP has an internal process to control the quality of reserve bookings which forms part of an 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 key 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.

Table of Contents

The second key element is the capital allocation processes whereby delegated authority is exercised to commit to capital projects that are consistent with the delivery of the Group s business plan. A formal review process exists to review that both technical and commercial criteria are met prior to the commitment of capital to projects.

The third key 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 key 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 and final key element is that we have 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 70% of the BP reserves base undergoes central review every two years and more than 80% is reviewed every four years.

There is no direct link between compensation for executive directors and reserves replacement. Below the level of the executive director in the Exploration and Production segment, no specific portion of compensation bonuses has been directly related to oil and gas reserves targets. Additions to proved reserves was one of several indicators by which the performance of a business unit in the Exploration and Production business segment was assessed for purposes of determining compensation bonuses. Other indicators included production costs, changes in working capital, drilling days, operating efficiency and greenhouse gas emissions.

For 2004, BP s variable pay program for the senior managers in the Exploration and Production business segment will be based on Annual Bonus Contracts. Annual Bonus Contracts are made up of two elements, one of which is based on certain elements of financial performance (cash from operations, capital expenditure, divestments) of the Group as a whole. The other is based on agreed items from the business performance plan, one of which, if they choose, could relate to oil and gas reserves.

Details of our net proved reserves of crude oil, condensate, natural gas liquids and natural gas at December 31, 2003, 2002 and 2001 and reserves changes for each of the three years then ended are set out in the Supplementary Oil and Gas Information section in Item 18 - Supplementary Oil and Gas Information beginning on page S-1. We disclose our share of reserves held in joint ventures and associated companies although we do not control these entities or the assets held by such entities.

Of the Group s oil and gas reserves held in consolidated companies, approximately 94% have been estimated by the Group s petroleum engineers and approximately 6% have been estimated by others such as the field operator or independent engineering consultants. Of the oil and gas reserves held in equity-accounted companies, approximately 24% have been estimated by the Group s petroleum engineers. The majority of the rest consists of reserves in TNK-BP which have been estimated by independent engineering consultants. For significant properties where BP has adopted the proved reserve estimates of others, BP s petroleum engineers reviewed such estimates before making their assessment of volumes to be booked by BP.

Our proved reserves are associated with both concessions (tax and royalty arrangements) and production sharing agreements (PSAs). In a concession, the consortium of which we are a part is entitled to the reserves that can be produced over the licence period, which may be the life of the field. In a PSA, we are entitled to recover volumes that equate to costs incurred to develop and produce the reserves and an agreed share of the remaining volumes or the economic equivalent. As part of our entitlement is driven by the monetary amount of costs to be recovered, price fluctuations will have an impact on both production volumes and reserves. 14% 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.

In our UK GAAP financial reporting, the Group uses its long-term planning prices in determining estimates of its proved reserves, which is an accepted practice 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). Planning prices 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 2003 were $16/bbl for oil and $2.70/mscf for natural gas. From 2004 we increased our planning prices to $20/bbl for oil and $3.50/mscf for natural gas. Applying higher year-end prices to reserve estimates has the effect of increasing proved reserves associated with concessions (tax and royalty arrangements) for which additional development opportunities become economical at higher prices or where higher prices make it more economical 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. On an aggregate basis, the impact on our proved reserves of using higher year-end prices instead of our planning prices is broadly in balance, although there are relatively larger variations on a regional basis. We believe that our long-term planning price assumptions provide the most appropriate basis for estimating oil and gas reserves and we will continue to use this basis for our UK reporting.

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. These principles are also applied for SEC reporting purposes.

The company has received comments from the Staff of the SEC relating to the Annual Report on Form 20-F for the year ended December 31, 2002 and as of the date of filing this Form 20-F this review process is still ongoing. The Company s proved reserves estimates for the year ended December 31, 2003 reported in this Form 20-F reflect year-end prices and some adjustments which 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 an increase of 23 mmboe included in our total proved reserves of 18,361 mmboe (including equity-accounted entities) compared to our reserves under UK SORP. Reserve estimates for prior years have not been adjusted (The 2003 year-end marker prices used were Brent $30.10/bbl and Henry Hub $5.76/mmbtu). These changes, together with the other 2003 movements in proved reserves, are reflected in the tables showing movements in oil and gas reserves by region in the Supplementary Oil and Gas Information on pages S-1 and S-5. These changes had no material impact on our profit for the year as adjusted to accord with US GAAP.

Total hydrocarbon proved reserves, on an oil equivalent basis and excluding equity-accounted entities, comprised 14,999 mmboe at December 31, 2003, a decrease of 4.3% compared with December 31, 2002. Natural gas represents about 50% of these reserves. This reduction includes net sales of 871 mmboe. The proved reserve replacement ratio, at 119% (2002 175%, 2001 191%), exceeded production for the eleventh consecutive year. 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,

Table of Contents

improved recovery, extensions, discoveries and other additions, excluding the impact of sales and purchases of reserves-in-place and excluding reserves related to equity-accounted entities. 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 proved reserve replacement ratio including sales and purchases of reserves-in-place but excluding equity-accounted entities was 39% (2002 190%, 2001 191%) and including both sales and purchases of reserves-in-place and equity-accounted entities was 160% (2002 198%, 2001 191%).

In 2003, total additions to the Group s proved reserves (excluding sales and purchases of reserves-in-place and equity-accounted entities) amounted to 1,289 mmboe, mostly through extensions to existing fields and discoveries of new fields. Of these reserve additions, approximately 65% are associated with new projects and are proved undeveloped reserve additions and the remainder are in existing developments where they represent a mixture of proved developed and proved undeveloped. Major new development projects typically take one to four years from the time of initial booking to the start of production. The principal reserve additions were in Angola (Greater Plutonio and Dalia), Norway (Ormen Lange), UKCS (Rhum), Azerbaijan (Shah Deniz), Gulf of Mexico (Atlantis) and Australia (Northwest Shelf LNG) and it is planned to bring these into production over the period 2004 - 2008.

Total hydrocarbon proved reserves, on an oil equivalent basis and including equity-accounted entities, comprised 18,361 mmboe at December 31, 2003, an increase of 4.5% compared with December 31, 2002. Natural gas represents about 45% of these reserves. This increase includes purchases of 1,657 mmboe, of which 1,600 mmboe represents the incremental addition as a result of the purchase of 50% of TNK-BP and sales of 1,016 mmboe following completion of the divestment of assets in the North Sea primarily Forties and the Bacton Area in the UK and Gyda in Norway, along with a package of assets in the Gulf of Mexico shelf and the dilution of our gas assets, In Amenas and In Salah, in Algeria.

Additions to proved developed reserves in 2003 were 1,370 mmboe. This included some reserves which were previously classified as proved undeveloped. The proved developed reserve replacement ratio (including both sales and purchases of reserves-in-place and equity-accounted entities) was 105% (2002 118%, 2001 95%).

In our existing profit centres our decline rates are averaging in the 3% to 4% range over the period 2002-2004. Beyond 2004, we estimate the decline will be approximately 3% per annum from 2004-2008. The decline rate is mitigated by the development of new projects and the investment in incremental reserves in and around existing fields. Cash returns will reduce slightly as we manage the decline. In our new profit centres, we anticipate strong volume growth and increasing cash returns. For a definition and discussion of cash returns, see Item 5 Operating and Financial Review and Prospects Prospects on page 101.

Our total hydrocarbon production (including equity-accounted entities) during 2003 averaged 3,606 thousand barrels of oil equivalent per day (mboe/d), an increase of 87 mboe/d, or 2.5% compared with 2002; this includes the 135 mboe/d impact of divestments offset by the inclusion of 205 mboe/d TNK-BP incremental volumes from August 29, 2003. 35% of our production was in the USA, 17% in the UK and 17% from equity-accounted entities, of which 53% is from TNK-BP and the former Sidanco. Total production for 2004 is estimated at an average of over 4 million barrels of oil equivalent per day (mmboe/d).

Table of Contents

The following tables show BP s aggregate estimated net proved reserves as at December 31, 2003.

Estimated net proved reserves of liquids at December 31, 2003 (a) (b)

	Developed	Undeveloped	Total
		(millions of barrels)	
UK	697	245	942
Rest of Europe	236	127	363
USA	1,902	1,499	3,401
Rest of Americas	385	354	739
Asia Pacific	82	81	163
Africa	190	632	822
Russia			
Other	73	711	784
	3,565	3,649	7,214
Equity-accounted entities			2,867
Total Group and BP share of equity-accounted entities			10,081

Estimated net proved reserves of natural gas at December 31, 2003 (a) (b)

	Developed	Undeveloped	Total
		(billion cubic feet)	
UK	2,996	1,095	4,091
Rest of Europe	262	1,255	1,517
USA	11,482	3,337	14,819
Rest of Americas	4,212	11,531	15,743
Asia Pacific	1,976	3,026	5,002
Africa	640	2,188	2,828
Russia			
Other	255	900	1,155
	21,823	23,332	45,155
Equity-accounted entities			2,869
Total Group and BP share of equity-accounted entities			48,024

Total proved reserves (mmboe)	18,361

(a) Net proved reserves of crude oil and natural gas, stated as of December 31, 2003, exclude production royalties due to others, whether payable in cash or in kind, and include minority interests in consolidated operations. We disclose our share of reserves held in joint ventures and associated undertakings that are accounted for by the equity method although we do not control these entities or the assets held by such entities.

Table of Contents

(b) In certain deepwater fields, such as fields in the Gulf of Mexico, BP has claimed proved reserves before production flow tests are conducted in part because of the significant safety, cost and environmental implications of conducting these tests. The industry has made substantial technological improvements in understanding, measuring and delineating reservoir properties without the need for flow tests. The general method of reserves assessment to determine reasonable certainty of commercial recovery which BP employs relies on the integration of three types of data: (1) well data used to assess the local characteristics and conditions of reservoirs and fluids; (2) field scale seismic data to allow the interpolation and extrapolation of these characteristics outside the immediate area of the local well control; and (3) data from relevant analog fields. Well data includes appraisal wells or sidetrack holes, full logging suites, core data and fluid samples. BP considers the integration of this data in certain cases to be superior to a flow test in providing a better understanding of the overall reservoir performance. The collection of data from logs, cores, wireline formation testers, pressures and fluid samples calibrated to each other and to the seismic data can allow reservoir properties to be determined over a greater volume than the localized volume of investigation associated with a short term flow test.

Historically, proved reserves recorded using these methods have been validated by actual production levels. BP has booked proved reserves in 18 fields in the deepwater Gulf of Mexico prior to production flow testing. Fourteen of these are now in production. Holstein, Mad Dog, Thunder Horse and Atlantis are due to begin production over the period 2004-2006.

Table of Contents

The following tables show BP s production by major field for 2003, 2002 and 2001.

Liquids

Production	Field or Area	Interest	Net production 2003	2002	2001
		(%)	(thousand barrels per day)		
Alaska	Prudhoe Bay*	26.4	105	113	123
	Kuparuk	39.2	73	74	76
	Northstar*	98.6	46	36	3
	Milne Point*	100.0	44	44	45
	Other	Various	43	42	41
Total Alaska			311	309	288
Lower 48 States onshore (a)	Total	Various	160	192	213
Gulf of Mexico (a)	Mars	28.5	43	41	42
	Horn Mountain*	66.6	42	1	
	King*	100.0	31	12	
	Pompano*	73.6	15	23	21
	Ursa	22.7	17	20	23
	Other	Various	107	167	157
Total Gulf of Mexico			255	264	243
Total USA			726	765	744
UK offshore (a)	ETAP	Various	56	61	80
	Foinaven*	Various	55	72	60
	Schiehallion/Loyal*	Various	42	43	40
	Magnus*	85.0	39	31	37
	Harding*	70.0	34	42	42
	Andrew*	62.8	17	23	25
	Forties*(b)	96.1	10	50	51
	Other	Various	95	107	114
Total UK offshore			348	429	449
UK onshore	Wytch Farm*	67.8	29	32	36
Total UK			377	461	485
Norway (a)	Draugen	18.4	25	37	40
	Valhall*	28.1	21	21	22
	Ula*	80.0	16	18	18
Other Norway and Netherlands	Various	Various	22	28	20

Total Rest of Europe	84	104	100

* BP operated.

BP operates the majority of the fields in this area.

28

Table of Contents

Production	Field or Area	Interest	Net production 2003	2002	2001
		(%)	(thousand barrels per day)		
Angola	Various	Various	35	29	1
Australia	Various	16.7	40	43	40
Azerbaijan	Azeri-Chirag-Gunashli*	34.1	38	38	35
Canada	Various	Various	13	16	18
Colombia (a)	Various	Various	53	46	48
Egypt	Various	Various	73	85	91
Trinidad	Various	100.0	74	67	48
Venezuela (a)	Various	Various	53	51	54
Other (a)	Various	Various	49	61	59
Total Rest of World			428	436	394
Total Group			1,615	1,766	1,723
Equity-accounted entities					
Abu Dhabi (c)	Various	Various	138	113	126
Argentina - Pan American Energy	Various	Various	60	53	50
Russia - TNK-BP (a)	Various	Various	228		
- Sidanco	Various	Various	68	73	20
Other	Various	Various	12	13	12
Total equity-accounted entities			506	252	208
Total Group and BP share of equity-accounted entities (d)			2,121	2,018	1,931

* BP operated.

Table of Contents

Natural gas (e)

Production	Field or Area	Interest	Net Production 2003	2002	2001
		(%)	(million cubic feet per day)		
Lower 48 States onshore (a)	San Juan Coal*	Various	578	601	615
	San Juan Conventional	Various	224	196	217
	Arkoma	Various	201	206	219
	Hugoton	Various	182	169	180
	Tuscaloosa	Various	136	138	187
	Jonah*	75.2	119	113	109
	Wamsutter*	70.5	111	108	100
	Other	Various	558	715	733
Total Lower 48 States onshore			2,109	2,246	2,360
Gulf of Mexico (a)	Marlin*	78.2	93	106	79
	King s Peak*	100.0	91	16	
	Mica	50.0	57	58	27
	Other	Various	695	1,005	1,077
Total Gulf of Mexico			936	1,185	1,183
Alaska	Various	Various	83	52	11
Total USA			3,128	3,483	3,554
UK offshore (a)	Bruce*	37.0	222	221	256
	Braes	Various	174	116	100
	Marnock*	62.0	98	135	125
	West Sole*	100.0	73	72	81
	Shearwater	27.5	70	66	19
	Armada	18.2	58	71	71
	Britannia	9.0	55	56	65
	Other	Various	696	813	996
Total UK			1,446	1,550	1,713
Netherlands	P/18-2*	48.7	30	41	47
	Other	Various	37	46	52
Norway (a)	Various	Various	52	60	48
Total Rest of Europe			119	147	147

* BP operated.

BP operates the majority of the fields in this area.

30

Table of Contents

Production		Field or Area	Interest	Net production 2003	2002	2001
			(%)	(million cubic feet per day)		
Rest of World						
Australia		Various	16.7	285	295	237
Canada		Kirby*	95.0	48	66	72
		Other	Various	374	448	512
China		Yacheng*	34.3	74	102	108
Egypt		Ha py	50.0	83	74	66
		Temsah	50.0	66	84	26
		Other	Various	104	98	98
Indonesia		Sanga-Sanga (direct)	26.3	165	174	164
		Pagerungan*	100.0	121	189	242
		Other*	46.0	97	94	95
Sharjah		Sajaa*	40.0	101	110	125
		Other	40.0	19	24	35
Trinidad		Amherstia*	100.0	624	492	244
		Mahogany*	100.0	503	521	529
		Immortelle*	100.0	235	154	128
		Parang*	100.0	152		
		Flamboyant*	100.0	68	40	52
		Other*	100.0	112	31	58
Other (a)		Various	Various	168	148	82
Total Rest of World				3,399	3,144	2,873
Total Group				8,092	8,324	8,287
Equity-accounted entities						
Argentina	- Pan American Energy	Various	Various	281	251	236
Russia	- TNK-BP (a)	Various	Various	96		
	- Sidanco	Various	Various	33	6	
Other		Various	Various	111	126	109
Total equity-accounted entities				521	383	345
Total Group and BP share of equity-accounted entities				8,613	8,707	8,632

* BP operated.

(a) In 2003, BP and the Alfa Group and Access-Renova merged certain of their Russian and Ukranian oil and gas businesses to create TNK-BP. BP also acquired the interests of Amerada Hess in Colombia and disposed of its interests in Forties, Montrose/Arbroath and Bacton Area assets in the UK North Sea, Gyda in Norway, LL652 in Venezuela, QHD and Liuhua in China, the Malaysia Thailand Joint Development Area, Aspen in the Gulf of Mexico, various shallow water fields in the Gulf of Mexico and various fields in the US Lower 48 states. In 2002, BP acquired additional working interest in the Badin acreage (Pakistan) from the government and disposed of its interest in the Al Rayyan field (Qatar), Qadirpur field (Pakistan) and Elgin/Franklin field (UK). In 2001, BP purchased part of the interests of Statoil in Vietnam and the interest of Inaquimicas in Cusiana/Cupiagua in Colombia.

(b) The sale of BP s interest in the Forties field was completed on April 2, 2003.

(c) The BP Group holds proportionate interests, through associated undertakings, in onshore and offshore concessions in Abu Dhabi expiring in 2014 and 2018, respectively.

(d) Includes NGLs from processing plants in which an interest is held of 70 mb/d, 69 mb/d, and 78 mb/d for 2003, 2002 and 2001, respectively.

(e) Natural gas production volumes exclude gas consumed in operations within the lease boundaries of the producing field.

Table of Contents

United States

2003 liquids production at 726 thousand barrels per day (mb/d) decreased 5% from 2002, while natural gas production at 3,128 million cubic feet per day (mmcf/d) decreased 10% compared with 2002.

Crude oil production was maintained at the 2002 level, with divestments and natural reservoir declines (25 mb/d) being offset by new projects and gains in operating efficiency (24 mb/d). The decline in the Natural Gas Liquids component of liquids production (39 mb/d) was caused by divestments, lower gas throughput and processing elections not to strip NGLs from produced gas (in order to sell rich gas in a high gas price environment) thus resulting in lower commercial NGL production. Gas production was lower because of divestments, natural reservoir decline and investment choices (436 mmcf/d), partly offset by new project startups and continuing ramp-up of 2002 projects (81 mmcf/d). Operational efficiency in the USA, i.e., actual production as a percentage of production capacity, was much improved in 2003, up 3% over 2002 to 93% due to less weather-related downtime and performance improvements.

Development expenditure in the USA (excluding midstream) during 2003 was $3,486 million, compared with $3,618 million in 2002 and $3,723 million in 2001. This reflects our continued focus on only investing in the best opportunities and optimizing operating efficiency.

Our activities within the United States take place in four main areas. Significant events during 2003 within each of these are indicated below.

Deepwater Gulf of Mexico

Deepwater Gulf of Mexico is one of our new profit centres and our largest area of growth in the United States. In 2003, our Deepwater Gulf of Mexico crude oil production was 215 mb/d, up 5% from 2002 levels. Gas production was 561 mmcf/d, up over 10% from 2002 levels.

Growth in 2003 was driven by new field startup activity, as well as strong performance from the existing major hubs. Key events include:

Production ramp up at the Horn Mountain (BP 66.6% and operator) and King s Peak (BP 100% and operator) fields. Both fields began production in late 2002.

The King West subsea project (BP 100% and operator) started production in June 2003.

Production from the Na Kika Development (BP 50% and operator) commenced in November 2003. The development consists of 5 fields and 10 subsea wells connected to a centrally-located floating host facility.

Mardi Gras transportation system construction is on track and the first segment, the Okeanos Gas Gathering System, started up in conjunction with first production from the Na Kika field in November.

The second phase of the Princess project (BP 22.69%), a 3-well subsea development to the Ursa platform, began producing in December 2003.

Development of four major projects continued in the Gulf of Mexico during 2003 Holstein (BP 50% and operator) is on track to start up late 2004 with the final stages of construction underway. Mad Dog (BP 60.5% and operator) and Thunder Horse (BP 75% and operator) are scheduled to commence production in 2005 with Atlantis (BP 56% and operator) following in 2006. These projects will be the major contributor to the anticipated growth in production from 312 mboe/d to 550 mboe/d.

Additionally, the divestment of the Aspen field (BP 40% and operator) was concluded in the second quarter of 2003 as part of BP s ongoing portfolio review to focus on high quality assets and to stop investing in those where others may see greater value.

32

Table of Contents

On January 30, 2004, we sold 45% of our interest in King s Peak in Deepwater Gulf of Mexico to Marubeni Oil & Gas (USA).

On May 22, 2004, the Mars platform was shut in due to a small leak.

Gulf of Mexico Shelf

The Shelf is a mature basin, with decline rates that average 40-50% per year. On March 13, 2003 BP completed the sale of 61 fields to Apache Corporation, which accounted for approximately 40% of 2002 production. In 2003, BP s gas production from Gulf of Mexico Shelf operations was 375 mmcf/d, which was down 44% compared to 2002. Liquids production was 39 mb/d, down 34% compared to 2002. The year-on-year drop in production is attributed to the divestment, normal decline and reduced capital spending. Capital spending has reduced from $428 million in 2002 to $205 million in 2003. This is as a result of our divestment programme as well as focusing our capital expenditure on better opportunities elsewhere in the segment. We operate more than 150 platforms and 350 wells on the Shelf and we drilled a total of 15 operated wells in 2003.

Lower 48 States

In the Lower 48 States we are one of the largest producers of natural gas, accounting for over 5% of total US onshore natural gas production. Production comes from over 12,000 wells, distributed across more than 600 oil and gas fields, of which we operate nearly 80%. Assets are situated principally in the states of Colorado, Kansas, Louisiana, New Mexico, Oklahoma, Texas and Wyoming.

Total production in 2003 was down 10% compared with 2002. Natural decline and strategic portfolio divestments accounted for 3% each and reduced gas throughput and changes in processing elections accounted for the remainder. In 2003, total liquids production was 160 mb/d and natural gas production was 2,109 mmcf/d.

In 2003, we drilled over 400 operated wells and maintained a level programme of activity utilizing, on average, 26 drilling and 50 service rigs. Year-on-year improvements continue to be delivered in safety, capital and cost efficiency across all the basins where we operate. Additionally, our environmental leadership has continued with a 286 kilotonnes (kte) reduction of CO_2 emissions, through delivery of focused greenhouse gas (GHG) reduction projects, including the installation of solar panels to power some of our pumping units at our wells in the San Juan South region.

Our production in the onshore Lower 48 States was derived primarily from two main areas:

- In the Western Basins (Colorado, New Mexico, and Wyoming) our assets produced 1,255 mmcf/d (94% operated) of natural gas and 78 mb/d of liquids in 2003.

In the Gulf Coast and Mid-Continental basins (Kansas, Louisiana, New Mexico, Oklahoma and Texas) our assets produced 854 mmcf/d (62% operated) of natural gas and 48 mb/d of liquids in 2003.

Alaska

In Alaska, crude oil production in 2003 was 311 mb/d, an increase of 0.6% from 2002, due principally to increases in Northstar production and development of satellite fields around Prudhoe Bay and Kuparuk.

Table of Contents

Key activities during 2003 in Alaska included:

As part of maximising the productivity of our existing profit centres, active reservoir management at Alaska s largest producing field, Prudhoe Bay, and the associated satellites (BP 26.4% and operator) included an ongoing active infill and new well drilling programme with 80 wells, which generated net production of 8.2 mboe/d. In 2003, BP had 6.5 operated rig-years (6 rigs full time, 1 rig half time) working across the North Slope. At the Milne Point Unit, 20 wells were drilled with 8 miles of horizontal hole achieving 45% lower non-productive time than 2003. The Northstar Unit drilled 8 wells in 2003, and the Endicott Unit drilled 4 sidetrack wells.

The Northstar Oil Field (BP 98.58%) completed its second full year of operations with operating efficiency and production rates well ahead of 2002 levels. Improved equipment reliability and the completion of additional development wells enabled an estimated operating efficiency rate of 86.5% and a daily gross production average of 63 mb/d.

Two agencies completed their investigations into the August 2002 A-22 well explosion with BP s full cooperation. The Alaska Department of Labor Occupational Health and Safety Division assessed a penalty of $6,300 in February 2003, which BP did not contest. The Alaska Oil and Gas Conservation Commission released its staff report on the incident in mid-December and proposed an enforcement action and a penalty in excess of $2.5 million. BP is contesting the penalty.

The Y-36 flowline spill occurred at Greater Prudhoe Bay in May 2003, spilling an estimated 1,300 gallons (US) of crude and 5,000 gallons (US) of produced water. The spill was caused by external corrosion beneath the flowline s insulation. The flowline has since been repaired and there has been no long-term damage to the environment. BP had noted increased corrosion of this type in late 2001 and nearly tripled its mitigation programme in 2003. As operator, BP expends approximately $50 million (gross) annually on corrosion management programmes at Greater Prudhoe Bay.

United Kingdom

We are the largest producer of oil and gas in the UK. In 2003, total liquids production was 377 mb/d, an 18% decrease on 2002, and gas production was 1,446 mmscf/d, a 7 % decrease on 2002. This decrease in production was driven by the divestment during 2003 of the Forties, Montrose/Arbroath and Bacton Area assets to Apache Corporation, Paladin Resources and Perenco, respectively, (49%) along with the natural decline of the mature North Sea basin and operational problems in the second and third quarters (51%). These operational problems included a compressor shutdown on Foinaven (BP operated), well integrity concerns on the Shearwater field (Shell operated) and a gearbox failure on Eastern Trough Area Project (BP operated). All fields were returned to production during the year. Our activities in the North Sea are focused on operations efficiency, in-field drilling and selected new field developments. Our development expenditure in the UK was $740 million in 2003 compared to $895 million in 2002 and $930 million in 2001.

Significant activities in 2003 included the following:

The Clair Phase I Development (BP 28.9% and operator) is in mid-construction and on schedule for first oil in late 2004.

In 2003, all major construction contracts were awarded for the Rhum development (BP 50% and operator) and fabrication was initiated. Rhum is a high pressure, high temperature gas field that is the first of its type for BP in the region. The field will be developed via a 44 km subsea tieback to the Bruce platforms. Startup is scheduled for 2005.

In 2003, cumulative oil production in the Harding field (BP 70% and operator) and in the Andrew field (BP 62.75% and operator) exceeded the total amounts estimated when the reserves

Table of Contents

were originally booked. Success in both fields is attributed to the application of new technologies and best practice reservoir management.

The Braemar field (BP 52%) began production at the end of the third quarter, following tie-back to the East Brae platform.

On the Machar field (BP 100% and operator) a project to sustain production by gas lifting the wells was completed and a significant new production well sanctioned for 2004 startup.

At Wytch Farm (BP 67.8% and operator) a seismic survey was shot offshore to define well locations for a 10-well extended reach drilling programme started in 2004.

On the Lomond (BP 22.2% and operator) and Erskine (BP 50%, ChevronTexaco operated) fields, mid-life compression projects have been sanctioned to extend field life. Mid-life compression refers to the installation of compression facilities on the platform which will supplement the natural pressure of the reservoir and thereby increase the flow rate of hydrocarbons.

The Ravenspurn North (BP 53.5% and operator) gas sales contract was renegotiated to transfer the control of production from the buyer to the joint venture partners with effect from October 1, 2003.

A one-off gas sales deal was agreed for Amethyst (BP 59.5% and operator) to increase gas sales during the 2003 summer period.

The NW Hutton (BP 26% and operator) well decommissioning was completed on January 22, 2004 with the removal of the last conductor. The total cost of decommissioning was $17.6 million (BP share).

Rest of Europe

Development expenditure, excluding midstream, in the Rest of Europe was $236 million compared with $219 million in 2002 and $271 million in 2001.

Norway

Production in Norway decreased from 113 mboe/d in 2002 to 92 mboe/d in 2003, a decline of 18%. The principal reasons behind this were: a reduction in Draugen production capacity and delays in restoring production from Rogn South wells following a shutdown; the SE1 well on Ula proved water in the main target rather than oil, hence the anticipated decline mitigation was not achieved; and Tambar, having reached plateau in 2002, was impacted by post-plateau natural decline. The total impact of these items was a decrease of 17 mboe/d. In addition, on September 1, 2003 we sold our 61% interest in the Gyda field to Talisman Energy (6 mboe/d). We have maintained production at 2002 levels on Valhall as a result of the Flank project coming on stream (first oil in the second quarter of 2003) and a high level of operating efficiency.

Main activities and achievements in 2003:

Valhall Water Injection project following technical difficulties in positioning the jacket foundation piles, repairs were successfully carried out and the topside was installed in the third quarter.

Valhall Flank Development Flank South achieved first oil in May 2003 and the North platform was installed in the third quarter with first oil achieved on January 7, 2004.

Ormen Lange The unit operating agreement, plan of development and the joint venture agreements for an export pipeline to the UK were agreed and approved by the partnership in December. BP has a 10.3% interest in this project.

Table of Contents

Rest of World

Development expenditure, excluding midstream, in Rest of World was $3,085 million in 2003 compared with $2,503 million in 2002 and $1,934 million in 2001.

Rest of Americas

Canada

In Canada, our 2003 production was 86 mboe/d, down 18% from 2002, mainly due to natural field decline. The Alberta Energy and Utilities Board ordered the industry to shut-in production from certain shallow gas fields overlaying bitumen deposits in northeastern Alberta with effect from September 1, 2003. BP s production impacted by this order was 1.3 mboe/d on an annualized basis. BP and other producers are pursuing legal and regulatory options challenging the shut-in requirement in addition to seeking appropriate compensation from the Alberta Government. Natural gas makes up 85% of Canada s production.

On February 9, 2004, we signed a sale and purchase agreement with Fairborne Energy Ltd. to sell a package of non-core assets in Alberta, Canada for $88 million. These assets contributed approximately 3 mboe/d during 2003.

Trinidad

In Trinidad, gas volumes increased by 37% over 2002. The increase in natural gas sales was principally driven by the successful startup of Atlantic LNG Train 3 in the second quarter of 2003, as well as a full year of sales to Atlantic LNG Train 2. During the year, BP completed the installation of Cassia B, the world s largest offshore processing facility (2 bcf/d), linked in to the new Bombax 48 gas pipeline evacuation system, which was successfully commissioned in the second quarter of 2003. Our next field development (Cannonball) was sanctioned in the fourth quarter of 2003. First gas is targeted for the fourth quarter of 2005.

On January 2, 2003, Repsol exercised their option to acquire an additional 20% interest in BP s upstream assets in Trinidad, taking their total interest in BP Trinidad and Tobago LLC to 30%. This transaction gives leverage for our upstream position in Trinidad to access gas markets and growth opportunities in Spain, thus providing a further platform for BP s future gas growth in Trinidad.

On May 15, 2003, we sold our 15% stake in the Titan Methanol Company, based in Trinidad, to Methanex Corporation. The Atlas methanol plant the world s largest, in which BP has a 36.9% interest commenced production on June 2, 2004.

Venezuela

In Venezuela three of the four base assets are reactivation projects (projects that are expected to continue and improve exploitation in mature fields) consisting of two operated properties, Boqueron and Desarollo Zuli Occidental (DZO), and one non-operated property, Jusepin, under risk service agreements to produce oil for the state oil company, Petroleos de Venezuela S.A. (PDVSA). A fourth asset, Cerro Negro, a non-operated property that is a heavy oil project from which production is sold directly by BP, was held for sale in

2002. In the absence of partner approval for the sale, the agreement was terminated in December 2003. There are no immediate plans to remarket this asset. During 2003 we executed a sale and purchase agreement to sell DZO and Boqueron to Perenco. In the first quarter of 2004, the sales agreement lapsed and we will now retain these fields. We had previously reported an exceptional loss on disposal of $217 million in respect of these assets, which has now been reversed. As a result of the lapse of the agreement, an impairment charge of $186 million was recognized in the first quarter of 2004. LL-652, also a reactivation project, was sold and transferred to ChevronTexaco during the year. The impact of the national strike, which began in December 2002, was 5 mb/d in 2003, with production back to pre-strike levels by mid-March 2003.

Table of Contents

Colombia

In Colombia, BP completed operations in November on the Niscota exploration well after testing water with traces of non-commercial hydrocarbons. While this well has been written off, additional prospectivity and disposition of the contract area will be determined in the second half of 2004 after evaluation of data obtained from drilling activities.

Argentina and Bolivia

In Argentina and Bolivia, activity is conducted through Pan American Energy (PAE), in which BP holds a 60% interest, and which is accounted for by the equity method. In 2003, total production of 117 mboe/d represented an increase of 10.3% over 2002, with oil increasing by 10.4% and gas by 10.2%. The main increase in oil production came from the continued focus on drilling and waterfloods in Golfo San Jorge in Argentina, where oil production was 52 mb/d compared to 45 mb/d in 2002. The field is now producing at its highest level since inception in 1958 and further expansion programmes are planned. Despite the economic crisis in Argentina, GDP increased by 8.7% in 2003. Gas demand grew due to the higher activity level, colder than normal weather and lack of hydroelectric power due to lower than average rainfall. Gas prices continued to be depressed. PAE also has interests in gas pipelines, electricity generation plants and other midstream infrastructure assets.

Africa

Algeria

In 2003, BP sold 50% and 49% of its interests in In Amenas and In Salah, respectively, to Statoil. Formal Algerian approval is currently outstanding.

In Algeria, BP and the Algerian state company, Sonatrach, continued development activities of the In Salah project (BP 51%), which is expected to start up in mid-2004. The first stage comprises the development of three of the seven deep Saharan natural gas fields expected to supply the fast-growing markets of Southern Europe.

BP and Sonatrach continued to progress the development of the In Amenas (BP 50%) project, expected to start up in early 2006.

Angola

Angola has several key projects which provide the foundation for volume growth over the next few years. Activities in 2003 included the following:

In Block 17 (BP 16.7%), the Jasmim field, a tie-back to the Girassol hub, commenced production in the fourth quarter of 2003. The Dalia project commenced development in the first quarter of 2003.

In Block 15 (BP 26.7%), the Xikomba field commenced production in the fourth quarter of 2003. Development activities progressed on Kizomba A and Kizomba B, with production expected to commence in the second half of 2004 on Kizomba A.

In Block 18 (BP 50% and operator), work has continued on the Greater Plutonio development, with internal sanction granted in the first quarter of 2003.

In Block 31 (BP 26.7% and operator), a 2-year extension to the initial exploration phase was granted in the second quarter of 2003.

Angolan oil projects have associated gas which BP is seeking both economic and environmental solutions for production and distribution as part of the Angola LNG project.

Table of Contents

Egypt

In Egypt, the Gulf of Suez Petroleum Company (GUPCO), a joint venture operating company between BP and the Egyptian General Petroleum Corporation, carries out our oil production operations. GUPCO operates seven PSAs in the Gulf of Suez and Western Desert, encompassing more than forty fields.

In 2003, physical gas production in Egypt was held close to 2002 rates. BP s 2003 PSA gas production reached 253 mmscf/d from the Ras El Barr, Temsah and other concessions.

BP has a 33% interest in the joint venture United Gas Derivatives, currently constructing a 1.1 bcf/d NGL extraction plant. Plant startup is scheduled in the fourth quarter of 2004. Temsah and Ha py development projects are on schedule to deliver 100% of the fields daily contracted quantities to ensure supply feedstock for the NGL plant.

Asia Pacific

Indonesia

BP is the largest private supplier of natural gas to Java through its holdings in the Offshore Northwest Java (46% BP) and Kangean (100% BP) Production Sharing Contracts.

Vietnam

BP participates in the country s biggest foreign investment, the Nam Con Son gas project. This is an integrated resource and infrastructure project including offshore gas production, pipeline transportation system and power plant. Gas sales from Block 6.1 (BP 35% and operator) commenced in early 2003. The gas is sold under a long-term agreement for electricity generation in Vietnam, including the Phu My 3 power plant (BP 33.33%), which commenced operations on March 1, 2004.

China

The Yacheng field (BP 34.3% and operator) supplies, under a long-term contract, 100% of the natural gas requirement of Castle Peak Power Company for Hong Kong power generation. Some natural gas is also piped to Hainan Island, where it is sold to the Fuel and Chemical Company of Hainan, also under a long-term contract. The Yacheng field operatorship was transferred to China National Offshore Oil Corporation (CNOOC) on January 1, 2004. In 2003, we have divested our interests in our other fields, QHD and Liuhua, to CNOOC.

Australia

We are one of six equal partners (BP 16.7%) in the North West Shelf (NWS) Venture. The operation covers offshore production platforms, a floating storage vessel, trunklines, and onshore gas processing plants, and is currently the principal supplier to the domestic market in Western Australia. During 2003, a fourth LNG Train was under construction and is on track to be commissioned in the second half of 2004, and a second trunkline was commissioned in February 2004.

Russia

Acquistion of TNK-BP interest

On August 29, 2003, BP and AAR (the Alfa Group and Access-Renova) completed the deal to combine their Russian and Ukrainian oil and gas businesses and create TNK-BP, a new company registered in the British Virgin Islands owned 50:50 and managed jointly by BP and AAR. The consideration from BP to AAR comprised an immediate $2.6 billion in cash (which was subsequently reduced by receipt of pre-acquisition dividends net of transaction costs of $0.3 billion) for its stake in the new company together with three annual tranches of $1.25 billion in BP shares payable on the subsequent anniversaries of the closing date. The assets contributed by BP included existing interests in Sidanco and Rusia, as well as its interest in the retail business in Moscow. The deal did not include BP s interest in Sakhalin or its Castrol operations in Russia. The net BP investment, after adjusting for pre-acquisition dividends, amounted to $6.7 billion. BP also agreed with AAR to incorporate AAR s 50% interest in Slavneft into TNK-BP in return for a cash payment by BP of $1.35 billion, subject to adjustments. This transaction was completed on January 16, 2004. Overall, this represents the largest transaction in Russian corporate history, as well as being the largest foreign indirect investment in Russia.

TNK-BP is jointly controlled by BP and Alfa Group and Access Renova (AAR). BP holds 50% of the voting rights in TNK-BP. BP s investment in TNK-BP is accounted as a joint venture under the gross equity method and as such we have reflected 50% of the proved reserves of TNK-BP as at December 31, 2003 (1.8 billion barrels of oil, of which 1.4 billion are developed). The reserves which were incremental to those contributed from our investment in Sidanco (1.6 billion barrels of oil) are shown as a purchase of reserves in place in equity-accounted entities. The return on our investment in TNK-BP is expected to come through cash dividends. Earnings for the period August 29 to December 31, were accretive to BP returns on capital and we expect this to continue at current prices. As with our other assets, an increase in oil prices will increase the returns on our investment. Our expected return on this investment in both the short and long term is estimated to be comparable to that of our non-Russian activity.

The shareholder agreement between BP and AAR establishes TNK-BP in the British Virgin Islands with English law principles governing the legal system. The shareholder agreement establishes joint control between AAR and BP. BP and AAR have equal representation on the TNK-BP Board, with AAR nominating the Chairman and Chairman of the Remuneration Committee, and BP the Vice Chairman and Chairman of the Audit Committee. BP appoints the Chief Executive Officer of TNK-BP and holds half of the senior management positions.

On June 11, 2004 BP and AAR agreed to change the dates on which BP is due, under the terms of that agreement, to issue AAR with three tranches of BP p.l.c. shares, each tranche with a value of $1.25 billion. The issue dates have been changed from August 29, 2004, August 29, 2005 and August 29, 2006 to September 20, 2004, September 20, 2005 and September 20, 2006, respectively. The issue dates have been moved in order to avoid BP s third quarter ex-dividend date falling within the calculation period for determining the number of BP p.l.c. shares to be issued to AAR in each tranche, thereby reducing the potential for volatility during that period. There is no incremental cost to BP or its shareholders as a result of this change in issue dates.

TNK-BP

TNK-BP has proved reserves of 3.6 billion barrels of oil, of which 2.8 billion are developed. Daily oil production currently amounts to some 1.3 million barrels of oil a day. The production base is largely centred in West Siberia (Samotlor, Nizhnevartovskoye Nefedobyvaushee Predpriyatie, Nyagan), which contributes about 0.8 million barrels a day, together with Volga Urals (Orenburgneft) contributing 0.4 million barrels a day. In excess of 50% of total oil production is currently exported as crude and 15% as refined product. Downstream, TNK-BP owns five refineries in Russia and Ukraine (including Ryazan and Lisichansk), with throughput of 0.5 million barrels a day (25 million tonnes a year). In retail, TNK-BP owns more than 2,100 filling stations in Russia and the Ukraine with a share of the Moscow retail market in excess of 20%. The workforce currently amounts to approximately 100,000 people.

BP s investment in TNK-BP is accounted for under the gross equity method. Production for the four-month post-completion period averaged 713 mboe/d; this generated some $392 million of net income in an environment where Urals marker prices (NW Europe) averaged around $27.3/bbl (from August 29, 2003). In full-year terms, BP s share of production averaged 244 mboe/d. A dividend of $297 million received in the fourth quarter was credited against the net investment cost and reduced net cash outflow to $2.35 billion.

Table of Contents

Slavneft

On January 16, 2004 a payment of $1.35 billion was made to AAR to incorporate AAR s 50% interest in Slavneft into TNK-BP. Slavneft will be included in the results of our 50% interest in TNK-BP in 2004. Slavneft has current production rates exceeding 0.3 million barrels of oil per day. It has two refineries in Russia (Yaroslavl) and an interest in the Mozyr refinery (Belarus) with total throughput of 384,000 barrels a day, as well as more than 550 retail filling stations in Russia.

Other

Middle East and Pakistan

Production in the Gulf States was dominated by the production entitlement of associated undertakings in Abu Dhabi, where we have equity interests of 9.5% and 14.7% in onshore and offshore concessions, respectively. In 2003, production in Abu Dhabi was up around 23% from 2002 as a result of OPEC quota increases.

In Pakistan, BP is the largest foreign operator producing around 43% of the country s oil and 8% of its natural gas on a gross basis.

Azerbaijan

BP, as operator of the Azerbaijan International Operating Company (AIOC), manages and has a 34.1% interest in the Azeri-Chirag-Gunashli (ACG) oil fields in the Caspian Sea, offshore Azerbaijan. The Azeri project continued in 2003 and is on track to deliver first oil from central Azeri in the first quarter 2005. Phase 3 of ACG full field development commenced the detailed engineering stage and is targeting sanction in 2004.

The Shah Deniz natural gas field (BP 25.5% and operator) was sanctioned in 2003 and remains on track to deliver first gas in 2006.

Midstream Activities

Oil and Natural Gas Transportation

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

BP, as BTC operator, manages and holds a 30.1% interest in the Baku-Tbilisi-Ceyhan (BTC) oil pipeline currently under construction. AIOC operates the Western Export Route Pipeline between Azerbaijan and the Black Sea coast of Georgia and the Azeri leg of the Northern Export Route Pipeline between Azerbaijan and Russia.

Our onshore US crude oil and product pipelines and related transportation assets are included under Refining and Marketing in this item. Revenue is earned on pipelines through charging tariffs. Our gas marketing business is described under Gas, Power and Renewables in this item.

Activity in oil and natural gas transportation during 2003 included:

Alaska

BP owns a 46.9% interest in TAPS, with the balance owned by four other companies. TAPS transported production from Prudhoe Bay and the other North Slope fields averaging 991 mb/d during 2003.

40

Table of Contents

There are a number of unresolved protests regarding tariffs charged for shipping oil through TAPS. These protests were filed between 1986 and 2003 with the Federal Energy Regulatory Commission and the Regulatory Commission of Alaska (RCA). In 2002, the RCA issued an Order requiring refunds to be made to TAPS shippers of intrastate crude oil for the years 1997 through 2000. BP has appealed this Order to the Alaska Superior Court. Pending the outcome of a hearing on intrastate rates from 2001 forward, the RCA imposed temporary intrastate rates (consistent with its 2002 Order) effective July 1, 2003.

The use of US-built and US-flagged ships is required when transporting Alaskan oil to markets in the USA. In accordance with this, BP America Inc. has a chartered fleet of nine US-flagged tankers to transport Alaskan crude oil to markets. Over the next few years, we plan to begin replacing our US-flagged fleet as existing ships are retired in accordance with the Oil Pollution Act of 1990. For discussion of the Oil Pollution Act of 1990, see Environmental Protection Maritime Oil Spill Regulations on page 69. BP has contracted for the delivery of four 1.3 million-barrel-capacity, double-hull tankers for use in transporting North Slope oil to West Coast refineries. The ships are being constructed by NASSCO in San Diego with deliveries in years 2004, 2005 and 2006. The first vessel was floated from drydock in November of 2003, in keeping with a 2004 delivery.

North Sea

FPS (BP 100%) is an integrated oil and NGLs transportation and processing system that handles production from over 40 fields in the Central North Sea. The system has a capacity of more than 1 mmb/d, with average throughput in 2003 at 751 mb/d.

During the fourth quarter of 2003, FPS reached agreement with Encana and others to transport and process hydrocarbons from the Buzzard Field. This is the largest UK sector transportation and processing deal in the last 10 years.

BP operates and has a 29.5% interest in CATS, a 400-kilometre natural gas pipeline system in the central UK sector of the North Sea. The pipeline has a transportation capacity of 1.7 bcf/d to a natural gas terminal at Teesside, Northeast England. CATS offers natural gas transportation services or transportation and processing via two 600 mmcf/d processing trains. In 2003, throughput was 1.6 bcf/d.

In addition, BP operates the Dimlington/Easington gas processing terminal (BP 100%) on Humberside and the Sullom Voe Gas Terminal in the Shetlands, which celebrated 25 years of operations in November 2003.

Asia (including the former Soviet Union)

BP, as BTC operator, manages and holds a 30.1% interest in the Baku-Tbilisi-Ceyhan (BTC) oil pipeline which is currently under construction and is on schedule to be ready for line fill by early 2005.

The South Caucasus pipeline (SCP) for the transport of gas from Shah Deniz in Azerbaijan to the Turkish border was sanctioned in February 2003. BP is the operator and holds a 25.5% interest.

Through the LukArco joint venture, BP holds a 5.75% interest in the Caspian Pipeline Consortium (CPC) pipeline. CPC is a 1,510-kilometre pipeline from Kazakhstan to the Russian port of Novorossiysk. The initial construction phase was completed in April 2003 on budget at a gross cost of $2.6 billion. The pipeline has an initial capacity of 28.2 million tonnes (approximately 225 mmboe) a year and carries crude oil from the Tengiz field (BP 2.3%). In addition to our interest in LukArco, we hold a separate 0.87% interest in CPC through a 49% holding in Kazakhstan Pipeline Ventures.

Table of Contents

Gulf of Mexico

Construction continued on the Mardi Gras pipeline system (BP approximately 65% and operator). When complete, the network of pipelines will extend in total more than 450 miles, and lie in waters of greater than 7,000 feet deep. It will be the largest capacity deepwater pipeline ever built.

Liquefied Natural Gas

Within BP, Exploration and Production is responsible for the supply of LNG and Gas, Power and Renewables is responsible for the subsequent marketing and distribution of LNG (see details under Gas, Power and Renewables New Market Development and LNG on page 45).

Significant activity during 2003 included the following:

We have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company, which in 2003 supplied 5.4 million tonnes (263 bcf) of LNG, up 2% on 2002.

In Australia, we are one of six equal partners (BP 16.7%) in the North West Shelf Venture. The joint venture operation covers offshore production platforms, a floating storage vessel, trunklines, and onshore gas processing plants. During 2003, a fourth LNG Train and second trunkline were under construction and are expected to be commissioned in 2004.

In Indonesia, BP participates in Indonesia s LNG exports through its holdings in the Sanga-Sanga (BP 38%) PSA. Sanga-Sanga delivers around 30% of the total gas feed to the Bontang LNG plant.

In addition, we have interests in the Wiriagar (BP 38% and operator), Berau (BP 48% and operator) and Muturi (BP 1%) PSAs in Northwest Papua. These PSAs will provide the natural gas feed to the Tangguh LNG project (BP 37% and operator), which is expected to become the third LNG centre in Indonesia. In 2003, as part of our strategy to serve gas markets in Southern China, we sold 12.5% of our Tangguh share to CNOOC. During 2003, BP continued to actively pursue LNG sales opportunities and secure lender commitment for the Tangguh development.

In Trinidad, Atlantic LNG Train 3 (BP 42%) was commissioned in the second quarter. In June 2003, the government of Trinidad and Tobago approved the Atlantic LNG Train 4 project - one of the largest LNG production plants in the world with a capacity of 5.2 million tonnes (253 bcf) per annum of LNG production. Train 4 is currently under construction and due to start up at the end of 2005.

Table of Contents

GAS, POWER AND RENEWABLES

The strategic purpose of the Gas, Power and Renewables segment is to maximize the value of BP s gas through marketing, to enhance the value of BP s natural gas liquids production and to build a profitable renewables business.

The segment is organized into four main activities: marketing and trading; natural gas liquids (NGL); new market development and LNG; and solar and renewables. On January 1, 2004, a number of worldwide NGL producing assets were transferred to Gas, Power and Renewables from the Exploration and Production segment in order to consolidate the management of our global NGL activity. The transferred assets include seven gas processing plants, six of which are located in the mid-continent of the United States in the Permian, Anadarko and Hugoton basins, and one in Northern Europe. BP is currently a partner in the construction of a gas processing plant, NGL storage and export facilities in Egypt which has also been transferred to this segment. The total operating profit for these transferred assets was $106 million in 2003, but the data below has not been restated to include this amount.

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Turnover	65,445	37,357	39,442
Total operating profit	478	405	407
Total assets	10,260	6,927	5,775
Capital expenditure and acquisitions	359	408	492

We seek to maximize the value of our gas by targeting higher value customer segments in selected markets and to optimize supply around our physical and contractual assets. Marketing and trading activities are focused on the relatively open and deregulated natural gas and power markets of North America, the United Kingdom and certain parts of continental Europe. Some small elements of long-term natural gas contracting activity are also still included within the Exploration and Production business segment because of the nature of gas markets and the long-term sales contracts.

Our NGLs business is engaged in the processing, fractionation and marketing of ethane, propane, butanes and pentanes extracted from natural gas. Our NGL activity is underpinned by our upstream asset base and serves third-party markets for both chemicals and clean fuels and also supplies BP s petrochemicals and refining activities.

New market development and LNG activities involve developing opportunities to capture sales for our upstream natural gas resources and are conducted in close collaboration with the Exploration and Production business. Our strategy is to capture a greater share of the growth in the international demand for natural gas and is focused on markets which offer significant prospects for growth. These include the USA, Canada, UK, Spain and many of the emerging markets of the Asia Pacific region, notably China, where we believe there could be substantial growth in demand. For our undeveloped gas resources, we believe the key is to gain markets ahead of supply with a longer-term aim of allowing natural gas resources to move into the market with the same ease that oil does today. Our LNG activities involve the marketing of BP and third-party LNG.

Our solar and renewables activities include the development, production and marketing of solar panels and the development of wind farms on certain company sites.

Other activities include gas-fired power generation projects, where our principal focus is on projects that will utilize our equity natural gas. Projects that will reduce Group power costs and/or reduce overall emissions are also a key focus area. BP continues to pursue the development of hydrogen fuel technology.

Table of Contents

Capital expenditure and acquisitions for 2003 was $359 million compared with $408 million in 2002 and $492 million in 2001. Excluding acquisitions, capital expenditure for 2003, 2002 and 2001 was $359 million, $335 million and $352 million, respectively. Capital expenditure excluding acquisitions for 2004 is planned to be around $600 million (including the NGL activity transferred from the Exploration and Production segment on January 1, 2004); the increase over the 2003 level is due to higher spending on the Guangdong terminal in China and the power project in Korea.

Marketing and Trading Activities

Our gas marketing and trading activities are concentrated in the markets of North America and the United Kingdom. Gas sales volumes have increased from 18.8 billion cubic feet per day (bcf/d) in 2001 to 21.6 bcf/d in 2002 and 26.3 bcf/d in 2003. Most of this growth was realized in the USA and Canada. Canada volumes are reported in the Rest of World volumes.

	Years ended December 31,		
Gas sales volumes (a)	2003	2002	2001
	(million cubic feet per day)		
UK	2,631	2,372	2,641
Rest of Europe	441	399	213
USA	11,528	9,315	8,327
Rest of World	11,669	9,535	7,613
Total	26,269	21,621	18,794

(a) Includes marketing, trading and supply sales.

Our policy toward natural gas price risk is described in Item 11 Quantitative and Qualitative Disclosures about Market Risk on page 175.

North America

BP is one of the leading wholesale marketers and traders of natural gas in North America, the world s largest natural gas market, a business which has been built on the foundation of our position as the continent s leading producer of gas based on volumes. Our North American total natural gas sales volumes have grown from 13.4 bcf/d in 2001 to 16.1 bcf/d in 2002 and to 20.6 bcf/d in 2003. Of these sales volumes, 4.1 bcf/d was supplied from BP upstream producing operations in 2001, 4.0 bcf/d in 2002 and 3.6 bcf/d in 2003. The decline in BP production in 2003 was primarily due to the divestment of various properties.

Our North American natural gas marketing and trading strategy seeks to provide unconstrained market access for BP s equity gas, increase margin through targeting higher value customer segments and optimizing around our network of connected assets to reduce cost of goods sold. These assets include those owned by BP and those contractually accessed through agreements with third parties such as pipelines and terminals.

United Kingdom

The natural gas market in the UK is significant in size and is one of the most progressive in terms of deregulation when compared with other European markets. BP is one of the largest producers of natural gas in the UK based on volumes. Our total natural gas sales volumes in the UK were 2.6 bcf/d in 2003, 2.4 bcf/d in 2002 and 2.6 bcf/d in 2001. Of these volumes, 1.5 bcf/d (2002 1.6 bcf/d and 2001 1.7 bcf/d) were supplied by BP s Exploration and Production operations. The majority of natural gas sales are to commercial and industrial customers, power generation companies and to other gas wholesalers via long-term supply deals. Some of the natural gas continues to be sold under long-term natural gas supply contracts that were entered into prior to market deregulation.

We have a 10% interest in the Interconnector, a 1.9-bcf/d, 240-kilometre, 40-inch diameter subsea natural gas pipeline between Bacton in the UK and Zeebrugge in Belgium, which effectively links the natural gas markets of the UK and continental Europe.

Rest of Europe

We are building a natural gas and power marketing and trading business in Europe. Our interest in the European market is driven by the size and growth potential of the market, deregulation and the proximity of BP natural gas supplies.

In Europe, our main marketing activities are currently in Spain. The Spanish natural gas market has continued to grow and is now deregulated ahead of the deadlines set by European law. Since April 2000, we have built a market position which currently places us as number two behind the incumbent Gas Natural. In July 2002, we purchased 5% of the shares in Enagas, the owner and operator of the majority of the high pressure Spanish gas transport grid and three of Spain s four regasification terminals.

Natural Gas Liquids

	Years ended December 31,		
NGL sales volumes	2003	2002	2001
	(thousand barrels per day)		
UK			
Rest of Europe			
USA	164	196	221
Rest of World	182	214	189
Total	346	410	410

BP is one of the leading producers and marketers of NGLs, based on sales volumes, in North America. NGLs, which are produced from gas chiefly sourced out of Alberta, Canada and the US onshore and Gulf Coast, are used as a heating fuel and as a feedstock for refineries and chemicals plants. NGLs are sold to petrochemical plants and refineries at prevailing market prices. In addition, a significant amount of NGLs are marketed on a wholesale basis under annual supply contracts that provide for price redetermination based on prevailing market prices.

We operate natural gas processing facilities across North America with a total capacity of 8.2 bcf/d. These facilities, which we own or have an interest in, are located in major production areas across North America including Alberta, Canada, the US Rockies, the San Juan basin and coast of the Gulf of Mexico. We also own or have an interest in fractionation plants (which process the natural gas liquids stream into its separate component products) in Canada and the USA, and own or lease storage capacity in Alberta, Eastern Canada, the US Gulf Coast and mid-continent regions.

New Market Development and LNG

Our new market development and LNG activities are focused on developing worldwide opportunities to capture international natural gas sales for our upstream natural gas resources.

BP Exploration and Production has interests in major existing LNG projects in Trinidad and Tobago, ADGAS in Abu Dhabi, the North West Shelf in Australia and we also supply gas (from Virginia Indonesia Co.) to the Bontang LNG project in Indonesia. Additional LNG supplies are being pursued through expansions of existing LNG plants in Trinidad and Tobago, the North West Shelf in Australia and greenfield developments such as Tangguh in Indonesia.

In April 2003, a third LNG train commenced operations in Trinidad, with initial deliveries to Lake Charles, Louisiana and, following Federal Energy Regulatory Commission (FERC) approval, to the Cove Point regasification facility in Maryland. BP has capacity access at the Cove Point terminal, which was officially commissioned in August and is operated by Dominion Resources. The Government of Trinidad and Tobago announced in June 2003 its approval for the Atlantic LNG Train 4 project in Trinidad. BP will be the largest shareholder in the new plant as well as the largest supplier of gas for liquefaction at the plant.

At Bilbao, northern Spain, construction was completed on Europe s first integrated LNG regasification and power generation complex (BP 25%). In November, BP signed a six-year sales and purchase agreement with Oman LNG who will supply 3.6 million tonnes (175 bcf) of LNG over the contract term starting in 2004. The shipments are intended for BP customers in Spain.

The Tangguh LNG project (BP 37.2%) in Indonesia was selected as the preferred supplier of LNG to two South Korean companies SK Power Company Limited and POSCO in what is the world s fastest growing LNG market. POSCO is the world s second largest steel maker and SK Power, at the time, was 100% owned by SK Corporation (SK Corp), South Korea s largest oil refiner. The bid process to purchase LNG was the first undertaken by South Korea s private sector and is for the supply of up to 1.35 million tonnes per annum (66 bcf per annum) of LNG for a 20-year term starting in 2005.

In late December 2003, BP and BPMIGAS, Indonesia s executive agency for oil and gas, signed a Heads of Agreement with Sempra Energy LNG Corp. for a 20-year supply of LNG from Indonesian sources to markets in the US and Mexico. Under the agreement, 3.7 million tonnes of LNG per annum (180 bcf per annum) will be delivered from the Tangguh fields over a period of 15 years beginning in 2007 to Sempra s proposed LNG import and regasification terminal near Ensenada in Baja California, Mexico. Sempra s terminal, when completed, will have the capacity to process up to 1 bcf/d of natural gas. During 2004, the parties to the Agreement intend to negotiate a definitive agreement.

The successful Tangguh supply bids are in addition to the LNG sales contract secured in 2002 for 2.6 million tonnes per annum (127 bcf per annum) for the Fujian LNG project in China commencing in 2007. The Tangguh project now has agreements in various stages of completion for 7 million tonnes per annum (341 bcf per annum).

In Southeast China, the feasibility study report for the Guangdong LNG project (BP 30%) has been approved by the Chinese Government and the contract to form a joint venture company to construct the terminal and trunkline was signed in February 2004. First gas is scheduled for mid-2006 under the gas purchase agreement signed with Australia LNG in October 2002 that will involve deliveries from the North West Shelf project (BP 16.7%).

BP and Sonatrach announced in October 2003 that they are to form a joint venture that will provide the first new supplies of LNG to the UK market with scope to expand the arrangement to the US and other markets. The two companies were also successful in bidding for the long-term capacity rights in the Isle of Grain import regasification facility which is being developed on the Medway River, 20 miles east of London and which is owned and operated by National Grid Transco (NGT). The capacity rights will enable the two companies to source and then supply around 3.7 million tonnes per annum (182 bcf per annum) of LNG into the UK market from 2005 representing approximately 5% of UK demand.

In December 2003, BP submitted its pre-filing request to FERC to construct an LNG regasification terminal located on the Delaware River in the state of New Jersey. This was approved in early January

Table of Contents

2004. The pre-filing process is a collaborative approach, coordinated by FERC, under which the various federal and state agencies having jurisdiction are engaged in the process, along with other potential stakeholders. The Project anticipates receiving final FERC approval in the middle of 2005. This timing should allow BP to begin construction during the third quarter of 2005 with a view to beginning terminal operation during the second half of 2008.

In March and June 2003, BP took delivery of the second and third of three new leased LNG ships from Samsung Heavy Industries in Korea. These ships are mainly employed in supplying our BP customers in Spain with supply from ADGAS and Qatar under short-term contracts signed in 2002. Our first LNG ship, the British Trader celebrated its first full year of service in mid-November and is mainly employed in lifting LNG cargoes from Trinidad and delivering to the US.

Solar and Renewables

Global market trends indicate a general move towards greener energy sources, including solar and wind. BP intends to participate in this developing market.

During 2003, BP has repositioned BP Solar in order to improve business performance. A number of specific restructuring measures have been taken in order to improve short-term results with the need to provide opportunities for long-term growth. These decisions involved the consolidation of manufacturing operations in Spain, staff and other overhead reductions across the global business and restructuring provisions related to improving the overall efficiency of the business. In addition, BP completed its exit from the manufacture of thin film solar products (announced in 2002). This will allow the Group to focus on core markets supported by global technology and manufacturing functions.

Our solar energy business in 2003 grew 6% to 71 megawatts (MW) of solar panels generating capacity (2002, 67 MW). This growth rate was lower than historical rates due to a near-term focus on restructuring the business. BP began production in its new 30 MW facility in Madrid, Spain in 2003.

Our Home Solutions programme, an extension of our brand directly into California, New York and New Jersey residential markets, was launched in 2003. It successfully generated awareness around the benefits of solar and is expected to result in over 400 new installations of solar electric systems.

During 2003, BP successfully reached agreement with the Phillipines Department of Agricultural Reform to begin the installation of specific solar packages on 79 Agrarian Reform Communities (ARC) in the region of Mindanao, targeted at improving social welfare, increasing agricultural productivity and empowering local ARC and farmer s organizations. The solar packages include lighting and electricity supply, vaccine refrigeration, potable water provision, communal lighting, etc.

We are building expertise in wind energy and implementing wind projects on selected BP sites. In 2002 we started up our 22.5 MW wind farm at the Nerefco oil refinery (both the refinery and wind farm are jointly owned with ChevronTexaco (BP 69%)) in the Netherlands, which provides electricity to the local grid.

Other Activities

We participate in power projects that support the marketing and sale of our natural gas and in cogeneration projects (i.e., power plants that produce more than one type of energy, typically power and steam) on certain BP refining and chemical manufacturing sites.

During the year, a 776 MW gas-fired power generation facility and an associated LNG regasification facility at Bilbao, Spain (BP 25% share in each) were completed and entered commercial operation.

Table of Contents

In December 2003, BP announced that it would acquire a 35% interest in SK Power, a company that was established to develop, finance, construct and operate a 1,074 MW gas-fired combined cycle power plant located in Kwangyang Province, South Korea. This was subsequent to the selection of the Tangguh LNG project as preferred supplier of LNG to SK Power and POSCO, which is detailed in the New Market Development and LNG section above. SK Corp will retain the remaining 65% interest in the power plant, the total cost of which is expected to be around $600 million and is expected to commence operations in 2006.

We have two further power generation construction projects underway. A 50 MW cogeneration plant is under construction near Southampton, UK (BP 100%), and a 570 MW cogeneration plant as part of a 50:50 joint venture with Cinergy Solutions, Inc. at Texas City, Texas commenced operations in early 2004. Texas City is BP s largest refining and petrochemical complex. BP will supply natural gas to the Texas City plant and will use the excess generation capacity to support power marketing and trading activities.

We own a 400 MW gas-fired power plant at Great Yarmouth in the UK (BP 100%). We are operating the plant and selling electric power, with BP providing the natural gas to the plant.

In alternative fuels, we are exploring market opportunities for hydrogen fuel cells through participation in various industry projects and organisations promoting fuel cells for transport and stationary power.

REFINING AND MARKETING

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

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Turnover (a)	149,477	125,836	120,233
Total operating profit	2,292	1,921	1,990
Total assets	60,088	55,815	43,553
Capital expenditure and acquisitions	3,080	7,753	2,415
		($ per barrel)	
Global Indicator Refining Margin (b)	3.88	2.11	4.06

(a) Excludes BP s share of joint venture turnover of $453 million in 2003, $415 million in 2002 and $403 million in 2001.

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

There are four areas of business in Refining and Marketing: Refining, Retail, Lubricants and Business to Business Marketing. Our strategy is to grow through focused investment in key assets and market positions. In all areas, we aim for greater operational efficiency, and at the same time we seek to improve our asset portfolio. The acquisition of Veba s marketing and refining operations in 2002 provided an important addition of high quality assets to our operations.

Refining and Marketing manages a portfolio of assets that we believe are competitively advantaged across the chain of downstream activities. Such advantage may derive from several factors, including location, operating cost and physical asset quality.

We are one of the major refiners of gasoline and hydrocarbon products in the USA, Europe and Australia. We have significant retail and business to business market positions in the USA, UK, Germany and the rest of Europe, Australasia, Africa and Southeast Asia and we are enhancing our presence in China and Mexico.

Divestments mandated in connection with the Veba transaction as a condition of regulatory approval of the deal were completed with the sale of a 45% stake in Bayernoil refinery, an 18% stake in the Trans Alpine Pipeline (TAL), 741 retail stations in Germany, 55 stations in Hungary and 11 in Slovakia in separate packages to PKN Orlen and OMV AG, for a total of $580 million in cash and assumption of debt.

Table of Contents

In March 2004, BP and the Singapore Petroleum Company Limited (SPC) announced that conditional agreement had been reached for SPC to purchase BP s interests and one-third stake in Singapore Refining Company Private Limited (SRC) for $140 million. Subsequent to this announcement we were notified that the remaining shareholders wished to exercise their preemption rights. This will result in BP s one-third share being divided equally between the two remaining shareholders in SRC, namely Caltex Singapore Private Ltd and SPC. As a result, these two companies will also acquire BP s one-sixth equity interest in Tanker Mooring Services Company Pte Ltd (TMS). The transaction is expected to be concluded in mid-2004.

In the first quarter of 2004, BP and Lembaga Tabung Angkatan Tentera (LTAT) announced that agreement had been reached for LTAT to purchase BP s 70% shareholding in the BP Malaysia Sdn Bhd fuels business. Subject to receiving the necessary regulatory consents, this transaction is expected to be concluded during the third quarter of 2004.

The decision to divest the Singapore and Malaysian fuels business is part of BP s global strategy of concentrating on markets and segments where we believe we can obtain scale and build a significant presence. The sale has no impact on BP s other activities in Malaysia.

Capital expenditure and acquisitions in 2003 was $3,080 million compared with $7,753 million in 2002 (including $5,038 million for the Veba acquisition) and $2,415 million in 2001. Excluding acquisitions, capital expenditure was $3,006 million in 2003 compared with $2,682 million in 2002 and $2,386 million in 2001. Capital expenditure excluding acquisitions is expected to be around $2.8 billion in 2004.

Refining

The Company s global refining strategy is to own interests in and to operate advantaged refineries that provide distinctive returns through vertical integration with our marketing and trading operations and horizontal integration with other parts of the Group s business. Refining s focus is to maintain and improve competitive position through sustainable, safe, reliable and efficient operations of the refining system and disciplined investment for growth.

For BP, the strategic advantage of a refinery relates to the refinery s location, the refinery s scale and its configuration to produce fuels in line with the demand of the region from low-cost feedstocks. Efficient operations are measured primarily using regional refining surveys conducted by third parties. The surveys assess our competitive position against benchmarked industry measures for margin, energy efficiency and costs per barrel. Investments in our refineries are focused on maintaining our competitive position and developing the capability to produce the cleaner fuels that meet our customers and the communities requirements.

In December 2003, we announced the sale of our European Special Products business, including the Neuhof base oil refinery in Hamburg, Germany. The sale was completed in January 2004.

In June 2004, the shareholders of the ATAS Refinery (Anadolu Tasfiyehanesi A.S.) in Mersin, Turkey announced that the refinery will continue its operations as a fuels supply terminal henceforth. ATAS will commence a process to change its operations to become a terminal in early September 2004 and will be operated by the same partners and continue to supply petroleum fuels to southern Turkey.

Table of Contents

The following table summarizes the BP Group interests and crude distillation capacities (at December 31, 2003):

	Refinery	Group interest (b) %	Crude distillation capacities (a) (mb/d) Total	BP Share
UK	Coryton*	100.00	172	172
	Grangemouth*	100.00	207	207
Total UK			379	379
Rest of Europe				
France	Lavéra*	100.00	218	218
	Reichstett	17.00	84	14
Germany	Bayernoil*	22.50	267	60
	Gelsenkirchen*	50.00	272	136
	Karlsruhe	12.00	308	37
	Lingen*	100.00	87	87
	Neuhof*	100.00		
	Schwedt	18.75	221	42
Netherlands	Nerefco*	69.00	400	276
Spain	Castellón*	100.00	110	110
Turkey	Mersin* (c)	68.00	100	68
Total Rest of Europe			2,067	1,048
USA				
California	Carson*	100.00	260	260
Washington	Cherry Point*	100.00	232	232
Indiana	Whiting*	100.00	420	420
Ohio	Toledo*	100.00	155	155
Texas	Texas City*	100.00	470	470
Total USA			1,537	1,537
Rest of World				
Australia	Bulwer*	100.00	92	92
	Kwinana*	100.00	139	139
New Zealand	Whangerei	23.66	109	25
Singapore	SRC*+	33.00	248	82
Kenya	Mombasa	17.00	90	15
South Africa	Durban	50.00	182	91
Total Rest of World			860	444
Total			4,843	3,408

* Indicates refineries operated by BP.

Indicates lubricants refinery which does not have crude distillation capacity. The sale of our interest in this refinery was completed in January 2004.

+ The sale of our interest in this refinery was announced in March, 2004.

51

Table of Contents

(a) Gross rated capacity is defined as the maximum achievable utilization of capacity (24-hour assessment) based on standard feed.

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

(c) The closure of the refinery and transformation to a fuels terminal was announced in June 2004.

The following table outlines by region the volume of crude oil and feedstock processed by BP for its own account and for third parties and for the Group by other refiners under processing agreements. Corresponding BP refinery capacity utilization data are summarized.

	Years ended December 31,		
	2003	2002	2001
Refinery throughputs (a)			
	(thousand barrels per day)		
UK	397	389	364
Rest of Europe	932	918	663
USA	1,386	1,439	1,526
Rest of World	382	357	376
	3,097	3,103	2,929
For BP by others		14	14
Total	3,097	3,117	2,943
Refinery capacity utilization			
Crude distillation capacity at December 31, (b)	3,408	3,534	3,259
Crude distillation capacity utilization (c)	91%	91%	94%
United States	91%	93%	95%
UK and Rest of Europe	90%	91%	94%
Rest of World	94%	85%	93%

(a) Refinery throughput reflects crude and other feedstock volumes.

(b) Crude gross rated capacity is defined as the maximum achievable utilization of capacity (24 hour assessment) based on standard feed.

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

BP s 2003 refinery throughput increased in the Rest of Europe compared with 2002, primarily due to higher margins. In 2002 lower margins required that many of the refineries reduce throughput. The decrease in the USA in 2003 was due to the sale of the Yorktown, Virginia refinery in May 2002, reducing capacity by 23 mb/d, and the balance was due to major turnaround activities in 2003 compared with 2002.

Capacity utilization in the US was affected by various power outages and the hurricane Claudette during 2003.

Table of Contents

Marketing

Marketing comprises three business areas: Retail, Lubricants and Business to Business Marketing. We market a comprehensive range of refined oil products worldwide. These products include gasoline, gasoil, marine and aviation fuels, heating fuels, LPG, lubricants and bitumen.

The following table sets out refined product sales by area.

	Years ended December 31,		
Sales of refined products (a)	2003	2002	2001
	(thousand barrels per day)		
Marketing sales:			
UK (b)	271	253	266
Rest of Europe	1,316	1,467	1,062
USA	1,797	1,874	1,866
Rest of World	648	586	603
Total marketing sales (c)	4,032	4,180	3,797
Trading/supply sales (d)	2,692	2,383	2,409
Total refined products	6,724	6,563	6,206
	($ million)		
Proceeds from sale of refined products	102,003	87,520	82,241

(a) Excludes sales to other BP businesses.

(b) UK area includes the UK-based international activities of Refining and Marketing.

(c) Marketing sales are sales to service stations, end-consumers, bulk buyers, jobbers, i.e., third parties who own networks of a number of service stations and small resellers.

(d) Trading/supply sales are to large unbranded resellers and other oil companies.

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

Years ended December 31,

Marketing sales by product	2003	2002	2001
	(thousand barrels per day)		
Aviation fuel	532	529	515
Gasolines	1,694	1,744	1,659
Middle distillates	1,199	1,232	1,077
Fuel oil	312	451	351
Other products	295	224	195
Total marketing sales	4,032	4,180	3,797

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

BP s marketing sales volumes were lower in 2003 mainly due to planned portfolio changes. The planned portfolio impacts were the sale of Veba retail sites in Germany, the sale of retail sites in Cyprus and the transfer of retail sites in Russia to TNK-BP.

Table of Contents

Retail

Success in retail relies on having superior locations, a superior offer, and executing that offer well, time after time. Our strategy is to focus our capital into the best locations in the high growth metropolitan markets where we can be number one or two in market share, whilst continuing to upgrade our offers and drive for operational efficiencies.

We are working to make our offer continuously more attractive to customers so that they come preferentially to BP. There are two components of our retail offer. The convenience offer, where we sell convenience items to customers from advantaged locations in metropolitan areas and the fuel offer, which we deploy in all our markets, in many cases without the convenience offer. We have a high quality shop offer in each of our key markets, whether it is the new BP Connect offer in Europe and the Eastern USA, am/pm west of the Rocky Mountains, or the Aral offer in Germany. Each of these brands carries a very strong offer itself, but we are also sharing best practices between them. We have also upgraded our fuel offer with the introduction of Ultimate gasoline and diesel, which have greater efficiency and power and lesser environmental impacts. We launched the new fuels in UK, Spain, Greece and three markets in the United States during the past year.

Our strategic focus has resulted in investment in our convenience offer through increased numbers of BP Connect sites and in our premium fuels offer with the rollout of BP Ultimate diesel and gasoline. This strategic focus will continue going forward with roll-out of our convenience and premium fuels offers in high-growth metropolitan markets where we can be number one or two.

Our focus on operational efficiencies through targeted programmes of performance improvement has allowed us to increase our fuel throughput per site and increase our store sales per square metre. This strategic focus on executing excellence will continue going forward as we target increased fuel and store efficiencies.

Across the network, our large format stores achieved store sales growth above the market average, and we plan to invest primarily in additional store space on existing real estate in our core metropolitan convenience markets. During 2003, our same store sales across Australia, Europe and the USA grew 3%, a lower rate than the previous year driven by overall weaker economic growth. Same site fuel volumes grew in these areas by 0.5%.

	Years ended December 31,		
Shop sales (a)	2003	2002	2001
		($ million)	
UK	567	527	458
Rest of Europe	3,000	2,638	904
USA	1,620	1,585	1,510
Rest of World	521	421	362
Total	5,708	5,171	3,234
Direct managed	2,090	1,869	1,650
Franchise	3,508	3,216	1,504
Shop alliances	110	86	80

Total	5,708	5,171	3,234

(a) Shop sales reported are sales through direct-managed stations, franchises and the BP share of shop alliances and joint ventures. Sales figures exclude sales taxes and lottery sales but include quick service restaurant sales.

Table of Contents

Our retail network is largely concentrated in Europe and the USA, with established operations in Australasia, Southeast Asia and Southern Africa. We are developing networks in China and Mexico. In 2003, we concluded the mandatory divestments of about 800 stations in Germany following the acquisition of the Aral network (approximately 3,200 service stations in Germany and Central Europe) in 2002. The rationalization of the portfolio includes the divestment of the Aral-branded sites in Slovakia and Hungary.

BP s worldwide network consists of approximately 28,000 stations branded BP, Amoco, ARCO and Aral. Whilst in Austria and Poland all sites have now been rebranded to BP, in Germany the network is about to become single branded Aral. As planned, the 41 stations in which we have an interest in the Moscow metropolitan area have become part of TNK-BP, our Russian joint venture, with effect from the third quarter of 2003.

BP expects its total number of service stations to decline further in future years reflecting the continued optimization of our retail network and efforts to increase the consistency of our site offer. We also continue to improve the efficiency of our retail asset network through a process of regular review. During 2003, further portfolio upgrading has been concluded by divesting sites and networks.

In 2003 we accelerated our rollout of BP Connect sites primarily in the UK and USA continuing our retail strategy that builds on our advantaged locations, strong market positions and brand. These are service stations with large convenience stores featuring our branded BP Connect offer that provide our customers cleaner fuels, a wider range of services and a distinctive food offer. The new BP Connect sites include service stations that are new, those that have been rebuilt, and those where extensive upgrading and remodelling has taken place. At December 31, 2003, 496 BP Connect stations were open (this count reflects the transfer of 41 sites to TNK-BP). In addition the number of stations with the new BP Helios design increased by about 6,300 during 2003 to a total of 16,745.

At December 31, 2003, BP s retail network in the USA comprised approximately 14,700 service stations of which approximately 10,600 were owned by jobbers. Through regular review and execution of business opportunities we are continuing to concentrate our ownership of real estate in markets designated for development of the convenience offer. In the USA, we increased the number of stations with the new BP Helios design by approximately 5,100 in 2003.

In the UK and the Rest of Europe, BP s network comprised about 9,500 service stations at December 31, 2003. In 2003 we opened 49 BP Connect sites in Europe with the majority being in metropolitan areas of the UK. The number of stations throughout Europe that use the new BP Helios design was about 6,400 by the end of 2003.

Our distinctive fuel product offer has expanded through the launches of our BP Ultimate gasoline and diesel products in Greece, Portugal, Spain and the UK and expansion across the network in the USA and Australia.

At December 31, 2003, BP s retail network in the rest of the world comprised some 3,600 service stations. Our established networks are primarily in Australia, New Zealand, Southern Africa and Southeast Asia. BP is growing in China through two strategic alliances. BP s joint venture with PetroChina in Guangdong Province in the coastal region of China had 400 stations at December 31, 2003. BP has agreed in principle with Sinopec to form a second alliance through a joint venture to acquire, revamp or build 500 fuels service stations in the Zhejang Province, in Eastern China. The Sinopec joint venture is expected to start development of sites in 2004, subject to obtaining government approvals.

Lubricants

We manufacture and market lubricant products and also supply related products and services to business customers and end-consumers in over 60 countries directly, and to the rest of the world through local distributors. Our business is concentrated on the higher margin sectors of automotive lubricants, especially in the consumer sector, but also has a strong presence in business markets such as commercial vehicle fleets, aviation, marine and specialized industrial segments.

Table of Contents

We aim to achieve growth by further focusing our resources and capabilities on selected market sectors. Customer focus, distinctive brands and superior technology remain the cornerstone of our long-term strategy.

BP markets through its two major brands, Castrol and BP, and several secondary brands including Duckhams and Veedol. The Veba acquisition strengthened our lubricants position in Germany and in Central Europe with the addition of the Aral brand to the BP Lubricants portfolio.

In the consumer sector of the automotive segment we supply lubricants, other products and related business services to intermediate customers (e.g., retailers, workshops) who in turn serve end-consumers (e.g., car, motorcycle, leisure craft owners) in the mature markets of Western Europe and North America and also in the fast growing markets of the developing world (e.g., Russia, China, India, Middle East, South America and Africa). The Castrol brand is recognized worldwide and we believe it provides us with a significant competitive advantage.

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

Business to Business Marketing

Our Business to Business Marketing encompasses marketing a comprehensive range of products to other businesses. This business aims to build relationships with customers that not only purchase a wide variety of products in large quantities but also additional services. Logistics play a crucial role in this business. We aim to attract more customers through innovation in multi-product offers and cleaner fuels, packaged with a range of value-added services and solutions.

Our aviation business sells fuels and lubricants to airlines and general aviation customers, as well as providing technical services to airlines and airports. During the last few years, our aviation business has strengthened its position in established markets and pursued opportunities in new or emerging markets. The business now markets in approximately 95 countries and is the third largest jet fuel supplier globally.

Our liquefied petroleum gas (LPG) businesses sell bulk, bottled, automotive and wholesale products to a wide range of customers in over 20 countries. During the past few years, our LPG business has strengthened its position in established markets, pursued opportunities in new and emerging markets and rationalized its operations. During 2003, we continued to grow our LPG business in China, where we now have sole ownership over three key importing facilities in the important markets of Eastern and Southern China. With imports of over 1.5 million tonnes in 2003 and the capacity to grow to 2.5 million tonnes per annum, BP is now the number one importer of LPG into the China market.

In our marine business, we supply lubricants and fuels on a global basis to major shipping companies as well as to smaller operators. We are the leading global participant in the marine lubricants market where we operate in over 800 ports, have offices in 40 countries and supply points in 80 countries.

In our specialized industrial segment, we supply metal-working fluids and lubricants alongside a range of business services, such as fluid management, to equipment manufacturing customers. We also have a significant high performance industrial lubricants business in some key markets.

Our European Business Marketing (EBM) business comprises a portfolio of Business to Business, Business to Consumers, Bitumen and certain Cards activities throughout Europe. Thus, EBM supplies commercial and industrial customers and private end consumers with fuel oil, motor spirit, diesel, heating oil and lubricants. EBM also offers a fuel and service card for fleet and truck customers, as well as supplying industrial customers with bitumen for the road and roof industries.

Table of Contents

Supply and Trading

We are one of the world s major traders of crude oil and refined products, dealing extensively in physical and futures markets. Our portfolio of purchases and sales is spread among spot, term, exchange and other arrangements, and covers a range of sources and customers to match the location and quality requirements of the Group s refineries and various markets, whilst seeking to ensure flexibility and cost competitiveness. In addition, the Group s oil-trading function undertakes trading in physical and paper markets in order to contribute to the Group s income.

Refer to Item 11 Quantitative and Qualitative Disclosures About Market Risk on page 170 for further information.

Transportation

Our Refining and Marketing business owns, operates or has an interest in extensive transportation facilities for crude oil, refined products and petrochemical feedstock in the US. It also has interests in a number of crude oil and product pipelines in the UK, the Rest of Europe and in the US.

We transport crude oil to our refineries principally by ship and through pipelines from our import terminals. We have interests in crude oil pipelines in the UK, the Rest of Europe and in the US.

Bulk products are transported between refineries and storage terminals by pipeline, ship, barge, and rail. Onward delivery to customers is primarily by road. We have interests in major product pipelines in the UK, the Rest of Europe and in the US.

In September, our BP Pipelines business closed the transaction for the sale of 90% of its Cushing to Chicago Pipeline System (CCPS) to Enbridge retaining 10% in line with Pipeline strategy to maximize the value of our assets.

Shipping

BP Shipping owns or operates an international fleet of crude oil and product tankers and LNG carriers transporting cargoes for the Group and for third parties. It also offers a wide range of marine-related services to Group and third-party customers.

Excluding BP companies in the USA, at December 31, 2003 the Group controlled or operated an international fleet of twenty-eight oil tankers and eight LNG ships, with capacity of approximately 1.08 million cubic meters. The Group had four Very Large Crude Carriers, fourteen Medium Crude Carriers, nine Product Carriers, and one North Sea shuttle tanker. It also operated three LNG carriers to trade globally, four LNG carriers for Abu Dhabi contracted gas and one LNG carrier for the Western Australia North West Shelf (NWS) project. BP holds an interest in six NWS gas carriers, of which this is one.

BP companies in the USA had seven Large Crude Carriers, three Medium Crude Carriers, and four Product Carriers totalling approximately 1.4 million dead weight tonnes (dwt) on long-term charter. BP owns four barges totalling 0.1 million dwt.

BP is in the middle of a new building programme, which saw 12 leased ships delivered into service in 2003.

These ships will be manned by either BP Maritime Services personnel or by those from a third party who provide the manning services for some of our new ships, whilst operating to BP Shipping s standards and reporting requirements. All the chartering of ships is controlled by BP Shipping, and the ships are utilized to carry either BP cargoes or third-party cargoes.

Table of Contents

PETROCHEMICALS

Our Petrochemicals business is a major producer of chemicals and plastics through subsidiaries, joint ventures and associated undertakings. The petrochemicals segment is also responsible for the supply, marketing and distribution of chemical products to bulk, wholesale and retail customers. BP has operations principally in the USA and Europe. We are increasing our activities in the Asia-Pacific region.

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Turnover (a)	16,075	13,064	11,515
Total operating profit	623	541	(102)
Total assets	17,649	16,595	15,098
Capital expenditure and acquisitions	775	823	1,926
		($/tonne)	
Chemicals Indicator Margin (b)	112	104	109

(a) Excludes BP s share of joint venture turnover of $434 million in 2003, $511 million in 2002 and $102 million in 2001.

(b) The Chemicals Indicator Margin (CIM) is a weighted average of externally based industry product margins. It is based on market data collected by Nexant in their quarterly market analyses, which we weight based on BP s product portfolio. While it does not cover our entire portfolio, it includes a broad range of products. Among the products and businesses covered in the CIM are the olefins and derivatives, the aromatics and derivatives, linear alpha-olefins (LAOs), acetic acid, vinyl acetate monomers and nitriles. Not included are fabrics and fibres, plastic fabrications, poly alpha-olefins (PAOs), anhydrides, engineering polymers and carbon fibres, speciality intermediates and the remaining parts of the solvents and acetyls businesses. This measure is not BP specific, rather it is an indicator of relative industry profitability and BP s actual margins will differ. While not entirely representative of BP s complete range of products, we believe it does provide investors with useful information about the environment for BP s products.

Our strategy is focused on seven core products, with the aim of providing world-class performance in all aspects of our activities. We are now managing our portfolio in two distinct parts Aromatics and Acetyls (A&A), comprising PTA, PX and acetic acid, and Olefins and Derivatives (O&D) comprising ethylene and related co-products, polypropylene, HDPE and acrylonitrile. On April 27, 2004, we announced our intention to set up a separate corporate entity for the O&D businesses. It is our intention to make a public offering of this new entity at an appropriate time. Based on the estimated lead-time required for such a transaction, and depending on market circumstances, we are aiming to make such an offering in the second half of 2005. We intend to retain and grow the A&A businesses, which will be transferred to the Refining and Marketing segment on January 1, 2005.

Our core products are eventually used in the manufacture of a wide variety of consumer goods, including plastic drinks bottles, computer housings, adhesives, inks, rigid packaging, pipes, food packaging and automobile components, as well as textiles for clothes and carpets. We compete through proprietary technology, leadership positions and value associated with the integration of group hydrocarbons and sites. Our investment and divestment activities are aligned with this strategy.

Significant investment activities during 2003:

- In January, we commissioned a new 350-ktepa PTA plant at Zhuhai in southern China.
- In April, China American Petrochemical Company (CAPCO), a BP associated undertaking in Taiwan, started producing from its new 700-ktepa PTA unit.

Table of Contents

BP increased the investment in our South Korean and Taiwanese joint ventures. BP acquired an incremental 9% interest in CAPCO to obtain a 59% holding and increased our ownership from 35% to 47% in Samsung Petrochemicals Company (SPC).

BP Solvay Polyethylene North America and its joint venture partners started a new and more efficient High Density Polyethylene (HDPE) plant at Cedar Bayou and discontinued BP Solvay Polyethylene North America s higher cost unit at Deer Park, Texas.

The Shanghai Ethylene Cracker Complex (SECCO) (BP 50%) is on schedule to start up during 2005. At the end of 2003, construction was approximately 50% complete.

BP Solvay Polyethylene Europe (BP 50%) commenced full-scale production from the newly constructed HDPE plant at Lillo, Belgium.

Capital expenditure and acquisitions in 2003 was $775 million compared with $823 million in 2002 and $1,926 million in 2001. Excluding acquisitions, capital expenditure was $775 million, $810 million and $1,446 million respectively. Capital expenditure excluding acquisitions is expected to be around $900 million in 2004.

Significant divestment activities during 2003:

During the second quarter, we divested PT Petrokimia Nusantara Interindo (PT Peni) (BP 75%), a polyethylene joint venture in Indonesia.

In March 2003, we announced our intention to sell our wholly owned specialty intermediate chemicals businesses including trimellitic anhydride (TMA), purified isophthalic acid (PIA) and maleic anhydride (MAN). The sale was completed on May 28, 2004.

Businesses outside of our A&A and O&D portfolios, their co-products, and closely related activity have been reviewed for sale, and to this end we announced in late March 2004 our intention to sell our Fabrics and Fibres and our LAO/PAO businesses. The LAO/PAO businesses may be included in the intended public offering of our O&D business.

During 2003, overall BP petrochemicals production capacity grew 2%.

The following table shows BP production capacity in kilotonnes per annum (ktepa) by product and by region at December 31, 2003.

	UK	Rest of Europe	USA	Rest of World	Total
Capacity by region (a)					
PTA		1,027	2,481	3,363	6,871
PX		482	2,320		2,802
Acetic acid	781		491	926	2,198

Ethylene and related co-products	1,575	4,198	2,246	64	8,083
Polypropylene	270	1,052	1,371		2,693
HDPE	165	618	490	184	1,457
Acrylonitrile/Acetonitrile		300	792		1,092
Other	1,839	4,926	2,221	301	9,287
Total	4,630	12,603	12,412	4,838	34,483

(a) Includes BP share of joint ventures, associated undertakings and other interests in production.

Table of Contents

BP is the world s third largest petrochemicals company in terms of production capacity, and currently manufactures and markets about 28 million tonnes of products each year.

As a result of growth and portfolio management, our seven core products now account for 70% of our capital employed.

The seven core products within our portfolio are:

Aromatics and Acetyls

Purified Terephthalic Acid (PTA)

PTA is important as a raw material for the manufacture of polyester used in textiles, fibres and films. BP is the world s largest producer of PTA, with an interest in approximately 20% of the world s PTA capacity. PTA is manufactured at Cooper River, South Carolina and Decatur, Alabama in the USA, Geel in Belgium, and Kuantan in Malaysia. We also produce PTA through BP Zhuhai (BP 85%), Samsung Petrochemical Company (SPC) in South Korea (BP 47.41%), CAPCO in Taiwan (BP 59.02%), PT AMI in Indonesia (BP 50%) and Rhodiaco in Brazil (BP 49%). The sites in Taiwan, South Korea, Belgium and the USA are among the largest PTA production sites in the world.

Major Activities

In 2003, BP Zhuhai (BP 85%) commissioned a 350-ktepa unit in southern China and CAPCO started up their new 700-ktepa unit in Taichung, Taiwan. Both projects use BP s proprietary PTA technology and were delivered safely, on budget and on time.

BP increased the investment in our Korean and Taiwanese joint ventures. BP acquired an incremental 9% interest in CAPCO to obtain a 59% holding and increased our ownership from 35% to 47% in SPC. As a result, BP s equity PTA capacity in Asia has increased by 14% to around 3 million tonnes a year.

We announced in early June that, due to market factors, we have decided to delay the final sanctioning of the proposed new world-scale PTA plant at Geel in Belgium. We will continue to explore potential options for further developing this project as and when the business environment improves. BP remains committed to the PTA business in Europe.

In May 2004, BP signed a letter of intent to examine the viability of expanding production at the BP Zhuhai (BP 85%) PTA plant from 350,000 tonnes per year to 1.2 million tonnes per year.

Paraxylene (PX)

PX is feedstock for the production of PTA and is manufactured from mixed xylene streams acquired from BP refineries and third-party producers. We are currently one of the world s leading producers of PX in terms of capacity. Our plants are located in Decatur, Alabama and Texas City, Texas in the USA and Geel in Belgium. We engage with Refining and Marketing to optimize sourcing of xylenes feedstock from BP refineries.

60

Table of Contents

Acetic Acid

We are a major manufacturer and supplier of acetic acid, a versatile chemical used in a variety of products such as foodstuffs, textiles, paints, dyes and pharmaceuticals. Acetic acid is also used in the production of PTA. BP has acetic acid operations at Hull, UK; in the USA through a capacity rights agreement with Sterling Chemicals at Texas City, Texas; in South Korea through Samsung BP Chemicals (BP 51%); in China through Yangtze River Acetyls Company (BP 51%) and in Malaysia through BP Petronas Acetyls Sdn. Bhd. (BP 70%).

Major Activities

- The joint venture project to build a 300-ktepa acetic acid plant in Taiwan with Formosa Chemicals and Fibre Corporation (BP 50%) continued to progress in 2003 and is on schedule to start up around mid 2005. Engineering contracts were awarded at the end of 2003.

- BP Petronas Acetyls Sdn. Bhd. (BP 70%) completed a debottleneck project in Kertih, Malaysia in the first quarter of 2003 which increased capacity to 500 ktepa.

- Expansion of Yangtze River Acetyls Company (Yaraco), China has progressed. The engineering, procurement and construction contract was awarded by BP in early 2004. Target expansion to 350 ktepa is planned to be completed by early 2005.

- BP has a 50% interest in a newly proposed 500-ktepa acetic acid plant in Nanjing, China. The heads of agreement was signed in May 2004, and completion of the plant is projected at the end of 2006.

Olefins and Derivatives

Ethylene (and Related Co-products)

We produce and market the basic petrochemical building blocks, known as olefins, that are used primarily as raw material for other chemical products. These olefins are derived from the steam cracking of liquid and gaseous hydrocarbons.

Olefins - ethylene, propylene and butadiene - are produced by crackers at Grangemouth, UK; Lavéra, France (Naphtachimie - BP 50%); Köln, Germany and Chocolate Bayou, Texas in the USA. Olefins are also manufactured by Ethylene Malaysia Sdn. Bhd. (BP 15%) at Kertih, Malaysia and by BP Refining and Petrochemicals (BPRP) at Gelsenkirchen and Munchmunster in Germany. Crackers produce the raw materials for the production of derivative products including polyethylene, polypropylene, acrylonitrile, styrene, ethanol and ethylene oxide, which are also produced at various BP plants.

Major Activities

During 2003, we continued to integrate the former Veba operations into our own. The company changed its name to BP Refining and Petrochemicals (BPRP) from Veba Oel Refining and Petrochemicals (VORP).

The construction of the 900-ktepa cracker complex in Shanghai by SECCO (BP 50%) progresses smoothly. By early 2004, construction was approximately 50% complete and is on schedule to startup in 2005.

In the USA, construction began on a project to increase ethylene capacity at Chocolate Bayou, Texas by 295 ktepa.

Table of Contents

Polypropylene

Polypropylene is used for moulded products, fibres and films. We are the second largest producer of polypropylene in the world, with manufacturing facilities at Chocolate Bayou and Deer Park, Texas and Carson City, California in the USA; Lillo and Geel, Belgium, Lavéra and Sarralbe, France and Grangemouth, UK.

Major Activities

The petrochemicals complex in Shanghai, planned by SECCO (BP 50%), is expected to add 250 ktepa of polypropylene when completed in 2005.

High Density Polyethylene (HDPE)

Polyethylene is used for packaging, pipes and containers. BP Solvay Polyethylene Europe (BP 50%) has HDPE plants at Grangemouth, UK; Lillo, Belgium; Sarralbe and Lavéra, France; and Rosignano, Italy. In addition, BP Solvay Polyethylene North America (BP 49%) has a HDPE plant at Deer Park, Texas and a joint venture plant with Chevron Philips Chemical Company at Cedar Bayou, Texas. We also produce HDPE through Polyethylene Malaysia Sdn. Bhd. (BP 60%) at Kertih, Malaysia.

Major Activities

BP Solvay Polyethylene North America (BP 49%), along with joint venture partner Chevron Philips Chemical Company, started a new 317-ktepa world scale HDPE plant (BP 25%) at Cedar Bayou, Texas. As a result, BP Solvay Polyethylene North America discontinued a 118-ktepa plant of smaller and less efficient capacity at Deer Park, Texas.

The sale of PT Peni (BP 75%), a 450-ktepa polyethylene plant in Merak, Indonesia was completed in April.

Exit of Bataan Polyethylene Company plant (BP 39%) continued to progress in 2003.

The complex in Shanghai, planned by SECCO (BP 50%), is expected to add 600 ktepa of HDPE/linear-low density polyethylene (LLDPE) when completed in 2005.

Acrylonitrile

BP is the world s largest producer and marketer of acrylonitrile, which is used in textiles and plastics for the automobile and consumer goods industries. We operate two acrylonitrile plants at Green Lake, Texas and Lima, Ohio in the USA. Green Lake, with a capacity of 460 ktepa, is the largest acrylonitrile production site in the world. Acrylonitrile is also produced at Köln, Germany and through a capacity rights agreement with Sterling Chemicals at Texas City, Texas. Additionally, BP is the world s largest producer and marketer of the co-product, acetonitrile, primarily sold for pharmaceutical applications.

Major Activities

The planned SECCO complex in Shanghai (BP 50%) is intended to produce 260 ktepa of acrylonitrile when complete in 2005.

62

Table of Contents

Other Products

In addition to the seven core products, we are involved in a number of other linked products. These include LLDPE and low density polyethylene (LDPE) which are used in a wide range of applications including packaging, as is styrene. Ethylene oxide and ethanol are all used in solvents, coatings and the automotive industry. LAOs are used as comonomers for polyethylenes and to manufacture synthetic lubricants, plasticizers, surfactants and oilfield chemicals. PAOs are used in both synthetic lubricants and surfactants. PIA is used for isopolyester resins and gel coats. Napthalene dicarboxylate (NDC) is used for photographic film and specialized packaging. Polybutene is used in lubricants and fuel additives. TMA is used by the automotive and consumer goods industries. Butanediol (BDO) is used in synthetic materials and engineering plastics. MAN is used in a wide range of plastics and resins. Ethyl acetate and vinyl acetate monomer (VAM) are used in coatings and textile applications. Polypropylene resins are also converted into woven and non-woven fabrics for industrial products, such as, carpet backing, geo-textiles and various packaging materials.

BP operates LLDPE plants at Grangemouth in the UK and Köln in Germany. The complex at Köln also produces LDPE.

We operate styrene monomer plants at Texas City, Texas in the USA and Marl in Germany. Polystyrene plants are operated at Marl in Germany, Wingles in France and Trelleborg in Sweden. Expanded polystyrene plants are operated at Wingles and Marl.

PIA is produced at Joliet, Illinois in the USA and in Geel, Belgium. NDC is produced at our plant in Decatur, Alabama in the USA.

BP manufactures polybutene at Whiting, Indiana in the USA and at Lavéra, France.

LAOs are produced at our facilities in Pasadena, Texas in the USA; Joffre, Canada and Feluy, Belgium. We manufacture PAOs at our facilities in Deer Park, Texas in the USA and Feluy, Belgium.

TMA and MAN are produced at Joliet, Illinois in the USA. We manufacture BDO using our proprietary technology in a world-scale plant at Lima, Ohio in the USA.

In South Korea, the Asian Acetyls Company (BP 34%) operates a 150-ktepa plant producing VAM, a derivative of acetic acid.

Major Activities

We have implemented or announced a number of structural changes that we believe should significantly improve our portfolio. The most significant changes were as follows:

In March 2003 we announced our plan to sell our wholly-owned TMA, PIA and MAN business in Joliet, Illinois in the USA and PIA produced at our integrated aromatics and derivatives complex in Geel, Belgium. The sale was completed on May 28, 2004.

We sold our share in AG International Chemicals Company (BP 50%), a joint venture with Mitsubishi Gas Chemical Company in Japan manufacturing PIA.

We completed the divestment of Burmah Castrol Chemicals with the sale of Fosroc Mining and Sericol in January 2003.

We exited the ethylene vinyl acetate copolymers (EVA) business at Köln, Germany.

In February 2004, we announced the closure of the last manufacturing plant at Baglan Bay, UK. Production of isopropanol ceased in March, 2004.

In March 2004, we announced our intention to sell our Fabrics and Fibres and our LAO/PAO businesses. The LAO/PAO businesses may be included in the intended public offering of our O&D business.

On April 27, 2004, we announced our intention to set up a separate corporate entity for the O&D businesses. It is our intent to make a public offering of this entity at the appropriate time. Based on the estimated lead time required for such a transaction, and depending on market circumstances, we are aiming to make such an offering in the second half of 2005.

Manufacturing Facilities

BP has large-scale manufacturing facilities in Europe and the USA. The Group s major sites, with our share of their capacities, are: Grangemouth (2,930 ktepa) and Hull (1,595 ktepa) in the UK; Lavéra (1,800 ktepa) in France; Marl (630 ktepa), Gelsenkirchen (1,460 ktepa) and Köln (4,515 ktepa) in Germany; Geel (2,155 ktepa) in Belgium; and Texas City, Texas (2,800 ktepa), Chocolate Bayou, Texas (2,635 ktepa), Decatur, Alabama (2,280 ktepa), and Cooper River, South Carolina (1,330 ktepa) in the USA.

We aim to grow in the Asia-Pacific region, which we believe offers good prospects for demand growth. Our intention is to build further on the positions that the Group now holds in the region through planned investment and commercial relationships, such as joint ventures. Our share of capacity in Asia amounts to 4,450 ktepa, as follows: Indonesia (215 ktepa), South Korea (1,005 ktepa), Malaysia (1,460 ktepa), Taiwan (1,205 ktepa) and China (565 ktepa). When on line in 2005, our share of the complex in Shanghai, planned by SECCO (BP 50%), is expected to add 1,600 ktepa of capacity.

	Years ended December 31,		
Production by region (a)	2003	2002	2001
		(kte)	
UK	3,186	3,221	3,126
Rest of Europe	10,958	10,526	7,925
USA	10,068	10,201	8,943
Rest of World	3,731	3,040	2,722
Total Production (a)	27,943	26,988	22,716

(a) Includes BP share of joint ventures, associated undertakings and other interests in production.

BP s petrochemical products are sold to companies in a number of industries that manufacture components used in a wide range of applications. These include the agriculture, automotive, construction, furniture, household products, insulation, packaging, paint, pharmaceuticals and textile industries. Our products are marketed through a network of sales personnel and agents who also provide technical services.

Table of Contents

OTHER BUSINESSES AND CORPORATE

Other businesses and corporate comprises Finance, the Group s coal asset and aluminium asset, its investments in PetroChina and Sinopec, interest income and costs relating to corporate activities worldwide.

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Turnover	515	510	549
Total operating loss	(904)	(701)	(523)
Total assets	10,231	6,987	7,527
Capital expenditure and acquisitions	409	428	430

Finance coordinates the management of the Group s major financial assets and liabilities. From locations in the UK, Europe, the USA and the Asia Pacific region, it provides the link between BP and the international financial markets and makes available a range of financial services to the Group including supporting the financing of BP s projects around the world.

Coal activity consisted of our 50% interest in PT Kaltim Prima Coal, an Indonesian company which operates an opencast coal mine at Sangatta in Kalimantan, Indonesia. On October 10, 2003 we completed the sale of this interest to PT Bumi Resources.

Aluminium. Our aluminium business is a non-integrated producer and marketer of rolled aluminium products, headquartered in Louisville, Kentucky, USA. Production facilities are located in Logan County, Kentucky and are jointly owned with Alcan Aluminum. The primary activity of our aluminium business is the supply of aluminium coil to the beverage can business.

Investments in China. During 2000 BP made two investments in China, one of the world s fastest growing economies. BP invested $416 million in the China Petroleum and Chemical Corporation (Sinopec) and $578 million in PetroChina in the initial public offerings of both companies, obtaining around 2% in each company. On January 13, 2004 we sold our investment in PetroChina for $1.65 billion. On February 10, 2004 we sold our investment in Sinopec for $742 million. Separately, BP has formed a joint venture with PetroChina in Guangdong province which had 400 service stations at the end of 2003 and has agreed to form a joint venture with Sinopec to acquire, revamp or build 500 service stations in the Zhehang province. PetroChina and Sinopec are two of China s major companies in the oil and chemicals businesses.

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

Research and development is carried out using a balance of internal and external resources. Involving third parties in the various steps of technology development and application enables a wider range of technology solutions to be considered and implemented, improving the productivity of research and development activities.

Table of Contents

The innovative application of technology and the rapid transfer of this knowledge through the Group make a key contribution to improving BP s business performance, particularly in the areas of the introduction of new products, safety, the environment, cost reduction and efficiency of business operations. We believe that, in addition to improving existing business performance, the use of innovative technology can create new possibilities for the organic growth of our energy- and petrochemical-related businesses.

Across the Group, expenditure on research for 2003 was $349 million, compared with $373 million in 2002 and $385 million in 2001.

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 premia with attendant transaction costs. The position is reviewed from time to time.

66

Table of Contents

REGULATION OF THE GROUP S BUSINESS

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

Licences (or concessions) give the holder the right to explore for and exploit a commercial discovery. Under a licence, the holder bears the risk of exploration, development and production activities and provides the financing for these operations. In principle, the licence holder is entitled to all production minus any royalties that are payable in kind. A licence holder is generally required to pay production taxes or royalties, which may be in cash or in kind.

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

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

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

BP s other activities are also subject to a broad range of legislation and regulations in various countries in which it operates.

Health, safety and environmental regulations are discussed in more detail in the Environmental Protection section on page 68.

Table of Contents

ENVIRONMENTAL PROTECTION

Health, Safety and Environmental Regulation

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

The extent and cost of future environmental restoration, remediation and abatement programmes are often inherently difficult to estimate. They depend on the magnitude of any possible contamination, the timing and extent of the corrective actions required and BP s share of liability relative to that of other solvent responsible parties. Though the costs of future restoration and remediation could be significant, and may be material to the results of operations in the period in which they are recognized, it is not expected that such costs will have a material impact on the Group s overall financial position or liquidity. Refer to Item 18 Financial Statements Note 31 on page F-51 for the amounts provided in respect of environmental remediation and decommissioning.

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

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

For a discussion of the Group s environmental expenditures see Item 5 Operating and Financial Review and Prospects Environmental Expenditure on page 90.

BP operates in over 100 countries worldwide. In all regions of the world BP has processes to ensure compliance with applicable regulations. In addition, each individual in the Group is required to comply with the BP health, safety and environment policy and associated expectations and standards. Our partners, suppliers and contractors are also encouraged to adopt them. The Group is reviewing impacts of health safety and environment regulations and obligations related to our 50% ownership of TNK-BP. This document focuses primarily on the US and EU, where over 80% of our fixed assets are located, and on two issues of a global nature: climate change programmes and maritime oil spills regulations.

Table of Contents

Climate Change Programmes

Kyoto Protocol

In December 1997, at the Third Conference of the Parties to the United Nations Framework Convention on Climate Change (UNFCCC) in Kyoto, Japan, the participants agreed on a system of differentiated internationally legally binding targets for the first commitment period of 2008 to 2012. Before it can be implemented, the Kyoto protocol to the UNFCCC needs to be ratified by at least 55 nations, representing a minimum of 55% of global anthropogenic greenhouse gas (GHG) emissions. The US has indicated that it will not ratify. Therefore, in order for the treaty to come into force, Russia needs to ratify, in addition to those nations which have either already ratified or indicated that they will ratify. If the Kyoto treaty does enter into force and its targets are to be met, some reduction in the use of fossil fuels would be required within countries which have ratified the Kyoto treaty. The impact of the Kyoto agreements on global energy (and fossil fuel) demand is expected to be small (see International Energy Agency Global Energy Outlook, 2000 Edition).

Since 1997, BP has been actively involved in policy debate, worked with others on mitigating technologies, demonstrated global emissions trading and reduced the emissions from our facilities. In early 2002, we announced that we had succeeded in reducing our direct, equity share, GHG emissions by 10% and set a target to maintain our net emissions at 2001 levels through the next decade, with success being dependent upon the resolution of the various international policy discussions on market mechanisms.

BP is an advocate of market mechanisms to allow optimum utilization of resources to meet national Kyoto targets. Such systems are being considered, developed or implemented by individual countries and also internationally through the European Union. The relative success of these systems will determine the extent to which alternative fiscal or regulatory measures may be applied. Some EU member States have indicated that they require energy product taxes to enable them to meet their Kyoto commitments within the EU burden sharing agreement, and are already implementing national legislation, such as the UK Climate Change Levy.

United Kingdom Emissions Trading Scheme (UKETS)

The UKETS is a voluntary scheme with the UK Government. The Direct Participant section of the scheme provides a financial incentive for organizations that agreed to take on absolute greenhouse gas emissions reduction targets against a 1998-2000 emissions baseline. At present the market is small and any risk from BP s participation in the scheme is low.

European Union Emissions Trading Scheme

In July 2003, final agreement was reached on a Directive establishing a scheme for greenhouse gas emission allowance trading within the EU. Once implemented by member states, they will set limits on CO_2 emissions from qualifying installations and issue a finite number of tradable allowances. Under the Directive each installation will also require a GHG emissions permit, which carries an obligation to report, monitor and verify annual emissions and surrender enough allowances to cover these. Most major BP facilities within Europe will be included in the Directive. BP is currently assessing the likely impact on our business, although we expect this to be small, as we are well prepared following the operation of our own internal emissions trading system from 1999-2001, and in the UK from participation in the UKETS.

Maritime Oil Spill Regulations

Within the United States, the Oil Pollution Act of 1990 significantly increased oil spill prevention requirements. Details of this legislation are provided in the regional review below. Outside the United States, the BP operated fleet of tankers is subject to international spill response and preparedness

Table of Contents

regulations that are typically promulgated through the International Maritime Organization (IMO) and implemented by the relevant flag state authorities. The International Convention for the Prevention of Pollution From Ships (Marpol 73/78) requires vessels to have detailed shipboard emergency and spill prevention plans. The International Convention on Oil Pollution, Preparedness, Response and Co-Operation (OPRC) requires vessels to have adequate spill response plans and resources for response anywhere the vessel travels to. These conventions and separate Marine Environmental Protection Circulars also stipulate the relevant state authorities around the globe that require engagement in the event of a spill. All of these requirements together are addressed by the vessel owners in Shipboard Oil Pollution Emergency Plans. BP Shipping s liabilities for oil pollution damage under the United States Oil Pollution Act 1990 and outside the United States under the 1969/1992 International Convention on Civil Liability for Oil Pollution Damage are covered by marine liability insurance having a maximum limit of $1 billion for each accident or occurrence. This insurance cover is provided by two mutual insurance associations, The United Kingdom Steam Ship Assurance Association (Bermuda) Limited and The Britannia Steam Ship Insurance Association Limited.

At the end of 2003 our international fleet numbered 28 oil tankers with an average age of three years (25 are double-hulled, three are double-sided) and eight LNG ships with an average age of six years. Our fleet renewal programme will continue into the future and should see 11 modern double-hulled vessels delivered by the end of 2004, with a further 18 confirmed for 2005 to 2007. In addition to its own fleet, BP will continue to charter quality ships; currently these vessels include both single- and double-hulled designs but all are vetted prior to each use to ensure they are operated and maintained to meet BP s standards.

United States Regional Review

The following is a summary of significant US environmental legislation affecting the Group.

The Clean Air Act and its regulations require, among other things, new fuel specifications and sulphur reductions, enhanced monitoring of major sources of specified pollutants; stringent air emission limits and new operating permits for chemical plants, refineries, marine and distribution terminals; and risk management plans for storage of hazardous substances. This law affects BP facilities producing, refining, manufacturing and distributing oil and products as well as the fuels themselves. Federal and state controls on ozone, carbon monoxide, benzene, sulphur, MTBE, nitrogen dioxide, oxygenates and Reid Vapor Pressure impact BP s activities and products in the US. BP is continually adapting its business to these rules and has the know-how to produce quality and competitive products in compliance with their requirements. For example, in 1999 BP introduced a premium grade gasoline in Atlanta, Georgia, meeting stringent future sulphur standards and has expanded this offer in over 40 cities across the US. Beginning January 2006, all gasoline produced by BP will have to meet EPA s stringent low sulphur standards. Furthermore, by June 2006, at least 80% of the highway diesel fuel produced by BP will have to meet a sulphur cap of 15 parts per million (ppm).

In 2001, BP entered into a consent decree with the Environmental Protection Agency (EPA) and several states that settled alleged violations of various Clean Air Act requirements related largely to emissions of sulphur dioxide and nitrogen oxides at BP s refineries. This settlement requires the installation of additional controls at all of BP s US refineries at a cost currently estimated at $400 million, over at least an eight-year period, and the one-time payment of a $10 million penalty which was made in 2001.

In 2003 the South Coast Air Quality Management District filed a complaint against BP West Coast Products LLC and Atlantic Richfield Company in Los Angeles County Superior Court, alleging multiple violations of air quality regulations at the Carson oil refinery in California, USA. Atlantic Richfield Company operated the refinery until it was transferred to BP West Coast Products LLC on January 1, 2002. The complaint seeks penalties for non-compliance now amounting to $415 million. BP believes

Table of Contents

that it has valid defenses to many of the allegations of the complaint, believes that the amount of the penalty sought is disproportionate to any resulting environmental harm and intends to defend the action vigorously.

BP continues to comply with a plea agreement with the US Justice Department to develop, implement and maintain a nationwide environmental management system (EMS) consistent with the best environmental practices at Group facilities engaged in oil exploration, drilling and/or production in the US and its territories. BP fully implemented EMSs in Alaska and Lower 48 exploration and production performance units during 2003. BP has met the requirement to spend at least $15 million on the programme.

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

In 1995, a final federal rule was issued regarding protection of the Great Lakes watershed which has had ongoing impacts on water protection requirements. In 2000, a final federal rule was issued regarding use of Total Maximum Daily Load (TMDL) assessments to address pollutants not meeting water quality standards. EPA deferred implementation of the rule to April 2003 and subsequently withdrew the rule in March 2003, which had the effect of requiring more stringent permit limits at affected industrial facilities. In 2003, EPA published a final strategy for water quality standards and criteria. The strategy lays out actions over the next six years to address a broad range of issues with implications for industrial facilities; these include water use designations, antidegradation, TMDLs, mixing zones, water quality protection criteria and contaminated sediments.

In 2003, BP paid approximately $5.6 million in fines and penalties in the US, about half of which was paid for allegations related to underground storage tanks at its retail operations.

The Oil Pollution Act of 1990 (OPA 90) significantly increased oil spill prevention requirements, spill response planning obligations and spill liability for tankers and barges transporting oil and for offshore facilities such as platforms and onshore terminals. To ensure adequate fundings for response to oil spills and compensation for damages, when not fully covered by a responsible party, OPA 90 created a $1-billion fund which is funded by a tax on imported and domestic oil. OPA 90 also provides that all new tank vessels operating in US waters must have double hulls and existing tank vessels without double hulls must be phased out by 2015. In 2002, BP contracted for the construction of four double-hull tankers at a shipyard in San Diego, California. The first of these new vessels is expected to begin service in 2004, demise chartered to and operated by Alaska Tanker Company (ATC). The current ATC fleet consists of nine tankers: two with single hulls, four with double bottoms and three with double hulls. By the end of 2006 all ATC vessels are expected to be double hulled.

BP has a national spill response team, the BP Americas Response Team (BART), consisting of approximately 240 trained emergency responders at company locations throughout North America. The BART is ready to assist in a response to a major incident.

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

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

BP has been identified as a Potentially Responsible Party (PRP) under CERCLA and similar state statutes at approximately 800 sites. A PRP has joint and several liability for site remediation costs under some of these statutes and so BP may be required to assume, among other costs, the share attributed to insolvent, unidentified or other parties. BP has the most significant exposure for remediation costs at 74 of these sites. For the remaining sites, the number of PRPs can range up to 200 or more. BP expects its share of remediation costs at these sites to be small in comparison to the major sites. BP has estimated its potential exposure at all sites where it has been identified as a PRP and has established provisions accordingly. BP does not anticipate that its ultimate exposure at these sites individually, or in aggregate, will be significant except as reported for Atlantic Richfield Company in the matters below.

The State of Montana has pursued claims against Atlantic Richfield Company alleging natural resource damages arising out of Atlantic Richfield Company s predecessors mining and mineral processing activities. In addition, a tribe was allowed to intervene in the lawsuit, Montana vs. Atlantic Richfield Company. These matters were settled in part in 1999, except for the State s claims for $206 million for restoration damages at several sites. In 1989, the EPA filed a CERCLA cost recovery action against Atlantic Richfield Company for oversight costs at several of the Upper Clark Fork River Basin Superfund sites, US vs. Atlantic Richfield Company. Litigation is proceeding on both the EPA s claim, and on Atlantic Richfield Company s counterclaims against various federal agencies seeking contribution from the federal agencies for remediation costs and for any natural resource damage liability it might incur in Montana vs. Atlantic Richfield Company. The settlements in Montana vs. Atlantic Richfield Company, and subsequent settlements resolved the claims and counterclaims in US vs. Atlantic Richfield Company pertaining to four sites and may provide a framework for possible future settlement of the remaining claims. The Group is also subject to other claims for natural resource damage (NRD) under several federal and state laws. This is a developing area under US law which could impact the cost of some cleanups. NRD claims have been asserted by government trustees against several refineries and other company operations.

In the US, many environmental cleanups are the result of strict groundwater protection standards at both the state and federal level. Contamination or the threat of contamination of current or potential drinking water resources can result in stringent cleanup requirements, but some states have addressed contamination of nonpotable water resources using similarly strict standards. BP has encouraged risk-based approaches to these issues and seeks to tailor remedies at its facilities to match the level of risk presented by the contamination.

Other significant legislation includes the Toxic Substances Control Act which regulates the development, testing, import, export and introduction of new chemical products into commerce; the Occupational Safety and Health Act which imposes workplace safety and health, training and process standards to reduce the risks of chemical exposure and injury to employees; the Emergency Planning and Community Right-to-Know Act which requires emergency planning and spill notification as well as public disclosure of chemical usage and emissions. In addition, the US Department of Transportation through agencies such as the Office of Pipeline Safety and the Office of Hazardous Materials Safety regulates in comprehensive manner the transportation of the Company s products such as gasoline and chemicals to protect the health and safety of the public.

BP is subject to Marine Transportation Security Act and Department of Transport Hazmat security compliance regulations in the United States. These regulations require many of our US businesses to conduct Security Vulnerability Assessments, which include requirements such as preparation of security mitigation plans, implementation of upgrades to security measures, appointment and training of a designated security person and submission of plans for approval and inspection.

See also Item 8 Financial Information Legal Proceedings on page 158.

European Union Regional Review

Within the European Union, member states enact regulations to meet the Directives of the European Commission. By joint agreement, European Union Directives may also be applied within countries outside Europe.

A European Commission Directive for a system of Integrated Pollution Prevention and Control (IPPC) was approved in 1996. This system requires permitting through the application of Best Available Techniques (BAT) taking into account the costs and benefits. In the event that the use of BAT is likely to result in the breach of an environmental quality standard, plant emissions must be reduced further. The European Commission has stated that it hopes that all processes to which it applies will be licenced by July 2005. All plants must be permitted according to the requirements of the IPPC Directive by November 2007. The Directive encompasses most activities and processes undertaken by the oil and petrochemical industry within the European Union and requires capital and revenue expenditure across these BP sites. The European Commission is expected to make recommendations for amendments to the IPPC Directive in 2004.

The European Union Large Combustion Plant Directive sets emission limit values for sulphur dioxide, nitrogen oxides and particulates from large combustion plants. It also required phased reductions in emissions from existing large combustion plants at the latest by April 1, 2001. A revised Large Combustion Plant Directive has been agreed and implementation was required by November 27, 2002. Plants will have to comply by 2008. The second important set of air emission regulations affecting BP European operations is the Air Quality Framework Directive and its three daughter Directives on ambient air quality assessment and management, which prescribe, among other things, limit values for sulphur dioxide, oxides of nitrogen, particulate matter, lead, carbon monoxide, benzene and ozone. A fourth daughter Directive may be agreed in 2004 addressing cadmium, nickel, arsenic and polycyclic aromatic hydrocarbons. Measured or modelled exceedences of air quality limit values will require local action to reduce emissions and may impact any BP operations whose emissions contribute to such exceedences.

BP continues to make investments in respect of cleaner fuels at its refineries worldwide. For our European refineries, these investments are important because availability of cleaner fuels is a part of the EU strategy to combat air pollution. In April 1999, the EU adopted a Directive to further reduce the sulphur content of liquid fuels, but excluding marine bunker fuel oil, and marine gas oil used by ships crossing a frontier between a third country and an EU Member State. Sulphur in gas oil is limited to 0.2% from July 2000 and 0.1% from January 2008. From January 2003, sulphur in heavy fuel oil is limited to 1%, except where use of heavy fuel oil up to 3% sulphur can be used in combustion plants without exceeding specific emission limits, and provided that local air quality standards are met.

The EU has set stringent objectives to control exhaust emissions from vehicles, which are being implemented in stages. In 1998, the EU adopted directives to set emission limits for cars and light vehicles to apply from 2000, together with specifications for gasoline and diesel fuel to apply from that date. In 1999, this was followed by emission limits for heavy commercial vehicles. Maximum sulphur levels for gasoline and diesel fuels to apply from 2005 have also been agreed at 50 ppm and 35% maximum aromatic content for gasoline from the same date. Agreement was reached in December 2002 on a further Directive to make petrol and diesel with a maximum sulphur content of 10 ppm mandatory

Table of Contents

throughout the EU from January 2009, and from 2005 member states will also have to supply low-sulphur fuel at enough locations to allow the circulation of new low-emission engines requiring the cleaner fuel.

In Europe there is no overall soil protection regulation, although a draft Directive is expected in 2004. Certain individual member states have soil protection policies, but each has its own contaminated land regulations. There are common principles behind these regulations, including a risk based approach and recognition of costs versus benefits. Much of the technical guidance supporting these regulations is in draft form.

The European Commission adopted an official proposal on October 29, 2003 for a future regulation on European Chemical Policy referred to as REACH; Registration, Evaluation and Authorisation of Chemicals. This proposal will now be discussed by the European Parliament and Council. Dependent on the discussions, entry in force of the regulation could happen by 2007. Although polymers have been temporarily exempted from the process under the current proposal, about 30,000 other chemicals will have to be re-registered and evaluated. For the Group, this will primarily affect petrochemicals, lubricants and refinery products. At present we do not believe this regulation will have a material impact on our business based on the Group s current range of products, although it will require significant management and administration.

The European Commission issued a proposed Directive on Environmental Liability on January 23, 2003, which is currently under consideration within the European Parliament and Council. The proposal seeks to implement a strict liability approach for damage to biodiversity from high-risk operations.

The Commission s Clean Air for Europe Programme aims to conduct a review of the health and environmental effects of air pollution and predicted European Air Quality up to 2020. It will also examine cost-effective solutions to any residual air pollution problems, firstly in a strategy document (expected in 2005) and secondly in legislative proposals (expected between 2005 and 2007) which may include revisions to current regulations on air quality limit values, fuel quality standards, plant emission standards and totally new regulations. BP through various industry bodies is among the various stakeholders contributing to the scientific activities underpinning this work.

Other environment-related existing regulations include: the Major Hazards Directive which requires emergency planning, public disclosure of emergency plans and ensuring that hazards are assessed, and effective emergency management systems; the Water Framework Directive which includes protection of groundwater; and the Framework Directive on Waste to ensure that waste is recovered or disposed without endangering human health and without using processes or methods which could harm the environment.

Table of Contents

PROPERTY, PLANTS AND EQUIPMENT

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

Table of Contents

ORGANIZATIONAL STRUCTURE

The significant subsidiary undertakings of the Group at December 31, 2003 and the Group percentage of ordinary share capital (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 Company are marked with an asterisk (*), the percentage owned being that of the Group unless otherwise indicated. Refer to Item 18 Financial Statements Note 42 on page F-77 and Note 45 on page F-80 for information on significant joint ventures and associated undertakings of the Group.

Subsidiary undertakings	%	Country of incorporation	Principal activities
International			
BP Chemicals Investments	100	England	Petrochemicals
BP Exploration Operating 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
Europe			
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
France			
BP France	100	France	Refining and marketing and petrochemicals
Germany			
Deutsche BP	100	Germany	Refining and marketing and petrochemicals
Veba Oil	100	Germany	Refining and marketing and petrochemicals
Netherlands			
BP Capital	100	Netherlands	Finance
BP Nederland	100	Netherlands	Refining and marketing
Norway			
BP Norge	100	Norway	Exploration and production
Spain			
BP España	100	Spain	Refining and marketing
Middle East			
BP Egypt Co.	100	US	Exploration and production
BP Egypt Gas Co.	100	US	Exploration and production
Far East			
Indonesia			
BP Kangean	100	US	Exploration and production
Singapore			
BP Singapore Pte*	100	Singapore	Refining and marketing
Africa			
BP Southern Africa	75	South Africa	Refining and marketing

Table of Contents

Subsidiary undertakings	%	Country of incorporation	Principal activities
Australasia			
Australia			
BP 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
New Zealand			
BP Oil New Zealand	100	New Zealand	Marketing
Western Hemisphere			
Canada			
BP Canada Energy	100	Canada	Exploration and production
BP Canada Finance	100	Canada	Finance
Trinidad			
BP Trinidad (LNG)	100	Netherlands	Exploration and production
BP Trinidad and Tobago	70	US	Exploration and production
US			
Atlantic Richfield Co.	100	US)	
BP America*	100	US)	
BP America Production Company	100	US)	Exploration and production,
BP Amoco Chemical Company	100	US)	gas, power and renewables,
BP Company North America	100	US)	refining and marketing,
BP Corporation North America	100	US)	pipelines and petrochemicals
BP Products North America	100	US)	
BP West Coast Products	100	US)	
Standard Oil Co.	100	US)	
BP Capital Markets America	100	US	Finance

Table of Contents

ITEM 5 OPERATING AND FINANCIAL REVIEW AND PROSPECTS

GROUP OPERATING RESULTS

	Years ended December 31,		
	2003	2002	2001
	($ million except per share amounts)		
Turnover	232,571	178,721	174,218
Profit for the year	10,267	6,845	6,556
Exceptional items, net of tax	(708)	(1,043)	(165)
Profit before exceptional items	9,559	5,802	6,391
Profit for the year per ordinary share (cents)	46.30	30.55	29.21
Dividends per ordinary share (cents)	26.00	24.00	22.00

On February 1, 2002, BP acquired a 51% interest in and operational control of Veba. Veba has been fully consolidated within the Group s results from this date. The remaining 49% of Veba was acquired on June 30, 2002.

Trading conditions in 2003 were affected by tight supplies in oil and gas markets and by the early signs of a world economic recovery, following two years of below-trend growth. The global economy is expected to strengthen further in 2004.

Average crude oil prices in 2003 were the highest for 20 years, driven by supply disruptions in Venezuela, Nigeria and Iraq, OPEC market management and a recovery in oil demand growth following three exceptionally weak years. The Brent price averaged $28.83 per barrel, an increase of almost $4 per barrel over the $25.03 per barrel average seen in 2002 and moved in a range between $22.88 and $34.73 per barrel.

Natural gas prices in the USA were also exceptionally strong during 2003. The Henry Hub First of the Month index averaged $5.37 per million british thermal unit (mmbtu), up by more than $2 per mmbtu compared with the 2002 average of $3.22 per mmbtu. A combination of cold first quarter weather and weak domestic production kept working gas inventories relatively low for much of the year. UK gas prices were also up strongly in 2003, averaging 20.28 pence per therm at the National Balancing Point versus a 2002 average of 15.78 pence per therm.

Refining margins weakened somewhat towards the end of the year but were above historical average levels for 2003 as a whole, reflecting low commercial product inventories in key US and European markets. Retail margins for the year were relatively strong, especially in the US and Europe. Petrochemicals margins remained depressed in 2003, coming under pressure from high feedstock prices.

The trading environment was challenging during 2002, with natural gas prices and refining margins significantly weaker than in the previous year, owing to the global economic slowdown. Demand improved in most parts of the business after the first half of the year but economic conditions remained sluggish. The adverse business conditions had the greatest impact on Refining and Marketing. Worldwide refining margins were depressed for much of the year, at nearly half the average level of 2001. Margins in Petrochemicals were at levels similar to the bottom of previous cycles.

Oil prices were volatile in 2002. The Brent price ranged from around $18 per barrel to above $31 per barrel. The crude oil price increased during the second half of the year, partly reflecting a war premium . Brent prices averaged $25.03 per barrel compared with $24.44 per barrel in 2001. Natural gas prices in the USA were on average lower than in 2001, at around $3.36 per mmbtu compared with $3.96 per mmbtu, owing to a large surplus of natural gas in storage during the 2001-2002 heating season. Cold

Table of Contents

weather and the start of a decline in domestic production in the USA brought about a rise in price to around $5 per mmbtu towards the end of 2002.

The trading environment was generally favourable in the first half of 2001. Natural gas and oil prices remained high until clear evidence of the global economic slowdown emerged after the first few months. Business conditions deteriorated in the second half and remained weak following the events of September 11. Oil prices were 15% down against the levels seen in 2000; refining margins were weak; retailing was fiercely competitive; and in the chemicals sector, margins were at levels below those seen at the bottom of the previous business cycle.

Hydrocarbon production increased by 2.5% in 2003, reflecting an increase of 5.1% for liquids and a decrease of 1.1% for natural gas. The increase was 2.9% in 2002 against a target of 5.5%, reflecting production growth of 4.5% for crude oil and 0.9% for natural gas.

The increase in turnover for 2003 principally includes approximately $44 billion from higher oil, gas and product prices, approximately $10 billion from higher sales volumes and approximately $8 billion from the effect of the weaker US dollar.

The increase in turnover for 2002 reflects approximately $14 billion from production and sales volume increases partly offset by a decrease of approximately $10 billion due to lower natural gas prices.

Profit for 2003 was $10,267 million including inventory holding gains of $16 million and net exceptional gains after tax of $708 million in respect of net profits on the sale of fixed assets and businesses or termination of operations. Inventory holding gains or losses represent the difference between the cost of sales calculated using the average cost of supplies incurred during the year and the cost of sales calculated using the first-in first-out method. The results for 2003 include:

- in Exploration and Production, impairment charges and asset writedowns of $691 million and restructuring charges of $117 million;

- in Refining and Marketing, Veba integration costs of $287 million, a $246 million charge resulting from a reassessment of our environmental remediation provisions, charges of $123 million in respect of new environmental remediation provisions and a credit of $10 million arising from the reversal of restructuring provisions;

- in Petrochemicals, a $43 million charge comprising a provision to cover future rental payments on surplus property and a charge resulting from a reassessment of environmental remediation provisions, and a credit of $5 million resulting from a reduction in the provision for costs associated with the closure of polypropylene capacity in the USA;

- in Other businesses and corporate, a charge of $132 million in respect of new environmental remediation provisions, a provision of $74 million to cover future rental payments on surplus property and a credit of $10 million resulting from a reassessment of our environmental remediation provisions;

- a credit of $280 million related to tax restructuring benefits.

Refer to Environmental Expenditure on page 90 for more information on environmental remediation charges.

Profit for 2002 was $6,845 million including inventory holding gains of $1,104 million and net exceptional gains after tax of $1,043 million in respect of net profits on the sale of fixed assets and businesses or termination of operations. The results for 2002 include:

in Exploration and Production, impairment charges of $1,091 million, restructuring charges of $184 million, $94 million for the write-off of our Gas to Liquids demonstration plant in Alaska and $55 million of litigation costs;

Table of Contents

in Gas, Power and Renewables, impairment costs of $30 million;

in Refining and Marketing, impairment costs of $30 million in Gas, Power and Renewables; a credit related to business interruption insurance proceeds of $184 million, as well as charges of $348 million related to Veba integration, $132 million restructuring costs, $62 million costs associated with an Olympic pipeline incident in 1999, a $35 million write-down of retail assets in Venezuela and $22 million settlement costs associated with a pre-acquisition Atlantic Richfield Company US MTBE supply contract;

in Petrochemicals, a $140 million write-down of our Indonesian manufacturing assets, costs of $81 million related to major site restructuring and Solvay and Erdölchemie integration and $29 million for restructuring our research and technology facilities;

in Other businesses and corporate, a $140 million charge for future rental payments on surplus property and a $46 million charge related to environmental remediation liabilities;

$355 million adjustment to the North Sea deferred tax balance for the supplementary UK corporation tax rate and $150 million tax restructuring benefits.

For 2001, profit was $6,556 million after inventory holding losses of $1,900 million and including net exceptional gains after tax of $165 million in respect of net profits on the sale of fixed assets and businesses or termination of operations. The results for 2001 include

in Exploration and Production, impairment charges of $175 million, $77 million additional severance costs in respect of Atlantic Richfield Company terminations, $60 million litigation and $10 million restructuring costs;

in Refining and Marketing, integration and rationalization costs of $435 million and $52 million additional severance charges mainly related to former employees of Atlantic Richfield Company;

in Petrochemicals, charges of $114 million related to Grangemouth restructuring and Solvay and Erdölchemie integration;

in Other businesses and corporate, $73 million restructuring charges.

When used in this section, the word result refers to total operating profit.

The increase in the 2003 result compared with 2002 primarily reflects higher oil and gas prices, higher refining and marketing margins and higher production. The reduction in the 2002 result compared with 2001 reflects the challenging environment, although the impact of lower natural gas prices and refining margins was partly offset by higher production and sales volumes, lower costs in certain businesses, improved Petrochemicals performance and contributions from Veba and other acquisitions. Further information on the impact of these factors and others on our results is included in the Business Operating Results section following.

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

Employee numbers decreased from 115,250 at December 31, 2002 to 103,700 at December 31, 2003, with 20% of the decrease resulting from the disposal of Fosroc Mining, 20% from the reduction of service station staff in the US, 17% from the transfer of employees in Russia into TNK-BP and 16% from reorganization of Refining and Marketing operations in Germany. The increase in 2002 was mainly due to the Veba acquisition.

Table of Contents

Return on average capital employed (ROACE) is the ratio of profit including minority shareholders interest and excluding post-tax interest on finance debt to average capital employed for the period. Capital employed is defined as net assets plus total finance debt. Management believes this performance measure is useful as an indication of capital productivity over the long term. The increase in ROACE for 2003 compared with the prior year is due to higher profits. ROACE for 2002 is flat compared with the prior year. Increases in average capital employed are mainly due to acquisitions and upstream investment.

	Years ended December 31,		
Return on average capital employed (ROACE)	2003	2002	2001
		($ million)	
Profit for the year	10,267	6,845	6,556
Interest on finance debt (a)	332	602	798
Minority shareholders interest	170	77	61
	10,769	7,524	7,415
Average capital employed	95,722	89,616	87,259
ROACE	11%	8%	8%

(a) For the ROACE calculation, interest expense includes interest on finance debt on a post-tax basis, using a deemed tax rate equal to the US statutory tax rate.

	Years ended December 31,		
Capital expenditure and acquisitions	2003	2002	2001
		($ million)	
Exploration and Production	9,658	9,266	8,627
Gas, Power and Renewables	359	335	485
Refining and Marketing	3,006	2,682	2,386
Petrochemicals	775	810	1,446
Other businesses and corporate	251	228	256
Capital expenditure	14,049	13,321	13,200
Acquisitions (a)	6,026	5,790	924
Capital expenditure and acquisitions	20,075	19,111	14,124
Disposals	(6,432)	(6,782)	(2,903)
Net Investment	13,643	12,329	11,221

(a) 2003 includes $5,794 million for the acquisition of our interest in TNK-BP. 2002 includes $5,038 million for the Veba acquisition.

Capital expenditure and acquisitions in 2003, 2002 and 2001 amounted to $20,075 million, $19,111 million and $14,124 million, respectively. Acquisitions in 2003 included our interest in TNK-BP. Acquisitions during 2002 included Veba, an additional 15% interest in Sidanco and several minor acquisitions. Acquisitions during 2001 included the purchase of Bayer s 50% interest in Erdölchemie and a number of minor acquisitions. Excluding acquisitions, capital expenditure for 2003 was $14,049 million compared with $13,321 million in 2002 and $13,200 million in 2001.

Exceptional Items

For 2003, net exceptional gains, consisting of the profit or loss on sale of fixed assets and businesses or termination of operations, were $831 million before tax ($708 million after tax). The major elements of the profit on sale of fixed assets of $1,894 million relate to the divestment of a further 20% interest in BP Trinidad and Tobago LLC to Repsol and 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, the divestment of our interest in the In Amenas gas condensate project in Algeria to Statoil and the disposal of BP s interest in

PT Kaltim Prima Coal also contributed to the profit on disposal. The loss on sale of fixed assets of $1,035 million includes losses on exploration and production properties in China, Norway and the US, the loss on the sale of refining and marketing assets in Germany and Central Europe and the provision for losses on sale in early 2004 of exploration and production properties in Canada and Venezuela. The loss on sale of businesses or termination of operations for 2003 of $28 million relates to the sale of our European oil speciality products business.

Net exceptional gains were $1,168 million before tax ($1,043 million after tax) in 2002. The major part of the profit on the sale of fixed assets during 2002 arises from the divestment of the Group s shareholding in Ruhrgas. The other significant elements of the profit for the year are the gain on the redemption of certain preferred limited partnership interests BP retained following the Altura Energy common interest disposal in 2000 in exchange for BP loan notes held by the partnership, the profit on the sale of the Group s interest in the Colonial pipeline in the US and the profit on the sale of a US downstream electronic payment system. The profit on the sale of businesses relates mainly to the disposal of the Group s retail network in Cyprus and the UK contract energy management business. The major element of the loss on sale of fixed assets for the year relates to provisions for losses on sale of exploration and production properties in the US announced in early 2003. For 2002 the loss on sale of businesses or termination of operations relates to the disposal of our plastic fabrications business, the sale of the former Burmah Castrol speciality chemicals business Fosroc Construction, our withdrawal from solar thin film manufacturing and the provision for the loss on divestment of the former Burmah Castrol speciality chemicals businesses Sericol and Fosroc Mining.

For 2001, net exceptional gains were $535 million before tax ($165 million after tax). The profit on the sale of fixed assets of $948 million includes the profit from the divestment of the refineries at Mandan, North Dakota, and Salt Lake City, Utah; the Group s interest in the Alliance and certain other pipeline systems in the USA; and BP s interest in the Kashagan discovery in Kazakhstan. The profit on the sale of businesses of $182 million relates to the sale of the Group s interest in Vysis. In 2001, the loss on sale of fixed assets of $345 million arose from a number of transactions. The loss on sale of businesses and termination of operations of $250 million during 2001 arose principally from the sale of the Group s Carbon Fibers business and the write-off of assets following the closure or exit from certain chemicals activities.

Interest Expense

Interest expense in 2003 was $851 million compared with $1,279 million in 2002 and $1,670 million in 2001. These amounts included charges arising from early bond redemption of $31 million, $15 million and $62 million respectively. After adjusting for these charges, the decrease in Group interest expense in 2003 compared with 2002 mainly reflects lower average interest rates and lower average debt. The decrease in 2002 compared with 2001 primarily reflects lower average interest rates.

Taxation

The charge for corporate taxes in 2003 was $5,972 million, compared with $4,342 million in 2002 and $6,375 million in 2001. The effective rate was 36% in 2003, 39% in 2002 and 49% in 2001. The lower rate in 2003 reflects tax restructuring benefits, as well as the rateably lower impact of goodwill amortisation and the depreciation charge on uplifted asset values (for which no tax deduction is available) on higher income in 2003. The tax rate in 2002 additionally reflected the inclusion of a $355 million charge to increase the North Sea deferred tax provision for the supplementary UK tax. The lower rate in 2002 reflects non-taxable inventory holding gains compared with inventory holding losses in 2001.

Table of Contents

Business Operating Results

Total operating profit, which is before interest expense, taxation, minority interests and exceptional items, was $16,429 million in 2003, $11,375 million in 2002 and $14,127 million in 2001.

Exploration and Production

		Years ended December 31,		
		2003	2002	2001
Turnover	($ million)	31,341	25,753	28,229
Profit before interest and tax	($ million)	14,853	8,483	12,550
Exceptional (gains) losses	($ million)	(913)	726	(195)
Total operating profit	($ million)	13,940	9,209	12,355
Results included:				
Exploration expense	($ million)	542	644	480
Key statistics:				
Average BP crude oil realizations (a)	($ per barrel)	28.23	24.06	23.27
Average BP NGL realizations (a)	($ per barrel)	19.26	12.85	16.27
Average BP liquids realizations (a) (b)	($ per barrel)	27.25	22.69	22.50
Average West Texas Intermediate oil price	($ per barrel)	31.06	26.14	25.89
Average Brent oil price	($ per barrel)	28.83	25.03	24.44
Average BP US natural gas realizations (a)	($ per thousand cubic feet)	4.47	2.63	3.99
Average Henry Hub gas price (c)	($ per thousand cubic feet)	5.37	3.22	4.26
Crude oil production (net of royalties) (d)	(mb/d)	2,121	2,018	1,931
Natural gas production (net of royalties) (d)	(mmcf/d)	8,613	8,707	8,632
Total production (net of royalties) (d) (e)	(mboe/d)	3,606	3,519	3,419

(a) The Exploration and Production business does not undertake any hedging activity. Consequently, realizations reflect the market price achieved.

(b) Crude oil and NGL.

(c) Henry Hub First of Month Index.

(d) Includes BP s share of equity-accounted entities.

(e)

Expressed in thousands of barrels of oil equivalent per day (mboe/d). Natural gas is converted to oil equivalent at 5.8 billion cubic feet : 1 million barrels.

Turnover for 2003 was $31,341 million compared with $25,753 million in 2002 and $28,229 million in 2001. The increase in 2003 reflected the impact of higher liquids and natural gas realizations of approximately $7.0 billion with an offset of $1.4 billion as a result of a decrease in production volumes in the USA and UK following divestments. The decrease in 2002 included approximately $2.3 billion due to lower natural gas prices with a small offset of $100 million as a result of higher production and crude oil realizations.

Total hydrocarbon production for 2003 was 3,606 mboe/d, an increase of 2.5% compared with 2002. This includes the 135 mboe/d impact of divestments offset by the inclusion of 205 mboe/d TNK-BP volumes incremental to Sidanco, from August 29, 2003.

Profit before interest and tax for 2003 includes net exceptional gains of $913 million, which includes a gain on the sale of the UK North Sea Forties oil field together with a package of shallow-water assets in the Gulf of Mexico, a gain resulting from Repsol s exercise of its option to acquire a further 20% interest in BP Trinidad and Tobago LLC and net losses resulting from the sale of various other upstream assets. Profit before interest and tax for 2002 includes net exceptional losses of $726 million, which includes a gain resulting from the redemption of certain preferred partnership interests BP retained following the disposal in 2000 of the Altura Energy common interest in exchange for BP loan notes held by the partnership and net losses on the disposal of various other upstream interests. Profit before interest and tax in 2001 includes net exceptional gains of $195 million, which includes a gain on the sale of our interest in the Kashagan discovery in Kazakhstan together with net losses on the sale of various other upstream interests.

Total operating profit for 2003 was $13,940 million including inventory holding gains of $3 million. The result for 2003 includes an impairment charge of $296 million related to four assets in the Gulf of Mexico Shelf following technical reassessments and reevaluation of future investments options; an impairment charge of $133 million related to the Miller field in the UK following a decision not to proceed with waterflood and gas import options; an impairment charge of $108 million related to the Kepadong field in Indonesia; an impairment charge of $105 million related to the Yacheng field in China; and a $49 million write-down of the Viscount asset in the North Sea. All of these fields continue in operation. Additionally, there were restructuring charges of $117 million in respect of ongoing restructuring activities in the UK and North America.

For 2003, the year on year increase in operating profit reflects higher natural gas realizations partly offset by higher costs and other factors. Higher natural gas realizations contributed $5.4 billion to operating profit. This was offset by an increase of approximately $790 million in the charge for depreciation and an increase in other costs of around $340 million. Lower production volumes in the USA and the UK reduced profit by approximately $100 million and the net impact of acquisitions and divestments was a further reduction of about $100 million. Exploration expense was $102 million lower in 2003 compared with 2002. The annual impact in 2003 of the removal of the unrealized profit in inventory in the Exploration and Production business for product held by other areas of the Group s business was a charge of $61 million compared with a charge of $154 million in 2002.

Finding and development costs in 2003 averaged $6.49 per barrel of oil equivalent (boe), compared with $4.14 in 2002 and $3.68 in 2001. Finding and development costs are those costs incurred during the year on exploration activity (exploration drilling, licence awards, exploration geological and geophysical expense) and costs incurred in the development of our tangible fixed assets, excluding midstream activities. In the determination of finding and development costs per barrel, the summation of these costs is divided by reserves either added, or removed, by revisions, discoveries, extensions and improved recovery. The denominator excludes volumes associated with purchases and sales. The increase reflects the focus on our new profit centres and the build phase of our major projects. Finding costs were $0.73/boe, compared with $0.79 in 2002 and $0.54 in 2001. Finding costs are based on exploration costs incurred per barrel of oil equivalent added as a result of extensions and discoveries. On a three year rolling average basis, the finding costs were $0.66/boe for 2003 compared with $0.78 for 2002 and $0.82 for 2001 reflecting the significant discoveries made during the period 2000 to 2002. BP has discovered more giant fields (greater than 250 mmboe) in the period 1998 2003 than our competitors. Unit lifting costs (i.e., production costs per unit) were $2.80/boe (compared with $2.60 in 2002 and $2.70 in 2001). Adjusting for the impact of foreign exchange from our non-US dollar denominated business activities, which has had a more significant impact in 2003 as a result of the weakening of the US dollar, would give $2.70/boe in 2003. This reflects our continued focus on controlling cash costs. Unit lifting costs are based on total production costs divided by the production from those entities whose costs are consolidated. Production costs include expenditure incurred in lifting, gathering and treating, field processing and other directly related facilities, but exclude production-related depreciation.

Table of Contents

Total operating profit for 2002 was $9,209 million including inventory holding gains of $3 million. The result for 2002 includes a charge of $1,091 million related to the impairments of Shearwater in the North Sea, Rhourde El Baguel in Algeria, LL652 and Boqueron in Venezuela, Pagerungan in Indonesia and Badami in Alaska, following full technical reassessments and evaluations of future investment opportunities. All these fields continued in operation. In addition, there were restructuring charges of $184 million relating to significant restructuring to reposition the business in North America and the North Sea, $94 million for the write-off of our Gas to Liquids demonstration plant in Alaska and $55 million of litigation costs. The restructuring costs comprised $145 million of severance, $19 million repatriation and other costs of $20 million, which were mostly settled in 2002.

The decrease in the 2002 result compared with 2001 was primarily as a result of significantly lower natural gas realizations, accounting for approximately $2.3 billion of the reduction. This was offset slightly by the impact of higher crude oil realizations of $110 million, production growth of 4.5% for crude oil and 0.9% for natural gas (2.9% overall) which generated $360 million and a 4% decrease in unit lifting costs and other costs amounting to approximately $540 million. Other factors which impacted the results were an increase in exploration expense of $164 million, the impact of prices on the provision for unrealized profit in inventory of $322 million and increases in depreciation, depletion and amortization (including impairments).

Total operating profit for 2001 was $12,355 million after inventory holding losses of $6 million. The result for 2001 includes a $175 million impairment of our partner-operated Venezuelan Lake Maracaibo operations, following a technical reassessment, $77 million additional severance costs which related to US pension and benefits incurred in respect of terminations by Atlantic Richfield Company and were settled in 2001, $60 million litigation and $10 million restructuring costs related to the Grangemouth operating site in Scotland.

Total hydrocarbon production for 2002 was 3,519 mboe/d, an increase of 2.9% compared with 2001. This reflects a 252 mboe/d impact of production from new fields and acquisitions partly offset by: 53 mboe/d from operational problems mainly in the UK and Alaska; 25 mboe/d from OPEC reductions and lower natural gas demand as a result of warm weather, 20 mboe/d from severe storm patterns in the Gulf of Mexico and 4 mboe/d from the general strike in Venezuela.

Gas, Power and Renewables

		Years ended December 31,		
		2003	2002	2001
Turnover	($ million)	65,445	37,357	39,442
Profit before interest and tax	($ million)	472	1,956	407
Exceptional (gains) losses	($ million)	6	(1,551)	
Total operating profit	($ million)	478	405	407
Total natural gas sales volumes (a)	(mmcf/d)	26,269	21,621	18,794

(a) Includes marketing, trading and supply sales.

Turnover was $65,445 million in 2003 compared with $37,357 million in 2002, reflecting $20 billion additional turnover from higher natural gas prices and approximately $8 billion from higher gas sales volumes. The decrease in 2002 from $39,442 million in 2001 reflected a decrease of approximately $9 billion due to lower prices, particularly in North America, partly offset by an increase of approximately $7 billion from higher natural gas sales volumes.

Profit before interest and tax for 2003 includes net exceptional losses of $6 million resulting from several small transactions. Profit before interest and tax for 2002 includes net exceptional gains of $1,551 million that primarily relate to the disposal of our interest in Rurhrgas. Profit before interest and tax for 2001 includes no exceptional gains or losses.

Total operating profit for 2003 was $478 million including inventory holding gains of $6 million.

Total operating profit for 2002 was $405 million including inventory holding gains of $51 million. The result for 2002 includes a charge of $30 million related to the impairment of a cogeneration power plant under construction in the UK. The impairment is the result of a significant fall in power prices in the UK over the previous two years.

Total operating profit for 2001 was $407 million after inventory holding losses of $81 million.

The increase in the result for 2003 compared with 2002 reflects improvement in the marketing and trading business. Marketing and trading results increased by approximately $250 million with equal contributions from higher volumes and improved margins. Results for the LNG business also improved showing an increase of $90 million. This more than offset decreases of $70 million in the NGL business due to high natural gas prices relative to liquids prices in North America which led to lower sales volumes, the absence of any contribution from the Ruhrgas shareholding (sold in August 2002 and contributed $112 million in 2002) and a restructuring charge of $45 million in our Solar business.

The decrease in the result in 2002 compared with 2001 is due to a $75 million lower contribution from Ruhrgas (shareholding held for 7 months prior to disposal) and a decline of $80 million from a weaker marketing and trading environment, partly offset by better performance in the NGL business of $10 million and $50 million from increased natural gas sales volumes which were up by 15%.

Refining and Marketing

		Years ended December 31,		
		2003	2002	2001 (a)
Turnover	($ million)	149,477	125,836	120,233
Profit before interest and tax	($ million)	2,079	2,534	2,461
Exceptional (gains) losses	($ million)	213	(613)	(471)
Total operating profit	($ million)	2,292	1,921	1,990
Global Indicator Refining Margin (a)	($/bbl)	3.88	2.11	4.06
Refining availability (b)	(%)	95.5	96.1	95.4
Refinery throughputs	(mb/d)	3,097	3,103	2,929
Total marketing sales	(mb/d)	4,032	4,180	3,797

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

Table of Contents

(b) Refining availability is the weighted average percentage of the period that refinery units are available for processing, after accounting for downtime such as turnarounds.

Turnover for 2003 was $149,477 million compared with $125,836 million for 2002 and $120,233 million for 2001. Higher oil prices contributed approximately $14 billion of the increase in 2003, with foreign exchange movements and higher volumes (including trading and supply sales) contributing a further $8 billion and $3 billion respectively. The increase in turnover for 2002 compared with 2001 is due primarily to volume increases from the Veba acquisition. Results for Veba have been included from February 1, 2002.

Profit before interest and tax for 2003 includes net exceptional losses of $213 million resulting from a number of disposals which primarily relate to retail assets. Profit before interest and tax for 2002 includes net exceptional gains of $613 million which include gains on the sale of our interest in Colonial Pipeline and a US downstream electronic payment system, along with a number of smaller items. Profit before interest and tax for 2001 includes net exceptional gains of $471 million, which includes a gain from the sale of the refineries at Mandan, North Dakota and Salt Lake City, Utah, a gain from the the sale of Group s interests in Alliance and certain other pipelines in the US and net losses from other items.

Total operating profit for 2003 was $2,292 million after inventory holding losses of $48 million. The result for 2003 includes Veba integration costs of $287 million, a $246 million charge resulting from a reassessment of our environmental remediation provisions, charges of $123 million in respect of new environmental remediation provisions following a detailed review earlier in the year and a credit of $10 million arising from the reversal of restructuring provisions. The Group undertakes an annual review of its environmental provisions in relation to current and former refinery, retail and other sites taking account of new legislation and emerging industry practice.

Total operating profit for 2002 was $1,921 million including inventory holding gains of $1,049 million. The result for 2002 includes a credit related to business interruption insurance proceeds of $184 million, as well as charges of $348 million related to Veba integration, $132 million restructuring costs, $62 million costs associated with an Olympic pipeline incident in 1999, a $35 million write-down of retail assets in Venezuela and $22 million settlement costs associated with a pre-acquisition Atlantic Richfield Company US MTBE supply contract.

Total operating profit for 2001 was $1,990 million after inventory holding losses of $1,583 million. The result for 2001 includes Burmah Castrol integration costs of $334 million, charges of $101 million related to rationalization costs in the downstream European commercial business and Grangemouth restructuring and $52 million additional severance charges mainly related to former employees of Atlantic Richfield Company.

The result for 2003 compared with 2002 reflects approximately $1,400 million from improved refining margins and approximately $600 million from marketing margins improvement. This was offset by adverse foreign exchange effects of around $100 million, additional portfolio impacts of around $150 million and additional pension charges of approximately $200 million. Refining throughputs were relatively flat compared with 2002, with refining availability for the year at 95.5% in 2003 compared with 96.1% in 2002. Marketing volumes for 2003 were 4% lower than 2002, as expected, due to divestments.

The result for 2002 compared with 2001 reflects the impact of a decline of worldwide refining margins, down by around $2,400 million, lower marketing margins of around $400 million, additional environmental provisions of $150 million and increased pension charges of $100 million. The decrease was partly offset by the net impact of portfolio activity, including the Veba transaction, of approximately $400 million. Refining throughputs increased by 6% over the prior year and marketing volumes increased by 10%, primarily due to Veba. Excluding Veba, marketing volumes were slightly down. Retail shop sales grew 60% due to Veba and the increased number of BP Connect stations, 10% excluding Veba. Retail sales grew 7% in 2002 in stores that were also operating in 2001.

Table of Contents

The integration of Veba, which began in February 2002, was essentially completed during 2003. The 2003 charges of $287 million relating to the Veba acquisition comprised some $46 million of severance costs, $37 million of other integration costs such as consulting, studies and internal project teams, $48 million of system infrastructure and application costs and the balance of $156 million related to additional synergy projects. 2003 cash outflows related to these special charges were approximately $260 million. Annual synergies of approximately $300 million have so far been delivered, in excess of the $200 million previously anticipated.

The 2002 charges of $348 million related to the Veba acquisition comprised $210 million of severance costs, $77 million of other integration costs such as consulting, studies and internal project teams, $24 million of system infrastructure and application costs, $22 million of office consolidation and relocation and $15 million of additional synergy projects. 2002 cash outflows related to these special charges were approximately $140 million. The $132 million special restructuring costs were associated with several restructuring and cost reduction initiatives during 2002 in different business units and support functions, primarily in the USA, Western Europe and in Africa. The largest single functional area affected was information technology. In Venezuela an impairment review was triggered by the current political crisis and poor business performance in 2002.

The integration of the Atlantic Richfield Company businesses was largely completed during 2001 and primarily affected the Western USA. The anticipated downstream synergies were achieved, resulting from cost reduction, hydrocarbon procurement and working capital reduction. The charges associated with the integration were $52 million in 2001. The major components of the costs were severance payments, office consolidation and information technology infrastructure.

The integration of the Burmah Castrol businesses was mostly completed by the end of 2001. The anticipated synergies of $260 million per year, resulting from efficiencies in supply chain and support activities, were exceeded by $20 million and delivered one year in advance. The costs associated with restructuring, integration and rationalization were $485 million ($334 million in 2001 and $151 million in 2000). The majority of the costs were related to severance payments, relocation and infrastructure.

Petrochemicals

		Years ended December 31,		
		2003	2002	2001
Turnover	($ million)	16,075	13,064	11,515
Profit before interest and tax	($ million)	661	285	(399)
Exceptional (gains) losses	($ million)	(38)	256	297
Total operating profit	($ million)	623	541	(102)
Chemicals Indicator Margin (a)	($/te)	112	104	109
Production volumes (b)	(kte)	27,943	26,988	22,716

(a) The Chemicals Indicator Margin (CIM) is a weighted average of externally based industry product margins. It is based on market data collected by Nexant in their quarterly market analyses, which we weight based on BP s product portfolio. While it does not cover our entire portfolio, it includes a broad range of products. Among the products and businesses covered in the CIM are the olefins and derivatives, the aromatics and derivatives, linear alpha-olefins (LAOs), acetic acid, vinyl acetate monomers and nitriles. Not included are fabrics and fibres, plastic fabrications, poly alpha-olefins (PAOs), anhydrides, engineering polymers and carbon fibres, speciality intermediates and the remaining parts of the solvents and acetyls businesses. This measure is not BP specific, rather it is an indicator of relative industry profitability and BP s actual margins will differ. While not entirely representative of BP s complete range of products, we believe it does provide investors with useful information about the environment for BP s products.

Table of Contents

(b) Includes BP share of joint ventures, associated undertakings and other interests in production.

Turnover has increased from $11,515 million in 2001 to $13,064 million in 2002 and to $16,075 million in 2003. The increase in turnover for 2003 compared with 2002 primarily reflects higher sales prices. The increase in turnover for 2002 compared with 2001 primarily reflects higher production as a result of acquisitions, organic growth and improved site reliability.

Profit before interest and tax for 2003 includes net exceptional gains of $38 million resulting from a number of small transactions. Profit before interest and tax for 2002 includes net exceptional losses of $256 million, including a loss on the sale of our plastic fabrications business, a loss on the sale of Fosroc Construction, a loss associated with the closure of polypropylene capacity at Cedar Bayou, Texas and several other small transactions. Profit before interest and tax for 2001 includes net exceptional losses of $297 million, including losses on the sale of termination of a number of petrochemical activities including the Carbon Fibers business.

Total operating profit for 2003 was $623 million including inventory holding gains of $55 million. The result for 2003 includes a $43 million charge comprising a provision to cover future rental payments on surplus property and a charge resulting from a reassessment of our environmental remediation provisions and a credit of $5 million resulting from a reduction in the provision for costs associated with the closure of polypropylene capacity in the USA.

Total operating profit for 2002 was $541 million including inventory holding gains of $26 million. The result for 2002 includes a $140 million write-down of our Indonesian manufacturing assets held for sale following a review of immediate prospects and opportunities for future growth in a highly competitive market, costs of $81 million related to major site restructuring and Solvay and Erdölchemie integration and $29 million for restructuring our research and technology facilities.

Total operating loss for 2001 was $102 million after inventory holding losses of $230 million. The result for 2001 includes charges of $114 million related to Grangemouth restructuring and Solvay and Erdölchemie integration.

The 2003 result reflects a decrease of around $180 million resulting from prolonged margin weakness, primarily in our European polymers business, a result from SARS-affected businesses in Asia that was approximately $60 million lower during the first half of the year and additional charges of $55 million related to additional depreciation from new plants, asset writedowns and provisions for bad debt, partly offset by an increase of $130 million due to higher sales volumes when compared to 2002.

The 2002 result increased relative to 2001 in an overall trading environment that was similar. Increased production contributed around $500 million of this improvement and $24 million was driven by lower costs.

BP s share of production for 2003 was 27,943 thousand tonnes, up 3.5% on 2002 due to improved asset utilization across the business as well as new production capacity and increased ownership in our Asian associated undertakings. Production for 2002 was 26,988 thousand tonnes, up 19% on 2001 as a result of new production from existing and acquired assets. Production for 2001 was 22,716 million tonnes.

Table of Contents

Other Businesses and Corporate

		Years ended December 31,		
		2003	2002	2001
Turnover	($ million)	515	510	549
Loss before interest and tax	($ million)	(805)	(715)	(357)
Exceptional (gains) losses	($ million)	(99)	14	(166)
Total operating loss	($ million)	(904)	(701)	(523)

Other businesses and corporate comprises Finance, our coal and aluminium assets, our investments in PetroChina and Sinopec, interest income and costs relating to corporate activities worldwide.

On January 1, 2002, the solar, renewables and alternative fuels activities were transferred to Gas, Power and Renewables. Comparative information has been restated.

The loss before interest and tax for 2003 includes net exceptional gains of $99 million, which includes a gain on the sale of our interest in PT Kaltim Prima Coal, an Indonesian coal mining company, partly offset by net losses on several small transactions. The loss before interest and tax in 2002 includes net exceptional losses of $14 million resulting from several small transactions. The loss before interest and tax for 2001 includes net exceptional gains of $167 million, which primarily relate to a gain on the disposal of the Group s majority interest in Vysis.

The net cost of Other businesses and corporate amounted to $904 million in 2003, $701 million in 2002 and $523 million in 2001. The net cost for 2003 includes a charge of $132 million in respect of new environmental remediation provisions, a provision of $74 million for future rental payments on surplus leasehold property and a credit of $10 million resulting from a reassessment of our environmental remediation provisions. The net cost for 2002 includes provisions of $140 million for future rentals on surplus leasehold property and a charge of $46 million for environmental liabilities in respect of a divested business. The net cost for 2001 includes additional severance charges of $73 million mainly related to former employees of Atlantic Richfield Company.

In early 2004, we sold our investment in PetroChina for $1.65 billion and our investment in Sinopec for $0.7 billion.

Environmental Expenditure

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Operating expenditure	498	485	436

Clean-ups	45	49	67
Capital expenditure	546	548	423
New provisions for environmental remediation	515	312	180
New provisions for decommissioning	1,159	308	156

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

Table of Contents

Operating expenditure and clean-ups for 2003 were broadly in line with the 2002 and 2001 levels. Capital expenditure for 2003 was flat compared with 2002. The increase in 2002 compared with 2001 was primarily a result of projects to reduce refinery emissions associated with our agreement with the Environmental Protection Agency and upgrades required to meet new US emission requirements for gasoline and highway diesel. Capital expenditures are expected to be at levels similar to 2003 in the near term. In addition to operating and capital expenditures, we also create provisions for future environmental remediation. The charge for new provisions in 2003 principally includes $236 million resulting from a reassessment of environmental remediation provisions and $255 million in respect of new environmental remediation provisions. The increase in new provisions in 2003 and 2002 is primarily related to US retail sites and results from ongoing review of the liabilities and new regulations. Expenditure against such provisions is normally incurred in subsequent periods and is not included in environmental operating expenditure reported for such periods.

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 the 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 (with similar assets) engaged in similar industries or that our competitive position will be adversely affected as a result.

In addition, we make provisions to meet the cost of eventual decommissioning of our oil- and gas-producing assets and related pipelines. New provisions for decommissioning in 2003 include amounts for certain fields on installation of production facilities and increases in respect of reassessment of existing provisions. On installation of oil or natural gas production facility a provision is established which represents the discounted value of the expected future cost of decommissioning the asset. During the year, six new fields came on stream and provisions for these were established for the first time. Additionally, we undertake periodic reviews of existing provisions. These reviews take account of revised cost assumptions, changes in decommissioning requirements and any technological developments. The outcome of the periodic reviews conducted during 2003 indicated that an increase in certain provisions was required.

Provisions for environmental remediation and decommissioning are usually set up on a discounted basis, as required by Financial Reporting Standard No. 12, Provisions, Contingent Liabilities and Contingent Assets . Further details of decommissioning and environmental provisions appear in Item 18 Financial Statements Note 31 on page F-51. See also Item 4 Information on the Company Environmental Protection on page 68.

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 premia with attendant transaction costs. The position is reviewed from time to time.

Table of Contents

LIQUIDITY AND CAPITAL RESOURCES

Cash Flow

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Net cash inflow from operating activities	21,698	19,342	22,409
Net cash inflow (outflow)	1,342	(344)	1,002

Net cash inflow for 2003 was $1,342 million, compared with an outflow of $344 million in 2002, as operating cash flow increased $2,356 million and acquisition spending decreased $1,762 million, which was partly offset by an increase in tax payments of $1,710 million, an increase in equity dividends of $390 million and a decrease in disposal proceeds of $350 million. The decrease in net cash flow for 2002 compared with 2001 reflected a decrease in operating cash flow of $3,067 million, an increase in acquisition spending of $3,114 million and $437 million higher equity dividends, partly offset by a $1,566 million decrease in tax payments and $3,879 million higher disposal proceeds.

Net cash inflow from operating activities increased to $21,698 million in 2003 from $19,342 million in 2002, reflecting an increase in profit of $4,717 million and an increase in the net charge for provisions of $680 million, partly offset by an additional working capital requirement of $3,372 million which included $2,533 million discretionary funding for the Group s pension plans. The decrease in 2002 from $22,409 million in 2001 was due to $2,119 million lower profit and an additional working capital requirement of $2,318 million which were partly offset by a $1,543 million increase in depreciation resulting from impairments.

Dividends from joint ventures and associated undertakings have decreased from $632 million in 2001 to $566 million in 2002 and to $548 million in 2003. The decrease in 2003 compared with 2002 was related to the Ruhrgas and Altura transactions in 2002 partly offset by the contribution from TNK-BP in 2003. The decrease in 2002 compared with 2001 was related to the Erdölchemie transaction and the Altura transaction partly offset by an increase from Watson Cogeneration.

The net cash outflow from servicing of finance and returns from investments was $711 million in 2003, $911 million in 2002 and $948 million in 2001. The lower cash outflow in 2003 and 2002 is primarily due to lower interest payments.

Tax payments increased to $4,804 million in 2003 from $3,094 million in 2002, primarily reflecting the increase in profits for the period. The decrease in 2002 compared with 2001 reflects the decline in profits across the period.

Payments for capital expenditures on fixed assets net of proceeds from sales of fixed assets, amounted to $6,187 million in 2003 compared with $9,646 million in 2002 and $9,849 million in 2001. The decrease in 2003 reflects higher disposal proceeds. The decrease in 2002 over 2001 was due to slightly lower capital expenditure and higher disposal proceeds.

Acquisitions and disposals of businesses produced net cash outflows of $3,548 million in 2003, $1,337 million in 2002 and $1,755 million in 2001. The higher outflow in 2003 reflects lower disposal proceeds. In 2002, the impact of the Veba acquisition was more than offset by higher disposal proceeds.

Overall net cash outflow for capital expenditure and acquisitions, net of disposals, was $9,735 million in 2003 compared with $10,983 million in 2002 and $11,604 million in 2001.

Table of Contents

Dividend payments have increased to $5,654 million in 2003 compared with $5,264 million in 2002 and $4,827 million in 2001. The increase in both years reflects the impact of the higher dividend per share, partly offset by share repurchases.

The Group has had significant levels of investment for many years. Investment, excluding acquisitions, was $14.0 billion in 2003, $13.3 billion in 2002 and $13.2 billion in 2001. Sources of funding are completely fungible, but the majority of the Group s funding requirements for new investment come from cash generated by existing operations. There has been very little change in the Group s level of net debt, that is debt less cash and liquid resources; net debt has increased from $19.6 billion at the end of 2001 to $20.3 billion at the end of 2002 and was $20.2 billion at the end of 2003.

Over the period 2000 to 2003 our cash inflows and outflows were balanced, with sources and uses both totalling $92 billion. Since 2000, the year in which we completed the purchase of Atlantic Richfield Company, the price of Brent has averaged $26.7/bbl, somewhat higher than was expected as the period opened. The following table summarizes the four year sources and uses of cash in post-tax terms:

Sources	$ billion	Uses	$ billion
Adjusted operating cash flow(a)	67	Capital Expenditure	52
Divestments	25	Acquisitions	14
		Share buybacks	6
		Dividends	20
	92		92

(a) Refer to page 103 for a definition of adjusted operating cash flow.

Capital expenditure used about 70% of post-tax operating cash flow from 2000 to 2003, a proportion which is significantly higher than for most other major oil companies. Significant acquisitions made for cash were more than offset by divestitures. Net investment over the same period has averaged $10 billion per year. Dividends, which grew by 6.8% per year in dollar terms, used $20 billion. $6 billion was used for share repurchases. Finally, cash was used to strengthen the financial condition of certain of our pension funds.

Future Cash Flows and Capital Expenditure

Over the next three or four years we expect to see additional cash flows coming from three main sources:

First, having contributed $2.5 billion in 2003 to address deficits in our funded pension plans, we now expect to return to a normal funding programme of $400-500 million per year. We have the capacity to adjust this funding should unforeseen circumstances warrant.

Secondly, organic capital expenditure, that is capital expenditure excluding acquisitions, will decline as we pass the peak of the recent investment cycle. This is already happening today, with projected 2004 organic capital expenditure down on 2003 despite some upward pressure from the weaker US dollar.

Lastly, and most importantly, that we expect operations to be our main source of additional cash. This includes the benefits from capital coming into service in our new Exploration and Production profit centres and greater margin contributions from our Customer Facing Businesses.

Table of Contents

Our plans for the future level of investment and divestment are shown on the table below:

	Years ended December 31,		
	2003	2004	2005
		($ billion)	
Capital expenditure			
Exploration and Production	9.7	9.0	
Gas Power and Renewables	0.3	0.6	
Refining and Marketing	3.0	2.8	
Petrochemicals	0.8	0.9	
Other	0.2	0.2	
	14.0	13.5	12.0-12.5
Acquisitions	6.0	1.4	
Divestments	(6.4)	(3.0-4.0)	(1.0)

We expect capital expenditure for the Company to decrease to a level of $12 billion to $12.5 billion per year in 2005 and 2006 and divestment to a level of around $1 billion per year (about half the level of the recent past), mostly due to routine portfolio upgrading. These figures exclude the effects of the possible public offering of our Olefins and Derivatives business. The only currently identified acquisition over this period is the purchase of the remainder of Solvay s stake in our high-density polyethylene joint venture, should Solvay decide to exercise their put option to us.

The existing profit centres in our upstream business have proved reserves of 9.3 billion boe, including joint ventures and associates, and in 2003 contributed some 2 million boe/d of production. We estimate the decline in production will be around 3% per year from 2004 to 2008. This is in line with a decline of between 3 and 4% per year on average between 2002 and 2004. However, production from our existing and new upstream profit centres (but excluding Russia), we estimate will grow in aggregate by around 5% per year on average between 2003 and 2008.

Financing the Group s Activities

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

The Group s finance debt is almost entirely in US dollars and at December 31, 2003 amounted to $22,325 million (2002 $22,008 million) of which $9,456 million (2002 $10,086 million) was short term.

Net debt was $20,193 million at the end of 2003, a decrease of $80 million compared with 2002. The ratio of net debt to net debt plus equity was 21% at the end of 2003 and 22% at the end of 2002.

The maturity profile and fixed/floating rate characteristics of the Group s debt are described in Item 18 Financial Statements Notes 26 and 29 on pages F-39 and F-47, respectively.

We have in place a European Debt Issuance Programme (DIP) and a US Shelf Registration under each of which the Group may raise $8 billion and $6 billion of debt respectively for maturities of one month or longer. At June 23, 2004, the amount drawn down against the DIP was $3,476 million, and $5,475 million had been raised under the US Shelf Registration.

Commercial paper markets in the USA and Europe are a primary source of liquidity for the Group. At December 31, 2003 the outstanding commercial paper amounted to $4,243 million (2002 $4,853 million).

Table of Contents

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

In addition to reported debt, BP uses conventional off balance sheet arrangements such as operating leases and borrowings in joint ventures and associated undertakings. At December 31, 2003 the Group s share of third party borrowings of joint ventures and associated undertakings was $2,151 million (2002 $457 million) and $922 million (2002 $849 million) respectively. These amounts are not reflected in the Group s debt on the balance sheet.

The Group has issued third party guarantees under which amounts outstanding at December 31, 2003 are summarized below. Some guarantees outstanding are in respect of borrowings of joint ventures and associated undertakings noted above.

	Guarantees expiring by period						
	Total	2004	2005	2006	2007	2008	2009 and thereafter
	($ million)						
Guarantees issued in respect of:							
Borrowings of joint ventures and associated undertakings	635	93	129	29	138	28	218
Liabilities of other third parties	304	115	82	31	8	40	28

At December 31, 2003 contracts had been placed for authorized future capital expenditure estimated at $6,420 million. Such expenditure is expected to be financed largely by cash flow from operating activities. The Group also has access to significant sources of liquidity in the form of committed facilities and other funding through the capital markets. At December 31, 2003, the Group had available undrawn committed borrowing facilities of $3,700 million ($3,600 million at December 31, 2002).

Table of Contents

Contractual Commitments

The following table summarizes the Group s principal contractual obligations at December 31, 2003. Further information on borrowings and capital leases is given in Item 18 Financial Statements Note 29 on page F-47 and further information on operating leases is given in Item 18 Financial Statements Note 17 on page F-29.

Expected payments by period under contractual obligations and commercial commitments	Payments due by period						
	Total	2004	2005	2006	2007	2008	2009 and thereafter
				($ million)			
Borrowings (a)	20,143	9,366	2,674	2,786	1,299	945	3,073
Finance lease obligations	4,634	127	243	248	240	248	3,528
Operating leases	8,115	1,275	1,066	895	799	728	3,352
Decommissioning liabilities	7,504	86	156	173	154	156	6,779
Environmental liabilities	2,430	465	441	402	276	186	660
Pensions (b)	26,682	633	649	652	659	666	23,423
Other post-employment benefits (c)	11,768	242	252	259	263	264	10,488
Unconditional purchase obligations (d)	67,828	45,491	7,076	3,133	1,888	1,655	8,585

(a) Expected payments exclude interest payments on borrowings.

(b) Represents the expected future contributions to funded pension plans and payments by unfunded pension plans.

(c) Represents the expected future payments for postretirement benefits.

(d) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas, feedstocks and pipeline systems. In addition, the amounts shown for 2004 include purchase commitments existing at December 31, 2003 entered into principally to meet the Group s short term manufacturing and marketing requirements. The price risk associated with these crude oil, natural gas and power contracts is discussed in Item 11 Quantitative and Qualitative Disclosures about Market Risk on page 170.

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

Unconditional purchase obligations payments due by period	Payments due by period						
	Total	2004	2005	2006	2007	2008	2009 and thereafter
				($ million)			
Crude oil and oil products	22,043	19,350	844	452	422	374	601

Natural gas	19,439	13,189	2,575	1,141	489	398	1,647
Chemicals and other refinery feedstocks	10,049	2,277	1,666	753	563	545	4,245
Utilities	11,612	9,622	1,231	289	62	54	354
Transportation	2,814	738	510	365	247	204	750
Use of facilities and services	1,871	315	250	133	105	80	988
Total	67,828	45,491	7,076	3,133	1,888	1,655	8,585

96

Table of Contents

The following table summarises the Group s capital expenditure commitments at December 31, 2003 and the proportion of that expenditure for which contracts have been placed. The Group expects its total capital expenditure excluding acquisitions to be around $13.5 billion in 2004 and to be in the range $12.0 billion to $12.5 billion in 2005.

Capital expenditure commitments including amounts for which contracts have been placed	Total	2004	2005	2006	2007	2008	2009 and thereafter
				($ million)			
Committed on major projects	17,455	8,372	3,536	2,362	1,031	1,087	1,067
Amounts for which contracts have been placed	6,420	4,449	1,185	490	148	91	57

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 from 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 December 31, 2003, the Group had available undrawn committed facilities of $3,700 million. These committed facilities, which are mainly with a number of international banks, expire in 2004. The Group expects to renew the facilities on an annual basis.

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 and natural gas 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.

Table of Contents

OUTLOOK

The world economy grew at above the ten-year average in the first quarter of 2004, and appears to have slowed somewhat through the second quarter to a growth rate close to trend. The US and Asian economies, particularly China, remain robust. Europe, with the exception of the UK, continues to lag. For 2004 as a whole, the consensus is for global growth close to trend, with the US and Asia expected to grow at or above trend and mainland Europe expected to remain below trend.

At just over $32 per barrel (dated Brent), crude oil prices during the first quarter were the highest since the fourth quarter of 1990 (immediately prior to the first Gulf War). Prices have averaged around $35.47 so far in the second quarter (through close June 23, 2004). Strong oil demand growth, low inventories, a tight US gasoline market and concern about possible supply disruptions have kept crude oil prices supported, notwithstanding the continuing high levels of OPEC production. OPEC s decision in early June to raise quotas and signs that Saudi Arabia and the U.A.E. are adding around 1 million barrels per day to production this month suggest that the market will be fully supplied as we head into the second half of the year.

US natural gas prices traded in a relatively narrow range for most of the first quarter, averaging $5.69/mmbtu (Henry Hub first of the month index). The index has been even higher in the second quarter, at $6.00/mmbtu, reflecting the exceptional strength of oil prices. Spot gas prices have traded between residual fuel oil and distillate parity for most of the last year. Working gas in storage currently stands well above last year s levels and very close to the five-year (1999-2003) average. With storage at adequate levels and with growth in supply and demand looking more balanced than in recent years, we expect that gas prices will remain strongly influenced by movements in oil prices for the remainder of 2004. Summer temperatures will also be an important determinant of third quarter prices.

Refining margins in the first quarter strengthened relative to the fourth quarter 2003 in the face of declining product inventories, strong global oil demand growth and cold US weather. Margin gains were most pronounced in the US, where low gasoline inventories and specification changes raised concerns about supply during this year s driving season. During the second quarter, refining margins reached record highs as strong US gasoline demand growth prevented inventories from building despite a partial recovery in import volumes. Meanwhile, global marketing unit margins have continued to be under pressure due to the further rise in crude price and product costs, though have recently shown some recovery.

Petrochemical margins in the first half of 2004 improved compared to the previous six months but were still under pressure from the high cost of feedstocks. This pressure is expected to continue for the balance of the year. We continue to remain cautious regarding the overall petrochemicals market although we expect sales in 2004 to be higher compared to last year provided the global economic recovery is sustained.

Table of Contents

PROSPECTS

Set forth below under the heading Business Strategy and Prospects are statements regarding the strategy and prospects of the Group. Terms used in these statements and not defined elsewhere in this Form 20-F are defined below. These statements also include references to non-GAAP financial measures. Under Defined Terms and Non-GAAP Financial Measures below, we identify and define these measures, provide the nearest equivalent GAAP financial measures and explain why Management believes these measures provide investors with useful information.

Under the heading Reconciliation of Non-GAAP Financial Measures on pages 115 to 119 below we include a quantitative reconciliation of the historical non-GAAP financial measures to the nearest equivalent GAAP financial measures. We also refer to forward-looking non-GAAP financial measures for which at this time there are no comparable GAAP measures and which at this time cannot be quantitatively reconciled to comparable GAAP measures.

The discussion below contains forward-looking statements with respect to the plans and prospects of the Group, future capital expenditure, forward-looking rules of thumb, future hydrocarbon production volume, date or period(s) in which production is scheduled or expected to come on stream, changes to BP s financial reporting due to the adoption of FRS 17, operating capital employed/capital in service, cash returns, underlying cash flows, finding and development costs, BP s intentions with respect to shareholder distributions and share buybacks, gearing, opportunities for material acquisitions and costs for providing pension and other postretirement benefits. These forward-looking statements are based on assumptions which management believes to be reasonable in the light of the Group s operational and financial experience, however, no assurance can be given that the forward-looking statements will be realized. You are urged to read the cautionary statement under Forward-Looking Statements on page 12 and Risk Factors on pages 10 and 11 which describe the risks and uncertainties that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements. The Company provides no commitment to update the forward-looking statements or to publish financial projections or forward-looking statements in the future.

All forward-looking non-GAAP information has been calculated at plan conditions, i.e., based on assumed prices of $20 per barrel Brent, $3.50 per mmbtu Henry Hub natural gas and a global refining indicator margin of $2.70 per barrel. Comparative non-GAAP financial information for 2003 and prior years has been adjusted based on the same planning assumptions used for the forward-looking information.

References to production and proved reserves in the comments below represent the sum of the production and reserves of subsidiaries and equity-accounted entities. BP does not control the production or reserves of equity-accounted entities.

When we discuss production, we mean a number, usually in barrels of oil equivalent, which is an indicator of the trend of average daily output of hydrocarbons. It is not an amount which can be targeted, nor is it a specific forecast for a year. The indicator does not include any provision for downtime above the average observed over the last five years, the effect of prices above $20 per barrel Brent on entitlement volumes from PSAs, the effect of weather patterns outside of the normal trend, as well as other items noted in the cautionary statement. We have come to the view that defining production in this way is more useful than an indicator of capacity, which is a concept with an unhelpfully wide range of interpretations.

When we talk about growth rates in production, these are calculated as cumulative average growth rates over a period. They are not therefore growth rates that might be observed year after year.

Table of Contents

2004 Reporting Changes

The changes we have made for 2004 reporting are summarized below.

In 2004 we are:

- adjusting our accounting for employee share ownership plans as required by a new UK law;
- transferring certain NGL operations from the Exploration and Production segment to the Gas, Power and Renewables segment;
- adopting Financial Reporting Standard No. 17 (FRS 17), the new UK GAAP pension and benefit reporting standard;
- moving to what has become the industry norm of not adjusting headline earnings for exceptional items and those items previously designated as special items, though we will continue to identify those non-operating items which have a material impact on our results;

We have restated the historical results for these changes, and this is the basis for the discussion of BP s strategy below. The effects of the first three changes set out above on our historical financial information are quantified under the heading The Effect of Accounting Changes in 2004 on Prior Period Financial Information on page 111.

Rules of Thumb: 2004 Operating Environment

We believe that investors may find it useful to apply the following forward-looking rules of thumb to estimate the impact of changes in the trading environment on BP s 2004 pre-tax earnings. These rules of thumb are approximate. We consider rules of thumb more useful on an annual basis than for quarter-to-quarter comparisons, as annual comparisons tend to smooth out much of the volatility in differentials, working capital effects and the like. Many other factors will affect BP s earnings quarter by quarter. Actual results may therefore differ significantly from the estimates implied by the application of these rules. These rules of thumb have been developed under existing operating and tax arrangements and are considered to be useful only for 2004 results.

	Full Year
	$ million
Oil Price Brent +/- $1/bbl	570
Gas Henry Hub +/- $ 0.10/mmbtu	110
Refining(a) GIM +/- $ 1/bbl	1,120
Petrochemicals(b) CIM +/- $10/te	200

(a) Refer to Item 4 Information on the Company Segmental Information Refining and Marketing, page 49, for definition of Global Indicator Refining Margin (GIM).

(b) Refer to Item 4 Information on the Company Segmental Information Petrochemicals, page 58, for definition of Chemicals Indicator Margin (CIM).

Table of Contents

Defined Terms and Non-GAAP Financial Measures

Cash Returns

Cash returns are the ratio of the cash returns numerator divided by the cash returns denominator, expressed as a percentage.

Underlying cash returns are the ratio of the cash returns numerator, adjusted for the environment, divided by the cash returns denominator, expressed as a percentage.

The cash returns numerator is operating profit before inventory holding gains and losses adjusted for depreciation, depletion and amortization.

The cash returns denominator is average operating capital employed excluding the fixed asset revaluation adjustment and goodwill consequent upon the Atlantic Richfield and Burmah Castrol acquisitions.

Operating capital employed is capital employed excluding liabilities for current and deferred taxation.

The cash returns numerator, adjusted for the environment, is the cash returns numerator adjusted to oil and natural gas prices and refining margins consistent with BP s planning assumptions.

The nearest equivalent GAAP measures to (i) the cash returns numerator is profit before interest and tax, (ii) the cash return denominator is operating capital employed and (iii) cash returns is return (i.e., profit before interest and tax) on average operating capital employed.

Table of Contents

Management believes that because there will be significant changes in BP s financial reporting due to the adoption of FRS 17 in 2004 and International Financial Reporting Standards in 2005, focusing on cash returns and underlying cash flow (defined below) through this period of change will provide investors with consistent insight into the Group s performance. Cash returns and underlying cash flows are presented for prior periods to provide comparative information for future periods.

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Profit before interest and tax			
Exploration and Production	14,669	8,280	12,466
Gas, Power and Renewables	576	2,020	491
Refining and Marketing	2,270	2,582	2,461
Petrochemicals	623	191	(399)
Other businesses and corporate	(184)	(744)	(357)
Group	17,954	12,329	14,662
Customer Facing Businesses (a)	3,469	4,793	2,553
Cash returns numerator			
Exploration and Production	20,681	15,789	18,057
Gas, Power and Renewables	739	548	664
Refining and Marketing	5,489	3,578	5,875
Petrochemicals	1,281	1,170	716
Other businesses and corporate	(143)	(652)	(427)
Group	28,047	20,433	24,885
Customer Facing Businesses (a)	7,509	5,296	7,255
Average operating capital employed			
Exploration and Production	62,539	60,501	58,251
Gas, Power and Renewables	3,636	3,216	3,489
Refining and Marketing	34,298	30,038	26,813
Petrochemicals	13,010	12,257	11,502
Other businesses and corporate	(8,311)	(4,962)	1,437
Group	105,172	101,050	101,492
Customer Facing Businesses (a)	50,944	45,511	41,804
Average cash returns denominator			
Exploration and Production	54,179	49,880	45,324
Gas, Power and Renewables	3,636	3,216	3,489
Refining and Marketing	27,641	22,882	19,001
Petrochemicals	13,010	12,257	11,502
Other businesses and corporate	(8,311)	(4,962)	1,437
Group	90,155	83,273	80,753
Customer Facing Businesses (a)	44,287	38,355	33,992
		(%)	
Return on Average Operating Capital Employed			
Exploration and Production	23	14	21
Gas, Power and Renewables	16	63	14
Refining and Marketing	7	9	9
Petrochemicals	5	2	(3)
Other businesses and corporate	2	15	(25)

Group	17	12	14
Customer Facing Businesses (a)	7	11	6
Cash returns			
Exploration and Production	38	32	40
Gas, Power and Renewables	20	17	19
Refining and Marketing	20	16	31
Petrochemicals	10	10	6
Other businesses and corporate	2	13	(30)
Group	31	25	31
Customer Facing Businesses (a)	17	14	21

(a) Customer Facing Businesses comprises Gas, Power and Renewables, Refining and Marketing and Petrochemicals.

Table of Contents

Cash Flow

Adjusted operating cash flow (post-tax) is net cash inflow from operating activities, plus dividends from joint ventures and associated undertakings less the net cash outflow from the servicing of finance and returns on investments less tax paid (excluding tax payments attributable to the sale of fixed assets and businesses or termination of operations).

Underlying operating cash flow is adjusted cash flow after further adjusting for the after-tax cash outflow for incremental discretionary pension funding and oil and natural gas prices and refining margins consistent with BP s planning assumptions.

Free cash flow is adjusted operating cash flow after further adjusting for the after-tax cash outflow for incremental discretionary pension funding less net cash outflow for capital expenditure and financial investment and less net cash outflow for acquisitions and disposals. BP s definition of free cash flow may differ from that of other companies.

Underlying free cash flow is free cash flow adjusted to oil and natural gas prices and refining margins consistent with BP s planning assumptions.

The nearest equivalent GAAP financial measures to the non-GAAP financial measures described above are net cash inflow from operating activities and net cash inflow or outflow. Management believes that underlying cash flow gives a better indication to investors of the cash flow available from the activities of the Group, after meeting tax and interest payments, which is available for capital investment, dividend payments and other discretionary options such as share buybacks and incremental pension scheme funding. Similarly, free cash flow gives a better indication of the cash flows available for dividend payments and other discretionary options after investing in sustaining and growing the capital base of the Group.

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Net cash inflow from operating activities	21,698	19,342	22,409
Net cash inflow (outflow)	1,405	(326)	1,035
Adjusted operating cash flow (pre-tax)	21,535	18,997	22,093
Free cash flow	8,705	4,984	5,909

Operating Capital Employed in Service

Operating capital employed in service for the Exploration and Production segment is operating capital employed excluding: the fixed asset revaluation adjustment and goodwill consequent upon the Atlantic Richfield acquisition; our net investment in Russia (TNK-BP); segment tangible fixed assets under construction; and intangible exploration costs.

Management believes that this measure of capital employed, when used in cash return measures, gives an indication of the profitability of the segment s assets that are in service and generating revenue.

The nearest equivalent GAAP financial measures to the non-GAAP financial measures described above are operating capital employed and return on average operating capital employed.

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Average operating capital employed	62,539	60,501	58,251
Average operating capital employed in service	39,072	39,660	37,643
		(%)	
Return on average operating capital employed	23	14	21
Cash return	38	32	40

Table of Contents

Gross Margin

Gross margin is Group turnover less cost of sales excluding the impact of inventory holding gains and losses and is a non-GAAP financial measure. Management believes this measure enables investors to better understand BP s trading performance from period to period. The nearest equivalent GAAP measure is historical cost gross margin which is calculated as Group turnover less cost of sales.

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Historical cost gross margin	31,236	24,106	25,325
Gross margin	31,224	22,979	27,217

Net Investment

Net investment is the sum of net cash inflow or outflow for capital expenditure and financial investment and net cash inflow or outflow for acquisitions and disposals.

Business Strategy and Prospects

Through mergers, acquisitions and organic growth, BP has built itself into one of the leading companies in the international oil industry. Our strategy for future growth rests upon four key elements:

- scale: the most attractive projects require very large scale financial, human and physical resources; scale affords the benefits of economies (from for example, procurement, overheads and skills), competitively strong market access and diversification of risk;
- scope: successful companies need to operate globally to access the best opportunities, often in challenging areas;
- capability: successful companies need integrated know-how , the ability to combine technical, commercial and diplomatic skills. This is critical in making large projects happen as activity moves to more politically complex areas;
- capacity: each project or business is different and complex in its own way. Managing a portfolio of these requires a degree of multi-tasking that requires a specific corporate capability.

Having achieved scale, our challenge is to add new cash flow streams to existing ones, with new ones having cash returns at least as good as the existing ones.

One important dimension of our increased scale is the growth in oil and gas reserves. At the end of 1997 prior to the merger with Amoco, BP s proved developed and undeveloped reserves, including 1.8 billion boe in respect of our share of the reserves of joint ventures and associated undertakings, were 8.6 billion boe.

At the end of 2003, reserves have risen to about 18.3 billion boe including 3.3 billion boe of reserves of joint ventures and associated undertakings including our 50% of TNK-BP. Part of this is due to the fact that over the last five years we have replaced about 150% of production.

We disclose our share of reserves held in joint ventures and associated undertakings that are accounted for by the equity method although we do not control these entities or the assets held by such entities.

Building the Group was designed to give us access to economies of scale. An initial route to this was the realisation of the immediate synergies that came from putting together our merged and acquired companies.

Table of Contents

We are now transitioning to a phase of internally generated growth in free cash flow from the high-graded opportunity set of the expanded Group. We have managed the sources and uses of funds over the last few years to position us for this. Since 2000, the year in which we completed the purchase of Atlantic Richfield Company, the price of Brent has averaged $26.7/bbl, somewhat higher than was expected as the period opened. The following table summarizes the four year sources and uses of cash in post-tax terms:

Sources	$ billion	Uses	$ billion
Adjusted operating cash flow	67	Capital expenditure	52
Divestments	25	Acquisitions	14
		Share buybacks	6
		Dividends	20
	92		92

Capital expenditure used about 70% of post-tax operating cash flow from 2000 to 2003, a proportion which is significantly higher than for most other major oil companies. Significant acquisitions made for cash were more than offset by divestitures. Net investment over the same period has averaged $10 billion per year. Dividends, which grew by 6.8% per year in dollar terms, used $20 billion. $6 billion was used for share buybacks. Finally, cash was used to strengthen the financial condition of certain of our pension funds.

Higher oil prices allowed BP to invest in attractive assets and markets at a somewhat faster rate than it might otherwise have been able to do.

We divide our operating business segments into two groupings: Resources Business , namely, Exploration and Production; and Customer Facing Businesses , namely, Refining and Marketing, Petrochemicals, and Gas, Power and Renewables.

Over the last few years we have invested heavily in the new profit centres in the Resources Business. Investment was also significant in the Customer Facing Businesses, into which we invested all the operating cash flow generated by them.

The rationale behind the expansion in the Customer Facing Businesses was:

- an upgrading of quality and a degree of scale was required to get to the point where underlying cash returns from the Customer Facing Businesses could at least be maintained going forward;
- the volatility of earnings is generally lower in Customer Facing Businesses than in the Resources Business in relation to such activities as gas to liquids or heavy oil;
- Customer Facing Businesses allow us to balance risk to returns from the oil price. At very low oil prices (that is around $16/bbl) the Customer Facing Businesses begin to have cash returns in excess of those from the Resources Business. The Resources Business gives us upside potential at higher prices.

The selection of the assets and markets in which we invest is guided by our strategy, which has the objective of maximizing long run shareholder value. The essence of our strategy remains unchanged and is:

- for the Resources Business: to build production with steadily improving underlying cash returns by investing in the largest, lowest cost, new hydrocarbon deposits and managing the decline of existing production assets;

for the Customer Facing Businesses: to expand customer capture, improve quality to offset competitive forces in order to increase cash flow while keeping underlying cash returns at least constant.

BP s results are affected by economic conditions and in particular the oil price. Oil prices are impossible to predict, either on a short or long term basis. There are many uncertainties. One is demand, which has been volatile and has grown by less than 1% per year on average since 1997. Another is the growing level of production and new capacity, both outside the control of OPEC and in some OPEC countries.

Based on our analysis of average Brent oil prices over the last 20 years, it is our view that it is reasonable to use an oil price of $20/bbl for resource allocation to reflect the right balance between the Customer Facing Businesses and the Resources Business, always testing projects at $16/bbl on the downside.

For financial planning, we believe it is necessary to retain sufficient debt capacity to see us through a period of $16/bbl oil prices while not stretching gearing unreasonably, that is to keep it below 35%. This is our contingency plan. As a base case, we now see cash flows balancing at around $20/bbl over the next couple of years. Over time, production rises and capital expenditure declines so that the oil price at which cash flows balance is expected to fall below $20/bbl.

The price of oil will, in large part, determine the size of BP s distributions of excess free cash flows to shareholders over and above our dividend.

Resources Business

Our Resources Business strategy is founded on creating profit centres with leadership positions in the basins in which we operate. Our Resources Business can be viewed in four parts: existing profit centres, new profit centres, our 50% interest in TNK-BP and future growth.

Existing Profit Centres

Our existing profit centres include our operations in Alaska, Egypt, Latin America (including Argentina, Brazil, Colombia, Mexico and Venezuela), Middle East (including Abu Dhabi, Sharjah and Pakistan), North America Gas (Onshore US, the Gulf of Mexico Shelf and Canada) and the North Sea (UK, Netherlands and Norway).

These centres have proved reserves of 9.3 billion boe, including joint ventures and associates, and in 2003 contributed some 2 million boe/d of production. We estimate the decline in production will be around 3% per year from 2004 to 2008. This is in line with a decline of between 3 and 4% per year on average between 2002 and 2004. We expect capital expenditure to decrease over time and unit cash costs to remain stable at an average of around $5.0 per barrel. We expect underlying cash returns for existing profit centres to reduce slightly as the overall production declines.

In managing the production from these existing centres, we focus on:

new projects, primarily in Argentina and the North Sea;

the rate of recovery with a particular emphasis on operational uptime;

the addition of proved reserves. Over the period 2000 to 2003, we have replaced some 75% of the proved developed reserves which have been produced;

the control of investment and costs made possible by the application of appropriate technology. Finding and development costs in the existing centres have been around $6/boe and the selection of future investments is expected to limit increases to the range of $6 to $7.5/boe.

New Profit Centres

The new profit centres comprise our operations in Asia Pacific (Australia, Vietnam, Indonesia, China), Azerbaijan, Algeria, Angola, Trinidad, Deepwater Gulf of Mexico and Russia.

For new profit centres, the single most important challenge is to ensure that projects start production on time within budgeted capital costs. The major projects are presently on track for their scheduled start of production as shown below:

2004	**2005**
Atlas Methanol, Trinidad	Mad Dog, Gulf of Mexico
In Salah, Algeria	Thunderhorse, Gulf of Mexico
Kizomba A, Angola	Azeri, Azerbaijan
Holstein, Gulf of Mexico	BTC, Azerbaijan
NW Shelf LNG T4, Australia	In Amenas, Algeria
	Trinidad LNG T4, Trinidad

More fields are expected to come on stream in 2006.

In contrast to the existing centres, the new profit centres generally have much lower finding and development costs because the fields are large and new. Unit cash costs are generally also around half the level of those of the existing centres.

We expect capital in service to rise from around 60% in 2004 to a more representative level of 80% in 2008, as production builds, and cash returns to rise accordingly.

Combining both the existing and new profit centres (but excluding Russia), cash returns decline as there is less operating capital employed in service but begin to rise as capital comes into service. Our mid-point estimates of capital expenditure fall within the range of around $8.0 - $8.5 billion per annum in 2005 and 2006, so the free cash flow expands with increased production. Excluding Russia, we estimate that between 2003 and 2008 production will grow by around 5% per year on average.

TNK-BP

We believe that our investment in Russia is attractive and is self-financing in the short term, but also has longer-term strategic importance. The most recent estimates from the International Energy Agency show that for the longer term, which means from 2010 onwards, three areas will supply the bulk of world trade in oil and gas Russia, the Persian Gulf (that is Saudi Arabia, Iran and Iraq) and West Africa. On this basis, our positions in Russia and Angola are important to our long-term strategy.

There are pressures on costs from transportation tariffs, reflecting export constraints, since these tariffs have been set for the oil price conditions of today. They are expected to moderate if oil prices fall. Some of the increases are being offset in TNK-BP by synergies and additional production.

BP receives cash from TNK-BP by way of a dividend, in accordance with our original agreement. We expect that at $20/bbl, TNK-BP will be able to pay dividends equal to 40% of TNK-BP s US GAAP net income, as well as fund its capital expenditure programme.

Future Growth

Capital spending on exploration is expected to rise from an average of $300 million per year for 2000 to 2003 to around $450 million per year in 2004 and beyond. With finding and development costs in the range of $4 to $5 per barrel (based on a rolling five year average), we estimate our medium-term capital expenditure, excluding acquisitions, to be around $8 billion to $8.5 billion per year and longer term expenditure in the range of $8 billion to $9 billion per year (in 2007 and beyond) in order to continue to grow proved reserves and production.

Customer Facing Businesses

We have invested considerably in the Customer Facing Businesses with the main objective of improving our acquisition and retention of customers as a source of enduring value. During their building, these segments produced no surplus cash flow to the Group and our intention now is to target them to produce underlying free cash flow (free cash flow adjusted for oil and gas prices and refining margins) in proportion to their capital employed.

The essence of our strategy is to focus on quality in order to meet continued intense competition.

Capital expenditure, excluding acquisitions, for the Customer Facing Businesses has been in the range of $3.8 billion to $4.3 billion for 2000 to 2003. Operating capital employed was $44 billion in 2003 and for the period 2004 to 2006 we expect the level to remain broadly constant. These figures have not been adjusted for the proposed divestment of Olefins and Derivatives.

Cash returns over the period 2001 to 2003 have varied both as the Customer Facing Businesses have changed and market conditions (after adjusting for refining margins) have moved, but on average have been around 17% including restructuring costs associated with the material acquisitions made since 2000. No adjustments have been made to Petrochemicals or marketing margins.

Projections of market conditions are difficult to make for each segment and so we assume that cash returns for the whole of the Customer Facing Businesses will remain constant over time. Our objective, however, is to improve returns.

In aggregate, our Customer Facing Businesses are an important part of the Group which can further be improved. A key medium-term objective is to bring our capabilities to acquire and retain customers to the level of our technological capabilities.

Capturing the most gross margin and controlling costs are our key operational targets. This set of businesses has long-term potential in not only the United States and Europe (our principal areas of focus) but also in new markets in which we are developing, such as China.

Refining and Marketing

In refining, our objective is to maintain the quality of our US portfolio (rated in the top quartile by the Solomon Net Margin Index). In Europe, improvements to the configuration of our portfolio are still needed. Our operational focus is keeping availability high (the rate was 95.5% in 2003), controlling operating costs and reducing the unit cost of goods sold. Our capital expenditure is reducing slightly as investments in relation to clean air and clean fuels are decreasing. We intend to continue to limit our exposure to refining assets.

In oil products marketing, we are continuing to expand the reach of our new convenience format, BP Connect, and introducing new products (such as premium fuels like BP Ultimate). Sales are showing strong trends.

Petrochemicals

Petrochemicals cash returns have been around 10% over the period 2000 to 2003. Our objective is to improve these returns without relying on a better trading environment. In order to do so, we intend to

Table of Contents

continue our programme of divestitures and our focus on reliability (which was 95% in 2003) and cost reductions.

We are now managing our Petrochemicals businesses in two portfolios: A&A (PX, PTA and acetic acid) and O&D. Operating capital employed in A&A is around $5 billion and in O&D it is around $8 billion.

Historically, aromatics and acetyls, which have significantly higher market shares and more proprietary technological content, have generated better returns. They are also positioned to benefit from the high growth in Asian markets. Our focus is therefore to invest more in these products while maintaining capital at very low levels in O&D. We believe our O&D portfolio has competitive advantages in the O&D part of the industry. Acceptable returns will, however, be very dependent upon utilization rates (which are driven by demand) and cost of feedstock, given its competitive intensity and fragmentation. On April 27, 2004, we announced our intention to set up a separate corporate entity for the O&D businesses. It is our intention to make a public offering of this new entity at an appropriate time. Based on the estimated lead time required for such a transaction, and depending on market circumstances, we would aim to make such an offering in the second half of 2005. We intend to retain and grow the A&A businesses, which will be transferred to the Refining and Marketing segment on January 1, 2005.

Gas, Power and Renewables

This segment comprises gas marketing and trading, NGLs and LNG. This is our smallest segment in financial terms, its financial results are comprised of the marketing margins only for gas and gas products. This segment plays a vital long-term role in the development of customers for our gas so that markets are available for equity gas when produced.

Our gas sales have been increasing at 22% per year from 2000 to 2003 and we expect growth to continue at a rate of 3 to 5% per year for the next five years, which is above global gas demand. NGL sales have increased at a rate of 13% per year over the same period, and BP is the leading marketer of NGLs in the United States. LNG sales have also been growing; last year we took material steps in implementing our strategy with the startup of Train 3 in Trinidad and the securing of access to new markets in the Atlantic and Pacific Basins. During 2003, we supplied 1.4 billion cubic feet per day of equity gas into LNG plants, up from 0.7 billion cubic feet per day in 2000. We expect to add a further 0.8 billion cubic feet per day by 2006, bringing our total volume to over 2.2 billion cubic feet per day.

Capital expenditure, acquisitions and divestments

Our plans for the future level of investment and divestment are shown on the table below:

	Years ended December 31,		
	2003	2004	2005
		($ billion)	
Capital expenditure			
Exploration and Production	9.7	9.0	

Gas, Power and Renewables	0.3	0.6	
Refining and Marketing	3.0	2.8	
Petrochemicals	0.8	0.9	
Other	0.2	0.2	
	14.0	13.5	12.0-12.5
Acquisitions	6.0	1.4	
Divestments	(6.4)	(3.0-4.0)	(1.0)

Table of Contents

We expect capital expenditure to decrease to a level of $12 billion to $12.5 billion per year in 2005 and 2006 and divestment to a level of around $1 billion per year, mostly due to routine portfolio upgrading. These figures exclude the effects of the possible spin-off of our O&D business. The only currently identified acquisition over this period is the purchase of the remainder of Solvay s stake in our high-density polyethylene joint venture, should Solvay decide to exercise their put option to us.

Cash returns

Cash returns for the Group decreased from 2001 to 2003, as the amount of capital not in service in the Exploration and Production segment remained high. They should improve as we go forward and we expect the average return for 2004 to 2006 to be equal to that for 2001 to 2003.

Dividends and Other Distributions to Shareholders and Gearing

The Board intends to continue with a progressive dividend policy. In establishing the level of dividend the Board uses its discretion but is guided by several considerations, including:

- the actual prevailing circumstances of the Group, including its cash flows, indebtedness and results;
- the future expected sustainable profit of the Group, excluding amortization of the fixed asset valuation adjustment and goodwill consequent upon the Atlantic Richfield and Burmah Castrol acquisitions and inventory holding gains and losses, at underlying conditions of $20/bbl Brent, $3.50/mmbtu Henry Hub natural gas and a global indicator refining margin of $2.70/bbl;
- the effect of circumstances which may require planning assumptions to be modified;
- our track record of dividend growth which has been 6.8% per year in dollar terms since 1999, the year in which we started to announce our dividends in dollars.

Importantly, these considerations are assessed in the broader context of our approach to long-term value creation based on cash returns. Accordingly, we remain focused on ensuring that the spread between our return and our weighted average cost of capital is optimized.

Therefore, we manage our gearing to a level of 25-30%, assuming oil prices are about $20/bbl, in order to provide the appropriate cushion against potential oil price volatility, but also to prevent an increase in our weighted average cost of capital, which would result from an over-capitalised balance sheet. This gearing range could be extended to 35% if oil prices go down to $16/bbl.

In periods of high oil prices, subject to unforeseen circumstances the Group generates significant excess free cash flow after capital expenditure and dividends. Rather than using this cash to reduce debt below our target gearing levels, we intend to return 100% of this excess free cash flow to our investors, for as long as oil prices remain above $20/bbl, all other things being appropriate. While it is possible that some of the excess might be used, for example, for material acquisitions if we saw opportunities that fit our strategy, we see no such opportunities at present.

Our plan is to continue, subject to market conditions, our programme of share buybacks. Since the completion of the Atlantic Richfield acquisition in 2000 until the end of 2003 we have repurchased some 775 million shares at a cost of $6 billion, reducing the number of shares in issue (after accounting for the issuance of shares under employee stock programmes) by 2.5%. During the first quarter of 2004, we bought back 154.7 million shares, at a cost of $1.25 billion.

Table of Contents

Assessing performance

We have three targets:

- to underpin growth by a focus on performance, particularly on cash returns, investing at a rate appropriate for long term growth;
- to increase the dividend in the light of the considerations outlined below;
- to distribute to shareholders 100% of all post-tax cash flows in excess of investment and dividend needs, generally when the price of oil is above $20/bbl, all other things being appropriate.

We presently track the first of these targets through five strategic indicators. Strategic indicators are estimates of outcomes and are not targets; they are parameters by which we assess the performance of the business. We keep these indicators under review and if we find a better way of measuring the achievement of our targets, we will change the indicators accordingly.

- Oil and gas production. We currently estimate the rate of growth of oil and gas production at an average of around 5% per year between 2003 and 2008, excluding production from TNK-BP, and at an average of around 7% per year including TNK-BP. Our estimates for the years 2005 to 2008 do not include unidentified projects or exploration successes but do include our view of some reserves which are currently not booked as proved;
- Cash returns. We expect an improvement in underlying cash returns of approximately two percentage points between 2003 and 2006;
- Operating capital employed. We expect an increase in operating capital employed of around 15% between 2003 and 2006;
- Finding and development costs. We expect to keep the five year rolling average of finding and development costs in the range of $4 to $5 per boe over the period to 2006;
- Capital expenditure. We expect capital expenditure of around $13.5 billion in 2004, $12 to $12.5 billion over 2005 to 2006 and around $12 to $13 billion beyond 2007.

Table of Contents

The Effect of Accounting Changes in 2004 on Prior Period Financial Information

Employee Share Ownership Plan Trusts

The Group has adopted UITF Abstract No. 38 Accounting for Employee Share Ownership Plan (ESOP) Trusts with effect from January 1, 2004. The effect of adopting the Abstract is to transfer BP ordinary shares held by the ESOP Trust from fixed assets - investments to BP shareholders interest.

	Restated			Reported		
Balance sheet at December 31,	2003	2002	2001	2003	2002	2001
			($ million)			
Fixed assets - Investments	17,458	10,652	11,697	17,554	10,811	11,963
Years ended December 31,						
Net cash inflow (outflow)	1,405	(326)	1,035	1,342	(344)	1,002

Transfer of Natural Gas Liquids Activities

With effect from January 1, 2004, the natural gas liquids (NGL) activities were transferred from Exploration and Production to Gas, Power and Renewables. The adjustments between these two segments for 2003, 2002 and 2001 are set out below.

	2003	2002	2001
		($ million)	
Years ended December 31,			
Group operating profit	106	68	84
Share of profits of joint ventures			
Share of profits of associated undertakings			
Total operating profit	106	68	84
Exceptional items			
Profit before interest and tax	106	68	84
Inventory holding gains (losses)			
Capital expenditure and acquisitions	82	40	8
Balance sheet at December 31,			

Operating capital employed	389	322	314
Tangible assets	289	289	287

Table of Contents

Adoption of New Accounting Standard for Pensions and Other Postretirement Benefits

With effect from January 1, 2004 the Group has adopted Financial Reporting Standard No. 17 Retirement Benefits . Financial information for 2003 and 2002 has been restated. Financial information for 2001 and earlier years has not been restated.

Years ended December 31,	As restated		As reported	
	2003	2002	2003	2002
	($ million)			
Turnover	236,045	180,186	236,045	180,186
Less: Joint ventures	3,474	1,465	3,474	1,465
Group turnover	232,571	178,721	232,571	178,721
Cost of sales	201,335	154,615	202,029	154,401
Production taxes	1,723	1,274	1,723	1,274
Gross profit	29,513	22,832	28,819	23,046
Distribution and administration expenses	14,072	12,632	14,072	12,632
Exploration expense	542	644	542	644
	14,899	9,556	14,205	9,770
Other income	786	641	786	641
Group operating profit	15,685	10,197	14,991	10,411
Share of profits of joint ventures	924	347	924	347
Share of profits of associated undertakings	514	617	514	617
Total operating profit (a)	17,123	11,161	16,429	11,375
Profit (loss) on sale of businesses or termination of operations	(28)	(33)	(28)	(33)
Profit (loss) on sale of fixed assets	859	1,201	859	1,201
Profit before interest and tax	17,954	12,329	17,260	12,543
Interest expense	644	1,067	851	1,279
Other finance expense	547	73		
Profit before taxation	16,763	11,189	16,409	11,264
Taxation	6,111	4,317	5,972	4,342
Profit after taxation	10,652	6,872	10,437	6,922
Minority shareholders interest equity	170	77	170	77
Profit for the year	10,482	6,795	10,267	6,845
Dividend requirements on preference shares	2	2	2	2
Profit for the year applicable to ordinary shares	10,480	6,793	10,265	6,843
Profit per ordinary share cents				
Basic	47.27	30.33	46.30	30.55

Diluted	46.72	30.19	45.87	30.41
Dividends per ordinary share cents	26.00	24.00	26.00	24.00
Average number outstanding of 25 cents ordinary shares (in thousands)	22,170,741	22,397,126	22,170,741	22,397,126

(a) Total operating profit

Exploration and Production (b)	13,756	9,006	13,940	9,209
Gas, Power and Renewables (b)	582	469	478	405
Refining and Marketing	2,483	1,969	2,292	1,921
Petrochemicals	585	447	623	541
Other businesses and corporate	(283)	(730)	(904)	(701)
	17,123	11,161	16,429	11,375

(b) Restatement includes the transfer of the natural gas liquids (NGL) activities from Exploration and Production to Gas, Power and Renewables.

113

Table of Contents

Balance sheet at December 31, 2003	Restated	Reported
	($ million)	
Fixed assets		
Intangible assets	13,642	13,642
Tangible assets	91,911	91,911
Investments (a)	17,458	17,554
	123,011	123,107
Current assets	47,651	54,465
Creditors - amounts falling due within one year	50,584	50,584
Net current assets (liabilities)	(2,933)	3,881
Total assets less current liabilities	120,078	126,988
Creditors - amounts falling due after more than one year	18,959	18,959
Provisions for liabilities and charges		
Deferred taxation	14,371	15,273
Other provisions	8,815	15,693
Net assets excluding pension and other postretirement benefit balances	77,933	77,063
Defined benefit pension plan surplus	1,021	
Defined benefit pension plan and other postretirement benefit plan deficits	(7,510)	
Net assets	71,444	77,063
Minority shareholders interest	1,125	1,125
BP shareholders interest (a)	70,319	75,938
Balance sheet at December 31, 2002		
Fixed assets		
Intangible assets	15,566	15,566
Tangible assets	87,682	87,682
Investments (a)	10,652	10,811
	113,900	114,059
Current assets	41,167	45,066
Creditors - amounts falling due within one year	46,301	46,301
Net current liabilities	(5,134)	(1,235)
Total assets less current liabilities	108,766	112,824
Creditors - amounts falling due after more than one year	15,377	15,377
Provisions for liabilities and charges		
Deferred taxation	13,514	13,514
Other provisions	7,978	13,886
Net assets excluding pension and other postretirement benefit balances	71,897	70,047
Defined benefit pension plan surplus	221	
Defined benefit pension plan and other postretirement benefit plan deficits	(7,831)	

Net assets	64,287	70,047
Minority shareholders interest	638	638
BP shareholders interest (a)	63,649	69,409

(a) Restatement includes the recategorization of shares held by ESOP Trusts from Fixed assets - Investments to BP shareholders interest.

114

Table of Contents

Reconciliation of Non-GAAP Financial Measures

(i) Reconciliation of profit before interest and tax to cash returns numerator and cash returns numerator, adjusted for environment	Years ended December 31,		
	2003	2002	2001
		($ million)	
Group			
Profit before interest and tax	17,954	12,329	14,662
Inventory holding (gains) losses	(16)	(1,129)	1,900
Exceptional items	(831)	(1,168)	(535)
Operating profit before inventory holding (gains) losses	17,107	10,032	16,027
Depreciation, depletion and amortization	10,940	10,401	8,858
Cash returns numerator	28,047	20,433	24,885
Adjustment for oil and natural gas price environment	(7,709)	(1,895)	(3,580)
Adjustment for Global Indicator Refining Margin	(1,334)	671	(1,461)
Cash returns numerator, adjusted for environment	19,004	19,209	19,844
Exploration and Production			
Profit before interest and tax	14,669	8,280	12,466
Inventory holding (gains) losses	(3)	(3)	6
Exceptional items	(913)	726	(195)
Operating profit before inventory holding (gains) losses	13,753	9,003	12,277
Depreciation, depletion and amortization	6,928	6,786	5,780
Cash returns numerator	20,681	15,789	18,057
Remove TNK-BP	(569)	(89)	(10)
Adjustment for oil and natural gas price environment	(7,172)	(2,505)	(5,400)
Cash returns numerator, adjusted for environment	12,940	13,195	12,647
Gas, Power and Renewables			
Profit before interest and tax	576	2,020	491
Inventory holding (gains) losses	(6)	(51)	81
Exceptional items	6	(1,551)	
Operating profit before inventory holding (gains) losses	576	418	572
Depreciation, depletion and amortization	163	130	92
Cash returns numerator	739	548	664

Table of Contents

(i) Reconciliation of profit before interest and tax to cash returns numerator and cash returns numerator, adjusted for environment (continued)	Years ended December 31,		
	2003	2002	2001
		($ million)	
Refining and Marketing			
Profit before interest and tax	2,270	2,582	2,461
Inventory holding (gains) losses	48	(1,049)	1,583
Exceptional items	213	(613)	(471)
Operating profit before inventory holding (gains) losses	2,531	920	3,573
Depreciation, depletion and amortization	2,958	2,658	2,302
Cash returns numerator	5,489	3,578	5,875
Adjustment for Global Indicator Refining Margin	(1,334)	671	(1,461)
Cash returns numerator, adjusted for environment	4,155	4,249	4,414
Petrochemicals			
Profit before interest and tax	623	191	(399)
Inventory holding (gains) losses	(55)	(26)	230
Exceptional items	(38)	256	297
Operating profit before inventory holding (gains) losses	530	421	128
Depreciation, depletion and amortization	751	749	588
Cash returns numerator	1,281	1,170	716
Other businesses and corporate			
Profit before interest and tax	(184)	(744)	(357)
Inventory holding (gains) losses			
Exceptional items	(99)	14	(166)
Operating profit before inventory holding (gains) losses	(283)	(730)	(523)
Depreciation, depletion and amortization	140	78	96
Cash returns numerator	(143)	(652)	(427)

Table of Contents

(i) Reconciliation of profit before interest and tax to cash returns numerator and cash returns numerator, adjusted for environment (concluded)

	Years ended December 31,		
	2003	2002	2001
	($ million)		
Customer facing businesses			
Profit before interest and tax	3,469	4,793	2,553
Inventory holding (gains) losses	(13)	(1,126)	1,894
Exceptional items	181	(1,908)	(174)
Operating profit before inventory holding (gains) losses	3,637	1,759	4,273
Depreciation, depletion and amortization	3,872	3,537	2,982
Cash returns numerator	7,509	5,296	7,255
Adjustment for Global Indicator Refining Margin	(1,334)	671	(1,461)
Cash returns numerator, adjusted for environment	6,175	5,967	5,794

117

Table of Contents

(ii) Reconciliation of operating capital employed to cash returns denominator and operating capital employed in service	Years ended December 31,		
	2003	2002	2001
		($ million)	
Group			
Capital employed	93,769	86,295	86,910
Liabilities for current and deferred taxation	16,068	14,211	14,815
Operating capital employed	109,837	100,506	101,725
Acquisition adjustment	(13,362)	(16,672)	(18,882)
Cash returns denominator	96,475	83,834	82,843
Exploration and Production			
Operating capital employed	63,618	61,460	59,832
Acquisition adjustment	(6,983)	(9,737)	(11,506)
Cash returns denominator	56,635	51,723	48,326
Net investment in Russia	(3,583)	(766)	(297)
Tangible fixed assets under construction	(10,406)	(7,482)	(3,863)
Intangible exploration assets (net of acquisition adjustment)	(3,792)	(4,184)	(4,138)
Operating capital employed in service	38,854	39,291	40,028
Gas, Power and Renewables			
Operating capital employed	4,292	2,979	3,439
Acquisition adjustment			
Cash returns denominator	4,292	2,979	3,439
Refining and Marketing			