BP PLC
Form 20-F
March 28, 2002

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

[x] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2001

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)

Britannic House
1 Finsbury Circus
London EC2M 7BA
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	22,432,076,754
Cumulative First Preference Shares of (pound)1 each	7,232,838
Cumulative Second Preference Shares of (pound)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 x No

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

Item 17 Item 18 x

TABLE OF CONTENTS

CERTAIN DEFINITIONS

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

Oil and natural gas reserves

'Proved reserves' -- Estimated quantities of crude oil or natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, that is prices and costs as of the date the estimate is made.

'Proved developed reserves' -- 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 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' -- 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.

Miscellaneous terms

'ADR' -- American Depositary Receipt.

'ADS' -- American Depositary Share.

'Amoco' -- The former Amoco Corporation and its subsidiaries.

'ARCO' -- 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.

'Billion' -- 1,000,000,000.

'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.

'Crude oil' -- Includes condensate and natural gas liquids.

'Dollar' or '$' -- The US dollar.

'FSA' -- Financial Services Authority.

'Gas' -- Natural Gas.

'LNG' -- Liquefied Natural Gas.

'London Stock Exchange' or 'LSE' -- London Stock Exchange Limited.

'LPG' -- Liquefied Petroleum Gas.

'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.

'North America' -- the USA and Canada.

'OECD' -- Organization for Economic Cooperation and Development.

'Oil' -- Crude oil, condensate and natural gas liquids.

'OPEC' -- The Organization of Petroleum Exporting Countries.

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

'Pence' or 'p' -- One hundredth of a pound.

'Pound', 'sterling' or '(pound)' -- The pound sterling.

'Preference Shares' -- Cumulative First Preference Shares and Cumulative Second Preference Shares in BP p.l.c. of(pound)1 each.

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

'Tonne' or 'metric ton' -- 2,204.6 pounds.

'Trillion' -- 1,000,000,000,000.

'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.

'Vastar' -- Vastar Resources Inc. and its subsidiaries.

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,				
	2001	2000	1999	1998	1
	($ million except per share amounts)				
UK GAAP					

Income statement data					
Turnover	175,389	161,826	101,180	83,732	108,
Less:joint ventures	1,171	13,764	17,614	15,428	16,
Group turnover	174,218	148,062	83,566	68,304	91,
Total replacement cost operating profit (a)	16,135	17,756	8,894	6,521	10,
Replacement cost profit before exceptional items (b)	9,880	11,214	5,330	3,959	6,
Profit for the year	8,010	11,870	5,008	3,220	5,
Per ordinary share (c): (cents)					
Profit for the year:					
Basic	35.70	54.85	25.82	16.77	29
Diluted	35.48	54.48	25.68	16.70	29
Dividends (d)	22.00	20.50	20.00	19.75	18
Average number outstanding of 25 cents ordinary shares (shares million)	22,436	21,638	19,386	19,192	19,
Balance sheet data					
Total assets	141,158	143,938	89,561	84,915	86,
Net assets	74,994	74,001	44,342	43,573	43,
Share capital	5,629	5,653	4,892	4,863	4,
BP shareholders' interest	74,367	73,416	43,281	42,501	42,
Finance debt due after more than one year	12,327	14,772	9,644	9,641	8,
Debt to borrowed and invested capital (e)	14%	17%	18%	18%	
Other data					
Per ordinary share: (cents)					
Replacement cost profit before exceptional items	44.03	51.82	27.48	20.62	34.
Net cash inflow from operating activities (f)	22,409	20,416	10,290	9,586	15,5
Net cash outflow from capital expenditure acquisitions and disposals	11,604	6,207	5,142	6,520	10,0

	Years ended December 31,				
	2001	2000	1999	1998	1
	($ million except per share amounts)				
US GAAP					
Income statement data					
Revenues	174,218	148,062	83,566	68,304	91,
Profit for the period	4,164	10,183	4,596	2,826	5,
Comprehensive income	2,569	7,562	3,674	2,848	4,
Profit per ordinary share (c)(g): (cents)					
Basic	18.55	47.05	23.70	14.72	29
Diluted	18.44	46.74	23.56	14.66	29
Profit per American Depositary Share (c)(g): (cents)					
Basic	111.30	282.30	142.20	88.32	177
Diluted	110.64	280.44	141.36	87.96	176
Balance sheet data					
Total assets	146,244	152,236	90,342	85,538	87,
BP shareholders' interest	62,322	65,554	37,838	37,334	37,

Other data

Net cash used in investing activities.........	11,685	6,326	4,922	6,861	10,
Net cash used in financing activities.........	5,853	7,852	3,332	2,161	3,

----

(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.

BP determines operating profit on a replacement cost basis, which eliminates the effect of inventory holding gains and losses. For the oil and gas industry, the price of crude oil can vary significantly from period to period; hence the value of crude oil (and products) also varies. As a consequence, the amount that would be charged to cost of sales on a first-in, first-out (FIFO) basis of inventory valuation would include the effect of oil price fluctuations on oil and products inventories. BP therefore charges cost of sales with the average cost of supplies incurred during the period rather than the historical cost of supplies on a FIFO basis. For this purpose, inventories at the beginning and end of the period are valued at the average cost of supplies incurred during the period rather than at their historical cost. These valuations are made quarterly by each business unit, based on local oil and product price indices applicable to their specific inventory holdings, following a methodology that has been consistently applied by BP for many years. Operating profit on the replacement cost basis and a derivative measure, that is, profit adjusted for depreciation and amortization arising from the fixed asset revaluation adjustment and goodwill consequent upon the ARCO and Burmah Castrol acquisitions, and adjusted for special items (non-recurring charges and credits that are not classified as exceptional under UK GAAP), are used by BP management as the primary measures of business unit trading performance and BP management believes that these measures assist investors to assess BP's underlying trading performance from period to period.

Replacement cost is not a US GAAP measure. The major US oil companies apply the last-in, first-out (LIFO) basis of inventory valuation. The LIFO basis is not permitted under UK GAAP. The LIFO basis eliminates the effect of price fluctuations on crude oil and product inventory except where an inventory drawdown occurs in a period. BP management believes that where inventory volumes remain constant or increase in a period, operating profit on the LIFO basis will not differ materially from operating profit on BP's replacement cost basis.

Where an inventory drawdown occurs in a period, cost of sales on a LIFO basis will be charged with the historical cost of the inventory drawn down, whereas BP's replacement cost basis charges cost of sales at the average cost of supplies for the period. To the extent that the historical cost on the LIFO basis of the inventory drawn down is lower than the current cost of supplies in the period, operating profit on the LIFO basis will be greater than operating profit on BP's replacement cost basis. To the extent that the historical cost on the LIFO basis of the inventory drawdown is greater than the current cost of supplies in the period, operating profit on the LIFO basis will be lower than operating profit on BP's replacement cost basis.

(b) Replacement cost profit before exceptional items excludes profits and losses on the sale of fixed assets and businesses or termination of operations and fundamental restructuring costs, which are defined by UK GAAP. This measure and a derivative measure, that is, profit adjusted for depreciation and amortization arising from the fixed asset revaluation adjustment and goodwill consequent upon the ARCO and Burmah Castrol acquisitions, and adjusted for special items (non-recurring charges and credits that are not classified as exceptional under UK GAAP), are used by the BP board in setting targets for and monitoring performance within the Group. BP's management believes these indicators provide the most relevant and useful measures for investors because they most accurately reflect underlying trading performance.

6

(c) With effect from October 4, 1999 BP split (or subdivided) its ordinary share capital. As a result, the number of 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. Comparative figures for 1997 and 1998 have been changed accordingly.

(d) BP dividends per share represent historical dividends per share paid by The British Petroleum Company p.l.c., for 1997 and 1998.

(e) Finance debt due after more than one year, compared with such debt plus BP and minority shareholders' interests.

(f) The net cash inflows from operating activities are presented in accordance with the requirements of Financial Reporting Standard No. 1 (Revised 1996) issued by the UK Accounting Standards Board. For a cash flow statement prepared on a US GAAP basis see Item 18 -- Financial Statements -- Note 43.

(g) FASB Statement of Financial Accounting Standards No. 128 -- 'Earnings per Share' (SFAS 128) was adopted for the accounting period ending December 31, 1997.

(h) The Group adopted Financial Reporting Standard No. 12 'Provisions, Contingent Liabilities and Contingent Assets' with effect from January 1, 1999. Comparative figures for 1997 and 1998 have been changed accordingly.

Exchange Rates

The following table sets forth, for the periods and dates indicated, certain information concerning the Noon Buying Rate for the pound in New York City for cable transfers in pounds as certified for customs purposes by the Federal Reserve Bank of New York. This is expressed in dollars per (pound)1.

	At period end	Average(a)	High	Low
Year ended December 31,				
1997...	1.63	1.64	1.70	1.58
1998...	1.66	1.66	1.72	1.61
1999	1.62	1.61	1.68	1.55
2000	1.50	1.51	1.65	1.40
2001...	1.45	1.44	1.50	1.37
Month of				
September 2001.................................	1.47	1.46	1.47	1.44
October 2001...................................	1.45	1.45	1.48	1.42
November 2001..................................	1.43	1.44	1.47	1.41
December 2001..................................	1.45	1.44	1.46	1.42
January 2002...................................	1.41	1.43	1.45	1.41
February 2002..................................	1.41	1.42	1.43	1.41

March 2002 (through March 26)..................	1.43	1.42	1.43	1.41

(a) The average of the Noon Buying Rates on the last day of each month during the calendar year or, in the case of monthly averages, the average of all days in the month.

(b) The Noon Buying Rate on March 26, 2002 was $1.43 = (pound)1.

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 ARCO shareholders do not have the right to receive dividends.

At least until December 31, 2003, BP will announce dividends for Ordinary Shares in US dollars and state an equivalent pounds sterling dividend. Dividends on BP ordinary shares will be paid in pounds sterling and on BP ADSs in US dollars. Prior to the fourth quarterly dividend of 1998 The British Petroleum Company p.l.c. announced dividends in sterling. Foreign exchange rates may affect dividends paid. However, when setting the dividend the directors are mindful of dividend fluctuation in sterling terms.

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. 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. Dividends have been translated from pounds per ADS up to and including the third quarterly dividend for 1998, and from dollars per ADS for the fourth quarterly dividend of 1998 and thereafter, at an exchange rate in London on the business day last preceding the day when the directors announced their intention to pay the quarterly dividends for those years.

		Quarterly				
Dividends per American Depositary Share (a)(b)		First	Second	Third	Fourth	Total
1997.........................	UK pence	19.7	20.6	20.7	21.5	82.5
	US cents	31.9	33.6	34.6	35.3	135.4
	Can. cents	44.1	46.4	48.6	50.5	189.6
1998.........................	UK pence	21.5	22.5	22.5	23.0	89.5
	US cents	36.0	36.5	37.5	33.4	143.4
	Can. cents	51.4	55.3	57.8	50.0	214.5

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

(a) With effect from June 6, 1997 the Company split existing ADSs on a two-for-one basis so that an ADS is now equivalent to six BP ordinary shares.

(b) 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. Comparative figures for 1997 and 1998 have been changed accordingly.

The share dividend plan, whereby holders of BP ordinary shares could elect to receive new shares (out of unissued share capital) instead of cash dividends at a rate equivalent to the sum of the net cash dividend and related tax credit, was withdrawn following the third quarterly 1998 dividend.

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 (formerly known as Morgan Guaranty Trust Company).

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.

8

RISK FACTORS

There is strong competition, both within the oil industry and with other industries, in supplying the fuel needs of commerce, industry and the home.

The oil industry is particularly 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, control 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.

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.

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 oil supply and oil prices.

Natural gas prices are subject to regional supply and demand. Prices can fluctuate significantly.

Refining profitability can be volatile with both oversupply and periodic supply tightness in various regional markets.

The marketing of petroleum and related products, especially to retail customers, can be affected by intense competition.

Crude oil prices are generally set in 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.

Sectors of the chemicals industry are also subject to fluctuations in supply and demand within the chemicals market, with consequent effect on prices and profitability, and to governmental regulation and intervention in such matters as safety and environmental controls.

In addition to the adverse effect on revenues, margins and profitability from any future fall in oil and natural gas prices, a prolonged period of low prices or other indicators would lead to a review for impairment of the Group's oil and natural gas properties. This review would reflect management's view of long-term oil and natural gas prices. Such a review could result in a charge for impairment which could have a significant effect on the Group's results of operations in the period in which it occurs.

9

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 business 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', 'may', 'should', 'is likely to', 'intends', 'believes' or 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, planned expansion, investment or other projects, expected or targeted production volume, capacity or rate, the date or period in which production is scheduled or expected to come on stream or a project or action is scheduled or expected to be completed, (ii) the statements in Item 4 -- Information on the Company -- Strategy and Financial Targets with respect to the Group's ratio of net debt to net debt plus equity, dividend policy, the manner in which we use cash surpluses, the target to reduce the cost structure of the Group, hydrocarbon production growth, targeted performance improvements and effect on pre-tax results, and levels of annual investment, and (iii) the statements in Item 5 -- Operating and Financial Review and Prospects including the statements under 'Outlook' with regard to trends in the trading environment, oil and gas prices, refining, marketing and chemicals margins, inventory and product inventory levels, supply capacity, profitability, results of operation, liquidity or financial position 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 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; future levels of industry product supply, demand and pricing; political stability and economic growth in relevant areas of the world; development and use of new technology and successful partnering; the actions of competitors; natural disasters and other changes to business conditions; wars and acts of terrorism or sabotage; and other factors discussed elsewhere in this report. 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.

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, without the exclusion of 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 of the USA and The British Petroleum Company p.l.c. of the UK. Following this merger, Amoco Corporation became a wholly owned subsidiary of The British Petroleum Company p.l.c. and was renamed BP Amoco Corporation, and The British Petroleum Company p.l.c. was renamed BP Amoco p.l.c. Amoco Corporation was incorporated in Indiana, USA, in 1889 and The British Petroleum Company p.l.c. was incorporated in England in 1909. On April 14, 2000 we acquired the Atlantic Richfield Company (ARCO) and on July 7, 2000, we completed our successful tender offer for Burmah Castrol plc of England. To signify the single entity that has successfully been created through these combinations, the name of the company was changed to BP p.l.c. with effect from May 1, 2001.

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.
Britannic House
1 Finsbury Circus
London EC2M 7BA
United Kingdom

Tel: +44(0)20 7496 4000

Internet address: www.bp.com

Business Overview

Our main businesses are Exploration and Production, Gas and Power, Refining and Marketing, and Chemicals. 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 and Power activities include marketing and trading of natural gas, liquefied natural gas (LNG), natural gas liquids (NGL) and power, the development of international opportunities that monetize gas resources and involvement in select power projects. The activities of Refining and Marketing include oil supply and trading as well as refining and marketing (downstream activities). Chemicals activities include petrochemicals manufacturing and marketing. In addition, we have a solar energy business which is one of the world's largest manufacturers of photovoltaic modules and systems. The Group provides high quality technological support for all its businesses through its research and engineering activities.

We have well established operations in Europe, the USA, Canada, South America, Australasia and parts of Africa. More than 70% of the Group's capital is invested in Organization for Economic Cooperation and Development (OECD) countries with just under one half of our fixed assets located in the USA, and just under one third 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 businesses:

-- In Exploration and Production we have substantial upstream interests in the USA, with onshore natural gas production, oil and natural gas production in the Gulf of Mexico and oil production in Alaska; the UK where we are the largest producer of both oil and natural gas; Norway, Canada, South America, Africa, the Middle East and Asia. We also have significant midstream activities in support of these interests.

-- In Gas and Power, which has been reported as a separate business since January 1, 2000, we have established and growing marketing and trading businesses in North America (USA and Canada), the UK and Europe. Our marketing and trading activities include natural gas, LNG, NGL and power. Our international gas monetization activities are focused on growing 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 and Spain. Effective January 1, 2001, BP's North American NGL business was transferred from Refining and Marketing to Gas and Power. On January 1, 2002, the solar, renewables and alternative fuels activities were transferred to the Gas and Power business from Other Businesses and Corporate.

-- 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 2000 by buying out ExxonMobil's interest in the BP/Mobil European fuels business. In 2000, we purchased Burmah Castrol, which significantly increased our lubricants activities throughout the world. In addition we have established or are growing businesses elsewhere in the world under the BP brand.

-- In Chemicals we have a strong manufacturing and marketing base in the USA and Europe, and are aiming to grow in the Asia Pacific region where we already have interests in a number of production facilities. We have a strong position in the technology and production of olefins and derivative products (polyethylene, acetic acid and acrylonitrile), a leading position in aromatics and derivative products (purified terephthalic acid, paraxylene and metaxylene) and have strengthened our polymers market position during 2001 through our deal with Solvay.

On April 13, 2000 BP and ARCO announced that they had received clearance from the US Federal Trade Commission (FTC) for the combination of the two companies and the combination was completed on April 18, 2000. The combination has been accounted for as an acquisition under UK GAAP and as a purchase under US GAAP. The results of ARCO have been included with effect from April 14, 2000, the day following the approval by the US Federal Trade Commission of the acquisition. ARCO stockholders received for each share of ARCO common stock held as of April 17, 2000, 9.84 BP ordinary shares. Such shares were delivered in the form of BP ADSs, or at the election of the holder of ARCO common stock, BP ordinary shares.

On March 15, 2000 ARCO entered into an agreement to sell its Alaskan businesses to Phillips Petroleum Company (Phillips) for approximately $6.5 billion cash subject to purchase price adjustments (and up to an additional $500 million based on the prices realized on production subsequent to December 31, 1999). Under the agreement ARCO agreed to sell all of the outstanding shares of ARCO Alaska Inc., together with certain other subsidiaries of ARCO engaged principally in the operation of ARCO's Alaskan businesses, along with certain pipeline and marine assets associated with the transport of Alaskan crude oil. The major portion of the sale closed on April 26, 2000.

BP acquired Burmah Castrol of the UK on July 7, 2000 for $4.8 billion through a cash offer to shareholders of (pound)16.75 per share. The public share price on the date of announcement, March 10, 2000, was (pound)9.65. Burmah Castrol is a global marketer of specialized lubricant and chemical products and services. Burmah Castrol had operations in over 50 countries and employed some 18,000 people.

In December 1999, we agreed with ExxonMobil on the principles under which the BP/Mobil European joint venture would be dissolved in response to the conditions of the European Commission's authorization of the Exxon and Mobil merger. Under the agreement BP purchased ExxonMobil's 30% interest in the fuels business for $1.5 billion with effect from August 1, 2000. In addition, the two companies divided the assets of the lubricants business broadly in line with their equity stakes (Mobil 51%, BP 49%). This dissolution was substantially completed in 2000, thus increasing BP's share of all European markets where the fuels joint venture was active.

On September 15, 2000 we acquired through ARCO the common stock of Vastar held by minority shareholders at a price of $83 per share for a total consideration of $1.6 billion. The public share price on the date of announcement, March 16, 2000, was $71 7/16. Vastar became a wholly owned subsidiary of the Company.

During 2000 BP made two strategic 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. BP has a 2.2% interest in each company. Separately, BP announced plans to form joint ventures with both companies: in natural gas marketing and fuels retailing with PetroChina and in fuels and petroleum products marketing and chemicals with Sinopec. PetroChina and Sinopec are two of China's major companies in the oil and chemicals businesses.

Following completion of the merger between BP and Amoco on December 31, 1998 and in the context of low oil prices at the time, BP undertook a strategic and portfolio review in early 1999. This was completed in the Spring of 1999 and resulted, among other things, in the development of an asset divestment programme. The guiding principle of the strategic and portfolio review was to concentrate the combined Group's operations on areas of competitive strength and, in the upstream portfolio, to dispose of assets which would not be robustly economic on the basis of conservative assumptions about future oil and natural gas prices. Divestitures under this programme continued in 2000, and the programme was completed in 2001.

12

Strategy and Financial Targets

In Exploration and Production our goal is to have significant shares of the larger oil and natural gas fields where our supply costs can be fully competitive with all other producers. The Gas and Power business is specifically designed to extend our interests as the mix of world energy consumption shifts in favour of natural gas. In Refining and Marketing we intend to invest in geographic markets which are growing and in convenience retailing, while focusing our refining on advantaged areas. In Chemicals we focus on excellence in manufacturing and close links to both the supply of resources and actual and potential demand growth.

As part of this strategy we developed a financial framework to maintain a ratio of net debt to net debt plus equity, after adjusting equity for the fixed asset revaluation adjustment and goodwill consequent upon the ARCO and Burmah Castrol acquisitions, of around 20-30% and a dividend policy with the aim of returning to shareholders around 50% of our replacement cost profit before exceptional items and after adjusting for special items and acquisition amortization, adjusted to mid-cycle operating conditions. Special items are non-recurring charges and credits that are not classified as exceptional items under UK GAAP. Acquisition amortization refers to depreciation relating to the fixed asset revaluation adjustment and amortization of goodwill consequent upon the ARCO and Burmah Castrol acquisitions. Mid-cycle operating conditions reflect not only adjustments to hydrocarbon prices and margins, but also costs and capacity utilization, to levels which we would expect on average over the long term. If circumstances give us a larger surplus of cash than is required to fund our capital programme and meet operational needs, the surplus may be used to pay down debt to a level at the lower end of our gearing range and/or be returned to shareholders.

In January 2002 BP adopted a new UK Financial Reporting Standard No. 19 'Deferred Tax' (FRS 19). This standard requires deferred tax to be accounted for on a full rather than a partial provision basis. Prior years will be restated. The new standard will increase the effective tax rate and reduce profit and shareholders' interest. For example, if this new standard had been applied to the reported results for 2001, the tax charge for the year would have increased by $1,358 million to $6,375 million, and at December 31, 2001 there would have been a reduction of $9,050 million in shareholders' interest. It will have no effect on cash flow. In order to maintain the substance of the existing financial framework, we are restating BP's target band of net debt to net debt plus equity, after adjusting equity for the fixed asset revaluation adjustment and goodwill consequent upon the ARCO and Burmah Castrol acquisitions, from around 20-30% to around 25-35% and our target dividend payout ratio from around 50% to around 60% of our replacement cost profit before exceptional items and after adjusting for special items and acquisition amortization, adjusted to mid-cycle operating conditions.

Following completion of the ARCO and Burmah Castrol acquisitions in 2000 we announced our 2001 targets which reflected the enlarged Group. Our cost reduction target was to reduce the combined cost structure of the enlarged Group by $5.8 billion by the end of 2001. Cost reductions also included the effect of disposals on cash costs and lower exploration write-offs. Certain cash costs in 2000 and 2001 were adjusted to reflect cost levels which we would expect on average over the long term. Total cost reductions achieved by the end of 2001 were $6.1 billion.

In February 2001, we announced further specific targets for 2001. We targeted underlying performance improvements, which include cost savings and volume growth, aiming to increase pre-tax results under mid-cycle operating conditions, adjusted for acquisition amortization and special items, by $2.0 billion in 2001; growth in hydrocarbon production of 5.5%; and annual investment, excluding acquisitions, in the $12-13 billion range. This level of expenditure was intended to permit growth investment in Exploration and Production to enable the business to achieve targeted production growth of 5.5% each year in the medium term. This amount of investment is consistent with historic levels for the enlarged Group.

We achieved underlying performance improvements of $2.0 billion and production growth of 5.5% in 2001. Investment, excluding acquisitions, in 2001 was $13.2 billion and total investment was $14.1 billion.

We achieved the original 1999-2001 target of $10 billion proceeds from disposals by end-2001. This excluded the FTC-mandated divestment of ARCO's Alaskan interests and certain other assets.

In February 2002, we confirmed that our targets going forward remain unchanged. Specifically, we aim to achieve pre-tax underlying performance improvements, under mid-cycle operating conditions, of $1.4 billion through cost savings and volume growth in 2002 and annual hydrocarbon production growth of 5.5% in the medium term. We continue to plan for annual investment, excluding acquisitions, in the $12-13 billion range.

The targets disclosed above for 2002 and beyond are forward looking statements and as such are subject to numerous risks and uncertainties which may cause actual results to differ as described under Item 3 -- Risk Factors and Item 3 -- Forward Looking Statements.

Financial and Operating Information

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

	Years ended December 31,				
	2001	2000	1999	1998	1997
	($ million)				
Turnover..............................	175,389	161,826	101,180	83,732	108,564
Less: joint ventures..................	1,171	13,764	17,614	15,428	16,804
Group turnover (sales to third parties)	174,218	148,062	83,566	68,304	91,760
Total replacement cost operating profit	16,135	17,756	8,894	6,521	10,683
Profit for the year*..................	8,010	11,870	5,008	3,220	5,673
Capital expenditure and acquisitions...	14,124	47,613(a)	7,345(b)	10,362	11,420
Total assets..........................	141,158	143,938	89,561	84,915	86,279

----

* After minority shareholders' interest

(a) Capital expenditure and acquisitions for 2000 includes $27,506 million for the acquisition of ARCO and $8,936 million for acquisitions for cash, the details of which can be found in Item 5 -- Operating and Financial Review and Prospects -- Group Results.

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

All capital expenditure and acquisitions have been financed from cash flow from operations, disposal proceeds and external financing.

Information for 2001, 2000 and 1999 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 44.

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,				
	2001	2000	1999	1998	1997
Total crude oil production (thousand barrels per day) (a)..........	1,931	1,928	2,061	2,049	1,930
Total natural gas production (million cubic feet per day) (a)................	8,632	7,609	6,067	5,808	5,858
Total estimated net proved crude oil reserves (million barrels) (b)..........	7,217	6,508	6,535	7,304	7,612
Total estimated net proved natural gas reserves (billion cubic feet) (b).......	42,959	41,100	33,802	31,001	30,374

(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 and reserves of equity-accounted entities.

During 2001, 2,164 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), replacing 191% of the volume produced. After allowing for production, which amounted to 1,133 mmboe, BP's proved reserves increased to 14,624 mmboe. These proved reserves are mainly located in the USA (42%), Trinidad and Tobago (16%) and the UK (14%).

----

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

14

Recent developments

With effect from February 1, 2002, BP acquired a majority stake in Veba Oil from E.ON. Veba Oil owns Aral, Germany's biggest fuels retailer. BP paid E.ON $1.63 billion in cash and assumed some $0.85 billion of debt in return for 51% and operational control of Veba Oil. Additionally, E.ON can require BP to buy the remaining 49% of Veba Oil for $2.40 billion in cash from April 1, 2002 under the terms of an agreement between the two companies announced in July 2001.

That agreement envisaged part of the payment for Veba Oil being met by the sale to E.ON of BP's wholly-owned subsidiary, Gelsenberg, which holds a 25.5% stake in Germany's largest natural gas distributor, Ruhrgas. Although that sale was prohibited by Germany's Federal Cartel Office, the decision is being appealed to the German Economics Ministry, which is expected to rule in mid-2002. If the German Economics Ministry were to approve the Ruhrgas transaction, BP would sell its Ruhrgas stake to E.ON for an agreed $2.10 billion.

As a condition of regulatory approval of the deal BP is 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.

Separately BP and E.ON announced that they had agreed, subject to various regulatory and other consents, to sell Veba's oil and natural gas exploration and production business to Petro-Canada for $2.00 billion. From this sale BP would receive $1.65 billion and E.ON the balance.

15

SEGMENTAL INFORMATION

The following tables show turnover and replacement cost profit by business and by geographical area, for the years ended December 31, 2001, 2000, and 1999.

	Years ended December 31,	
Turnover (a)	2001	2000 (b)

	Total sales	Sales between businesses	Sales to third parties	Total sales	Sales between businesses	Sales to third parties	
					($ million)		
By business							
Exploration and Production......	28,229	19,660	8,569	30,942	16,787	14,155	1
Gas and Power...................	39,208	2,954	36,254	21,013	346	20,667	
Refining and Marketing..........	120,233	2,903	117,330	107,883	5,923	101,960	6
Chemicals.......................	11,515	233	11,282	11,247	216	11,031	
Other businesses and corporate..	783	--	783	249	--	249	
Group turnover..................	199,968	25,750	174,218	171,334	23,272	148,062	9
Share of joint venture sales....			1,171			13,764	
			175,389			161,826	

	Total sales	Sales between areas	Sales to third parties	Total sales	Sales between areas	Sales to third parties	
					($ million)		
By geographical area							
UK (c)......................	47,618	13,467	34,151	45,400	10,970	34,430	3
Rest of Europe..............	36,701	7,603	29,098	20,553	1,911	18,642	
USA.........................	84,696	939	83,757	71,084	829	70,255	3
Rest of World...............	33,911	6,699	27,212	31,014	6,279	24,735	1
	202,926	28,708	174,218	168,051	19,989	148,062	9
Share of joint venture sales							
UK..........................			13			3,314	
Rest of Europe..............			30			12,316	
USA.........................			318			270	
Rest of World...............			810			686	
			1,171			16,586	
Sales between areas			--			2,822	
			1,171			13,764	

(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) 1999 and 2000 have been restated to reflect the transfer of the NGL business in North America from Refining and Marketing to Gas and Power.

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

16

Analysis of replacement cost profit	Group replacement cost operating profit(a)	Joint ventures	Associated undertakings	Total replacement cost operating profit(a)	Ex
			($ million)		
Year ended December 31, 2001					
By business					
Exploration and Production..........	11,858	373	186	12,417	
Gas and Power......................	337	--	184	521	
Refining and Marketing.............	3,347	83	195	3,625	
Chemicals..........................	21	(13)	120	128	
Other businesses and corporate......	(631)	--	75	(556)	
	14,932	443	760	16,135	
By geographical area					
UK (c)............................	2,657	(3)	14	2,668	
Rest of Europe.....................	1,579	(1)	236	1,814	
USA................................	6,740	76	233	7,049	
Rest of World......................	3,956	371	277	4,604	
	14,932	443	760	16,135	
Year ended December 31, 2000 (d)					
By business					
Exploration and Production..........	13,399	384	229	14,012	
Gas and Power......................	409	--	162	571	
Refining and Marketing.............	2,924	433	166	3,523	
Chemicals..........................	576	(9)	193	760	
Other businesses and corporate......	(1,152)	--	42	(1,110)	
	16,156	808	792	17,756	
By geographical area					
UK (c)............................	3,629	106	38	3,773	
Rest of Europe.....................	1,488	264	261	2,013	
USA................................	7,006	44	246	7,296	
Rest of World......................	4,033	394	247	4,674	
	16,156	808	792	17,756	
Year ended December 31, 1999 (d)					
By business					
Exploration and Production..........	6,686	175	122	6,983	
Gas and Power......................	258	--	179	437	
Refining and Marketing.............	1,111	380	123	1,614	
Chemicals..........................	561	--	125	686	
Other businesses and corporate......	(880)	--	54	(826)	
	7,736	555	603	8,894	
By geographical area					
UK (c)............................	2,063	(1)	49	2,111	

Rest of Europe	548	381	238	1,167
USA	2,803	13	185	3,001
Rest of World	2,322	162	131	2,615
	7,736	555	603	8,894

(a) Replacement cost operating profit is before inventory holding gains and losses and 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 and in addition for 1999 include fundamental restructuring costs.

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

(d) 1999 and 2000 have been restated to reflect the transfer of the NGL business in North America from Refining and Marketing to Gas and Power.

17

EXPLORATION AND PRODUCTION

The activities of our Exploration and Production business include oil, 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 liquefied natural gas (LNG) processing facilities - the midstream activities. We have Exploration and Production interests in 28 countries. Areas of activity include the USA, UK, Norway, Canada, South America, Africa, the Middle East, and Asia. Production during 2001 came from 23 countries. Our most significant midstream activities are in three major pipelines - the Trans Alaska Pipeline System (BP 46.9%), the Forties Pipeline System (BP 100%) and the Central Area Transmission System pipeline (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 Indonesia through the joint venture operating company Virginia Indonesia Co. (VICO) (BP 50%) and in Australia through our share of LNG from the North West Shelf natural gas development (BP 16.7%).

	Years ended December 31,		
	2001	2000	1999
	($ million)		
Turnover (a)	28,229	30,942	19,133
Total replacement cost operating profit	12,417	14,012	6,983
Total assets	69,572	65,904	44,967
Capital expenditure and acquisitions	8,861	6,383	4,194
	($ per barrel)		
Average BP oil realizations	22.50	26.63	16.74

Average West Texas Intermediate oil price................	25.89	30.38	19.33
Average Brent oil price.................................	24.44	28.44	17.94
	($ per thousand cubic feet)		
Average BP natural gas realizations......................	3.30	2.91	1.92
Average BP US natural gas realizations...................	3.99	3.72	2.06
Average Henry Hub gas price (b)..........................	4.26	3.90	2.27

(a) Excludes BP's share of joint venture turnover of $666 million in 2001, $585 million in 2000, and $497 million in 1999.

(b) Henry Hub First of Month Index.

Strategy and Overview

Our strategy remains unchanged, targeting profitable production growth of 5.5% per year, underpinned by the following strategic elements: to have a leading position in high quality basins around the world; to be a low-cost supplier of oil, competitive with OPEC producers; and to supply low-cost gas to markets. Evidence of 2001 delivery included capturing the remaining $500 million of $3.1 billion of synergy cost savings from the merger of BP and Amoco and the acquisition of ARCO, and achieving our production growth target of 5.5%. In the future, we intend that our strategy will continue to be underpinned by three key areas of focus: sustaining and maximizing the value of our base portfolio, exploring for and developing resources in existing and emerging basins, and upgrading the quality of our portfolio.

The first element underpinning our Exploration and Production strategy is to maximize the value of our base portfolio by optimising production volumes and driving efficiencies. We seek opportunities that are sustainable in the context of fluctuating oil and natural gas prices.

We optimise production volumes through decline management and enhanced recovery technologies to mitigate volume decline and increase ultimate recoveries in mature fields. For example, during 2001:

-- We made extensive use of time-lapse 3-D seismic technology to transform our in-field drilling programme. 21 operated fields are now covered worldwide. In the North Sea, our increased reservoir understanding led to additional production of 15 mboe/d compared to 2000 and should enable access to additional reserves in the region.

18

-- We continued to advance the technology associated with multi-lateral wells and achieved an industry first on the Harding field with the installation of sand control screens in such a well.

-- We successfully used the world's first commercial expandable liner hanger in a producing well in the US Lower 48 States. This technology should reduce drilling times and potentially reduce safety risks on deep wells.

-- We advanced the use of cost efficient Coil Tubing Drilling to drill multi-lateral wells, creating more economical access to the development of Alaska's viscous oil.

- -- We developed a technique in the North Sea that helps to identify bottlenecks or constraints throughout the production system. During 2001 we began deploying this technique throughout our upstream business. For example, in Azerbaijan we increased operating efficiency by 2%.

Since 1998, our unit production costs (often referred to as unit lifting costs) have decreased by 16%. We have driven operating efficiencies by:

- -- Leveraging the economies of scale achieved through business combinations and acquisitions.

- -- Benchmarking, internally and externally, and sharing best practices across the business units.

- -- Working with key suppliers, contractors and partners.

The second element underpinning our strategy is to explore for and develop resources in emerging basins, as well as in existing basins on a selective basis, to provide growth for the future. We do this through focused large projects and selective development of smaller satellite projects to take advantage of existing infrastructure.

- -- We are the largest leaseholder in the Gulf of Mexico and have interests in nine of the ten largest Gulf of Mexico developments (BP operates six). Our deepwater position in conjunction with integrated development programmes should allow delivery of both near-term and long-term production growth. In 2001, we announced the discovery at Blind Faith (BP 77.5% and operator) and saw the start up of the BP operated Nile Field (in addition to the non-BP operated Mica and Crosby Fields). We also approved investment capital for three of the four newest BP operated major field developments and began fabrication activities. In 2002 we expect to begin production from King, King's Peak, Princess (Phase I) and Horn Mountain fields. During 2003 to 2006, we expect to begin production at our NaKika, Princess (Phase II), Thunder Horse (formerly known as Crazy Horse), Holstein, Mad Dog and Atlantis fields. Production from these fields should contribute substantially to our growth.

- -- In Angola, we were involved in four new oil discoveries as well as the Girassol project which went into production in December 2001. We also sanctioned the Kizomba A and Jasmim developments.

- -- In Trinidad, we approved construction of the world's largest methanol plant and commenced expansion of the existing LNG plant by an additional two trains. Trains are facilities for compressing, liquefying, storing and offloading natural gas. BP will supply 50% of the natural gas for the second train and 75% for the third train, which we expect to come onstream in 2002 and 2003 respectively.

- -- In Vietnam, we announced the construction of the $1.3-billion Nam Con Son offshore natural gas project. The project is expected to develop significant offshore natural gas for use by three generating plants to provide electricity to Vietnam.

The third element underpinning our strategy is to upgrade the quality of our asset portfolio by focusing investments in core areas (where we have either critical mass and/or significant competitive position), selectively investing in growth, and disposing of non-strategic assets. We have a rigorous process for evaluating the economic merit and strategic fit of investment opportunities. For example, prior to sanctioning, we test new projects in an effort to ensure that they achieve a return in excess of the cost of capital at bottom of cycle prices (that is $11 Brent).

In support of continued growth, 2001 capital expenditure, at $8.9 billion (including $0.3 billion of acquisitions), was $2.5 billion higher than in 2000 ($6.4 billion).

Examples of our investment and divestment activity include:

-- In June 2001, we entered into an agreement to dispose of our 9.5% stake in the Kashagan discovery in Kazakhstan, after determining that it did not enhance our competitive position.

-- We acquired a further 9.7% stake in the Tangguh LNG project in Indonesia. This acquisition increased our share of Tangguh to about 50%. Tangguh is expected to be a long-term competitive supply source helping to meet rising demand in the region.

-- In December 2001, we announced that the assets of Chernogorneft had been returned to Sidanco (BP 11.2%). This completes the restructuring of Sidanco with its debt substantially repaid and non-core assets disposed of.

-- In January 2002, we acquired Statoil's interest in the Nam Con Son gas project. This acquisition increased our interest in Block 06.1 from 26.6% to 35%. Our interest in Block 05.2 increased from 35% to 100%.

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 2001 were $1,102 million compared to $1,295 million in 2000. About 65% of 2001 exploration and appraisal capital was directed towards appraisal activity as we delineated the significant discoveries made during 1999 and 2000. In 2001, we participated in 120 gross (48.4 net) exploration and appraisal wells in 21 countries. The principal areas of activity were Angola, Australia, Canada, Egypt, Norway, Trinidad, UK and the USA.

In 2001, we obtained upstream rights in several new tracts which are expected to provide a foundation for continued exploration success. These include the following:

-- In Egypt, we acquired a 16.67% interest in the West Med Block in the Nile delta. We also increased our working interest in the Nile Delta North Alex concession from 50% to 60%.

-- In the US Central Gulf of Mexico Lease Sale 178, we achieved a 74% success rate. We were successful in obtaining 6 new deepwater blocks including the primary block in a highly competitive prospect. Four of these deepwater blocks were near existing discoveries. We also achieved an 88% success rate in the Gulf of Mexico Shelf 178 licensing round. In addition, we submitted and won bids for two blocks on the

Shelf in the Western Gulf of Mexico 180 Lease Sale.

-- In the UK, we were awarded operatorship and 66.67% working interest in North Sea Block 204/18, the only block on which we bid in the UKCS 19th Licensing Round.

In 2001, we were involved in discoveries in Angola, Argentina, Australia, Egypt, Pakistan, Trinidad, 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 2001 discoveries included the following:

-- In the deepwater US Gulf of Mexico we announced a new discovery at Blind Faith (BP 77.5%), which is approximately 20 miles northeast of the Thunder Horse development, discovered in 1999.

-- Also in the deepwater US Gulf of Mexico, we announced the Aspen discovery (BP 80% and operator). In early 2002, we announced that Aspen would be 'fast tracked' to production and we reduced our interest to 40%.

-- In Trinidad, we made another significant natural gas discovery in the Cashima well (BP 100%).

-- In Angola, we were involved in three new oil discoveries: Violeta in Block 17 (BP 16.7%), and Mavacola and Vicango in Block 15 (BP 26.7%).

-- In Australia, we participated in the Io natural gas discovery on the Northwest Shelf (BP 13%).

-- In Egypt's Nile Delta we made two natural gas discoveries, Fayoum (BP 60% and operator) and Libra (BP 60% and operator).

-- In Argentina, our joint venture, Pan American Energy (BP 60%), established Tres Picos as a major natural gas discovery (BP 60%).

Reserves and Production

We annually review our total reserves of crude oil, condensate, natural gas liquids and natural gas to take account of production, field reassessments, the application of improved recovery techniques, the addition of new reserves from discoveries and economic factors. We also conduct selective periodic reserve reviews for individual fields.

Details of our net proved reserves of crude oil, condensate, natural gas liquids and natural gas at December 31, 2001, 2000, and 1999 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 -- Financial Statements.

Total hydrocarbon proved reserves, on an oil equivalent basis and excluding equity-accounted entities, comprised 14,624 million barrels of oil equivalent (mmboe) at December 31, 2001, an increase of 8% versus December 31, 2000. Natural gas represents about 51% of these reserves. Reserve replacement through extensions, discoveries, revisions and improved recovery exceeded production for the eighth consecutive year with a ratio of 191%.

In 2001, total additions to the Group's proved reserves (excluding purchases and sales and equity-accounted entities) amounted to 2,164 mmboe, mostly through extensions to existing fields and discoveries of new fields. The principal reserve additions were in Algeria, Angola, Azerbaijan, US Gulf of Mexico, UK and Trinidad, following development approval of the rest of the In Salah project, together with Kizomba A, Azeri-Chirag-Gunashli Phase 1, Thunder Horse and Clair fields and the sanctioning of the Atlas Methanol plant.

Our total hydrocarbon production (including equity-accounted entities) during 2001 averaged 3,419 thousand barrels of oil equivalent per day (mboe/d), an increase of 179 mboe/d, or 5.5% compared with 2000, as production declines in mature fields were more than offset by production start-ups and build-ups to full production. About 40% of our production was in the USA and 23% in the UK.

21

The following tables show BP's production by major field for the three years 1999 to 2001, and BP's aggregate estimated net proved reserves as at December 31, 2001:

Crude oil (a)

			Net production		
Production	Field or Area	Interest	2001	2000	1999
		(%)	(thousand barrels per da		
Alaska (b)	Prudhoe Bay*	26.3	123	146	202
	Kuparuk	39.2	76	81	90
	Milne Point*	100.0	45	40	42
	Endicott*	67.9	19	21	25
	Point McIntyre	32.2	10	16	25
	Other	Various	15	10	21
Total Alaska			288	314	405
Lower 48 States onshore	Altura(b)	Various	--	36	127
	Other	Various	213	182	133
Total Lower 48 States onshore			213	218	260
Gulf of Mexico (b)	Mars	28.5	42	38	36
	Troika	33.3	25	28	30
	Pompano*	75.0	21	26	29
	Other	Various	155	105	44
Total Gulf of Mexico			243	197	139
Total USA			744	729	804
UK offshore (b)	ETAP+	Various	80	85	80
	Foinaven*	72.0	60	64	56
	Forties*	96.1	51	53	66
	Harding*	70.0	42	57	58

	Schiehallion/Loyal*	Various	40	44	36
	Magnus*	85.0	37	47	48
	Andrew*	62.8	25	33	43
	Miller*	40.0	15	22	30
	Other	Various	99	89	123
Total UK offshore			449	494	540
Onshore	Wytch Farm*	50.5	36	40	40
Total UK			485	534	580
Norway	Draugen	18.4	40	38	37
	Valhall*	28.1	22	23	27
	Ula*	80.0	18	16	20
	Gyda*	56.0	12	12	14
Netherlands and other Norway	Various	Various	8	1	2
Total Rest of Europe			100	90	100

----

* BP operated.

\+ BP operates the majority of the fields in this area.

Production	Field or Area	Interest	Net production 2001	2000	1999
		(%)	(thousand barrels per da		
Australia	Various	16.7	40	37	23
Azerbaijan	Azeri-Chirag-Gunashli*	34.1	35	30	32
Canada (b)	Various	Various	18	19	56
Colombia	Cusiana/Cupiagua*	19.0	48	52	66
Egypt	October	30.4	22	30	35
	Other	Various	69	78	95
Trinidad	Various	100.0	48	47	49
Venezuela	Various	Various	54	46	30
Other (b)	Various	Various	60	51	21
Total Rest of World			394	390	407
Total Group			1,723	1,743	1,891
Equity-accounted entities					
Abu Dhabi (d)	Various	Various	126	127	113
Argentina	Various	Various	50	40	41
Other	Various	Various	32	18	16
Total equity-accounted entities			208	185	170
Total Group and BP share of equity-accounted entities (e)			1,931	1,928	2,061

----
*   BP operated.
\+   BP operates the majority of the fields in this area.

Estimated net proved reserves (a)	UK	Rest of Europe	USA	Rest of World	Total
	December 31, 2001 (millions of barrels)				
Subsidiary undertakings					
Developed................	1,008	269	2,195	836	4,308
Undeveloped.............	317	112	1,394	1,086	2,909
	1,325	381	3,589	1,922	7,217
Equity-accounted entities					1,159
Total Group and BP share of equity-accounted entities					8,376

Natural gas (a)(c)

Production	Field or Area	Interest (%)	Net production 2001	2000	1999
			(million cubic feet per d		
Lower 48 States onshore (b)	San Juan Coal*	Various	615	563	427
	Arkoma+	Various	219	94	111
	San Juan Conventional+	Various	217	185	129
	Tuscaloosa+	Various	187	171	175
	Hugoton+	Various	180	170	162
	Jonah*	79.1	109	77	57
	Wamsutter*	70.5	100	100	92
	Whitney Canyon+	Various	50	47	52
	Anschutz Ranch East*	Various	45	55	67
	Moxa Arch*	41.0	43	52	77
	Altura	Various	--	34	118
	Other	Various	595	613	227
Total Lower 48 States onshore			2,360	2,161	1,694
Alaska	Various	Various	11	9	10
Gulf of Mexico (b)	Marlin*	100.0	79	3	--
	Matagorda Island 623*	44.0	76	78	99
	Ram Powell (VK 912)	31.0	58	60	72
	Matagorda Island 519*	82.0	40	56	39

	Other	Various	930	687	361
Total USA			3,554	3,054	2,275
UK offshore (b)	Bruce*	37.0	256	201	175
	Marnock*	62.0	125	148	79
	Braes	Various	100	99	76
	West Sole*	100.0	81	89	97
	Armada	18.2	71	75	77
	Amethyst*	59.5	68	56	42
	Ravenspurn South*	100.0	66	77	87
	Britannia	9.0	65	41	--
	East Leman*	48.4	59	58	42
	Viking Complex	50.0	54	81	107
	Vulcan	50.0	33	44	26
	Other	Various	730	678	487
Onshore	Various	Various	5	5	6
Total UK			1,713	1,652	1,301
Netherlands	P/18-2*	48.7	47	52	63
	Other	Various	52	43	48
Norway	Various	Various	48	41	53
Total Rest of Europe			147	136	164

----

* BP operated.

\+ BP operates the majority of the fields in this area.

Production	Field or Area	Interest	Net production 2001	2000	1999
		(%)	(million cubic feet per d		
Rest of World					
Australia	Various	16.7	237	205	215
Canada (b)	Kirby*	71.9	72	69	132
	Brazeau River Gas*	70.0	71	63	41
	Ricinus*	70.0	61	52	54
	Marten Hills*	96.0	45	47	56
	Leismer*	54.2	28	32	64
	Other	Various	307	319	342
China	Yacheng*	34.0	108	77	--
Indonesia	Pagerungan*	100.0	242	199	103
	Sanga-Sanga	26.3	164	120	--
	Other*	46.0	95	54	--
Sharjah	Sajaa*	40.0	125	145	168
	Other	Various	35	39	38
Trinidad	Mahogany*	100.0	529	530	367
	Amherstia*	100.0	244	17	--
	Immortelle*	100.0	128	232	207
	Flamboyant*	100.0	52	69	92
	Other*	100.0	58	37	115

Other (b)	Various	Various	272	198	69
Total Rest of World			2,873	2,504	2,063
Total Group			8,287	7,346	5,803
Equity-accounted entities					
Argentina	Various	Various	236	187	145
Other	Various	Various	109	76	119
Total equity-accounted entities			345	263	264
Total Group and BP share of equity-accounted entities			8,632	7,609	6,067

----

*   BP operated.

\+   BP operates the majority of the fields in this area.

	December 31, 2001				
Estimated net proved reserves (a)	UK	Rest of Europe	USA	Rest of World	Total
	(billions of cubic feet)				
Subsidiary undertakings					
Developed.................	3,212	265	12,232	8,040	23,749
Undeveloped...............	1,160	43	2,535	15,472	19,210
	4,372	308	14,767	23,512	42,959
Equity-accounted entities					3,216
Total Group and BP share of equity-accounted entities					46,175

(a) Net proved reserves of crude oil and natural gas, stated as of December 31, 2001, exclude production royalties due to others, and include minority interests in consolidated operations.

(b) In 2001, BP purchased part of the interests of Statoil in Vietnam and the interest of Inaquimicas in Cusiana/Cuipiagua in Colombia.

In 2000, BP acquired the interests of ARCO outside Alaska. At the same time, a deal was concluded (primarily with Exxon and Phillips) in which the oil and natural gas interests in Prudhoe Bay (and some of the associated fields) were realigned. We also disposed of our interest in Altura Energy. In addition to portfolio management in the USA and Canada, we disposed of certain of our interests in Venezuela, Colombia and the UK and acquired an interest in Pakistan as part of the Burmah Castrol acquisition.

In 1999, BP sold certain interests in Canada and Venezuela. At the end of the year we purchased a significant part of Repsol YPF's share of the assets of the dissolved Crescendo Resources partnership, a major natural gas producer and processor in Texas and Oklahoma.

(c) Natural gas production volumes exclude gas consumed in operations.

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

(e) Includes NGL from processing plants in which an interest is held of 78, 41 and 54 thousand barrels per day for 2001, 2000 and 1999, respectively.

26

United States

We are the largest producer of both liquids (crude oil and NGLs) and natural gas in the USA.

Our 2001 US liquids and NGL production averaged 744 mb/d (thousand barrels per day), an increase of 2% from 2000. Approximately 39% of our 2001 oil production came from Alaska, 33% from the Gulf of Mexico, and the remainder from onshore Lower 48 States. Our US natural gas production in 2001 was 3,554 mmcf/d (million cubic feet per day), an increase of 16% over 2000.

Development expenditure in the USA (excluding pipelines) during 2001 was $3,723 million, compared with $2,328 million in 2000, an increase of 60%.

Gulf of Mexico

Our largest area of growth in the USA is focused in the deepwater Gulf of Mexico, which builds on our strong and stable US natural gas production base and more than offsets the decline in our current principal oil producing fields in Alaska. In 2001, our deepwater Gulf of Mexico liquids production was up over 23% from 2000 levels, averaging 243 mb/d. Gas production was up over 34% from 2000 levels, averaging 1,183 mmcf/d.

Growth in 2001 was driven by the activity in the major facility hubs in the deepwater Gulf of Mexico and comprised the following:

-- The Marlin hub (BP 80% and operator) reached record production rates exceeding 60 mboe/d, including a peak natural gas rate of 325 mmcf/d. In addition the Nile subsea development (BP 50% and operator) was completed on schedule in 2001. The King and King West subsea developments (BP 100% and operator) are scheduled for tie-in in 2002 and 2003 respectively.

-- The Pompano platform (BP 75% and operator) and subsea development booked 30 mmboe gross reserves in two major prospects: Pompano Subsalt and MC29. Production rates of 30 mmcf/d and 8 mboe/d gross from the subsalt well have exceeded expectations. The Pompano facility was upgraded to increase throughput by 30% in 2001. The Pompano facility improved its baseline run time from under 90% in 2000 to 93% in 2001.

The Mica subsea development (BP 50%) was successfully tied-in to the Pompano facility 60 days ahead of scheduled startup, and on budget. Mica is the longest oil subsea tieback in the Gulf of Mexico to date and production operations are on track.

-- Our active drilling and well work programme was successful at arresting field decline in the Troika field (BP 33% and operator) and we continued our work to optimise production configuration. Gross production in 2001 averaged 108 mboe/d from 6 subsea development wells.

-- Due to the continued successful development drilling results at Mars (BP 29%) and the start-up of the Europa (BP 33.33%) and MC 764 (BP 67%) subsea developments, the Mars field surpassed the 250 mmboe cumulative production milestone. Development drilling continued at Mars Tension Leg Platform in order to maintain a full system at 220 mmcf/d and 200 mboe/d.

-- The Ursa platform (BP 23%) continued to ramp up in 2001 with six new wells drilled and completed -- three Ursa wells and three from the start-up of Crosby, a subsea tieback (BP 50%). Ursa is the largest floating structure currently in the Gulf of Mexico and produced in excess of 92 mb/d of oil and 269 mmcf/d of natural gas on average for the year, achieving the 100 mmboe produced milestone in December 2001. In 2002 we expect to begin production from the Princess field (BP 23%).

-- The 300 mmboe Diana/Hoover (BP 33%) Western Gulf of Mexico basin opening development project began operations in 2000. The development consists of a floating deep-draft Caisson Vessel (DDCV) host located over the Hoover field in 4,500 feet of water. Diana, a five well subsea development, is tied back to the Hoover DDCV. The Hoover DDCV is the deepest floating production facility to date in the Gulf of Mexico. Production rates at year end averaged over 75 mboe/d.

Providing a strong foundation to our offshore portfolio are our Gulf of Mexico Shelf operations. BP accounts for 8% of the Gulf of Mexico Shelf production (Offshore Louisiana and Texas), which supplies 1/6th of the US natural gas market. We operate more than 200 platforms and 700 wells in up to 1,500 ft water depth. The Shelf is a mature basin with high decline rates, averaging 30-40% per year. In spite of that, we have maintained flat production over the last several years by utilizing advanced seismic technologies, reservoir studies, new completion technologies, and higher operating efficiencies. In 2001, we produced 198 mboe/d. We operated 12 rigs and drilled 61 operated wells.

Alaska

In Alaska, crude oil production in 2001 declined to 288 mb/d from a 2000 level of 314 mb/d. Despite this decline, we expect 2002 production in Alaska to be higher than 2001 due to the start-up of the Northstar field.

The current status of activity in Alaska is as follows:

-- Development is ongoing to mitigate the production decline at Alaska's largest producing field, Prudhoe Bay (BP 26.3% and operator). The overall observed decline rate for the Greater Prudhoe Bay Unit in 2001 was 16%. Production was characterized by continued decline in the Ivishak Producing Area and Greater Point MacIntyre Area, offset by increased production from new satellite fields.

-- The Borealis and Northwest Eileen fields (BP 26.3% and operator) came on line in the third quarter of 2001. Annualised satellite production averaged 13 mb/d (gross) for the year. By year-end, satellite field production had ramped up to 37 mb/d (gross). The satellite-drilling programme resulted in 19 new wells in the unit. The active drilling programme also resulted in the discovery of the new Orion Satellite.

-- Continued development of the Greater Prudhoe Bay Satellite fields in 2002 is expected to result in 34 additional wells and potential sanctioning of development of the Orion Satellite.

-- The Prudhoe Bay field continued an active infill drilling programme in 2001 with approximately 93 new and sidetracked wells. In 2002, we anticipate a 10% increase in the number of new and sidetracked wells.

-- The Northstar oil field (BP 99.1% and operator) was brought on line in October 2001 at a planned initial rate of 8 mb/d net and by December had reached a rate of 28 mb/d. The field is expected to reach a plateau rate of 50 mb/d net. BP's share of the full development cost is expected to be around $900 million.

-- Plans for the Point Thomson natural gas condensate field on the eastern North Slope have progressed in 2001. BP holds approximately 32% of this natural gas condensate field. While the field is expected ultimately to support a major natural gas pipeline off the North Slope, we are reviewing a project with natural gas sales as a future option, although no pipeline yet exists.

-- The Meltwater satellite development project at the Kuparuk field (BP 39.2%) began production in the fourth quarter of 2001. The field is expected to peak at about 20 mb/d gross.

-- In January 2002, we announced that we were suspending plans to develop the offshore Liberty field in favour of enhancing production at existing, large North Slope fields.

Lower 48 States

In the Lower 48 States, we remain the largest producer of natural gas, accounting for approximately 7% of total US onshore natural gas production. Production comes from a large number of fields situated principally in the states of Colorado, Kansas, Louisiana, New Mexico, Oklahoma, Texas and Wyoming.

In 2001, our production of oil and natural gas in the Lower 48 States was 620 mboe/d, up from 591 mboe/d in 2000 due to the full-year effect of the ARCO/Vastar acquisition in 2000. In 2001, we operated 34 drilling rigs and drilled 461 wells, adding reserves to replace 100% of production. Crude oil and NGL production was 213 mb/d, up 17% from 2000 levels. Natural gas production was 2,360 mmcf/d in 2001, up 9% from 2000 production.

Our production in the onshore Lower 48 States is derived primarily from the following assets:

-- In the mid-continent states (Kansas, Oklahoma, Texas and Louisiana) our operations produced 1,001 mmcf/d of natural gas and 11 mb/d of oil in 2001. Examples of improved efficiency to maintain rate in mature areas include:

    -- Western Kansas (Hugoton and Panoma fields) -- In 2001, through aggressive optimization of well operating conditions, we managed to hold production approximately flat in the Hugoton field. The Hugoton field is the largest natural gas field in the Lower 48 States and has previously experienced decline rates approaching 20%.

-- Oklahoma and Texas Panhandles (Anadarko Basin) -- We drilled and completed a 40 mmcf/d well, one of the biggest producing wells in recent history in the basin.

-- Louisiana (Tuscaloosa Trend) -- The Tuscaloosa asset set a new field production record of 373 mmcf/d in November 2001. The newly completed Martin No.1 well made a significant contribution to this record with a stabilized initial production rate of 80 mmcf/d.

-- Southeast Texas -- In the Northeast Thompsonville field, we successfully deployed the world's first commercial expandable liner hanger in a producing well. This technical innovation has the potential to reduce significantly drilling times (by reducing the number of trips) and safety risks (through its simpler design and ability to withstand higher pressures) on deep wells.

-- The Southern Wyoming (Overthrust Belt, Greater Green River Basin) operations produced 384 mmcf/d of natural gas and 9 mb/d of oil in 2001. Drilling activity has significantly increased in conjunction with a five-year drilling programme comprising more than 600 wells, primarily in the Jonah and Wamsutter fields. The 2001 drilling programme broke several field records, including most wells spudded in a single month (15), best drilling time (7.3 days/10,000 ft), and the deepest well drilled worldwide (9,500 ft) utilizing casing as the drill string. In other parts of the Greater Green River Basin, we achieved production growth of 20% through a combination of heavy drilling activity in the Jonah field and successful production base management in Moxa.

-- Colorado and New Mexico (San Juan Basin Coal and Conventional Gas fields) operations produced 832 mmcf/d of natural gas in 2001. Specific activities included the implementation of the Fruitland Coalbed Methane 160 acre infill programme and the final integration of BP and Vastar operations and personnel.

-- In the Permian Basin, 2001 production averaged 151 mmcf/d of natural gas and 55 mboe/d of liquids, an increase of 3% from 2000.

United Kingdom

We are the largest producer of both oil and natural gas in the UK. Our 2001 UK oil production of 485 mb/d was 49 mb/d lower than in 2000. Our UK natural gas production increased 4% from 1,652 mmcf/d in 2000 to 1,713 mmcf/d in 2001. The North Sea is a mature basin.

Our development expenditure in the UK (excluding pipelines) grew by 15% from $808 million in 2000 to $930 million during 2001. Significant 2001 activity included the following:

-- The Clair field Phase I development (BP 28.6% and operator) was sanctioned by BP and its partners in September, at an estimated net cost to BP of approximately $270 million. Currently the largest undeveloped resource on the UK Continental Shelf, the field was discovered in 1977 some 75 kilometres west of the Shetland Islands in 140 meters of water but was not developed due to technical difficulties. Advances in technology now make development of Clair commercially feasible. First production is expected in late 2004, with peak production rates of 20 mboe/d net in 2006.

-- The Foinaven field (BP 72% and operator), also west of the Shetland Islands in 600 meters of water, achieved a new production high of 138 mboe/d gross. This was in part due to production from the first two of five wells in Phase II, and in part due to first production from the East Foinaven field (BP 43% and operator) which began producing in September. East Foinaven is a subsea development consisting of three wells tied back to the Foinaven main field facilities. Starting in 2002, natural gas is planned to be exported from Foinaven and East Foinaven to Magnus through BP's newly constructed West of Shetland Pipeline System.

-- The natural gas pipeline which will support the Magnus Enhanced Oil Recovery Project (EOR) was completed. This pipeline will link the Magnus field (BP 85% and operator) to the deepwater west of Shetland Islands fields via the Sullom Voe Terminal Processing plant. Surplus natural gas from the Atlantic Margin fields is expected to flow beginning in mid-2002 into the Magnus reservoir and is expected to recover trapped oil which is expected to extend field life by some ten years and enable production at a plateau level of around 60 mboe/d gross until 2006. Surplus natural gas will be sold to market via existing pipelines.

-- The Bruce field (BP 37% and operator) saw the commencement of a two-year infill drilling programme. The second phase development of the Keith field (BP 35%) was sanctioned.

29

-- Harding field (BP 70% and operator) produced at a rate of 60 mb/d (gross) with the main part of the cluster (Harding South and Central) coming off plateau but being offset by production from satellite fields. The first infill well, part of a programme to fully exploit Harding South and Central reservoirs, was completed during the fourth quarter giving an additional 10 mb/d gross to the field. This well was the first UK Continental Shelf multilateral well with expandable sand screens. Further infill wells are expected to be drilled in 2002.

-- Maclure field development (BP 33.33% and operator) was sanctioned in December 2001 and is currently awaiting UK Government approval. Maclure is a subsea development with initial production rates of 12 mb/d oil and 3.5 mmcf/d natural gas expected to start up in mid-2002.

-- Eastern Trough Area Project (ETAP) production continued at high levels (108 mboe/d net) during 2001 despite the onset of natural decline in some of the initial fields (Machar in particular). During 2001 we increased our interest to 37.8% in the Madoes field (formerly known as Tornado) via an equity purchase from Phillips. We also sanctioned development of both Madoes and Mirren via subsea tieback to the ETAP central processing facility. First production from these satellite fields is expected in late 2002.

-- In the Southern North Sea area, there were a number of satellite and infill well activities. The North Davy well (BP 22% and operator), drilled in 2000, was successfully tied in and produced. The Amethyst Flowers well (BP 59.5% and operator) was also completed. The Hoton Project (BP 100% and operator) was completed on schedule with first production in December 2001.

-- A successful appraisal well was drilled to test an extension to the Vanguard field (BP 50%) and a development plan for the new field is under preparation.

-- The Shearwater Project (BP 27.5%) started production in mid-2001. Problems with plant and a number of wells were experienced, with net production averaging 7 mboe/d for the year. Production was shut down in December 2001 due to cracks in condensate pipework. We continue to work with the operator to restart production and to complete required remedial work on wells and pipework aimed at establishing steady state production during 2002.

Rest of Europe

Development expenditure in the Rest of Europe grew by 77% from $153 million in 2000 to $271 million in 2001.

Our Norwegian production increased from 95 mboe/d in 2000 to 108 mboe/d in 2001. Start-up of our Tambar field in July as well as new wells and increased efficiency at Ula are the main contributors to the increase. In addition, Draugen has increased field capacity in 2001. The natural decline of other fields has been offset by new wells at Valhall, the gas lift project at Hod and equal priority for Gyda at Ekofisk. Net production in 2001 was 40 mboe/d from Draugen (BP 18.4%), 26 mboe/d from Valhall (BP 28.1% and operator), 19 mboe/d from Ula (BP 80% and operator), 14 mboe/d from Gyda (BP 56% and operator), 6 mboe/d from Tambar (BP 55% and operator) and 2 mboe/d from Hod (BP 25% and operator). Appraisal activity included the Skarv oil and natural gas prospect (BP 30% and operator). The third Skarv well including a sidetrack was completed in June with positive results supporting a combined oil and natural gas development.

In the Netherlands, we are continuing to expand our role in natural gas storage services with the production and downstream natural gas marketing businesses working in close co-operation. The Peak Gas Installation, which came on stream in 2000, is a natural gas storage facility designed to assist in meeting peak demand requirements from consumers in the Netherlands. This installation has a storage capacity of 17,000 mmcf and is capable of withdrawing 1,270 mmcf/d.

Rest of World

The Group's net share of oil production from the Rest of World, including joint ventures and associated undertakings, increased to 602 mb/d in 2001 from 575 mb/d in 2000. Excluding joint ventures and associated undertakings production was 394 mb/d in 2001, up from 390 mb/d in 2000. Areas of oil production in 2001 were Abu Dhabi, Algeria, Angola, Argentina, Australia, Azerbaijan, Bolivia, Canada, China, Colombia, Egypt, Indonesia, Pakistan, Qatar, Russia, Sharjah, Trinidad and Venezuela.

Our share of natural gas production from the Rest of World, including joint ventures and associated undertakings, increased to 3,218 mmcf/d in 2001 from 2,767 mmcf/d in 2000. Excluding joint ventures and associated undertakings production averaged 2,873 mmcf/d in 2001, up from 2,504 mmcf/d in 2000. The largest part of 2001 production came from Trinidad and Tobago and from Indonesia, with the remainder from Argentina, Australia, Bolivia, Canada, China, Colombia, Egypt, Pakistan and Sharjah.

Canada, the Caribbean and South America

Development expenditure in the Rest of World (excluding pipelines) was $1,934 million in 2001, compared with $1,274 million in 2000, an increase of 52%.

-- In Canada, our portfolio covers a wide range of geographic areas, geological structures and infrastructure. Development activities within Canada are focused on opportunities to maintain production rates and position for growth within our existing core operating areas in the provinces of Alberta and British Columbia. In 2001, production was flat at 119 mboe/d, of which almost 85% was natural gas production (584 mmcf/d). BP has interests in 25 fields and operates approximately 1,200 wells (gross). During 2001 we operated 18 drilling rigs and drilled over 124 wells (gross).

Significant activity in South America in 2001 included the following:

-- The Colombian business is made up of mature producing assets (Cusiana/Cupiagua fields), assets under appraisal/development (Recetor and Florena fields) and a large prospect at the initial exploration stage (Niscota). Production for 2001 was 49 mboe/d. In 2001, the Florena field was successfully entered, ahead of schedule and with better than expected production rates. In addition, the successful Phase 1A development of the Recetor area, Cupiagua's northern extension, resulted in an additional commercial area and the acceleration of the overall Recetor development. BP has deepened its Recetor acreage equity from 63% to 80% (25% to 32% production equity).

-- In the Southern Cone, business in Argentina and Bolivia is conducted via our participation in Pan American Energy (PAE) in Argentina (BP 60%), which owns Empresa Petrolera Chaco in Bolivia.

Growth in 2001 was achieved in both oil and natural gas operations. These entities produced 50 mb/d of oil and 236 mmcf/d of natural gas (net to BP). Oil production increased by nearly 25% over 2000, largely as a result of a major drilling programme in Golfo San Jorge. Activity included infill and appraisal wells, water floods and electrification. Gas production increased by over 26% over 2000 with contributions from all operations. The most significant increase arose in Cerro Dragon and in the Northwest Basin where the first phase development of the Acambuco field came on stream during the first quarter of 2001.

Despite a severely depressed economy in Argentina, PAE was successful in increasing its natural gas market share from 9% to 12% during 2001. PAE also has significant interests in natural gas liquids plants, oil and natural gas pipelines, electricity generation plants, and other midstream infrastructure. Fiscal reform in Argentina is currently being debated and PAE management is actively involved in ongoing negotiations and in assessing the impact on our growth plans.

-- In Venezuela we produced 54 mboe/d from four core assets during 2001. These four base assets are reactivation projects consisting of two operated properties and two non-operated properties under operating fee agreements to produce oil for the government oil company, PDVSA. At the partner-operated Lake Maracaibo field (BP 27%), a slower than anticipated repressurization of the reservoir delayed and increased the uncertainty of oil production relative to the reactivation investment. Therefore we revised our reserve estimates downwards and recognized a charge for impairment of $175 million.

-- In Trinidad, production for 2001 reached 223 mboe/d (78% natural gas and 22% liquids) for 2001, up nearly 12% on 2000 production levels. Gas sales increased by 14% and liquid production increased by more than 3%. The increase in natural gas sales was principally due to increased purchases by The National Gas Company of Trinidad and Tobago. In late 2001, BP entered into an agreement to restructure certain natural gas contracts thereby providing for greater flexibility in choosing the field from which to source the natural gas. Major drilling activity in 2001 took place in the Mahogany and Amherstia fields, including several high rate wells one of which flowed at a rate of 200 mmcf/d.

Africa and the Middle East

Significant 2001 activity in Africa and the Middle East included:

-- In Angola Block 17 (BP 16.7%), the Girassol project went into production in December 2001 and ramp-up of production has gone well. The development of Jasmim, a tie-back to the Girassol hub, was approved. Additional development studies in Block 17, Rosa and Dalia, are well progressed.

Another significant milestone in Angola was achieved on Block 15 non-operated activities where the development approval of the large-scale Kizomba A (BP 26.7%) development (July 2001 sanction) was secured with first oil anticipated in 2004. Appraisal drilling commenced during the fourth quarter of 2001 with the aim of securing additional volumes to tie back to the Kizomba A hub and further improving Block 15 operating efficiencies. Future growth potential was also underpinned by progress on engineering studies for Kizomba B developments.

In Angola's BP operated Block 18 (BP 50% and operator), work has progressed well in the development engineering to determine the optimum development strategy for the six discoveries.

In Block 31 (BP 26.6% and operator), a dry hole was drilled and there is activity planned in 2002 to further delineate the Block.

-- In Egypt, our oil production operations are carried out by the Gulf of Suez Petroleum Company (Gupco), a joint operating company with the Egyptian General Petroleum Company (EGPC). Gupco operates seven production sharing contracts in the Gulf of Suez and Western Desert, encompassing more than forty fields. During 2001, Gupco produced 183 mb/d (87 mb/d net), almost 30% of Egypt's oil production, as well as 68 mmcf/d (33 mmcf/d net) of natural gas. Production operations were interrupted by a fire on the October platform in May 2001; October was fully back on line by the fourth quarter.

Gas production in Egypt grew 39% to 156 mmcf/d (net) with Ha'py (BP 50%) and Baltim (BP 50%) fields ramping up and the Temsah (BP 50%) natural gas field start-up was on schedule in March 2001. Collectively, we have agreements in place to supply 352 mmcf/d (working interest) to the domestic Egyptian market from these and other Nile Delta fields. The Akhen (BP 50%) drilling and development project was progressed in 2001 and the field is on schedule for production start-up in 2002.

In Egypt, BP has a 33% interest in the Med NGL project. The project involves the construction of a 1.1 bcf/d NGL plant. The plant is expected to start production in 2004, and should produce 280 thousand tonnes per annum (mtpa) of propane, 330 mtpa of LPG, and 2.7 mb/d of condensates.

-- 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 expiring in 2014 and 2018, respectively. Production in Abu Dhabi was 126 mb/d, down from 2000 as OPEC cuts made an impact throughout 2001.

-- In addition, Sharjah natural gas production was down 13% on 2000 to 160 mcf/d, although the field decline would have been more severe without plant modifications and drilling in 2001.

-- In Algeria, BP and the Algerian state company, Sonatrach, completed natural gas sales terms and let engineering, procurement and construction contracts in August 2001 for the In Salah project (BP 65%). The first stage comprises a development of four of the seven deep Saharan natural gas fields; the development is expected to cost $2.7 billion gross. In Salah is expected to supply the fast growing markets of southern Europe with up to 320 bcf annually with first deliveries forecast for 2004.

-- The In Amenas (BP 100%) pre-project programme was progressed with contract bids for engineering, procurement and construction analysed, and final stage appraisal/pre-development drilling. The Rhourde el Baguel (BP 60%) gas injection facilities redevelopment has been completed.

-- In June 2001, we signed a memorandum of understanding to take a major interest in Saudi Arabia's largest natural gas development and the first significant hydrocarbons project for 25 years in which the Saudi government has invited foreign companies to participate.

-- In Iran we are carrying out studies of a potential redevelopment plan for the Ahwaz Bangestan fields and are conducting a feasibility study of a South Pars LNG project. At this stage, no agreements have yet been concluded that commit BP to any significant investments in Iran.

Asia

Significant 2001 activity in Asia (including the former Soviet Union) included:

-- BP, as operator of the Azerbaijan International Operating Company (AIOC), manages and has 34.1% interest in the Azeri-Chirag-Gunashli (ACG) oil fields in the Caspian Sea, offshore Azerbaijan. In 2001, ACG production grew to 35 mb/d net (119 mb/d gross) from the Chirag 1 platform and this early production is expected to plateau at 37 mb/d (127 mb/d) in 2002. The next step in the development of the ACG field was achieved in 2001 with the approval in August of ACG Phase 1 ($3.4 billion estimated gross capital expenditure). First oil is expected in 2005. Development engineering for ACG Phase 2 and Phase 3 was also progressed as the follow-on phases of development.

BP is also the operator of the Shah Deniz natural gas field with a 25.5% interest. Project definition progressed in 2001, predicated on a staged development concept. Shah Deniz Stage 1 is anticipated to come on-stream in 2005 comprising an offshore production facility, with platform and subsea wells, separate natural gas and condensate lines to shore, a processing terminal at Sangachal and a new 42-inch diameter natural gas line through Azerbaijan and Georgia to Turkey along the Baku-Tbilisi-Ceyhan route up to the Georgian/Turkish border. Boru Hatlari ile Petrol Tasima (BOTAS) in Turkey and State Oil Company of the Azerbaijan Republic (SOCAR) signed a Sales and Purchase Agreement (SPA) in March 2001. It is anticipated that this SPA, with appropriate amendments, will be assigned in full to Shah Deniz interest owners. Transit agreements with the Governments of Azerbaijan, Georgia, and Turkey to support the natural gas export pipeline (South Caucasus Pipeline) and natural gas sales, have also been completed.

-- In December, we announced that we had secured our ownership interest in the Russian integrated oil company A O Sidanco (Sidanco) and overseen the rightful return of the Chernogorneft producing assets during the fourth quarter of 2001. This completes the restructuring of Sidanco with its debt substantially repaid, and non-core assets disposed of. We believe that Sidanco is now positioned as a low cost Russian producer. As a result of transactions in 2001, we increased our production and beneficial interest to an effective 11.2% equity interest in Sidanco. We have a three-year management contract for Sidanco, acting with effectively a 25% voting interest. BP-seconded personnel hold a number of the senior management positions and a BP executive acts as Chairman of the Sidanco Board of Directors. We also have an interest in Kovytka (BP 28.4%), an undeveloped East Siberian natural gas field.

-- In Kazakhstan, we agreed to dispose of a non-strategic portion of our portfolio by selling surplus capacity in the Caspian Pipeline Consortium (CPC) (BP 5.75%) pipeline. We also agreed to sell our interest in the Kashagan field.

-- In Indonesia, BP is now the largest supplier of natural gas to Java. In addition, the VICO (BP 50%) operated Sanga Sanga production sharing contract (PSC) provides 30% of the natural gas feed into the Bontang LNG operation for export and East Kalimantan domestic consumption. Our share of Indonesian production in 2001 was 21 mb/d of liquids, 236 mmcf/d of natural gas sold to the Bontang LNG plant and 339 mmcf/d sold domestically in Indonesia. Under the terms of the PSC, the reported production entitlement varies inversely with price to effect recovery of costs which are fixed in US dollars; as prices decrease therefore, a higher entitlement is received.

-- In China, BP operates the Yacheng natural gas field and the Liu Hua oil field. Yacheng supplies 100% of the natural gas supply into Hong Kong where it is sold to Castle Peak Power Company (CAPCO) under a long-term contract. Excess natural gas and liquids are piped to Hainan Island where the natural gas is sold to the Fuel and Chemical Company of Hainan also under a long-term contract. The QHD oil field (operated by CNOOC) began production in October and is expected to reach plateau during the fourth quarter of 2002.

BP's Hedong Coal Bed Methane (CBM) (BP 70%) project is located in the Ordos Basin in Shanxii province approximately 800 kilometers southwest of Beijing. BP has met all the contractual obligations of the Production Sharing Agreements and, after two years of pilot production testing, has decided to exit the project for technical reasons.

-- In Vietnam, BP (35% and consortium leader) and partners signed key elements of a $1.3 billion integrated natural gas project at the end of 2000. Construction of the Block 06.1 natural gas development and associated infrastructure commenced in early 2001 and is now well advanced. This scheme is intended to provide the basis for clean, reliable gas-fired power generation in southern Vietnam. First production is planned for late 2002.

-- In Pakistan, BP is the largest foreign operator producing 50% of the country's oil and 10% of its natural gas on a gross basis.

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 in the USA and the Forties Pipelines System in the UK sector of the North Sea. We also operate and have an interest in the Central Area Transmission System for natural gas in the UK sector of the North Sea. Our onshore US crude and product pipelines and related transportation assets are included under 'Refining and Marketing'. Our gas marketing business is described under 'Gas and Power'.

-- The Trans Alaska Pipeline System (TAPS) consists of a 48-inch diameter crude oil pipeline running approximately 1,300 kilometers from Prudhoe Bay to a tank farm and marine terminal at the ice-free port of Valdez on Alaska's southern coast. The Alyeska Pipeline Service Company operates the pipeline and terminal at Valdez. As part of the equity alignment related to ownership of the Prudhoe Bay Unit and Point Thompson Unit, BP sold 3.1% of its interest to Phillips in 2001.

-- BP now owns a 46.9% interest in TAPS, with the balance owned by five other companies. Each of the TAPS participants uses its undivided interest in TAPS as a common carrier, separately publishing tariffs and receiving tenders for shipments through its share in the capacity of TAPS, and paying its volumetric share of operating costs. At peak throughput, the TAPS system carried around 2 mmb/d. In 2001, TAPS transported production from Prudhoe Bay and the other North Slope fields averaging 1 mmb/d. In October, TAPS was vandalized and punctured by a bullet, resulting in a leak of 6,600 bbls of oil. Following a shut-in of 62 hours for repair, during which 730,000 barrels (net) of production was lost , full operation was restored. Clean-up operations continue into 2002. Security measures on the line and at the North Slope fields were increased in September and remain at a high level.

For a description of the procedures relating to the tariffs to be charged to users of TAPS and a general description of pipeline regulation, see Regulation of the Group's Business -- United States within this item.

There are a number of unresolved protests with regard to the yearly tariffs which are filed and which set out the charges for shipping oil through TAPS. These items are in the process of resolution at the Federal Energy Regulatory Commission (FERC) and the Regulatory

Commission of Alaska.

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 10 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, whose average age is 23.3 years, are retired in accordance with the Oil Pollution Act of 1990. For discussion of the Oil Pollution Act of 1990, see Regulation of the Group's Business -- Environmental Protection. In September 2000, BP contracted for the delivery of three 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 2003, 2004 and 2005. In 2001, BP exercised the first of three options for additional vessels. This fourth tanker is scheduled for delivery in 2006.

-- The Forties Pipeline System in the UK (BP 100%) is an integrated oil and natural gas liquids transportation and processing system that handles production from over 40 fields in the central North Sea. The system was upgraded in 1993 and has a capacity of more than 1 mmb/d. During 2001, average throughput was approximately 783 mb/d, compared with 804 mb/d in 2000.

-- BP operates and has a 29.5% interest in the Central Area Transmission System (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. It carries both proprietary and other companies' volumes to a natural gas terminal at Teesside, Northeast England. CATS offers its customers the choice of natural gas transportation services or transportation and processing via two 600 mmcf/d processing trains with the capability to deliver NGLs for export or for local industry with natural gas entering the UK National Transportation System. In 2001 CATS handled throughput of 1.6 bcf/d.

-- BP, as AIOC operator, manages and has a 34.1% interest in the Western Export Route Pipeline between Sangachal, which is near Baku in Azerbaijan, and Supsa on the Black Sea coast of Georgia. AIOC also operates the Azeri leg of the Northern Export Route Pipeline between Sangachal and Novorossiysk in Russia. The combined capacity of the pipelines is in excess of 200 mb/d. Transit agreements were completed with the governments of Azerbaijan, Georgia, and Turkey to support implementation of a 1 mmb/d pipeline from Baku to Ceyhan via Tbilisi on the Turkish Mediterranean coast. BP along with seven partners in the consortium to promote development of the BTC pipeline have completed a number of Host and Inter-Government Agreements in 2001, including one for Georgia. Front-End Engineering Design has been started. The additional export capacity provided is expected to be largely taken by future production from ACG and other Azerbaijan developments.

-- In October 2001 CPC (BP 5.75%) commissioned a 1,510 kilometre pipeline from Kazakhstan to the Russian port of Novorossiysk. The pipeline has an initial capacity of 28.2 million tonnes a year and will carry crude from the Tengiz field (BP 2.3% through the Lukarco joint venture).

-- A joint study team, including BP and the other major North Slope natural gas resource owners, is nearing completion of a major study investigating a pipeline project to deliver Alaskan natural gas to major North American markets. Key activities in 2002 will be to mitigate the risks inherent in a project of this magnitude, including working with legislative bodies to establish an appropriate regulatory framework.

Liquefied Natural Gas

Within BP, the Exploration and Production business is responsible for the supply of Liquefied Natural Gas (LNG) and BP's Gas and Power stream is responsible for the subsequent marketing and distribution of LNG (see details under 'Gas and Power -- International Gas and LNG').

-- BP has a 34% interest in the first train of the Atlantic LNG plant in Trinidad and is the sole supplier of natural gas to this train, which commenced operations in February 1999. In the fourth quarter of 2000, government and partner approvals were obtained to expand Atlantic LNG by an additional two trains. In 2001, construction of Train 2 progressed as planned, with first sales expected in the third quarter of 2002. Gas for Train 2 will come from the Amherstia field (BP 100% and operator) initially. To enable delivery of gas to Atlantic LNG's planned Train 3, BP is constructing its biggest offshore gas processing platform (Kapok) and its largest offshore pipeline (Bombax). Construction is proceeding on schedule to meet the planned start-up of Train 3 in 2003. Also in 2001, the Front-End Engineering and Design for a fourth LNG train was started. BP is expected to supply at least 34% of the natural gas requirements for this 4.8-mtpa (millions of tonnes per annum) plant.

-- In Trinidad and Tobago, we announced our agreement to hold a 37% share in the Atlas methanol plant, with Methanex, the Canadian operator, holding the remainder. Atlas is expected to be the largest methanol plant ever built and is intended to set new standards for cost, efficiency and environmental emissions as a result of the use of innovative leading edge technology. BP, through its customer NGC, will supply 100% of the natural gas demand for the plant.

-- In Indonesia, the VICO (BP 50%) operations produced 1.21 bcf/d of the natural gas supply to the LNG plant at Bontang; of this total, 236 mmcf/d is the BP net share. VICO, as well as operating the extensive East Kalimantan pipeline network, is natural gas co-ordinator for all of the 4 bcf/d natural gas feedstock to the Bontang facility and is Technical Advisor to PT Badak, the LNG plant operating company. Bontang, currently the world's largest LNG facility, consists of eight LNG trains with a nominal total capacity of 22.6 mmtpa, with the possibility of expanding to a ninth train being considered.

-- In addition, we operate the Wiriagar and Berau fields in Papua. These should provide the largest share of natural gas feed to the Tangguh LNG project which is expected to become the third LNG centre in Indonesia, the world's largest LNG-producing country.

-- In early 2001, BP was selected as the leading foreign company (BP 30% equity share) in China's first LNG re-gasification terminal project near Shenzhen in Guangdong Province. Planned activities in 2002 include the completion of the feasibility study and the formation of the joint venture company. The terminal is expected to start-up in late 2005 and is planned initially to have a capacity of 3.2 mmtpa with the ability to be expanded well beyond that.

-- In 2002, construction is expected to be completed on an $86 million gas-to-liquids demonstration unit, located in Nikiski, Alaska. This plant will utilize BP's compact reformer technology, enabling a significant improvement in gas-to-liquids commercial competitiveness.

Plant start-up is scheduled for second quarter of 2002.

-- In Australia, our interest in the North West Shelf Venture (BP 16.7%) saw BP's production increase 3.3% to 80.6 mboe/d in 2001. Growth was gas-led by LNG (up 0.9 mboe/d) and domestic natural gas (up 1.6 mboe/d). Along with production growth, cost savings were a considerable value driver yielding $25 million of additional earnings. In April 2001, construction of LNG Train 4 was sanctioned. The Train, scheduled to commence in June 2004, should increase North West Shelf LNG capacity by approximately 50%. In December 2001, two Echo Yodel condensate wells were commissioned, three months earlier than initially planned.

-- We have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company (ADGAS), which in 2001 supplied 5.4 million tonnes of LNG, up 4% on 2000.

35

GAS AND POWER

The Gas and Power business was created to market our substantial natural gas reserves and to develop a leading gas and power marketing and trading business. Since its inception, we have been investing in both organizational capability and capital assets to grow this new business segment.

The business is organized into three activities: natural gas marketing and trading; international natural gas and liquefied natural gas (LNG); and power activities. On January 1, 2001, the NGL business, located in North America, was transferred to the Gas and Power business from Refining and Marketing and is included in the marketing and trading activities. On January 1, 2002, the solar, renewables and alternative fuels business activities were transferred to the Gas and Power business from Other Businesses and Corporate. Also from that date the segment has been renamed Gas, Power and Renewables.

	Years ended December 31,		
	2001	2000	1999
		($ million)	
Turnover	39,208	21,013	8,073
Total replacement cost operating profit	521	571	437
Total assets	5,313	6,605	2,831
Capital expenditure and acquisitions	359	336	81

Marketing and trading activities within the stream are focused on the relatively open and liberalized natural gas and power markets of North America, the United Kingdom and certain parts of the Rest of Europe, although elements of long-term natural gas contracting activity are also still included within the Exploration and Production business segment. Our business is built on the foundation of our major natural gas supply reserves being within or in close proximity to these markets. As natural gas and power markets converge, our entry into power marketing and trading is a logical extension of our natural gas business. We market and trade BP and third-party natural gas and, to a much lesser extent, power and related energy management services. Our NGL business, a part of our North America marketing and trading activities, is engaged in the processing, fractionation and marketing of ethane, propane, butanes and pentanes extracted from natural gas.

International natural gas and LNG activities involve developing opportunities to monetize our upstream natural gas resources, and as such, are conducted in close collaboration with the Exploration and Production business. Our international natural gas strategy is to capture a disproportionate share of growth in the international demand for natural gas and is focused on growing natural gas markets including the USA, Canada, Spain and many of the emerging markets of the Asia Pacific region, notably China, where substantial demand growth is expected. LNG activities are focused on the marketing and trading of BP and third party LNG. There is close linkage between the LNG supply activities in the upstream business and Gas and Power's LNG marketing and trading activities.

In addition to power marketing and trading activities noted above, we are involved in several gas-fired power generation projects. Our power strategy focuses on projects that either monetize our equity natural gas and/or cogeneration projects on Group sites that contribute additional value from the reduction of Group power costs and/or enable excess power to be sold.

Marketing and Trading Activities

Our marketing and trading activities are concentrated in the markets of North America and the United Kingdom. Gas sales volumes have increased from 14.5 bcf/d in 2000 to 18.8 bcf/d in 2001. Most of this growth was realized in North America.

	Years ended December 31,		
Gas sales volumes (a)	2001	2000	1999
	(million cubic feet per day)		
UK	2,641	2,526	1,693
Rest of Europe	213	178	167
USA	8,327	6,524	4,047
Rest of World	7,613	5,243	3,023
Total	18,794	14,471	8,930

(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.

36

North America

BP is the leading natural gas producer in North America, the world's largest natural gas market. We are building our natural gas and power marketing and trading business in North America upon this strong foundation. Our North

American total natural gas sales volumes have grown from 5.4 bcf/d in 1999 to 9.7 bcf/d in 2000 and to 13.4 bcf/d in 2001. Of these volumes, 4.1 bcf/d (2000 3.6 bcf/d) were supplied from BP upstream producing operations. The sales volumes were a mixture of sales to commercial and industrial customers, sales to trade counter parties and term sales.

Our North America natural gas marketing and trading strategy seeks to maximize returns from building a distinctive network of connected assets, customers and activities thereby optimizing our portfolio and supply chain management and adding value through trading. These assets could be owned by BP or contractually accessed through agreements with our customers or other third parties. The extension of this network of assets is the principal purpose of our capital expenditure programme in North America for our marketing and trading activities.

NGL sales volumes	Years ended December 31, 2001	2000	1999
	(thousand barrels per day)		
UK	--	--	--
Rest of Europe	--	--	--
USA	221	154	115
Rest of World	189	195	192
Total	410	349	307

The transfer of the North American NGL business to Gas and Power in 2001 recognizes that NGLs are an integral part of the overall natural gas value chain and will also take advantage of our natural gas marketing and trading skill base in North America. The majority of BP's NGLs are marketed on a wholesale basis under annual supply contracts that provide for price redetermination based on prevailing market prices. 2001 sales volumes of NGL averaged 410 mb/d (2000 349 mb/d). NGLs are also supplied to our chemical and refining activities. We operate natural gas processing facilities across North America with a total capacity of 8.3 bcf/d. We own or have an interest in five fractionator plants in Canada and the United States. Two of these are located in Canada in Fort Saskatchewan, Alberta and Sarnia, Ontario, and three are located in the United States in Hobbs, New Mexico, Baton Rouge, Louisiana and Mont Belvieu, Texas.

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 the largest producer of natural gas in the UK. Total natural gas sales in the UK were 2.5 bcf/d in 2001, 2.5 bcf/d in 2000 and 1.7 bcf/d in 1999. Of these volumes 1.7 bcf/d (2000 1.7 bcf/d and 1999 1.3 bcf/d) were supplied from our upstream producing operations. Some of the natural gas is sold under long-term natural gas supply contracts to customers such as Centrica, the largest distributor of gas in the UK. However, the majority of natural gas sales are to commercial and industrial customers, power generation companies and via long-term supply deals with other gas wholesalers. We also trade physical natural gas on the UK spot market.

From October 1, 2001 we have agreed to purchase 56 bcf of natural gas per annum for 15 years from Statoil, a Norwegian oil and natural gas producer. This is the first significant contract for natural gas supplies to the UK from the

Norwegian continental shelf since the Frigg contract in 1977.

We have a 10% interest in the Interconnector, a 1.9-bcf/d, 240-kilometre, 40-inch sub-sea 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 continuing to build a natural gas and power marketing and trading business in northern and southern 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 northern Europe, we have established marketing activities in the Netherlands, Belgium, France and Germany. In March 2001, we acquired a 51% interest in Pmax Portfolio Management GmbH (Pmax), based in Hamburg, Germany. Pmax is an electricity marketing company, which markets electricity to medium and large customers in Germany. This investment has enabled the growth of our energy marketing business in Germany and extends our energy services and trading opportunities within northern Europe.

As part of the Veba deal, we announced the proposed divestment of our 25.5% interest in Ruhrgas. This sale has since been prohibited by Germany's Federal Cartel Office although the decision is being appealed to the German Economics Ministry, which is expected to rule in mid-2002.

In southern Europe we maintained our focus on Spain and Italy. The Spanish natural gas market has continued to grow and it is liberalizing largely ahead of the rest of continental Europe. We built on our position of being the first foreign company to secure a licence permitting us to market natural gas to industrial consumers outside the former monopoly, by growing the business to maintain some 7% of the eligible industrial market by the end of 2001. To achieve our growth, BP emerged with the maximum 25% share allowed from the Release Gas programme run by the Spanish authorities (this was the programme which required the incumbent Spanish natural gas supplier, Gas Natural, to release 150 bcf of natural gas to new entrants over a 2 year period from December 2001) and we added a major LNG supply contract from a Middle Eastern supplier backed by leasing an LNG carrier. We used the power commercializer license we were awarded in December 2000 to market power to a set of test industrial consumers in Spain's liberalized power market. Italy continues to be a significant and growing natural gas and power market (the second largest in Continental Europe) which is liberalizing and presenting opportunities to us.

International Gas and LNG

Our international natural gas and LNG activities are focused on developing worldwide opportunities to capture international natural gas growth and to monetize our upstream natural gas resources.

Construction is underway on the Bahia de Bizkaia project in Bilbao, Spain, an integrated 97.1 billion cubic feet per annum LNG import/regasification and 800 megawatt combined cycle, gas-fired power generation facility. BP has a 25% equity share in the facility and BP equity natural gas from Trinidad and Tobago will supply the facility. After regasification of the LNG, approximately 40% of the natural gas will feed the power plant, while the remaining natural gas will be fed into the local natural gas distribution system.

China is another area of activity. Currently, natural gas meets only two percent of China's energy needs, but this is expected to increase significantly. BP announced in March 2000 that it had plans to form a natural gas marketing joint venture with PetroChina aimed at supplying the growing energy markets of eastern China. Longer term, the alliance allows BP to be involved in marketing natural gas from East Siberia where BP has an interest in the substantial undeveloped Kovyktinskoye field. In 2001, BP was selected as the foreign partner in the joint venture tasked to develop the Guangdong project, China's first LNG import terminal near the city of Shezhen. Phase 1 of the project will have a capacity of 3 million tonnes a year and an associated 300 kilometres of pipeline to link the terminal to the region. Guangdong is due on stream in 2006.

In a major step forward for the Pertamina and BP operated Tangguh LNG Project in eastern Indonesia, Pertamina signed a Letter of Intent (LOI) in November 2001 for delivery of LNG to GNPower of the Philippines. The LOI provides for an exclusive period for Pertamina and GNPower to negotiate the supply of LNG from Tangguh field.

The development of the LNG business requires the development of appropriate LNG shipping capacity. During 2000, BP ordered two LNG tankers from Samsung Heavy Industries for delivery in 2002 and 2003, together with options for a further three ships. The first of these options was exercised in the first quarter of 2001 for delivery in 2003.

As described under the heading Exploration and Production -- Midstream activities -- Liquefied Natural Gas, our major LNG supplies are from Trinidad and Tobago, VICO in Indonesia, ADGAS in Abu Dhabi and the North West Shelf in Australia.

Power Activities

This business sector primarily participates in (i) power projects that support monetization of our equity natural gas and (ii) cogeneration projects on advantaged BP sites e.g., refining and chemical manufacturing sites. In addition to power marketing and trading discussed above, we are also involved in three power generation construction projects, including the Bahia de Bizkaia project covered above.

Following the announcement of power development plans at BP's largest refining and petrochemical complex, located in Texas City, Texas, construction work at the site began in 2001 for the development of a 570-megawatt (MW) cogeneration plant as a 50:50 joint venture with Cinergy Solutions, Inc. This project is expected to provide low-cost steam, power and process heat to our refining and chemicals businesses. The project is further expected to provide improved generation efficiency, reduced power costs and reduced nitrogen oxide emissions at the site. BP will supply natural gas to the plant and its excess generation capacity will be used to support power marketing and trading activities.

In December 2000, our 400 MW gas-fired power plant project at Great Yarmouth in the UK entered its commissioning phase. Commissioning has been delayed throughout 2001 due to technical problems. Work is underway with the view to making it fully operational during 2002. We plan to operate this project as a merchant plant, i.e. a power plant that sells electric power to 'spot' customers, and BP is expected to provide natural gas to the plant.

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. It operates primarily in Europe and North America, but also markets its products across South America, Australalasia and in parts of South East Asia and Africa.

	Years ended December 31,		
	2001	2000	1999
	($ million)		
Turnover (a)	120,233	107,883	60,143
Total replacement cost operating profit	3,625	3,523	1,614
Total assets	43,102	45,785	26,099
Capital expenditure and acquisitions	2,415	8,693	1,571
	($ per barrel)		
Global Indicator Refining Margin (b)	4.06	4.22	1.24

(a) Excludes BP's share of joint venture turnover of $403 million in 2001, $13,112 million in 2000 and $17,117 million in 1999.

(b) The Global Indicator Refining Margin (GIM) is the average of seven regional indicator margins weighted 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.

There are four key components of the Refining and Marketing stream each with its own focus and strengths. In refining, the focus is on top-quartile performance; to measure this we primarily use the regional refining surveys by Solomon Associates to assess our competitive position against benchmarked industry measures such as costs per barrel. In retail, the focus is on high-growth geographical areas and customer segments through the convenience-store market. In lubricants, the focus is on capitalizing on the leading Castrol and BP brands, potentially giving increased growth in both margin and volume. Finally, with respect to the stream's commercial and industrial activities, such as aviation, we focus on attractive customer segments to capture margin and growth.

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 leading refiners and marketers of gasoline and hydrocarbon products in the USA. We have extensive retail and commercial businesses in the UK, the Rest of Europe, Australasia, Africa and South East Asia. Worldwide, BP continues to be a leading marketer of fuels, served by a refining network with key refineries among the top performers in their regions.

The merger of BP and Amoco on December 31, 1998 and the acquisitions of ARCO, Burmah Castrol and ExxonMobil's interest in the fuels business of the BP/Mobil European joint venture in 2000 substantially strengthened our position in refining and marketing in the USA, UK, and Western Europe.

With effect from February 1, 2002, BP acquired Veba Oil's retail and refining assets in Germany and Central Europe. The Veba acquisition makes BP the market leader in Germany and Austria, and substantially strengthens BP's position in Poland and in several other Central European countries. Veba's retail stations are branded Aral. Veba has interests in five high quality clean fuels refineries in Germany.

In 2001, BP completed the integration of Burmah Castrol, sold its Mandan, North Dakota, and Salt Lake City, Utah refineries and restructured its commercial business in Northern Europe. Growth in the number of employees in other areas was more than offset by these activities with employee numbers decreasing from 67,000 at the start of the year to 64,600 at the year end.

Refining

In refining, our key objective is to safely operate an advantaged refining system more profitably than those of our competitors. For BP, advantaged characteristics relate to supply - the refinery's position in relation to the market; clean fuels - how the refinery supports our clean fuels strategy; and integration value - how the refinery adds value by virtue of integration with other parts of the Group's business. Refining's focus remains continued safe, reliable, and efficient operations, income growth, and increased supply of cleaner burning transport fuels for BP's Clean Cities programme.

In line with the Company's global refining strategy, to retain only those refineries that either provide advantaged supplies for its marketing operations, or are integrated with other parts of the business, BP completed the sale of its Salt Lake City, Utah, and Mandan, North Dakota refineries to Tesoro, on September 6, 2001. BP has reached agreement with Giant Industries, Inc. for Giant to acquire BP's wholly owned Yorktown, Virginia refinery; the sale is anticipated to close in the second quarter of 2002. BP has also announced the intention to sell its 33% equity interest in the Singapore Refining Company (SRC).

In the US, BP owns and operates five large modern fuels refineries with extensive clean fuel capability consistent with our strategy. These are located in Texas City, Texas; Whiting, Indiana; Toledo, Ohio; Carson City, California; and Cherry Point, Washington.

In Europe, BP operates seven fuels refineries. These are Bayernoil in Germany, Castellon in Spain, Coryton and Grangemouth in the UK, Lavera in France, Mersin in Turkey, and Nerefco in the Netherlands. All are wholly owned by BP except Bayernoil, Mersin, and Nerefco, where BP's equity interests are 55%, 68%, and 69%, respectively. Additionally, BP has a 17% equity interest in the Reichstett refinery in France, and wholly owns the Hamburg, Germany lubricants refinery. BP has announced a major restructuring project at the Grangemouth refinery in 2002 to increase the long-term competitiveness of the refinery and chemical complex.

In the rest of the world BP operates three principal refineries. These are located at Bulwer Island, Australia, Kwinana, Australia, and Singapore. Both Australian refineries are wholly owned by BP.

BP also has a 50% interest in the Durban, South Africa refinery, a 24% interest in the Whangarei, New Zealand refinery, and a 13% equity interest in the Mombasa, Kenya refinery.

With effect from February 1, 2002 BP acquired a 51% stake in Veba Oil. Veba Oil owns the Lingen refinery and has interests in four other refineries - Gelsenkirchen (50%), Schwedt (18.75%), Miro (12%), and Bayernoil (12.5%). These interests are held through Ruhr Oil, a 50/50 joint venture with Petroleos de Venezuela SA (PdVSA). Veba's total net refining capacity amounts to roughly 310,000 barrels per day. Besides adding refining capacity in advantaged geographic areas, we believe that the addition of these plants will significantly enhance BP's clean fuels capability within Central Europe.

41

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 summarised.

	Years ended December 31,		
Refinery throughputs	2001	2000	1999
	(thousand barrels per day)		
UK (a)	364	324	271
Rest of Europe (a)	663	602	540
USA	1,526	1,625	1,340
Rest of World	376	365	371
	2,929	2,916	2,522
For BP by others	14	12	19
Total	2,943	2,928	2,541
Refinery capacity utilization			
Crude distillation capacity at December 31, (a) (b)	3,259	3,203	2,801
Crude distillation capacity utilization (c)	94%	95%	95%
USA	95%	97%	95%
Europe	94%	96%	94%
Rest of World	93%	87%	96%

(a) Includes the BP share of the BP/Mobil joint venture until August 1, 2000.

(b) The crude distillation capacity figures are based on gross rated capacity, which assumes no loss of capacity due to shutdowns. The figures for 2001 reflect the sale of the Salt Lake City, Utah and Mandan, North Dakota refineries. The figures for 2000 reflect the unwinding of the BP/Mobil European joint venture, the Alliance, Louisiana refinery sale, and the acquisition of ARCO's two west coast fuels refineries: Carson City, California and Cherry Point, Washington.

(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).

Marketing

Marketing comprises three business areas: Retail, Commercial and Industrial, and Lubricants. 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. A significant increase in sales was achieved in 2001 as a result of the full year impact of the acquisition in 2000 of ARCO, Burmah Castrol and ExxonMobil's interests in the BP/Mobil European fuels business.

	Years ended December 31,		
Sales of refined products (a)	2001	2000	1999
	(thousand barrels per day)		
Marketing sales:			
UK (b)(c)	266	256	235
Rest of Europe (b)	1,062	901	794
USA	1,866	1,783	1,427
Rest of World	603	480	423
Total marketing sales (d)	3,797	3,420	2,879
Trading/supply sales (d)	2,409	2,103	1,816
Total refined products	6,206	5,523	4,695
	($ million)		
Proceeds from sale of refined products (b)	82,241	74,239	41,497

(a) Excludes sales to other BP businesses.

(b) Includes the BP share of the BP/Mobil European joint venture until August 1, 2000.

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

(d) Marketing sales are sales to service stations, end-consumers, bulk buyers, jobbers and small resellers. Trading/supply sales are to large unbranded resellers and other oil companies.

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

Marketing sales by product	2001	2000	1999
	Years ended December 31, (thousand barrels per day)		
Aviation fuel	515	474	366
Gasolines	1,659	1,512	1,298
Middle distillates	1,077	945	765
Fuel oil	351	338	319
Other products	195	151	131
Total marketing sales	3,797	3,420	2,879

In marketing our aim is to grow our customer base, both in existing and new markets - in terms of attracting new customers and by covering a wider geographic area. We are aiming at increasing our revenue per customer by attracting retail customers to spend more in convenience stores and business customers to spend more on value-added services and solutions.

Our objective is to create a more capital-efficient, higher-return business by differentiating where we choose to invest directly from where we seek to invest through partners. 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 able to meet these customer needs.

During 2001 we continued implementation of our clean fuels initiative with BP marketing cleaner fuels in 113 cities at December 31, 2001.

Retail

In retail, we differentiate between two distinct segments: a fuels segment in which we only supply fuel to retail customers through dealers and jobbers, and a convenience segment, incorporating an integrated fuel and convenience store offering, the operation of which will either be directly managed or franchised. We plan to concentrate our investment primarily in developing additional store space on existing real estate in our core metropolitan markets.

Shop sales (a)	2001	2000	1999
	Years ended December 31, ($million)		

UK	458	357	265
Rest of Europe	904	663	569
USA	1,510	1,251	542
Rest of World	362	353	365
Total	3,234	2,624	1,741
Direct-- managed	1,650	1,397	994
Franchise	1,504	1,154	707
Shop alliances	80	73	40
Total	3,234	2,624	1,741

(a) Shop sales reported are sales through direct-managed stations, franchisees and the BP share of shop alliances. Sales figures exclude sales taxes and lottery sales but include quick service restaurant sales. The sales include the BP share of the relevant sales within the BP/Mobil European joint venture until August 1, 2000.

Our retail network is concentrated in Europe and the USA, with established operations in Australasia and Southern Africa as well. We are developing networks in China, Poland and Russia.

In 2001, we opened 335 new BP Connect sites primarily in the UK and US as part of our retail strategy that builds on our advantaged locations, strong market positions and brand. These new BP Connects include new sites, razed and rebuilt sites, and extensive upgrading and remodeling of some existing stations. The BP Connect sites offer our customers cleaner fuels, a wider range of services and a distinctive food offer. In addition, over 4,600 stations worldwide were reimaged to the new BP Helios.

At the same time as we are rolling out the new convenience offer, we continue to improve the efficiency of our retail network by reducing operating costs through a process of regularly reviewing the network. Actions taken during 2001 have included divesting sites and networks, principally in those markets where our growth will be focused on a fuels only offer delivered through dealers and jobbers. Alongside this activity, we have continued to upgrade existing sites and invest in new sites, principally in markets where we believe there is growing demand for our full convenience offer.

At December 31, 2001, there were approximately 26,800 BP, Amoco and ARCO branded service stations worldwide, some 2,200 less than at the end of 2000. The Veba Oil acquisition will add approximately 3,000 Aral-branded stations in Central Europe prior to regulatory required divestments. Subsequent to the integration of the Aral-branded stations the worldwide number of stations is expected to decline over the next few years as we continue to optimize the efficiency of our retail network.

At December 31, 2001, BP's retail network in the USA comprised about 15,500 service stations of which approximately 10,600 were jobber owned. Developments in the USA during 2001 included the divestment of about 500 service stations in line with the strategy to concentrate ownership of real estate in markets designated for development of the convenience offer and stations and jobbers previously supplied from BP's Mandan, North Dakota and Salt Lake City, Utah refineries. In the US, we opened 196 BP connect sites and reimaged 1,525 stations to the new BP Helios.

In the UK and the Rest of Europe, BP's network comprised about 7,500 service stations at December 31, 2001. We opened 80 BP Connects in Europe with the majority being in the metropolitan London area and reimaged throughout Europe approximately 3,000 stations to the new BP Helios image. The Veba acquisition has significantly strengthened our retail position in Germany and Central Europe making BP the market leader in Germany and Austria by adding over 2,500 stations in Germany and 155 stations in Austria. In Central Europe, Aral has over 130 stations in the Czech Republic, Slovakia and Hungary. The combination of the BP and Aral network in Poland makes BP the largest foreign oil company in Poland with over 270 stations. In Russia, we continued to expand our retail network by adding seven stations in 2001 bringing our total number of stations in the Moscow metropolitan area to 34 at December 31, 2001.

At December 31, 2001 BP's retail network in the rest of the world comprised some 3,800 service stations. Our established networks are primarily in Australia, New Zealand, Southern Africa and South East Asia. BP is growing in China through two strategic alliances. BP's alliance with Petrochina in Guangdong Province in the coastal region of China had 201 stations at December 31, 2001, 105 of which BP reports as its share of the joint venture. 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, east China. The dual-branded service stations will sell gasoline produced by Sinopec and sell other petroleum products supplied by each partner. The Sinopec joint venture is expected to start development of sites in 2002. In addition, BP has 112 stations in Venezuela and 15 stations in Mexico. BP has agreed to sell its 21 service stations in Japan to Japan Energy with the sale expected to be completed in the first half of 2002. BP's exit from retail marketing in Japan is not expected to have any impact on its other business activities there.

Commercial and Industrial

In our Commercial and Industrial 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, thus aiming to increase customer spend and growth in volumes at above the rate of market growth. For example, our offer to Commercial and Industrial customers has expanded to include BP's flexible pricing mechanism complete with a range of clean fuels and energy saving lubricants. Our Commercial and Industrial business operates in Australasia, Europe, Southern Africa and the USA. In 2001, BP restructured its small volume domestic and commercial fuels business exiting some markets and consolidating operations in other markets.

Our aviation business sells jet and other aviation fuels 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. The effect of the events of September 11, 2001 has been a reduction in aviation sales volumes.

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 value sectors of automotive lubricants, especially in the consumer sector, but also has a strong presence in commercial sectors such as marine and specialized industrial segments.

BP markets through its two major brands, Castrol and BP, and several secondary brands including Duckhams and Veedol. The Veba acquisition will increase our lubricants position in Central Europe as the Aral brand is integrated into the BP Lubricants organization.

Our lubricants business is organized by market segment. The main characteristics of each part of the business are as follows:

Consumer markets: We supply lubricants, other products and related business services to intermediate customers (for example retailers, workshops) who in turn serve end-consumers (car, motorcycle, leisure craft owners) in the mature markets of Europe and North America and also in the fast growing markets of the developing world (Asia, India, Middle East, South America and Africa). The Castrol brand is recognized worldwide and we believe it provides us with a significant competitive advantage.

Commercial vehicle and general industrial markets: We supply lubricants and lubricant related services to automotive manufacturers and other industrial customers.

Marine market: We supply lubricants and fuels, on a global basis, to major shipping companies as well as to small fishing vessel operators. We are the leading global participant in the marine lubricants market and operate a network of offices and supply points in more than 900 ports across 90 countries. During 2000, we formed an innovative global strategic partnership 'Marine Alliance' with Unitor, a major supplier of marine consumables, to supply a full range of products and services to marine customers. This partnership is targeting market growth through supplying an expanded range of products and services.

Specialist industrial market: We supply metalworking fluids and lubricants alongside a range of business services, such as fluid management, to the metal component manufacturing sector. We also have a significant high performance industrial lubricants business in some key markets.

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 the various markets, while seeking to ensure flexibility and cost-competitiveness. In addition, the Group's oil-trading division undertakes trading in physical and paper markets in order to contribute to the Group's income.

Transportation

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

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

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 nine major product pipelines in the UK and the Rest of Europe and six in the USA.

During 2001 BP sold several transportation assets directly connected with BP refineries that had been divested including the products pipelines associated with the Alliance, Louisiana refinery, the products and crude lines associated with the Mandan, North Dakota refinery, and BP's 43.75% interest in the Frontier Pipeline crude oil pipeline associated with the Salt Lake City, Utah refinery.

BP also sold its 26.5% interest in the Pacific Pipeline in June 2001, and in March 2002 sold its interests in three Rocky Mountain pipelines.

Shipping

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

At December 31, 2001 the Group controlled or operated an international fleet of five Product Carriers, totalling approximately 0.19 million deadweight tons (dwt). Excluding BP companies in the USA, the Group had fourteen crude oil tankers (six Very Large Crude Carriers (VLCCs), and eight Medium Crude Carriers) totaling approximately 2.88 million dwt.

It also had an interest in six LNG carriers which are dedicated to transportation of Australian North West Shelf natural gas.

BP Companies in the USA had 19 tankers (ten Large Crude Carriers, four Medium Crude Carriers and five Product Carriers), totalling approximately 1.84 million dwt on long-term charter. BP owns four barges totalling 0.1 million dwt and has four vessels under construction totalling 0.64 million dwt.

In addition, a large number of small vessels are used by Group companies around the world.

CHEMICALS

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

	Years ended December 31,		
	2001	2000	1999
		($ million)	

Turnover (a)	11,515	11,247	9,392
Total replacement cost operating profit	128	760	686
Total assets	15,098	13,674	13,021
Capital expenditure and acquisitions	1,926	1,585	1,215
		($/tonne)	
Chemicals Indicator Margin (b)	108(c)	126 (d)	114

(a) Excludes BP's share of joint venture turnover of $102 million in 2001, $67 million in 2000, and nil in 1999.

(b) The Chemicals Indicator Margin (CIM) is a weighted average of externally based product margins. It is based on market data collected by Chem Systems in their quarterly market analyses, then weighted 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, acetic acid, vinyl acetate monomers and nitriles. Not included are fabrics and fibers, plastic fabrications, poly-alpha olefins, anhydrides, engineering polymers and carbon fibres, speciality intermediates, and the remaining parts of the solvents and acetyls businesses.

(c) Provisional. The data for the current year is based on eleven months of actual data and one month of provisional data.

(d) Restated following review of product margins with Chem Systems.

Chemicals margins are subject to industry cyclicality. The external drivers of our results in 2001 were determined by market demand levels, new industry supply starting up, pressures on feedstock prices, portfolio restructuring and business combination activity. In 2002, the chemical industry's external environment is expected to continue to see margins under pressure.

Our strategy is to create competitive advantage in petrochemicals through adding value to Group hydrocarbons, industry cost leadership, world-leading technology, strong market positions, and a bias to high growth products.

The Chemicals portfolio comprises three main sectors:

Aromatics and Derivatives. This sector comprises the production and conversion of Aromatics (Xylenes) into Purified Isophthalic Acid (PIA) and Purified Terephthalic Acid (PTA). PIA and PTA are chemical intermediates that are used in the production of fibres, containers, films and coatings.

Olefins and Polymers. The Olefins sector covers the production of the basic building blocks of chemical intermediates, such as ethylene and propylene. These are used in our polymers businesses to produce a wide range of polymers for commonly used products such as packaging, coatings, lubricants and detergents.

Intermediates. This business sector adds value to raw materials produced by our other chemicals activities and includes acetic acid and other derivatives. Intermediates are used by the automotive, construction, engineering plastics and resins, consumer goods and packaging industries.

Management of the portfolio is underpinned by five strategic tenets:

Adding value to BP Group hydrocarbons. As the petrochemicals arm of an oil major, we believe this is a key element of our competitive advantage, notably by allowing us to combine feedstock, refining and chemical processing across large integrated sites/systems.

Industry cost leadership. Continuing competitive pressures in the chemicals industry require an enduring focus on cost reduction and we have made cost management an important ongoing part of our business. We plan to continue to reduce underlying costs in 2002 through a number of targeted actions, such as achieving lower unit cost procurement, higher efficiency in our conversion processes and utilizing new technology applications. We also intend to continue to manage costs structurally by focusing our investment on a limited number of world-class manufacturing sites. By limiting the number of sites, we benefit from increased economies of scale and integration of chemical operations along the various value chains associated with our portfolio.

World leading technology. We believe technology will continue to distinguish the most successful companies from their competitors. Leading technology makes us a preferred supplier and a preferred joint venture partner. We intend to maintain and extend our leadership in the fundamental technologies that underpin our core businesses. BP already has a number of leading technologies in operation and is currently investing in production capacity, utilizing recent breakthroughs in butanediol, vinyl acetate monomer and ethyl acetate manufacture.

Strong market positions. This can be measured in a number of ways, such as market share, growth potential or performance in terms of returns. We have global leadership in paraxylene (PX), PTA, acetic acid, acrylonitrile, trimellitic anhydride (TMA) and a number of other products. We have also instituted a programme of marketing initiatives to improve our commercial capability. The programme includes developments in e-commerce, including the introduction of web-based marketing channels.

Bias to higher growth products. The majority of the BP portfolio is in market sectors that have historically grown more rapidly than the industry average.

We will therefore continue to focus our portfolio by investing in areas offering a good fit and divesting where there is insufficient alignment with the strategic tenets described above.

During 2001, we implemented or announced a number of structural changes that should significantly strengthen our position as the petrochemicals arm of an integrated energy company. The most significant structural changes were as follows:

-- In May 2001 we acquired from Bayer the 50% of Erdoelchemie we did not already own.

-- In November 2001 we finalized a transaction with Solvay, aimed at strengthening our polymers businesses in both Europe and the United States. Solvay has transferred its US and European polypropylene businesses to BP. The two companies have combined their European and US high-density polyethylene (HDPE) businesses to form BP Solvay Polyethylene Europe (BP share 50%) and BP Solvay Polyethylene North America (BP share 49%), respectively. In addition, BP has transferred its engineering polymers business to Solvay.

-- In February 2002 BP acquired a majority stake in Veba Oil, based in Germany. Veba's petrochemicals business, based at Gelsenkirchen and

Munchmunster, with net ethylene capacity of 0.7 million tonnes per year, will help meet BP's future chemical feedstock needs in the region.

We intend to divest the Fabrications, Fabrics and Fibers, and Burmah Castrol Chemicals businesses when the external environment is favourable as these businesses do not satisfy the five strategic tenets described above.

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 (2,851 kilotonnes per annum (ktepa)) and Hull (1,615 ktepa) in the UK; Lavera (1,825 ktepa) in France; Marl (628 ktepa) and Koln (4,276 ktepa) in Germany; Geel (2,075 ktepa) in Belgium; and Texas City, Texas (2,654 ktepa), Chocolate Bayou, Texas (3,285 ktepa), Decatur, Alabama (2,176 ktepa), and Cooper River, South Carolina (1,332 ktepa) in the USA.

We also aim to grow in the Asia-Pacific region, which offers prospects for demand growth. The 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 about 3,000 ktepa as follows: Indonesia (550 ktepa), Korea (828 ktepa), Malaysia (1,291 ktepa), Taiwan (663 ktepa), China (107 ktepa), Philippines (60 ktepa) and Japan (43 ktepa).

	Years ended December 31,		
Production by region (a)	2001	2000	1999
	(thousand tonnes)		
UK	3,125	3,137	3,737
Rest of Europe	7,925	6,713	5,993
USA	8,943	9,874	9,917
Rest of World	2,723	2,341	2,206
Total production	22,716	22,065	21,853

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

The following table shows BP production capacity by major products and by product group at December 31,2001.

Intermediates

	Aromatics and Derivatives	Olefins and Polymers	and Fabrications	Tota
	(thousand tonnes per annum)			
Purified terephthalic acid............	5,594	--	--	5,59
Ethylene..............................	--	4,004	--	4,00
Paraxylene............................	2,702	--	--	2,70
Polypropylene.........................	--	3,091	--	3,09
Styrenics.............................	--	1,538	--	1,53
Polyethylene..........................	--	2,483	--	2,48
Acetic acid/anhydride.................	--	--	2,260	2,26
Linear/poly alpha-olefins.............	--	--	1,280	1,28
Acrylonitrile.........................	--	--	949	94
Other	151	3,281	4,534	7,96
Total production capacity (a)	8,447	14,397	9,023	31,86

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

The production capacity increase from 2000 of approximately 5,000 ktepa resulted from our acquisition of the 50% share of Erdoelchemie, the Solvay transaction and organic growth from new plants and de-bottlenecking.

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.

Aromatics and Derivatives

The leading market positions of our key products give us access to a wide range of high-quality options, in terms of both investments and growth. We strive to be number one or two in terms of market share in the markets in which we compete, and we are currently a global leader in PTA and PX. Our strategy has been to bias our portfolio towards products that have been growing at a rate of approximately 8-10% per year. This is approximately three times the rate of global economic growth and compares with an estimated average of 4% for the petrochemicals industry as a whole.

Products

PTA is important as a raw material for the manufacture of polyester; PIA is used for isopolyester resins and gel coats; napthalene dicarboxylate (NDC) is used for photographic film and specialized packaging.

BP is the world's largest producer of PTA, with an interest in approximately 21% 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 Samsung Petrochemical Company (SPC) in Korea (BP 35%), China America Petrochemical Company (CAPCO) in Taiwan (BP 50%), PT Ami in Indonesia (BP 50%), Rhodiaco in Brazil (BP 49%) and TEMEX in Mexico (BP 8.55%). The site in Taiwan is the largest PTA production site in the world, followed by our Cooper River site, which is the second largest. These two, together with the Korean and Decatur sites, represent four of the five largest PTA production sites in the world.

PIA is produced in Joliet, Illinois; Geel, Belgium; and by the AGIC joint venture (BP 50%) with Mitsubishi Gas Chemical Company in Japan. NDC is produced at our plant in Decatur, Alabama.

BP is one of the world's largest producers of PX and metaxylene (MX), the feedstocks for PTA and PIA, respectively. PX and MX are produced from mixed xylene streams acquired from BP refineries and third party producers. The Aromatics and Derivatives business is largely integrated, using our manufactured PX as feedstock for the production of our PTA product.

Major Activities

-- Two new PTA plants are under construction in China and Taiwan, which will use BP's new PTA technology. The Zhuhai (BP 85%) unit in China should add 350-ktepa capacity. A new plant at our CAPCO joint venture in Taiwan (BP 50%) should add a further 700-ktepa capacity. The new Zhuhai and CAPCO units are both expected to commence operation in 2003.

-- Advanced manufacturing technology projects were completed at Texas City and Decatur during 2001. These initial projects are part of a broader plan to implement the introduction of leading edge process technology and control systems.

-- The de-bottlenecking of the PTA No. 3 unit at Geel was successfully completed, increasing capacity by 100 ktepa to 600 ktepa. This project had demonstrated the ability to stretch our in-house technology.

-- Options were developed for site and technology for the next European PTA investment (PTA No. 4). This is intended to be a world-scale development sited in northwestern Europe to take account of integration with customers and feedstock.

-- Joint efforts with Downstream resulted in a project to source PX feedstock from BP Group refineries. This project has the two aims of enabling northwestern European refineries to meet the increasingly strict gasoline aromatic content regulations and bringing feedstock supply for PX in house.

-- BP, in collaboration with several industry partners, has developed a polyethylene terephthalate (PET) beer bottle that is believed to be technically best in class and cost competitive with glass. Market evaluation and roll out is expected to occur in the first half of 2002. The vision is to establish PET as a competitive third packaging material in the global beer market, developing substantial new markets for BP's polyester intermediate product lines.

Olefins and Polymers

Our goal is to achieve a strong polymers market position. Through the dissolution of our Appryl joint venture we acquired operational control of a polypropylene plant at Grangemouth, UK. The Solvay deals increase our polypropylene business and our interests in global HDPE and the additional 50% share of Erdoelchemie (now called BP Cologne) represents an increase of some 10% of our total chemicals production volumes. The Veba acquisition further enhances our olefins production capability. In addition to these business-repositioning changes, we will continue to invest in our existing businesses. We aim to build on our existing technology base, which includes metallocene catalyst, the proprietary technology used in Innovene, our gas-phase polyethylene production process. Our product portfolio is biased to differentiated products, such as HDPE and polypropylene, which are further enhanced as a result of the Solvay transaction.

Products

We produce and market the basic petrochemical building blocks, known as feedstocks, that are used primarily as raw material for other chemical products. Feedstock chemicals are derived from the steam cracking of liquid and gaseous hydrocarbons. The olefins - ethylene, propylene and butadiene - are produced by crackers at Grangemouth, UK; Lavera, France (Naphtachimie - BP 50%); Cologne, Germany and Chocolate Bayou, Texas. Olefins are also manufactured by Ethylene Malaysia Sdn. Bhd. (BP 15%) at Kertih, Malaysia. Our production share of the Veba crackers at Gelsenkirchen and Munchmunster will be added during 2002. These 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.

50

The polymers product line includes polypropylene, used for moulded products, fibres and films; polyethylene, used for packaging, pipes and containers; and styrene polymers, used in packaging and containers. We are the second-largest producer of polypropylene in the world. Polypropylene is manufactured at Chocolate Bayou, Deer Park and Cedar Bayou, Texas; Antwerp and Geel, Belgium; Sarralbe, France and at Carson City, California. In addition, BP operates a new polypropylene plant at Grangemouth, UK, commissioned during 2000, and from 2001 we have an interest in the manufacturing joint venture at Lavera, France. BP has its own proprietary polypropylene technology.

During 2001 BP gained clarification on the license to operate with metallocene catalysts for its Innovene gas phase polyethylene process, following an agreement between BP and other interested parties. The combination of metallocene catalysts with the Innovene process produces differentiated polyethylene film products that have an improved balance of performance and processability compared to traditional metallocene or Ziegler-Natta based materials.

We are one of Europe's leading producers of polyethylene; the world's most widely used plastic. BP operates linear low-density polyethylene (LLDPE) plants at Grangemouth in the UK and Cologne in Germany. Cologne also produces low-density polyethylene (LDPE). We also produce LLDPE through PT Peni (BP 75%) at Merak, Indonesia and through Polyethylene Malaysia Sdn. Bhd. (BP 60%) at Kertih, Malaysia. BP Solvay Polyethylene Europe (BP 50%) has HDPE plants at Grangemouth, UK; Antwerp, Belgium; Sarralbe and Lavera, France; and Rosignano, Italy. In addition BP Solvay Polyethylene North America (BP 49%) has a HDPE plant at Deer Park, Texas.

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

Major Activities

-- A 270-ktepa ethylene expansion at Grangemouth was commissioned late in 2001. The expansion boosts Grangemouth's ethylene capacity to 1 million tonnes. This additional production will feed new derivative plants at both Grangemouth and Hull.

-- BP completed the purchase of Bayer's 50% stake in Erdoelchemie (renamed BP Cologne) in May 2001.

-- The transaction with Solvay has made BP the world's second largest producer of polyproylene (and the largest in North America) and positioned BP as the world's fourth-largest polyolefins producer. However, due to the current difficult business environment, we idled 205 ktepa of polypropylene capacity at Chocolate Bayou in the fourth quarter of 2001 and in March 2002 we announced its permanent closure. Also in March 2002 we announced the closure of our 261 ktepa polypropylene facility at Cedar Bayou.

-- Restructuring programmes were begun at sites in Cologne, Lavera and Grangemouth to realize incremental integration value.

-- The company announced its intention to shut down an older polyethylene production unit, Rigidex 2, within the Grangemouth chemicals site. BP also closed its LDPE manufacturing operations at Wilton on Teesside due to difficult market conditions.

-- During 2001 the Chocolate Bayou and Texas City sites were integrated into a single management structure to increase standardization and take advantage of the overall scale and buying power of the combined BP chemicals and refining activities in south Houston.

-- A major fire at Chocolate Bayou in February 2001 was managed safely and efficiently with operations restored by July and with minimal impact to customers or internal businesses. Record production volumes were achieved in October as operations became fully restored.

-- Late in 2001 we increased our interest in the Carson City refinery polypropylene unit from 67% to 85%.

-- In light of continuing difficult market conditions in the Philippines, BP is reassessing its involvement in the Bataan Polyethylene Co. plant (BP 39%).

-- In December 2001 BP, Sinopec and SPC announced the formation of SECCO (BP 50%) which plans to build a $2.7 billion petrochemicals complex near Shanghai. The complex is expected to begin operation in 2005. In January 2002 we announced a loan agreement worth $1.8 billion with nine domestic and two international banks to fund two-thirds of the project.

Intermediates

As with Aromatics, we aim to be number one or two in terms of market share in markets where we compete. New investments will build on existing leadership positions and distinctive technology.

Products

The intermediate businesses add value to raw materials produced by our other chemicals businesses and include acetic acid and its derivatives; a range of solvents and industrial chemicals; linear alpha-olefins (LAOs); polybutenes; acrylonitrile; TMA, used by the automotive, construction, consumer goods, and packaging industries; butanediol (BDO), used in synthetic materials and engineering plastics; and maleic anhydride (MAN), used in a wide range of plastics and resins.

We are a major supplier of acetic acid, a versatile chemical used in a variety of products such as foodstuffs, textiles, paints, dyes and pharmaceuticals. BP has acetyls operations in Europe, the USA, in 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%)

In Korea, the Asian Acetyls Company (BP 34%) operates a 150-ktepa vinyl acetate monomer (VAM) plant. A new 250-ktepa VAM plant at Hull was commissioned during 2001 and the VAM plant at Baglan Bay in Wales is due to close during 2002.

BP is a leading supplier of polybutene which we manufacture at Whiting, Indiana and at Lavera, France. A plant at Texas City, Texas is due to cease production in 2002. Polybutene is used in fuel additives, lubricants, adhesives, sealants, cable filling compounds, personal care products, tackified polyethylene, explosives and many other products.

LAOs are used in the production of polyethylene, for the manufacture of plasticizers for polyvinyl chloride, for the manufacture of poly alpha-olefins for synthetic lubricants, for the production of biodegradable surfactants, in synthetic-based drilling muds for the oil field and for a host of other intermediate and final products. LAOs are produced at our facilities in Pasadena, Texas; Joffre, Alberta and Feluy, Belgium.

BP is a leading supplier of poly alpha-olefins, high viscosity index materials primarily used in the production of high performance, environmentally friendly, synthetic lubricants and motor oils. These materials are manufactured at our facilities in Deer Park, Texas and Feluy, Belgium.

BP is the world's largest producer and marketer of acrylonitrile. We operate two acrylonitrile plants at Green Lake, Texas and Lima, Ohio. Green Lake, with a capacity of 460 ktepa, is the largest acrylonitrile production site in the world. Acrylonitrile is also produced at Cologne, 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 acetonitrile, primarily sold into pharmaceutical applications.

The anhydride business unit produces TMA and MAN at Joliet, Illinois, and is the world's largest producer of TMA. In 2000, we entered the global market for BDO using our proprietary technology in a world-scale plant at Lima, Ohio. BDO and its derivatives are used in pharmaceuticals, a variety of personal care products, plastics, auto parts and sports clothing.

Major Activities

-- The new 220-ktepa ethyl acetate plant at Hull was commissioned successfully in June 2001. The 110-ktepa ethanol plant at Grangemouth is nearing mechanical completion and is due to start up during 2002. The ethyl acetate investment is based on BP's innovative 'direct addition' method, which uses ethylene and acetic acid and does not require ethanol as a raw material. To supply ethylene to the new plants a pipeline has been installed between Teesside and Hull, linking into the UK ethylene network.

-- First production was achieved from a new 250-ktepa VAM plant at Hull late in 2001. The plant uses the proprietary BP LEAP technology based on a fluid bed catalyst. The plant will replace production from Baglan Bay and the Enichem toll manufacturing agreement at Porto Marghera. The capacity of the new plant is planned to increase to 300 ktepa.

-- We completed construction of a 250-ktepa LAO facility at Joffre in Alberta, Canada. The plant started up in the fourth quarter of 2001 and is operating smoothly.

52

-- During 2001, both the phthalic anhydride and phthalates plants at Hull were closed. These units are being demolished during 2002. Late in 2001, we announced the closure of the S24 Acetate plant at Hull. The plant, which manufactured 175 ktepa of ethyl acetate, iso-propyl acetate and butyl acetate closed at the end of 2001. Also during the fourth quarter of 2001 we announced the sale of our butyl acetate business to Ineos. The sale will include the transfer of the 60-ktepa plant at Antwerp.

-- We announced the cessation of the production of alcohols on our site at Pasadena, Texas. The 60-ktepa plant will stop during the fourth quarter 2002 when this site will concentrate on the production of LAOs.

-- The proposed 65-ktepa TMA plant at our existing PTA complex in Kuantan, Malaysia has advanced to construction bid stage. As a consequence of current market conditions, this TMA plant construction has been temporarily suspended.

53

OTHER BUSINESSES AND CORPORATE

Other Businesses and Corporate comprises Finance, BP Solar, 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,		
	2001	2000	1999
		($ million)	
Turnover	783	249	198
Total replacement cost operating loss	(556)	(1,110)	(826)
Total assets	8,073	11,970	2,643
Capital expenditure and acquisitions (a)	563	30,616	284

(a) Capital expenditure and acquisitions in 2000 includes $27,506 million for the acquisition of ARCO and $994 million for the acquisition of interests in PetroChina and Sinopec.

Finance co-ordinates 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.

Moody's and Standard and Poor's have assigned long-term debt ratings to BP of Aa1 and AA+, respectively.

Finance has in place a European Debt Issuance Programme (DIP) and a US Shelf Registration under each of which the Group may raise an aggregate of $6 billion of debt for maturities of one month or longer. At March 26, 2002, the amount drawn down against the DIP was $564 million, and $1,500 million against the US Shelf Registration.

BP Solar. Our solar energy business increased production and shipments by 30% compared with 2000, selling a total of 55 megawatts (MW) of solar panel generating capacity (2000, 42 MW). Major projects in 2001 included the purchase of a new Madrid facility that will be one of the world's largest solar plants when the production facility upgrade is completed in late 2002, and the completion of a $48 million project to power 150 Philippine villages - the largest solar energy project to date.

Coal activity consists of our 50% interest in PT Kaltim Prima Coal, an Indonesian company. This company operates an opencast coal mine at Sangatta in Kalimantan, Indonesia.

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 strategic 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. BP has a 2.2% interest in each company. Separately, BP announced plans to form joint ventures with both companies: in natural gas marketing and fuels retailing with PetroChina and in fuels and petroleum products marketing and chemicals with Sinopec. 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 streams 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.

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.

Renewables and alternative fuels. In renewables we are further building expertise in wind energy with plans to construct a wind farm at our jointly owned Nerefco refinery in the Netherlands. We are exploring market opportunities for hydrogen and fuel cells through participation in various industry projects and organizations promoting fuel cells and hydrogen fuels. Examples include a joint project with DaimlerChrysler, First Bus, Transport for London and the Energy Savings Trust to introduce three hydrogen fuel cell buses to England's capital; and BP and Singapore's Economic Development Board (EDB) have signed a letter of intent to build hydrogen refueling stations for future Singapore motorists.

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 periodically.

Integrated supply and trading. During 2001, BP brought together the trading activities in Gas and Power, Refining and Marketing and Finance under single leadership. As Chemicals develops trading activities, they will be included as well. The financial results of the trading activities will remain with the business streams. This change provides the opportunity to improve our knowledge transfer, risk management, control and assurance processes and to optimize our systems investment.

REGULATION OF THE GROUP'S BUSINESS

United Kingdom

Licensing. Pursuant to, among other things, The Petroleum Act 1998, all petroleum existing in its natural condition in strata in the UK or beneath its territorial waters (including its continental shelf) is the property of the Crown, and licences to explore for and produce it may be granted, subject to conditions, by the Secretary of State for Trade and Industry (Secretary of State). These conditions include provisions relating to the term of the licence, the imposition of specific drilling obligations, environmental protection controls, controls over the development and decommissioning of oil and natural gas fields (including restrictions on production) and the payment of royalties.

Development of oil and natural gas reserves. The development and production of UK oil and natural gas reserves (including rates of production) require the approval or consent of the Secretary of State. There have been a number of policy statements by various UK Governments over the years with respect to production controls. Although successive Governments have made it clear that the imposition of production cut-backs in order to facilitate a coherent depletion policy has been kept under review, the steps taken by the Government since the early 1980s have tended to concentrate on encouraging exploration, development and production and no significant cut-backs of previously agreed rates of production are known to have been imposed.

Other controls. In addition to the regulatory powers of the Government referred to above, the Secretary of State has wide powers over the oil field operations, including gas flaring, the installation, use and tariffs of sub-marine pipelines, the construction or expansion of refining capacity and powers to impose programmes for the eventual decommissioning of offshore installations. Furthermore, the Secretary of State for Transport has powers to control the positioning of offshore installations if the chosen location is in or is close to a shipping lane. The UK Health and Safety Executive has wide powers and duties in relation to offshore health and safety. BP is also subject to European Union legislation, in particular the Procurement Directive which regulates the procedure for awarding major contracts.

Petroleum revenue tax. Petroleum revenue tax (PRT) was abolished in the Finance Act 1993 in respect of oil and natural gas fields given development consent on or after March 16, 1993 (Non-Taxable Fields). Profits from Non-Taxable Fields are charged to corporation tax under general principles. PRT is still charged on profits from fields given development consent before that date (Taxable Fields). PRT is charged in relation to Taxable Fields on profits from oil (which includes natural gas except where specifically excluded by statute) won under licences granted under either the Petroleum (Production) Act 1934 or the Petroleum (Production) Act (Northern Ireland) 1964. It is charged on a field-by-field basis, at the rate of 50% for chargeable periods ending after June 30, 1993 (75% for periods ending on or before that date), on the assessable profit arising in each chargeable period (normally the six months ending on June 30 and December 31 in each year), as reduced by any allowable losses and by an oil allowance (unless the maximum amount of oil allowance has already been used), and subject in certain years to an overall limit (safeguard). PRT is also chargeable on any consideration received in connection with the use by other fields and the disposal of certain 'qualifying assets', the expenditure on which is allowable for PRT, subject to an allowance in the case of the use of assets by fields which are themselves liable to PRT.

The assessable profit reflects, very broadly, the market value of oil won less the costs of discovery and production, including any Government royalties payable. Interest and other financing costs are not deductible in determining the assessable profit; instead, certain costs are designated as qualifying for a supplement of 35% (uplift). Uplift ceases for costs incurred after the end of the chargeable period in which the field's cumulative income exceeds its cumulative expenditure (payback).

Oil allowance exempts certain amounts from PRT. For each onshore field and offshore field given development consent before April 1982, an allowance of up to 250,000 tonnes of oil per chargeable period is available, subject to a cumulative total of 5 million tonnes. For each onshore field and each offshore field situated in the Southern Basin of the North Sea given development consent after March 1982, the oil allowance for chargeable periods ending after June 30, 1988 is 125,000 tonnes per chargeable period and the cumulative total is 2.5 million tonnes. For each offshore field not situated in the Southern Basin given development consent after March 1982, the allowance is 500,000 tonnes per chargeable period subject to a cumulative total of 10 million tonnes. The oil allowance is shared by the participants in each field in proportion to their shares of oil. Safeguard provides that the total PRT payable in respect of a field is limited to 80% of the amount (if any) by which the PRT profits for a chargeable period (specially adjusted for this purpose) exceed 15% of accumulated expenditure (as adjusted). Safeguard remains available after payback has been reached for half as many periods again as it took to reach payback from the first chargeable period.

Allowable losses in any chargeable period can be set off against the assessable profits of subsequent or, after making an appropriate claim, previous periods from the same field but, in relation to losses arising in respect of chargeable periods ending after June 30, 1993, the PRT repayment plus any interest thereon arising from the set-off of losses against profits of previous periods cannot exceed 60% of the losses set off (85% in respect of chargeable periods ending after June 30, 1991 and on or before June 30, 1993). In addition, relief is available against the assessable profit from a field for certain expenditure incurred outside the field. There are restrictions to prevent the obtaining of relief for expenditure incurred in connection with Non-Taxable Fields against profits from Taxable Fields. Exploration or appraisal expenditure incurred on or after March 16, 1983 and before March 16, 1993, in respect of an area for which no development decision has been made, may be set against the assessable profits of any Taxable Field together with any such expenditure incurred prior to that date which is designated as abortive. There is no relief for exploration and appraisal incurred after March 16, 1993 unless the Company was already committed to it at that date and it is incurred on or before March 16, 1995. There is an additional transitional relief for exploration and appraisal expenditure, subject to certain conditions, limited to a maximum of (pound)10 million for expenditure incurred on or after March 16, 1993 and before January 1, 1995. Finally, a loss from a Taxable Field in which the winning of oil has permanently ceased which cannot be relieved against the assessable profits of that field can be claimed against the assessable profit from any other Taxable Field. The offset of reliefs is limited to prevent a company buying into mature oil fields and setting pre-acquisition expenditures against the assessable profits of that field.

Royalties. Royalty is charged on the value of production from certain licences, in most cases payable at a rate of 12.5%. Royalty has been abolished for fields which received development consent after March 31, 1982. Production licences contain provision for Royalty to be charged and separate rules (called modes) will apply dependant on where the licence is located and when it was issued. There are seven separate modes for calculating Royalty. Royalty is calculated by reference to six month chargeable periods (CP) ending on June 30, and December 31, with a return and payment made two months after the end of the CP. Certain modes provide for relief of conveying and treating expenditure. The relief varies considerably depending upon which mode applies. Some modes provide no relief for expenditure.

Corporation tax. Companies are also subject to corporation tax on their profits or gains from oil extraction activities, although PRT is deductible in computing any corporation tax liability. There are restrictions on using reliefs from other activities against profits or gains from oil extraction activities, or from the disposal of interests in oil or of assets used in connection with a field in the UK or a designated area. There is also an exemption from capital gains taxation and capital allowance clawback for certain exchanges of licence interests before the development stage. An election can be made in relation to expenditure incurred after June 30, 1991 for 100% reliefs for certain net offshore decommissioning expenditure. Losses created by these decommissioning reliefs are available for set-off against profits of the previous three years.

United States

Tax. The State of Alaska imposes various taxes on the Group's operations in Alaska. At present, these include a severance tax on oil and natural gas produced, an ad valorem tax on all oil and gas exploration, production and pipeline equipment and a corporate income tax on companies doing business in Alaska. Following the Exxon Valdez oil spill, the State of Alaska passed an act to finance the State's Oil and Hazardous Substance Release Response Fund by imposing a conservation surcharge of $0.05 per barrel on all oil subject to the State's oil and gas properties production tax. Subsequently, the State amended the surcharge to suspend $0.02 per barrel of it when the balance in the Response Fund exceeds $50 million, and as a result the net surcharge is $0.03 per taxable barrel unless there is a spill that draws the Fund's balance below $50 million. Further, losses occurring in connection with a catastrophic oil discharge are not deductible as business expenses in determining the gross value of oil for tax purposes in the State of Alaska.

Pipeline regulations. The Interstate Commerce Act requires common carriers engaged in the transport by pipeline of oil in interstate or foreign commerce to file tariffs with the Federal Energy Regulatory Commission (FERC) showing all rates, classifications, rules and practices between all points on their system. It also prohibits them from collecting any different compensation for transportation from that specified in their approved tariffs. Third parties, or the FERC on its own motion, may initiate an investigation of any proposed tariff, which involves the scheduling of a hearing. If the FERC, at the conclusion of a hearing, finds that a new or increased rate is unreasonable or discriminatory, or otherwise in violation of the Interstate Commerce Act, it may order the carrier to cease and desist from charging that rate, may prescribe a rate for the future and order refunds to shippers of collected amounts found to be unreasonable. Similar corresponding provisions at a state legislative level and enforced through a state regulator may also apply to common carriers engaged in the transport by pipeline of oil in intrastate commerce.