BHP BILLITON LTD
Form 20-F
October 23, 2003
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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C.

FORM 20-F

(Mark One)

¨ **REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) OR 12(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 JUNE 30, 2003

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES AND EXCHANGE ACT OF 1934**

Commission file number: 001-09526	**Commission file number: 001-31714**
BHP BILLITON LIMITED	**BHP BILLITON PLC**
(ABN 49 004 028 077)	**(REG NO. 3106209)**
(Exact name of Registrant as specified in its charter)	**(Exact name of Registrant as specified in its charter)**

VICTORIA, AUSTRALIA **(Jurisdiction of incorporation or organisation)**	**ENGLAND AND WALES** **(Jurisdiction of incorporation or organisation)**
180 LONSDALE STREET, MELBOURNE,	**NEATHOUSE PLACE, VICTORIA, LONDON,**
VICTORIA 3000 AUSTRALIA **(Address of principal executive offices)**	**UNITED KINGDOM** **(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	Title of each class	Name of each exchange on which registered
American Depositary Shares*	New York Stock Exchange	American Depositary Shares*	New York Stock Exchange
Ordinary Shares**	New York Stock Exchange	Ordinary Shares, nominal value US$0.50 each**	New York Stock Exchange

* Evidenced by American Depositary Receipts. Each American Depositary Receipt represents two ordinary shares of BHP Billiton Limited or BHP Billiton Plc, as the case may be.

** Not for trading, but only in connection with the listing of the applicable American Depositary Shares.

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.

	BHP Billiton Limited	BHP Billiton Plc
Fully Paid Ordinary Shares	3,747,687,775	2,468,147,002

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

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In this annual report, the terms we, our, us, BHP Billiton and BHP Billiton Group refer to BHP Billiton Limited and BHP Billiton Plc, together with their respective subsidiaries. BHP Billiton Plc Group refers to the group that is BHP Billiton Plc and its subsidiary companies. BHP Billiton Limited Group refers to the group that is BHP Billiton Limited and its subsidiary companies. BHP Billiton Plc refers to the parent entity that was formerly Billiton Plc before the implementation of the DLC structure and BHP Billiton Limited refers to the parent entity that was formerly BHP Limited before the DLC structure.

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FORWARD LOOKING STATEMENTS

This annual report contains forward-looking statements, including statements regarding:

- estimated reserves;
- plans, strategies and objectives of management;
- closure or divestment of certain operations or facilities (including associated costs);
- anticipated production or construction commencement dates;
- expected costs or production output;
- the anticipated productive lives of projects, mines and facilities;
- contingent liabilities; and
- the combination of the operations of BHP Billiton Plc and BHP Billiton Limited through the implementation of the DLC structure.

These forward-looking statements are not guarantees or predictions of future performance, and involve known and unknown risks, uncertainties and other factors, many of which are beyond our control, and which may cause actual results to differ materially from those expressed in the statements contained in this annual report.

For example, our future revenues from our operations, projects or mines described in this annual report will be based, in part, upon the market price of the minerals, metals or petroleum produced, which may vary significantly from current levels. These variations, if materially adverse, may affect the timing of the feasibility of the development of a particular project, or the expansion of certain facilities or mines. Other factors that may affect the actual construction or production commencement dates, costs or production output and anticipated lives of operations, mines or facilities include our ability to profitably produce and transport the minerals, petroleum and/or metals extracted to applicable markets, the impact of foreign currency exchange rates on the market prices of the minerals, petroleum or metals we produce, activities of government authorities in certain of the countries where we are exploring or developing these projects, facilities or mines, including increases in taxes, changes in environmental and other regulations and political uncertainty and other factors identified in the desciption of the risk factors in Item 3D. We cannot assure you that our estimated economically recoverable reserve figures, closure or divestment of such operations or facilities, including associated costs, actual production or commencement dates, cost or production output, or anticipated lives of the projects, mines and facilities discussed in this annual report will not differ materially from the statements contained in this annual report.

GLOSSARY OF TERMS

Technical Terms

In the context of ADSs and listed investments, the term quoted means traded on the relevant exchange.

We refer in this annual report to tonnes, each of which equals 1000 kilograms, approximately 2,205 pounds or 1.102 short tons. Measures of distance referred to in this annual report are stated in kilometres, each of which equals approximately 0.62 miles, or in metres, each of which equals approximately 3.28 feet.

ADS means American Depositary Share

Brownfield project means the expansion of an existing operation.

Coal Reserves has the same meaning as ore reserves, but specifically concern coal.

Coking Coal, by virtue of its carbonisation properties, is used in the manufacture of coke, which is used in the steelmaking process.

Crude oil is a mixture of hydrocarbons that exist in liquid form in natural underground reservoirs, and remain liquid at atmospheric pressure after being produced at the well head and passing through surface separating facilities.

Condensate is a mixture of hydrocarbons which exist in gaseous form in natural underground reservoirs, but which condense to form a liquid at atmospheric conditions.

Direct reduced iron (DRI) is metallic iron formed by removing oxygen from iron ore without the formation of, or passage through, a smelting phase. DRI can be used as feedstock for steel production.

DLC merger means the merger between BHP Billiton Limited and BHP Billiton Plc, on June 29, 2001.

Dry gas is a mixture of hydrocarbon gases, inerts and other gases that are in the gaseous phase at pipeline conditions with no free liquids at operating conditions. It is principally composed of methane, ethane and low levels of propanes and butanes depending upon processing and pipeline specifications.

Energy coal is used as a fuel source in electrical power generation, cement manufacture and various industrial applications. Energy coal may also be referred to as steam or thermal coal.

Ethane, where sold separately, is largely ethane gas that has been liquified through pressurisation. One tonne of ethane is approximately equivalent to 26.8 thousand cubic feet of gas.

Federal unit is a combination of two or more US Minerals Management Service (MMS) defined blocks approved by MMS in circumstances where it can be demonstrated that the blocks are part of the same geological formation.

Green field project means the development of a new project.

Gigajoules = 1,000,000,000 joules (where joules is a measure of energy).

Heap leaching is the process by which a soluble mineral can be economically recovered by dissolution from ore piled in a heap.

Hot briquetted iron (HBI) is densified direct reduced iron where the densification is carried out at a temperature greater than 650 degrees Celsius. The resultant product has density greater than 5g/cm3. HBI can be used as feedstock for steel production.

Leaching is the process by which a soluble mineral can be economically recovered from ore by dissolution.

Liquified natural gas (LNG) consists largely of methane that has been liquified through chilling and pressurisation. One tonne of LNG is approximately equivalent to 45.9 thousand cubic feet of natural gas.

Liquified petroleum gas (LPG) consists of propane and butane and a small amount (less than 2%) of ethane that has been liquified through pressurisation. One tonne of LPG is approximately equivalent to 11.6 barrels.

Marketable Coal Reserves represents beneficiated or otherwise enhanced coal product and should be read in conjunction with, but not instead of, reports of coal reserves.

Megajoules = 1,000,000 joules (where joules is a measure of energy).

Metallurgical coal is a broader term than coking coal which includes all coals used in steelmaking, such as coal used for the Pulverised Coal Injection (PCI) process.

Oil and gas reserves mean those quantities of oil and gas that which are anticipated to be legally and commercially recoverable from known accumulations as of the date of the reserve estimate.

Ore reserves are that part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination.

Petajoules = 1,000,000,000,000,000 joules (where joules is a measure of energy).

Petroleum coke is a residue from the refining of heavy fraction oil into light fraction oil.

Probable ore reserves are reserves for which quantity and grade and/or quality are computed from information similar to that used for proven (measured) reserves, but the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. The degrees of assurance, although lower than that for proven (measured) reserves, is high enough to assure continuity between points of observation.

Proved ore reserves are the reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings on drill holes; grade and/or quality are computed from the results of detailed samplings and (b) the sites for inspection, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well established.

Recoverable coal reserves are the combination of the proved and probable ore reserves which specifically concern coal.

Take or pay means an obligation on a customer to pay for an agreed minimum quantity of a commodity even if it fails to take that agreed minimum quantity.

Terajoules = 1,000,000,000,000 joules (where joules is a measure of energy).

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Financial Terms

UK Terminology	**US equivalent**	**Australian equivalent**
Shareholders Funds	Stockholders Equity	Total Equity
Called up share capital	Subscribed Capital Stock	Contributed Equity
Ordinary Shares	Common Stock	Ordinary Shares
Profit and Loss Account	Retained Earnings	Retained Profits
	Appropriated Surplus	Reserve, e.g. General Reserve. Forms part of Shareholders Equity
Share Premium Account	Paid-in Surplus	Share Premium Reserve
Provision accrued liability, i.e., not part of Total Equity	Reserve can represent either part of Stockholders Equity, accrued liability or estimated depletion in the cost of an asset	Provision accrued liability, i.e., not part of Total Equity
Tangible Fixed Assets	Property, Plant and Equipment	Property, Plant and Equipment
Bonus Issue	Stock Dividend	Bonus Issue
Subsidiary	Subsidiary	Controlled Entity
Turnover	Sales Revenue	Sales Revenue
Depreciation	Depreciation and depletion	Depreciation
Profit for the financial year (attributable profit)	Net income	Net profit attributable to members

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IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISERS

ITEM 1. IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISERS

A. Directors and Senior Management

Not applicable.

B. Advisers

Not applicable.

C. Auditors

Not applicable.

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OFFER STATISTICS AND EXPECTED TIMETABLE

ITEM 2. OFFER STATISTICS AND EXPECTED TIMETABLE

A. Offer Statistics

Not applicable.

B. Method and Expected Timetable

Not applicable.

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KEY INFORMATION

ITEM 3. KEY INFORMATION

A. Selected Financial Data

Set forth below is selected consolidated financial information for (i) the BHP Billiton Group, which reflects the combined operations of both the BHP Billiton Limited Group and the BHP Billiton Plc Group, and (ii) the BHP Billiton Plc Group as a separate, stand-alone group. BHP Billiton Limited and BHP Billiton Plc each reports, as its primary financial statements under the requirements of the US Securities and Exchange Commission, the BHP Billiton Group s consolidated financial statements prepared in accordance with generally accepted accounting principles in the United Kingdom and presented in US dollars. These financial statements account for the dual listed company structure as a business combination and accordingly consolidate BHP Billiton Limited, BHP Billiton Plc and their respective subsidiaries for all periods presented. Under UK GAAP, the DLC structure has been accounted for under the pooling-of-interests method as though the DLC structure had been effective and the two groups had operated as one enterprise throughout the periods presented. The selected consolidated financial information for the BHP Billiton Plc Group on a stand-alone basis has been derived from the BHP Billiton Plc Group Consolidated Financial Statements, presented in US dollars and prepared in accordance with accounting policies that are in compliance with UK GAAP, except that these financial statements have been prepared as if the DLC merger had not occurred.

Under UK GAAP, the DLC structure has been accounted for as a merger (pooling of interests) in accordance with UK Financial Reporting Standard 6: Acquisitions and Mergers. Under US GAAP, the DLC structure is accounted for as a purchase business combination with the BHP Billiton Limited Group acquiring the BHP Billiton Plc Group on June 29, 2001. In a merger or a combination, the assets, liabilities and equity of the BHP Billiton Plc Group and the BHP Billiton Limited Group are combined at their respective book values as determined under UK GAAP. Under US GAAP, the reconciliation of shareholders equity includes the purchase adjustments required to recognise the BHP Billiton Plc Group assets and liabilities at their fair values, and to record goodwill.

BHP Billiton Limited s independent chartered accountant in Australia for the year ended June 30, 2001 was Arthur Andersen. On June 15, 2002, Arthur Andersen LLP, Arthur Andersen s US affiliated firm, was convicted by a jury in Houston, Texas on a single charge of obstructing justice in connection with its actions regarding Enron Corp. As of August 31, 2002, Arthur Andersen LLP ceased to practice before the SEC. As a US listed company, BHP Billiton Limited is required to file with the SEC annual financial statements audited by its independent certified public accountant. The SEC has said that it will continue accepting financial statements audited or reviewed by Arthur Andersen so long as Arthur Andersen is able to make certain representations to us. Although the financial statements of BHP Billiton Limited for the year ended June 30, 2001 are not included in this annual report, we have included the audit opinion of Arthur Andersen in this annual report because the audit opinion of PricewaterhouseCoopers for the BHP Billiton Group for the year ended June 30, 2001 insofar as it relates to amounts included in respect of BHP Billiton Limited has expressed reliance on the audit opinion of Arthur Andersen. In connection with its audit of the BHP Billiton Limited financial statements for the year ended June 30, 2001 and the revision to note 50 of such financial statements, which is dated March 22, 2002, included in this annual report, Arthur Andersen has made the representations to us that are required by the SEC. In the future, our access to the capital markets and our ability to make timely SEC filings could be impaired if the SEC ceases accepting financial statements audited by Arthur Andersen or if Arthur Andersen becomes unable to make the required representations to us. Further, it is possible that events arising out of the indictment may adversely affect the ability of Arthur Andersen to satisfy any claims arising from its provision of auditing and other services to us, including claims that may arise out of Arthur Andersen s prior audit of our financial statements.

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BHP Billiton Group

The selected consolidated financial information for the BHP Billiton Group set forth below as at and for the fiscal years ended June 30, 2003, 2002 and 2001 should be read in conjunction with, and is qualified in its entirety by reference to, the audited BHP Billiton Group Annual Financial Statements and the accompanying notes included in this annual report.

	Year ended June 30,			
Consolidated Profit and Loss Account	**2003**	**2002**	**2001**	**2000**
	(US$ millions except per share data)			
Amounts in accordance with UK GAAP				
Group turnover total	15,608	15,906	17,789	17,415
Group turnover from continuing operations	15,608	13,562	14,771	12,744
Operating profit (including share of profit of joint ventures and associates)				
- including exceptional items total	3,412	2,943	2,825	2,182
- excluding exceptional items from continuing operations	3,412	2,984	3,284	2,485
- including exceptional items from continuing operations	3,412	2,873	2,612	1,790
Net profit before minority interests				
- including exceptional items	1,941	1,737	1,252	1,527
Net profit attributable to members				
- including exceptional items	1,901	1,690	1,529	1,506
Dividends provided for or paid	900	784	754	788
Number of Ordinary Shares (millions)[(a)]				
- at period end	6,216	6,044	6,023	5,817
- weighted average	6,207	6,029	5,944	5,725
- weighted average diluted	6,222	6,042	5,973	5,736
Per Ordinary Share:[(a)]				
- Net profit attributable to members				
Including exceptional items				
- Basic	US$ 0.31	US$ 0.28	US$ 0.26	US$ 0.26
- Diluted	US$ 0.31	US$ 0.28	US$ 0.26	US$ 0.26
-Dividends provided for or paid BHP Billiton Plc	US$ 0.145	US$ 0.130	US$ 0.120	US$ 0.113
-Dividends provided for or paid BHP Billiton Limited	US$ 0.145	US$ 0.130	A$ 0.247	A$ 0.247

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Consolidated Profit and Loss Account	Year ended June 30, 2003	2002	2001	2000
	(US$ millions except per share data)			
Amounts in accordance with US GAAP (c)(d)				
Sales revenue from continuing operations	15,608	13,552	8,100	7,467
Other income from continuing operations	223	321	516	268
Operating income from continuing operations	2,698	1,969	629	14
Net income total	1,581	1,249	882	400
Net income from continuing operations	1,576	1,513	718	257
Net (loss)/income from discontinued operations	5	(264)	136	143
Per Ordinary Share(a):				
Net income attributable to members				
Basic from continuing operations	US$ 0.25	US$ 0.25	US$ 0.20	US$ 0.07
Diluted from continuing operations	US$ 0.25	US$ 0.25	US$ 0.20	US$ 0.07
Basic from discontinued operations		US$ (0.04)	US$ 0.04	US$ 0.04
Diluted from discontinued operations		US$ (0.04)	US$ 0.04	US$ 0.04
Basic total	US$ 0.25	US$ 0.21	US$ 0.24	US$ 0.11
Diluted total	US$ 0.25	US$ 0.21	US$ 0.24	US$ 0.11
Per ADS:				
Net income attributable to members				
Basic total	US$ 0.50	US$ 0.42	US$ 0.48	US$ 0.22
Diluted total	US$ 0.50	US$ 0.42	US$ 0.48	US$ 0.22

Balance Sheet	At June 30, 2003	2002	2001	2000
	(US$ millions)			
Amounts in accordance with UK GAAP				
Total assets	28,365	29,552	28,028	27,335
Total non-current portion of interest bearing liabilities(b)	6,288	5,534	6,521	5,040
Contributed equity	3,537	4,895	4,791	5,356
Equity attributable to members	12,013	12,356	11,340	11,036
Amounts in accordance with US GAAP (c)(d)				
Total assets total	35,001	35,795	35,232	17,698
Total assets of continuing operations	35,001	33,023	32,562	13,046
Total non-current portion of interest bearing liabilities total	6,414	6,350	6,607	3,501
Total non-current portion of interest bearing liabilities of continuing operations	6,414	6,296	6,544	3,412
Equity attributable to members	16,832	17,147	16,602	6,333

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(a) The calculation of the number of ordinary shares used in the computation of basic earnings per share is the aggregate of the weighted average number of ordinary shares outstanding during the period of BHP Billiton Plc and BHP Billiton Limited after deduction of the number of shares held by the Billiton share repurchase scheme and the Billiton Employee Share Ownership Trust and adjusting for the BHP Billiton Limited bonus share issue. Included in the calculation of fully diluted earnings per share are the BHP Billiton Limited options and partly paid shares and the BHP Billiton Plc executive share awards.

(b) Includes limited recourse finance and finance leases not repayable within 12 months.

(c) As discussed in Note 33. US Generally Accepted Accounting Principles disclosures in the attached 2003 BHP Billiton Group Annual Financial Statements, the Group changed its methods of accounting for goodwill and employee stock-based compensation, refer footnotes (D) and (R) respectively, under US GAAP in the year ended June 30, 2003.

(d) The US GAAP consolidated financial information for the BHP Billiton Group set forth below as at and for the year ended May 31, 1999 has been derived from the audited consolidated financial statements, prepared in Australian dollars, of the BHP Billiton Limited Group (the predecessor to the BHP Billiton Group) and converted to US dollars from Australian dollars at a US$/A$ rate of 0.6232 for the year ended May 31, 1999 and a rate of 0.6509 at May 31, 1999.

		Year ended May 31, 1999
		(US$ millions except per share data)
Sales revenue		11,984
Net loss attributable to members		(1,165)
Per ordinary share:		
- Net loss attributable to members		
- Basic	US$	(0.33)
- Diluted	US$	(0.33)
- Dividends provided for or paid		
- As declared	US$	0.318
- As declared, adjusted for the bonus issue	US$	0.154
Per ADS:		
- Net loss attributable to members		
- Basic	US$	(0.66)
- Diluted	US$	(0.66)
- Dividends provided for or paid		
- As declared	US$	0.636
- As declared, adjusted for the bonus issue	US$	0.308

	As at May 31, 1999
	(US$ millions)
Total assets	21,271
Total non-current portion of interest bearing liabilities	6,471
Equity attributable to members	6,509

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BHP Billiton Plc Group

The selected consolidated financial information for the BHP Billiton Plc Group for the period July 1, 2000 to June 28, 2001 and the two years ended June 30, 2000 set forth below has been derived from the audited consolidated financial statements for the BHP Billiton Plc Group included in this annual report and should be read in conjunction with, and is qualified in its entirety by reference to, those financial statements, including the accompanying notes.

Consolidated Profit and Loss Account	Period ended June 28, 2001	Year ended June 30, 2000	1999
		(US$ millions)	
Amounts in Accordance with UK GAAP			
Group turnover	7,333	5,550	5,174
Net profit before minority interest			
- excluding exceptional items	706	607	430
- including exceptional items	587	607	430
Net profit attributable to members of BHP Billiton Plc			
- excluding exceptional items	693	566	382
- including exceptional items	608	566	382
Dividends provided for or paid	278	232	218
Number of Ordinary Shares (millions)			
- at period end	2,319	2,138	2,138
- weighted average	2,255	2,076	2,108
- weighted average diluted	2,269	2,076	2,108
Per Ordinary Share[(a)]:			
Net profit attributable to members of BHP Billiton Plc			
Excluding exceptionals[(b)]			
Basic	US$ 0.31	US$ 0.27	US$ 0.18
Diluted	US$ 0.31	US$ 0.27	US$ 0.18
Including exceptionals			
Basic	US$ 0.27	US$ 0.27	US$ 0.18
Diluted	US$ 0.27	US$ 0.27	US$ 0.18
Dividends provided for or paid			
US$ per share as declared	US$ 0.120	US$ 0.113	US$ 0.105
Amounts in Accordance with US GAAP			
Sales revenue	7,333	5,550	5,174
Profit from ordinary activities before taxation and borrowing	988	927	675
Net income, attributable to members of BHP Billiton Plc	482	528	341
Per Ordinary Share:			
Net income, attributable to members			
Basic	US$ 0.21	$ 0.25	$ 0.16
Diluted	US$ 0.21	$ 0.25	$ 0.16
Dividends provided for or paid			
US$ per share as declared	US$ 0.120	US$ 0.113	US$ 0.105

(a) Based upon the weighted average number of shares on issue.

(b) While the presentation of earnings per share excluding exceptional items is acceptable under UK GAAP, this presentation is not permitted under US GAAP. Profit and earnings per share before exceptional items are not measures of financial performance under US GAAP and should not be considered an alternative to, or more meaningful than income from operations, net income or cash flows as defined by US GAAP as a measurement of the BHP Billiton Group s profitability or liquidity. All registrants do not calculate profit and earnings per share before exceptional items in the same manner, and accordingly, profit and earnings per share before exceptional items may not be comparable with other registrants. Refer to note 2 of the BHP Billiton Plc Group s financial statements for details of exceptional items that have been excluded.

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Currency of presentation

The BHP Billiton Group publishes its consolidated financial statements in US dollars. The financial statements of the BHP Billiton Plc Group included in this annual report are published in US dollars.

B. Capitalisation and Indebtedness

Not applicable.

C. Reasons for the Offer and Use of Proceeds

Not applicable.

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D. Risk Factors

We believe that, because of the international scope of our operations and the industries in which we are engaged, numerous factors have an effect on our results and operations. The following describes the material risks that could affect us.

Fluctuations in commodity prices may negatively impact the BHP Billiton Group s results

The prices we obtain for our oil, gas, minerals and other commodities are determined by, or linked to, prices in world markets, which have historically been subject to substantial variations because of fluctuations in supply and demand. We expect that volatility in prices for most of our commodities will continue for the foreseeable future. This volatility creates the risk that our operating results will be materially and adversely affected by unforeseen declines in the prevailing prices of our products.

Our profits may be negatively affected by currency exchange rate fluctuations

Our assets, earnings and cash flows are influenced by a wide variety of currencies due to the geographic diversity of the countries in which we operate. Fluctuations in the exchange rate of those currencies may have a significant impact on our financial results. The US dollar is the currency in which the majority of our sales are denominated. Operating costs are influenced by the currencies of those countries where our mines and processing plants are located and also by those currencies in which the costs of imported equipment and services are determined. The Australian dollar, South African rand and US dollar are the most important currencies influencing our operating costs. Given the dominant role of the US currency in our affairs, the US dollar is the currency in which the BHP Billiton Group measures its financial performance. It is also the natural currency for borrowing and for holding surplus cash. An exception to this is our borrowings denominated in South African rand, which at June 30, 2003 was approximately 9% of our total debt on a UK GAAP basis. This view-based strategy is based on the historical depreciation of the South African rand against the US dollar and the interest rate differential between the two currencies. We do not generally believe that active currency hedging provides long-term benefits to our shareholders. We may consider currency protection measures appropriate in specific commercial circumstances, subject to strict limits established by our Boards. Therefore, in any particular year, currency fluctuations may have a significant impact on our financial results.

Our losses due to legacy foreign currency hedging amounted to US$86 million, US$305 million and US$381 million in the years ended June 30, 2003, 2002 and 2001, respectively.

Failure to discover new reserves or enhance existing reserves could negatively affect the BHP Billiton Group s results and financial condition

Because a substantial portion of our revenues and profits are related to our oil and gas and minerals operations, our results and financial conditions are directly related to the success of our exploration efforts and our ability to replace existing reserves. A failure in our ability to discover new reserves or enhance existing reserves in sufficient quantities to maintain or grow the current level of our reserves could negatively affect our results and financial conditions.

We may have fewer mineral, oil or gas reserves than our estimates indicate

Our reserves estimations may change substantially if new information subsequently becomes available. Fluctuations in the price of commodities, variation in production costs or different recovery rates may ultimately result in our estimated reserves being revised. If such a revision were to indicate a substantial reduction in proven or probable reserves at one or more of our major projects, it could negatively affect our results, financial condition and prospects.

Compliance with health, safety and environment regulations may impose burdensome costs

The nature of the industries in which we operate means that our activities are highly regulated by health, safety and environmental laws. As regulatory standards and expectations are constantly developing, we may be exposed to increased litigation, compliance costs and unforeseen environmental remediation expenses. The December 1997 Kyoto Protocol established a set of emission targets for developed countries that have ratified the Protocol. It is uncertain at this stage how the Kyoto Protocol will affect our operations and our customers. There is a risk that the Kyoto Protocol may negatively impact our operations and our financial results. We may also be exposed to increased operational costs due to the costs and lost worker s time associated with the HIV/AIDS infection rate of our Southern African workforce. These compliance costs, litigation expenses, remediation expenses and operational costs could negatively affect our financial results.

Land tenure disputes may negatively impact the BHP Billiton Group s operations

We operate in several countries where ownership of land is uncertain, and where disputes may arise in relation to ownership. These disputes cannot always be predicted, and hence there is a risk that this may cause disruption to some of our mining projects and prevent our development of new projects.

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In Australia, the *Native Title Act (1993)* provides for the establishment and recognition of native title under certain circumstances. Like land ownership disputes, native title could materially and adversely affect our new or existing projects.

In South Africa, the Extension of Security of Tenure Act (1997) prevents evictions from taking place in the absence of a court order. Occupiers who reside on the owner s land, with the requisite consent of the owner, have rights to remain in occupation unless they breach their statutory obligations as occupiers. A process exists for long-term occupiers to enjoy life long tenure. However, the legislation provides for the option of provision of suitable alternative land for occupation. Furthermore, the Restitution of Land Rights Act (1994) permits dispossessed communities to reclaim land but only where such dispossession occurred after 1913 and as a consequence of a discriminatory practice or law. Both these Acts could materially and adversely affect new or existing projects of the BHP Billiton Group.

Actions by governments in the countries in which we operate could have a negative impact on our operations and results

Our operations could be adversely affected by government actions such as controls on imports, exports and prices, new forms of taxation, and increased government regulation in the countries in which we operate or service customers. We also could be adversely affected by regulatory inquiries into our business practices, such as the ongoing investigation of the copper concentrate market by the European Commission and the US and Canadian authorities.

Additional risks associated with emerging markets may negatively impact some of the BHP Billiton Group s operations

We operate in emerging markets which may involve additional risks that could have an adverse impact upon the profitability of an operation. These risks could include civil unrest, nationalisation, re-negotiation or nullification of existing contracts, leases, permits or other agreements, and changes in laws and policy as well as other unforeseeable risks. If one or more of these risks occurs at one of our major projects, it could have a negative effect on our operating results or financial condition.

We may not be able to integrate successfully our acquired businesses

We have grown our business in part through acquisitions and expect that some of our future growth will stem from acquisitions. There are numerous risks encountered in business combinations and we may not be able to successfully integrate acquired businesses or generate the cost savings and synergies anticipated, which could negatively affect our financial condition and results of operations.

We may not recover our investments in exploration and new mining and oil and gas projects

There is a risk that we will not be able to recoup the funds we spend identifying new mining and oil and gas properties through our exploration program. Increasing requirements relating to regulatory, environmental and social approvals can potentially result in significant delays in construction and may adversely impact upon the economics of new mining and oil and gas properties, the expansion of existing operations and our results of operations.

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INFORMATION ON THE COMPANY

ITEM 4. INFORMATION ON THE COMPANY

A. History and Development of BHP Billiton

Background

We are one of the world s largest diversified resources groups with a combined market capitalisation of approximately US$35 billion as of June 30, 2003 and combined revenues of US$17.5 billion for the year ended June 30, 2003. We hold industry leader or near-leader positions in a range of products, including:

- world s largest exporter of metallurgical coal for the steel industry;
- world s second largest exporter of energy coal;
- world s third largest producer of iron ore;
- world s fourth largest producer of copper;
- Western world s fourth largest producer of primary aluminium; and
- world s largest producer of manganese and chrome ferroalloys.

We also have substantial interests in oil, gas, liquefied natural gas, nickel, diamonds, silver and titanium minerals.

BHP Billiton Limited is incorporated under the name BHP Billiton Limited and is registered in Australia with ABN number 49 004 028 077. BHP Billiton Limited was incorporated on August 13, 1885 under the name of The Broken Hill Proprietary Company Limited.

BHP Billiton Plc is incorporated under the name BHP Billiton Plc and is registered in the United Kingdom with Company number 3196209. BHP Billiton Plc was incorporated on May 9, 1996.

On March 19, 2001, we announced that the Directors of BHP Limited and Billiton Plc had agreed to form a Dual Listed Companies structure to establish a diversified global resource group to be called BHP Billiton. The implementation of the DLC structure was completed on June 29, 2001. BHP Limited changed its name to BHP Billiton Limited and Billiton Plc changed its name to BHP Billiton Plc.

BHP Billiton Limited and BHP Billiton Plc are run by a unified Board and management team, with headquarters in Melbourne, Australia, and with a significant corporate management centre in London. The existing primary listings on the London and Australian stock exchanges continue to be maintained, as is the secondary listing of BHP Billiton Plc on the Johannesburg and Paris stock exchanges. On June 25, 2003 BHP Billiton Plc listed its sponsored American Depositary Receipts security on the New York Stock Exchange and BHP Billiton now maintains an American Depositary Receipt listing of both BHP Billiton Limited and BHP Billiton Plc on the New York Stock Exchange.

The shareholders of BHP Billiton Limited and BHP Billiton Plc take key decisions on matters affecting the combined group through a procedure in which the shareholders of both companies have equal voting rights per share. Accordingly, shareholders of BHP Billiton Limited and BHP Billiton Plc effectively have an interest in a single group combining all of the assets of both companies with a unified Board of Directors and management. Should any future corporate action benefit shareholders in only one of the two companies, an appropriate action will be taken to ensure parity between BHP Billiton Limited and BHP Billiton Plc shares.

Further information on the DLC structure is included in Item 4C of this annual report.

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We have grouped our major operating assets into the following Customer Sector Groups:

- Petroleum (oil, gas and liquefied natural gas);
- Aluminium (aluminium and alumina);
- Base Metals (copper, silver, zinc and lead);
- Carbon Steel Materials (metallurgical coal, iron ore and manganese);
- Diamonds and Specialty Products (diamonds, titanium minerals and metals distribution);
- Energy Coal (energy coal); and
- Stainless Steel Materials (nickel metal, and chrome and nickel ferroalloys).

The table below sets forth the contribution to combined turnover and profit (before tax) of each of these customer sector groups for the three years ended June 30, 2003.

	Turnover		
	Year ended June 30		
	2003	2002	2001
	(US$ millions)		
Group including share of joint ventures and associates			
Petroleum	3,264	2,815	3,361
Aluminium	3,386	2,857	2,971
Base Metals	1,954	1,821	1,719
Carbon Steel Materials	3,714	3,306	3,349
Diamonds and Specialty Products	1,485	1,480	1,318
Energy Coal	2,089	1,919	1,982
Stainless Steel Materials	1,106	868	994
Steel (discontinued operations)(1)		2,550	3,220
Group and unallocated items(1)	1,014	730	749
Intersegment	(506)	(568)	(584)
Total	17,506	17,778	19,079

Profit before tax

	Year ended June 30,		
	2003	2002	2001
	(US$ millions)		
Group including share of joint ventures and associates			
Petroleum	1,178	1,073	1,407
Aluminium	581	492	523
Base Metals	286	192	452
Carbon Steel Materials	1,045	1,084	918
Diamonds and Specialty Products	299	272	188
Energy Coal	190	536	382
Stainless Steel Materials	150	3	72
Steel (discontinued operations)[1]		86	218
Group and unallocated items[1]	(248)	(550)	(555)
Exceptional items	(19)	(212)	(1,066)
Net interest	(537)	(249)	(476)
Total	2,925	2,727	2,063

(1) The Group s Steel business was demerged in July 2002 and is disclosed as discontinued operations. Comparatives have been stated accordingly.

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The table below sets forth the contribution to combined turnover and net profit (before tax and net interest) by geographic origin for the three years ended June 30, 2003.

	Turnover		
	Year ended June 30,		
	2003	2002	2001
	(US$ millions)		
Geographic origin			
Australia	6,527	5,842	5,854
Europe	2,792	2,049	1,907
North America	2,186	2,143	1,909
South America	2,733	2,255	2,350
Southern Africa	3,147	2,696	3,107
Rest of World	121	243	738
Discontinued operations(1)		2,550	3,214
Total	17,506	17,778	19,079

	Profit before tax and net interest		
	Year ended June 30,		
	2003	2002	2001
	(US$ millions)		
Geographic origin			
Australia	1,890	1,549	1,456
Europe	259	233	191
North America	188	22	127
South America	576	301	444
Southern Africa	558	712	498
Rest of World	10	73	(395)
Discontinued operations(1)	(19)	86	218
Total	3,462	2,976	2,539

(1) The Group s Steel business was demerged in July 2002 and is disclosed as discontinued operations. Comparatives have been stated accordingly.

The table below sets forth the analysis of combined turnover by geographic market for the three years ended June 30, 2003.

Turnover

	Year ended June 30,		
	2003	2002	2001
	(US$ millions)		
Geographic market			
Australia	1,775	1,442	1,434
Europe	5,582	4,430	4,139
Japan	2,393	2,078	2,531
South Korea	1,203	1,068	906
Other Asia	2,388	1,998	1,857
North America	2,389	2,344	2,603
Southern Africa	944	936	1,159
Rest of World	832	932	1,236
Discontinued operations[1]		2,550	3,214
Total	17,506	17,778	19,079

(1) The Group s Steel business was demerged in July 2002 and is disclosed as discontinued operations. Comparatives have been stated accordingly.

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The ore reserves tabulated are all held within existing, fully permitted mining tenements. The BHP Billiton Group s minerals leases are of sufficient duration (or convey a legal right to renew for sufficient duration) to enable all reserves on the leased properties to be mined in accordance with current production schedules. Ore reserves are presented in the accompanying tables subdivided for each of the Customer Sector Groups.

All of the ore reserve figures presented are reported in 100% terms, and represent estimates at June 30, 2003. All tonnes and grade information has been estimated more precisely than the rounded numbers that are reported, hence small differences may be present in the totals.

As the reported reserves contained in this annual report have been reported based on historical average commodity prices in accordance with Industry Guide 7, they differ in some respects from the reserves we report in our home jurisdictions of Australia and the UK. Those jurisdictions require the use of the Australasian Code for reporting of Mineral Resources and Ore Reserves, September 1999 (the JORC Code), which contemplates the use of reasonable investment assumptions in calculating reserve estimates.

Reserves are estimated based on prices reflecting current economic conditions determined by reference to the three year historical average for each commodity. The prices used to estimate the reserves contained in this annual report are as follows:

	Price
	US$
Copper	0.74/lb
Zinc	0.41/lb
Nickel	3.19/lb
Aluminium (used for Alumina)	1,426/t
Alumina (12.75% of Aluminium)	182/t
Silver	4.63/oz
Lead	0.21/lb
Gold	292/oz

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B. Business Overview

Petroleum

Our principal activities in the petroleum sector are oil and natural gas exploration, production and development in Australia, the United Kingdom, the United States, Algeria, Trinidad and Tobago, Pakistan and Bolivia and exploration interests in the United States, Australia, Trinidad and Tobago, Pakistan, Brunei Darussalam, South Africa, Brazil and Gabon.

Operating Assets

Australia/Asia

In Australia we source production from Bass Strait, the North West Shelf, the Laminaria and Corallina oil fields and the Griffin Project.

Bass Strait

The Bass Strait oil and gas fields are located in the Gippsland Basin, offshore southern Australia. First production commenced in 1968. We have a 50% interest in the Bass Strait fields, Esso Australia Resources Pty Ltd (Esso Australia) has the other 50% and acts as operator. Production from most of the fields is subject to an overriding 2.5% royalty payable to Oil Basins Limited.

Most crude oil and condensate is dispatched from the fields to refineries in the State of Victoria, while the balance is sold elsewhere in Australia or overseas. Gross oil production during 2002-2003 averaged 133,000 barrels per day.

Most of the natural gas produced is sold to Gascor for on-sale to retailers for distribution throughout Victoria to meet its residential and commercial gas requirements. The contract is due to expire on 31 December 2009 or the depletion of the outstanding contractual volumes.

In April 2001, together with Esso Australia, we signed a long-term supply agreement with Duke Energy International for the introduction of approximately 51 million cubic feet of natural gas per day to Tasmania. Deliveries commenced in late 2002. This followed a long-term gas transport agreement we and Esso Australia signed with Duke Energy International in December 1998 for the transportation of Bass Strait natural gas to New South Wales.

In 2002 we signed Memorandums of Understanding with TXU Australia and AGL Wholesale for collectively over 0.7Tcf of long-term gas sales (BHPB share) from 2004.

During 2002-2003, total gas production averaged approximately 550 million cubic feet per day (gross). LPG (liquefied petroleum gases) and ethane extracted from the natural gas are sold in Australia and overseas. During 2002 2003, LPG production averaged 2,900 tonnes per day (gross) and ethane production averaged 530 tonnes per day (gross).

In December 2002, we, together with Esso Australia, completed the construction of a fourth Bass Strait gas pipeline from the Bream field into the joint venture s Gippsland production network.

We continue to pursue a strategy of seeking additional reserves in the Bass Strait in order to enhance existing production levels with high value incremental developments. We and our joint venture partner Esso Australia, have completed processing, and are currently interpreting, the largest three-dimensional seismic survey ever completed in Bass Strait. The 3,900-square kilometre survey covered all of the joint venture s northern oil and gas fields, and was designed to identify hydrocarbon targets over a range of geological horizons.

North West Shelf

We are a participant in the North West Shelf Project, an unincorporated joint venture of six participants, operated by Woodside Energy Ltd. The project was developed in two major phases: the domestic gas phase, which supplies gas to the Western Australia domestic market; and the LNG phase, which supplies LNG (liquefied natural gas) to Japan. The project also produces crude oil, condensate and LPG, primarily for export.

The domestic gas participants are Woodside Petroleum (50%), BP Developments Australia Pty Ltd (16.67%), Chevron Texaco Australia Pty Ltd (16.67%), our wholly-owned subsidiary BHP Billiton Petroleum (North West Shelf) Pty Ltd (8.33%) and Shell Development (Australia) Pty Ltd (8.33%). When domestic gas sales exceed 500 million cubic feet per day, ownership of the incremental gas is shared equally between all domestic gas participants and Japan Australia LNG (MIMI) Pty Ltd (jointly owned by Mitsubishi Corporation and Mitsui & Co), with each participant holding a 16.67% share. Participants in the LNG phase include the domestic gas participants and Japan Australia LNG (MIMI), each with a 16.67% interest.

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The onshore gas treatment plant is located at Withnell Bay on the Burrup Peninsula, 1,200 kilometres north of Perth, Western Australia and is supplied by the offshore North Rankin, Goodwyn, Perseus and Echo-Yodel gas and condensate fields. Production from the North Rankin and Perseus fields is through the North Rankin A platform, which has the capacity to produce 1,800 million cubic feet per day of gas and 40,000 barrels per day of condensate. Production from the Goodwyn and Echo-Yodel fields is through the Goodwyn A platform, which has the capacity to produce 1,400 million cubic feet per day of gas and 110,000 barrels per day of condensate (not concurrently). Production from these fields meets current contractual requirements for the domestic gas and LNG phases of the project. Plans are in place to develop the Angel field, and a group of smaller static resources, to meet future market requirements.

The North West Shelf domestic gas plant has a capacity of six hundred million cubic feet per day. The gas is delivered via pipeline to customers in Western Australia under long-term agreements. Production of domestic gas in 2002 2003 averaged 500 million cubic feet per day (gross).

The existing three-train LNG plant produces on average 21,750 tonnes of LNG per day, or 7.5 million tonnes per annum. The project sells approximately 7 million tonnes of LNG per year under long-term contracts to Japanese buyers. These contracts are due to expire in 2009. Additional spot sales are also made to the USA and Asia, depending on plant and shipping availability. Production for 2002-2003 averaged 22,030 tonnes per day (gross); this was due to higher LNG demand in Japan and Korea coinciding with ship chartering opportunities.

Construction of a fourth liquefaction train and offshore trunkline to support an expansion of the existing LNG business commenced in calendar year 2001. The expansion involves the construction of a 4.2 million tonnes per year liquefaction processing train and a 42-inch gas trunkline to be installed over a distance of 135 kilometres from the existing production platforms to the onshore processing plant. We expect first commercial production from the new facilities during calendar year 2004. The project has also ordered an additional LNG carrier to deliver some of the sales volumes associated with the expansion project. Our share of costs of the fourth liquefaction processing train, the pipeline and the additional carrier is expected to be approximately US$274 million.

Sales arrangements underpinning the expansion are in place with six Japanese gas and power companies for the supply of up to 3.9 million tonnes per year of LNG, for contracted periods of between 20 years and 30 years.

In October 2002, the North West Shelf joint venture participants signed Sales and Purchase agreements with the Guangdong LNG Project, for the purchase and supply of LNG from the North West Shelf. This is China s first LNG project and involves the construction of an LNG import terminal and high-pressure gas pipeline in two phases. The agreements were signed by the six North West Shelf LNG Sellers and cover the supply of approximately 3.3 million tonnes of LNG per year to Phase One of the Guangdong LNG Project for a period of 25 years expected to start in 2006. The agreements are subject to certain conditions precedent, including Chinese Government approvals, buyer financing arrangements and arrangements between the LNG buyer and natural gas end-buyers.

Following execution of the Guangdong LNG sales and purchase agreements, further agreements were signed in May 2003 with a subsidiary company of the China National Offshore Oil Corporation (CNOOC) in regard to equity participation by CNOOC in the North West Shelf Project. Under these agreements CNOOC will pay each of the NWS Venture participants approximately US$58 million to take up a 5.3% interest in titles to NWS Project raw gas reserves. CNOOC will also have a 25% interest in a new joint venture (BHPB share 12.5%) to be set up within NWS to supply LNG to Guangdong and will have rights to process its gas and associated products through NWS offshore and onshore infrastructure on payment of a tariff. Completion of this transaction is subject to regulatory and other approvals as well as satisfaction of a number of conditions precedent. The NWS Project and various Chinese shipping companies are currently finalising arrangements for the establishment of ship owning and ship management companies for LNG transport to China. Two or three LNG ships will be required to service the China trade route.

During 2002-2003, we also concluded the following LNG sales contracts with new customers in Japan and Korea:

- In January 2003, we executed a binding sales and purchase agreement with Shizuoka Gas for a total of 3 million tonnes of LNG to be delivered over the full term of a 24 year agreement commencing in 2005; and

- In March 2003, we executed a sales and purchase agreement with Korea Gas Corporation for the sale of approximately 480,000 tonnnes of LNG per year for a term of 7 years commencing in late 2003.

- In September 2003 we signed a heads of agreement with The Kansai Electric Power Company Inc., an existing Japanese customer, for long-term LNG supply of 500,000 tonnes of LNG a year between 2009 and 2014 and 925,000 tonnes of LNG a year between 2015 and 2023.

Condensate is separated from the natural gas in the onhore plant. Condensate production during 2002-2003 averaged 115,000 barrels per day (gross).

LPG production began in November 1995 and production in 2002 2003 was 2,200 tonnes per day (gross). We have a 16.67% interest in the LPG production.

The project s crude oil production is from the Wanaea, Cossack, Lambert and Hermes oil fields which are located about 30 kilometres north east of the North Rankin field. The oil is produced to a floating production storage and offloading unit, the Cossack Pioneer and production averaged 112,000 barrels of oil per day (gross) in 2002 2003. We have a 16.67% working interest in oil production.

Laminaria and Corallina

We are a participant in the Laminaria and Corallina joint venture with Woodside Energy Ltd and Shell Development (Australia) Pty Ltd. Woodside Energy Ltd is the operator of the venture. The Laminaria and Corallina fields are located in the Timor Sea, about 550 kilometres north-west of Darwin and 160 kilometres south of Timor in production licenses AC/L5 and WA-18-L. The Laminaria field was discovered in 1994 and the Corallina field in 1995. We have a 32.6125% working interest in the Laminaria oil field, with Woodside holding a 44.925% interest and Shell holding a 22.4625% interest. We have a 25% interest in the Corallina oil field, Woodside has a 50% interest and Shell has a 25% interest.

A floating production storage and offloading unit, the Northern Endeavour, produces the oil from these fields.

In 2002 2003, production from the Northern Endeavour averaged 71,000 barrels of oil per day (gross) and is expected to decline sharply in future years.

Carnarvon Basin

We are the operator of the Griffin oil and gas project, which includes the Griffin, Chinook and Scindian fields in the Carnarvon Basin, offshore Western Australia. We hold a 45% interest in the project, Mobil Exploration and Producing Australia Pty Ltd holds a 35% interest and Inpex Alpha Ltd holds the remaining 20% interest.

The Griffin project first produced oil through its floating production storage and offloading facility, the Griffin Venture, in January 1994. Production for 2002-2003 averaged 24,000 barrels per day of oil (gross).

We pipe natural gas to shore, where it is exported directly into a pipeline and sold under long-term contracts. Gas production in 2002-2003 averaged 22 million standard cubic feet per day (gross).

Pakistan

We are the operator of the Zamzama onshore gas project in the Dadu Block in the Sindh Province of Pakistan. We hold a 38.5% working interest in the project, ENI Pakistan (M) Ltd holds 17.75%, PKP Exploration Ltd (a jointly owned company between Kufpec and Premier Oil) holds 18.75% and the government of Pakistan holds the remaining 25% interest.

In 1998, we discovered gas in the Zamzama-1 well under the Dadu exploration permit. After a single well appraisal program identified commercial reserves we commenced production in March 2001 from Zamzama 1 and 2 wells through an extended well test (EWT) phase. For 2002-2003 production averaged 85 million cubic feet per day of gas (gross) and 500 barrels per day of condensate (gross).

In March 2002, we and our partners approved the Phase 1 development of the Zamzama gas field. This followed the Dadu joint venture signing the two gas sales and purchase agreements with the government of Pakistan, Sui Southern Gas Company and Sui Northern Gas Pipelines Company Limited. The agreements cover the supply of up to 320 million cubic feet per day of gas over the expected field life of 20 years. In April 2002, the government of Pakistan granted the Dadu joint venture a 20-year development and production license for the full field development of the Zamzama discovery.

The Phase 1 development consists of two additional processing trains, which are located on the existing EWT plant site, and a minimum of three additional development wells. First gas from the Phase 1 development commenced in July 2003 and our share of capital expenditure for this phase was less than the original budgeted amount of US$40 million.

Americas

Gulf of Mexico

Our Gulf of Mexico production is sourced from six producing assets: Typhoon, Boris, West Cameron 76, Green Canyon 18/Ewing Bank 988, Green Canyon 60 and Genesis.

We have a 50% working interest in the Typhoon oil and gas development, located in Green Canyon Blocks 236 and 237. Chevron Texaco has the other 50% working interest and is the operator. The field is located in 600 metres of water approximately 100

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kilometres off the coast of Louisiana, and was our first deepwater Gulf of Mexico development. The field consists of four subsea wells tied back to a local host mini tension leg platform. First production was in July 2001; peak production of approximately 38,600 barrels of oil and 50 million cubic feet of gas per day was reached in April 2002.

We also have a 50% working interest in and operate the Boris oil discovery in Green Canyon Block 282 adjacent to the Typhoon field. Boris was developed as a tie-back to the Typhoon production facility. Production commenced from the first well, Boris-1, in February 2003 and from the second well, Boris-2, in September 2003.

In 2002-2003, production from Typhoon and Boris fields through the Typhoon facility averaged 23,000 barrels per day of oil and 34 million cubic feet of gas (gross).

We also have a 33.8-78.8% working interest in and act as the operator of the West Cameron 76 gas field, a 25% working interest in the Green Canyon 18/Ewing Bank 988 oil field (operated by ExxonMobil) and a 45% working interest in the Green Canyon 60 field (also operated by ExxonMobil). Additionally, in September 2000, we purchased a 4.95% working interest in the Chevron Texaco operated Genesis oil field in Green Canyon blocks 160, 161 and 205. In total, our net share of production from these four properties during 2002-2003 was 3,600 barrels of oil and 32 million cubic feet of gas per day.

Bolivia

In July 1994, we acquired a 50% working interest in the Mamore exploration block in Bolivia, including the Surubi oil field, from Maxus Bolivia Inc, whose ultimate parent is Repsol of Spain. Production from the Surubi oil field began in 1993. The Paloma field was discovered in 1995, and the Bloque Bajo field was discovered in 1996. Gas sales from the block commenced in the second half of calendar year 1999. Gross production from these fields was 8,800 barrels per day of oil and 15 million cubic feet per day of gas in 2002 2003.

Europe/Africa/Middle East

Our petroleum production activities in the United Kingdom are based in the Irish Sea and the North Sea. The Liverpool Bay Development in the Irish Sea is our largest operated asset. We also have an interest in the Bruce oil and gas field and an interest in the Keith oil field, both in the North Sea.

Liverpool Bay

We are the operator of the Liverpool Bay oil and gas development, located off the North West coast of England, in which we have a 46.1% working interest. Other participants in the joint venture are Eni ULX Limited, which has a 45% interest, and Eni UK Limited, which has an 8.9% interest. The venture began first production of oil and gas in 1996. Oil production is from the Douglas and Lennox fields. Contracted long-term gas sales to Powergen are from the Hamilton, Hamilton North and Hamilton East gas fields.

The venture completed its third infill drilling campaign in 2003 with the completion of three oil development wells, one of which developed the Douglas West field.

Production during 2002 2003 averaged 52,000 barrels per day of oil and 230 million cubic feet per day of gas (gross).

Bruce / Keith

The Bruce field is located approximately 380 kilometres north-east of Aberdeen in the northern North Sea. We have a 16% interest in the field, which is operated by BP. The integrated oil, gas and LPG development concept for the field has been developed in three phases. During 2002-2003, our gas sales contracts with Centrica and Corby were cancelled and other sales arrangements established. This allowed reserves to be produced without restriction to gas demand and contractual constraints.

Gross production from the Bruce field during 2002 2003 averaged 28,000 barrels per day of oil, 570 million cubic feet per day of gas and 1,600 tonnes per day of LPG.

We also have a 31.83% interest in the Keith field, lying adjacent to the Bruce field in block 9/8a. The Keith field was developed by a tieback to the Bruce platform facilities. In 2002-2003, production from Keith averaged 2,700 barrels per day of oil and 4 million cubic feet per day of gas (gross).

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Exploration and Development

Australia/Asia

Minerva Development

We have a 90% working interest in and act as the operator of the Minerva development that is currently being constructed in southern Victoria.

In 1993, we discovered the Minerva gas field in the Otway Basin and in March 2002 signed a take or pay Sales Agreement with Pelican Point Power Limited (a wholly owned subsidiary of International Power plc) to provide gas into South Australia via a new pipeline. We approved the development of the Minerva field in May 2002. Our share of approved capital expenditure is US$123 million, however, total expected capital expenditure is under review.

Minerva is a natural gas field with a small amount of condensate. A single flowline will transport the gas to the coast, through a subterranean shore crossing to an onshore gas processing facility where liquids will be removed prior to exporting the gas to South Australia. The gas plant, when completed, will have a gross design capacity of 139 million cubic feet of gas per day and 600 barrels of condensate per day.

Coal Bed Methane Development

Our Petroleum and Energy Coal Customer Sector Group s have a combined 50% interest in the Moranbah Gas Project which is operated by CH4 Pty Ltd. CH4 is an unlisted company, majority owned and controlled by Macquarie Bank Limited. The project, which is situated in within the Queensland Bowen Basin coalfields, will utilise resources in Petroleum Lease (PL) 191 and Petroleum Lease Application (PLA) 196. The project comprises the extraction of coal bed methane from surface-to-seam wells using drilling techniques developed by us and CH4.

We and CH4 have signed a Gas Supply Agreement with the Queensland Power Trading Corporation, owned by the Queensland Government, for delivery of up to a maximum of 290 billion cubic feet (gross) over 15 years, with a take-or-pay quantity of 8 billion cubic feet per annum (gross) for the first 10 years.

Under the May 2000 Project Agreement with CH4, we will receive a revenue royalty on any gas sales plus an option to invest up to 50% in any project developed by CH4. This option has been exercised for the Moranbah Gas Project. Our share of the capital cost of this project is expected to be approximately US$38 million.

Australian Exploration

We are the operator of WA-255-P, holding a 50% working interest, which is located in the prospective Southern Exmouth Basin. We acquired over 1,000 square kilometres of 3-D seismic data in 2001 covering a portion of the WA-255-P permit and have drilled four exploration wells during the first half of calendar year 2003. One of the wells, Stybarrow-1, encountered a 23 metre gross oil column. Stybarrow-2, targetting the same geological feature, encountered a 22 metre gross oil column. Another well, Skiddaw-1, confirmed that the northerly extension of the Laverda field extends a small way into WA-255-P. Evaluation of these encouraging results and other exploration prospects is ongoing.

In 1999, Woodside discovered the Vincent oil field in its 100% held WA-271-P permit. Almost half of this field is now recognised to extend into WA-155-P Part 1, a permit that we operate and in which we have a 39.999% interest. In July 2003, we drilled the Ravensworth-1 exploration well, which targeted another geological feature and encountered a 37 metre gross oil column.

The Coniston-1 discovery , located in block WA-255-P and recognised as extending into WA-155-P Part 1, is currently considered sub-commercial, although this could be revised following successful development of other nearby discoveries such as Vincent.

We also have a 16.67% non-operated interest in the WA-10-R permit offshore Western Australia. In May 2003 the Egret-3 well was completed in this permit and encountered a 29 metre gross oil column and a small gas cap. Egret-2 was drilled in 1988 and encountered a 43 metre oil column in the north of the field. Based upon the results from Egret-2 and 3, the prospect is deemed commercial for further appraisal. An appraisal program is being planned by us and our partners.

We are the operator, holding a 50% interest, in WA-301-P, WA-303-P, WA-304-P and WA-305-P. These permits are located in the Outer Browse basin, a deep water, frontier exploration area. In April 2003 Maginnis-1 was drilled in WA-302-P. In May 2003 we acquired a 510-square kilometer 3D seismic survey on the border of WA-303-P and Wa-304-P. Evaluation of the well and seismic results is ongoing.

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Brunei Exploration

On January 29, 2002 the government of Brunei Darussalam awarded Block J to a joint venture of us (25% working interest), Total (60% working interest) and Amerada Hess Corporation (15% working interest). The award was subject to negotiating a production sharing contract. This was executed in March 2003. The Government of Malaysia have claimed that this block forms part of their territorial waters and has awarded the same acreage to a competing joint venture. The dispute is unresolved.

Americas

Gulf of Mexico

We expanded our presence in the deepwater Gulf of Mexico in the early 1990 s, with the majority of our current deepwater and ultra-deepwater leaseholds acquired at government sales in 1995 and 1996. At June 30, 2003, our deepwater portfolio consisted of 295 leases, making us one of the largest lease-holders in water depths greater than 1,500 feet. Additionally, we acquired 33 leases on the shelf in the Gulf of Mexico in 2003, with water depths ranging from 75 to 125 feet, as we initiated a deep gas exploration strategy. Our shelf inventory consists of 43 leases as of June 30, 2003.

As part of our strategy to efficiently allocate exploration expenditure and to increase our prospect inventory, we have entered into several joint venture arrangements with companies active in the deepwater of the Gulf of Mexico.

Mad Dog Development

The initial Mad Dog discovery well, in the Green Canyon area of the Atwater Foldbelt, was drilled in December 1998 followed by the drilling of three appraisal wells between 1999 and 2001. In February 2002, we and our partners sanctioned Mad Dog for development. Our share of capital expenditure up to US$335 million has been approved. The final expenditure will depend on the number of development wells needed to optimise the production of reserves.

The development plan includes the utilisation of a truss SPAR facility with an integrated drilling rig, which will be capable of operating in water depths of 4,500 feet. First production is expected by the end of calendar year 2004, with production at full design capacity expected to occur within 12 months. Nameplate capacity will be 80,000 barrels of oil per day and 40 million cubic feet of gas per day (gross).

We hold a 23.9% working interest in Mad Dog with partners BP (60.5%), the designated operator, and Unocal (15.6%).

Atlantis Development

The initial Atlantis discovery in the Green Canyon area was drilled in 1998. During calendar years 2000 and 2001 we drilled two more wells, each with major sidetracks, on the Atlantis structure. Both wells encountered significant oil bearing sands.

In February 2003 we approved a total of US$1.1 billion as full funding for the development of the Atlantis oil and gas reserves. First oil is expected from the field in the third quarter of calendar year 2006.

Located in 4,400-7,100 feet of water, Atlantis will be developed using a moored semi-submersible production facility with up to 20 subsea wells. Nameplate capacity will be 150,000 barrels of oil per day and 180 million cubic feet of gas per day (gross).

We have a 44% working interest in Atlantis. BP is the operator of the field and holds the remaining 56% interest.

Transportation Development

In February 2002, we took equity ownership in two limited liability companies that will transport hydrocarbons from Mad Dog, Atlantis and future discoveries in the proximity. The pipelines are part of a new system being built in the Southern Green Canyon area.

We acquired a 25% interest in the Caesar oil pipeline and a 22% interest in the Cleopatra gas pipeline. Our share of capital costs approved by the Board for this project is US$132 million.

The Caesar pipeline will have a design capacity of at least 450,000 barrels of oil per day and Cleopatra will have a capacity of 500 million cubic feet of gas per day. These pipelines will link with other pipelines already existing, or to be constructed, to transport product to the United States mainland.

Cascade Walker Ridge Exploration

As the operator, in June 2002, we drilled and completed an exploration well on the Cascade prospect and encountered an encouraging hydrocarbon column. The well was drilled in waters approximately 8,200 feet deep to a total depth of 27,979 feet.

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Further drilling will be necessary to determine the size of the find. We expect to drill a second Cascade well in the first half of calendar year 2004. We own a 50% working interest in Cascade, with Petrobras and Devon Energy Corporation each holding a 25% interest.

Shenzi Green Canyon Exploration

As the operator, we drilled and completed an exploration well on the Shenzi prospect in December 2002. The well was drilled in 4,400 feet of water and encountered a gross hydrocarbon column of 465 feet with 140 feet of net pay. We are planning to drill a Shenzi-2 appraisal well in late calendar year 2003 to further evaluate the size of the field.

We own a 44% working interest in Shenzi, with Amerada Hess and BP each owning a 28% working interest.

Chinook Walker Ridge Exploration

As the operator, we drilled and made an oil discovery with our second exploration well on the Chinook prospect in the ultra-deepwater Gulf of Mexico in June 2003. The well was drilled in water depths of approximately 8,830 feet and encountered a gross hydrocarbon column of 620 feet with 260 feet of net pay. Further evaluation will be necessary and more appraisal will be required before we can be definitive about the scale of the resource.

We own a 40% working interest in Chinook, with Petrobras America owning a 30% interest with Amerada Hess and Total each owning a 15% interest.

Neptune Exploration

In 1995, we farmed into the Neptune prospect, which was previously operated by BP, and drilled the discovery well, Neptune-1. A subsequent appraisal well, Neptune-2, was drilled in 1998 and abandoned after recovering hydrocarbon samples.

Subsequent to acquiring BP s interest with partners Woodside and Marathon, we, as operator, drilled and completed the Neptune-3 appraisal well and encountered an encouraging hydrocarbon column. The fourth appraisal well on the prospect was drilled in December 2002 which was non-commercial and has been temporarily plugged and abandoned.

We recently successfully negotiated a promoted arrangement to farmout a portion of our interest in the Neptune prospect to Maxus (US) Exploration Company, whose ultimate parent is Repsol of Spain. As a result of this arrangement, our working interest has decreased from 50% to 35%. Other partners working interests are Marathon Oil Company (30%), Woodside Petroleum Ltd (20%) and Maxus (15%).

Continuing as the operator, in July 2003 we drilled the Neptune-5 well and encountered a gross hydrocarbon column of nearly 1,200 feet, with more than 500 total vertical feet of net oil pay, and further appraisal and development planning activities are continuing on the Neptune prospect.

Other Significant Gulf of Mexico Exploration Joint Venture Agreements

Other significant agreements in the Gulf of Mexico include:

Vortex Prospect (Atwater Valley) We participated in a gas discovery on the Vortex Prospect in 8,344 feet of water in the Atwater Valley area during 2002-2003. The well was drilled to a total depth of 21,140 feet and sidetracked to a depth of 19,330 feet. We operate this prospect with a 33.34% working interest. Our partners are Kerr-McGee and Devon who each own a 33.33% working interest. We and our partners are assessing development options of this discovery.

Deep Gas Exploration (West Cameron, East Cameron, Vermillion Areas) In 2002-2003, we entered into a joint venture agreement with Newfield, to explore deep gas on the shelf of the Gulf of Mexico. We own a 55% working interest in these jointly owned leases and act as operator. Newfield owns the remaining 45% working interest. We are acquiring additional seismic data and will be maturing these leads in the near term while monitoring planned industry drilling activity in this trend.

Trinidad and Tobago

Angostura Development

We began exploring in Trinidad and Tobago in Block 2(c) in April 1996, signing the country s first Production Sharing Contract (PSC) under a new fiscal regime. During the six-year exploration phase of the PSC, we drilled four exploration and three appraisal wells, discovering significant oil and gas resources within a large faulted structure known as the Greater Angostura Structure

In March 2003, we committed to the development of the first phase of the Angostura integrated oil and gas development located in Block 2 (c), approximately 24 miles (38.5 km) east of the island of Trinidad. In the first phase of the development, oil will be produced from three wellhead protector platforms via flowlines to a steel jacket central production platform. Associated gas will be

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reinjected. Water depths are approximately 40 metres and the development utilises proven shallow-water technology. First oil production is scheduled for December 2004. Gas commercialisation (Phase 2) will commence approximately four to nine years after first oil, depending on reservoir performance.

Capital expenditure for the first phase of the Angostura integrated development is expected to be around US$726 million (gross), US$327 million net to BHP Billiton.

We are the operator of the Greater Angostura development and own a 45% working interest. Other participants are Total (30% working interest); and Talisman Energy (25% working interest).

Trinidad and Tobago Exploration

In April 2002, we were awarded the Angostura development area of approximately 100 square kilometres and exploration retention rights for the remaining 160 square kilometre area in south Block 2(c). We have a 64.28% working interest with Talisman Energy holding the remaining 35.72% interest in the exploration retention area. The second of the two commitment wells in this area is being drilled.

In October 2001, Trinidad and Tobago s Ministry of Energy and Energy Industries announced the award of exploration Block 3(a) to a consortium of BHP Billiton (30% working interest and operator), Talisman Energy (30% working interest), BG International (30% working interest), and Total (10% working interest). The PSC was signed on April 22, 2002. Block 3(a) is located 40 km off the east coast of Trinidad in water depths ranging from 30 to 91 metres and comprises 612 square kilometres adjacent to east of Block 2(c). The Joint Venture commenced the minimum work program with the acquisition of the Emerald 3D seismic survey in 2002- 2003. The survey will be completed in late calendar year 2003. Under the PSC, six wells must be drilled in the first three-year phase of the PSC s exploration period.

Brazil Exploration

In June 2002, we were successful in bidding for block BM-C-24 that covers 603 square kilometres offshore Brazil . We have a 100% interest in the block. The concession contract was signed in September 2002.

Europe/Africa/Middle East

Algeria

ROD Integrated Development

In Algeria, we hold a 45% working interest in Blocks 401a and 402a under a production sharing contract with the Algerian state oil company SONATRACH. Under the terms of the contract the Algerian government has contracted the development and extraction of the resources whilst retaining title to these resources. The blocks are located 900 kilometres southeast of Algiers, near the Tunisian border.

An integrated plan to develop the ROD, SFNE, BSF, RDB and RERN oil fields (and a subsequent exploration discovery RAR) partly located in Blocks 401a and 402a has been sanctioned by the Algerian government. The largest two of the fields, ROD and SFNE, extends into the neighbouring Block 403 operated by AGIP and SONATRACH. An agreement has been put in place to govern unitisation of the ROD and SFNE fields, the sharing of specified costs, operatorship and commercial arrangements for the development This agreement leaves us with a 38.75% share of costs in the unit. We have subsequently agreed with AGIP to amend this unitisation agreement with the result that, formally, we shall have a 36.04% share of costs when such an amendment is officially sanctioned by the Algerian authorities. We, together with AGIP, have implemented this revised cost sharing arrangement under the understanding that formal sanction will follow.

The fields are being developed through a new dedicated processing train, which will be built at the existing BRN production facility on Block 403 operated by AGIP and SONATRACH. From there, the venture will export oil through the established pipeline infrastructure to terminals located on the Algerian coast. The associated gas will be re-injected underground. We estimate that our share of the US$500 million development costs will be approximately US$190 million.

We and SONATRACH are the members of the joint operating entity which is undertaking the development. Operations will be conducted by the existing BRN joint operating entity comprising SONATRACH and AGIP. First production from the fields is expected in the first half of calendar year 2004, with an estimated gross peak production rate of 80,000 barrels of oil per day

Ohanet Development

We signed a Risk Service Contract (RSC) with SONATRACH for the development of four gas and condensate reservoirs in the Ohanet region of Algeria on July 2, 2000. Ohanet is located in the Illizi province of Algeria, approximately 1,300 kilometres

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southeast of Algiers and 100 kilometres west of Libya. The Algerian government formally approved the RSC on November 12, 2000. Production is scheduled to begin in late calendar year 2003 and we expect that peak liquids production will be approximately 58,000 barrels per day (gross).

We have an effective 45% working interest in the venture. The other participants are Japan Ohanet Oil & Gas Co Ltd (30%), Woodside Energy (Algeria) Pty Ltd (15%) and Petrofac Resources (Ohanet) LLC (10%). We estimate that the total cost of developing the Ohanet reservoirs will be approximately US$1 billion and that our share of this cost will be US$464 million.

The terms of the RSC specify that the total production from the fields is the property of SONATRACH. The foreign participants in the venture bear the total cost of developing the Ohanet reservoirs, and in return, will recover their investment, together with an agreed fixed profit consideration from liquids production, over a target eight-year period from the start of production. This eight-year period can be extended for up to four years under certain conditions.

The monetary entitlement will be translated into volumes of condensate, butane and propane that will be lifted from export ports on the Algerian coast. These volumes will be determined based on prices posted by SONATRACH.

Gabon Exploration

We hold a 40.12% interest in the Tolo block, situated offshore in the North Gabon Basin. As the operator we drilled one well that was plugged and abandoned. Having satisfied our commitments in Gabon, we are executing an exit strategy.

South Africa

In May 2002, we entered into a farm-in agreement with Global Energy Holdings to acquire a 90% operated working interest in deepwater exploration Block 3B/4B, offshore South Africa.

Marketing

Oil and Condensate

Our global trading and marketing teams based in Houston and Singapore manage the marketing and risk associated with our crude oil, condensate, LPG and petroleum products. We use a combination of floating price short term and long term contracts in both domestic and export markets. The global crude oil and products trading and marketing team forms part of the wider BHP Billiton Group marketing function.

LNG

As part of our expansion plans, we participate with the other North West Shelf joint venture partners in a marketing organisation, NWS Australia LNG, established to market LNG produced from Australian gas resources to overseas buyers. Along with our joint venture partners, we are actively pursuing opportunities in Japan, China, Taiwan and Korea.

LPG

We market our entitlements of LPG produced from the Bass Strait and North West Shelf projects mainly through term contracts with domestic Australian wholesalers of LPG and international LPG end users. Some spot sales are made when LPG produced exceeds our term commitments.

Reserves

The table below details our oil, condensate, LPG and gas reserves, estimated at June 30, 2003, 2002, and 2001 with a reconciliation of the changes in each year. Our reserves have been calculated using the economic interest method and represent our net interest volumes after deduction of applicable royalty, fuel and flare volumes. Our reserves have been subjected to economic tests specified in Statement of Financial Accounting Standard 69 to demonstrate their commerciality under prices and costs existing at the time of the estimates. Our reserves include quantities of oil, condensate and LPG which will be produced under several production and risk sharing arrangements that involve us in upstream risks and rewards but do not transfer ownership of the products to us. At June 30, 2003, approximately 19% (2002: 17 %, 2001: 14 %) of proved developed and undeveloped oil, condensate and LPG reserves, and nil amount (2002: nil, 2001: nil) of natural gas reserves are attributed to those arrangements. Our reserves also include volumes calculated by probabilistic aggregation of an area level for fields that share common infrastructure. These aggregation procedures result in enterprise-wide proved reserve volumes, which may not be realised upon divestment on an individual property basis.

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Proved Developed and Undeveloped Oil, Condensate and LPG Reserves[1]	Australia/Asia	Americas	Europe/Africa/ Middle East	Total
	(millions of barrels)			
Reserves at June 30, 2000	438.3	28.6	90.1	557.0
Improved Recovery	0.4			0.4
Revisions to previous estimates	5.3	0.5	0.5	6.3
Extension, Discoveries and Other	4.4	67.6	74.1	146.1
Purchases and Sales	(0.9)	3.8	(18.3)	(15.4)
Production[2]	(70.7)	(4.2)	(12.2)	(87.1)
Total changes	(61.5)	67.7	44.1	50.3
Reserves at June 30, 2001	376.8	96.3	134.2	607.3
Improved Recovery				
Revisions to previous estimates	12.1	3.2	(11.0)	4.3
Extension, Discoveries and Other	3.4	70.2		73.6
Purchases and Sales				
Production[2]	(63.3)	(9.0)	(14.3)	(86.6)
Total changes	(47.8)	64.4	(25.3)	(8.7)