BHP BILLITON LTD
Form 20-F
October 03, 2005
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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 30 JUNE 2005

OR

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

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

Date of event requiring this shell company report

Commission file number: 001-09526

BHP BILLITON LIMITED

(ABN 49 004 028 077)

(Exact name of Registrant as specified in its charter)

VICTORIA, AUSTRALIA

(Jurisdiction of incorporation or organisation)

180 LONSDALE STREET, MELBOURNE,

VICTORIA 3000 AUSTRALIA

(Address of principal executive offices)

Commission file number: 001-31714

BHP BILLITON PLC

(REG. NO. 3196209)

(Exact name of Registrant as specified in its charter)

ENGLAND AND WALES

(Jurisdiction of incorporation or organisation)

NEATHOUSE PLACE, VICTORIA, LONDON,

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	3,587,977,615	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

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

Yes ¨ No x

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In this annual report, the terms we, our, us, BHP Billiton, BHP Billiton Group and 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;
- trends in commodity prices;
- 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; and
- provisions and contingent liabilities.

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 or 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 description 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.

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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 1,000 kilograms, approximately 2,205 pounds or 1.102 short tonnes. 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.

A$ means the currency of the Commonwealth of Australia.

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 dual listed companies merger between BHP Billiton Limited and BHP Billiton Plc, on 29 June 2001.

DLC structure means the corporate structure resulting from the DLC merger.

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 steaming or thermal coal.

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

Farm-in is an arrangement between one or more parties and the company or group holding a lease title to an exploration or production area whereby the former pays to earn an interest in the permit. Payment may be in cash or in the form of a work programme.

Greenfield project means the development of a new project.

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 DRI where the densification is carried out at a temperature greater than 650 degrees Celsius. The resultant product has density greater than $5g/cm^3$. 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.

Liquefied natural gas (LNG) consists largely of methane that has been liquefied 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 liquefied 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.

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 process.

Oil and gas reserves mean those quantities of oil and gas that 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.

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 degree of assurance, although lower than that for proven (measured) reserves, is high enough to assure continuity between points of observation.

Proved or proven 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.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (i.e. prices and costs as of the date the estimate is made).

Spud means to commence drilling of an oil or gas well.

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

Total ore reserves represent proved ore reserves plus probable ore reserves.

Reserve life is current stated ore reserves divided by current rate of production.

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.

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Financial Terms

UK terminology	US equivalent
Shareholders Funds	Stockholders Equity
Called up share capital	Subscribed Capital Stock
Ordinary Shares	Common Stock
Profit and Loss Account	Income Statement
Profit and Loss Account Reserve	Retained Earnings
Share Premium Account	Paid-in Surplus
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
Tangible Fixed Assets	Property, Plant and Equipment
Bonus Issue	Stock Dividend
Turnover	Sales Revenue
Depreciation	Depreciation and depletion
Profit for the financial year (attributable profit)	Net income
Income-generating unit	Cash-generating unit

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PART I

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 the BHP Billiton Group, which reflects the combined operations of both the BHP Billiton Limited Group and the BHP Billiton Plc 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. Under UK GAAP, the DLC structure has been accounted for under the pooling-of-interests method in accordance with UK Financial Reporting Standard 6: Acquisitions and Mergers as though the DLC structure had been effective and the two groups had operated as one enterprise throughout the periods presented.

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 29 June 2001. Under the pooling-of-interests method, 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, at the date of combination, and to record goodwill.

The selected consolidated financial information for the BHP Billiton Group set forth below as at and for the fiscal years ended 30 June 2005, 2004 and 2003 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. The assets and liabilities of WMC Resources Ltd (WMC), which was acquired on 3 June 2005, have been included in the Consolidated Balance Sheet as at 30 June 2005 and the results of WMC for the period since the date of acquisition have been included in the Consolidated Profit and Loss Account for the year ended 30 June 2005.

	Year ended 30 June				
Consolidated Profit and Loss Account	**2005**	**2004**	**2003**	**2002**	**2001**
	(US$ millions except per share data)				
Amounts in accordance with UK GAAP					
Group turnover total	29,587	22,887	15,608	15,906	17,789
Group turnover from continuing operations	29,587	22,887	15,608	13,562	14,771
Operating profit (including share of profit of joint ventures and associates)					
- including exceptional items total	9,102	5,418	3,412	2,943	2,825
- excluding exceptional items from continuing operations	9,181	5,352	3,412	2,984	3,284
	9,102	5,418	3,412	2,873	2,612

- including exceptional items from continuing operations										
Net profit before minority interests										
- including exceptional items		6,630		3,476		1,941		1,737		1,252
Net profit attributable to members										
- including exceptional items		6,398		3,379		1,901		1,690		1,529
Dividends provided for or paid		1,695		1,617		900		784		754
Number of Ordinary Shares (millions) [a]										
- at period end		6,056		6,228		6,216		6,044		6,023
- weighted average		6,124		6,218		6,207		6,029		5,944
- weighted average diluted		6,158		6,246		6,222		6,042		5,973
Per Ordinary Share: [a]										
- Net profit attributable to members										
including exceptional items										
- Basic	US$	1.05	US$	0.54	US$	0.31	US$	0.28	US$	0.26
- Diluted	US$	1.04	US$	0.54	US$	0.31	US$	0.28	US$	0.26
-Dividends provided for or paid BHP Billiton Plc [b]	US$	0.28	US$	0.26	US$	0.145	US$	0.13	US$	0.12
-Dividends provided for or paid BHP Billiton Limited [b]	US$	0.28	US$	0.26	US$	0.145	US$	0.13	A$	0.247

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Consolidated Profit and Loss Account	2005	2004	2003	2002	2001
	Year ended 30 June				
	(US$ millions except per share data)				
Amounts in accordance with US GAAP					
Sales revenue from continuing operations	29,587	22,887	15,608	13,552	8,100
Other income from continuing operations	579	385	223	321	516
Operating income from continuing operations	7,430	3,489	2,780	1,698	629
Net income total	6,388	2,716	1,581	1,249	882
Net income from continuing operations	6,388	2,716	1,576	1,513	718
Net (loss)/income from discontinued operations			5	(264)	136
Per Ordinary Share [(a)]:					
Net income attributable to members					
- Basic from continuing operations	US$ 1.04	US$ 0.44	US$ 0.25	US$ 0.25	US$ 0.20
- Diluted from continuing operations	US$ 1.04	US$ 0.43	US$ 0.25	US$ 0.25	US$ 0.20
- Basic from discontinued operations				US$ (0.04)	US$ 0.04
- Diluted from discontinued operations				US$ (0.04)	US$ 0.04
- Basic total	US$ 1.04	US$ 0.44	US$ 0.25	US$ 0.21	US$ 0.24
- Diluted total	US$ 1.04	US$ 0.43	US$ 0.25	US$ 0.21	US$ 0.24
Per ADS:					
Net income attributable to members					
- Basic total	US$ 2.08	US$ 0.88	US$ 0.50	US$ 0.42	US$ 0.48
- Diluted total	US$ 2.08	US$ 0.86	US$ 0.50	US$ 0.42	US$ 0.48

Balance Sheet	2005	2004	2003	2002	2001
	At 30 June				
	(US$ millions)				
Amounts in accordance with UK GAAP					
Total assets	41,947	30,861	28,363	29,549	28,028
Total non-current portion of interest bearing liabilities [(c)]	8,024	5,453	6,288	5,534	6,521
Contributed equity	3,363	3,603	3,537	4,895	4,791
Equity attributable to members	17,153	14,038	12,091	12,370	11,340
Amounts in accordance with US GAAP					
Total assets total	47,647	36,675	35,001	35,795	35,232
Total assets of continuing operations	47,647	36,675	35,001	33,023	32,562
Total non-current portion of interest bearing liabilities total	9,622	5,452	6,414	6,350	6,607
Total non-current portion of interest bearing liabilities of continuing operations	9,622	5,452	6,414	6,296	6,544
Equity attributable to members	22,004	18,802	16,832	17,147	16,602

(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, the BHP Performance Share Plan Trust and the BHP Bonus Equity Plan Trust and adjusting for the BHP Billiton Limited bonus share issue. Included in the calculation of fully diluted earnings per share are shares and options contingently issuable under employee share ownership plans.

(b) Three dividends were declared for the year ended 30 June 2004, compared to two dividends declared for the year ended 30 June 2005 and prior to 2004, as a result of the Group s decision to realign dividend declaration dates to coincide with the announcements of our interim and full year results.

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

Currency of presentation

The BHP Billiton Group publishes its consolidated financial statements in US dollars.

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B. Capitalisation and Indebtedness

Not applicable.

C. Reasons for the Offer and Use of Proceeds

Not applicable.

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. 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.

Exchange rate movements negatively impacted our profit before interest and taxation in 2004-2005 by US$465 million compared to 2003-2004, including US$40 million relating to net monetary liabilities. Our losses on restatement of all non-US dollar net monetary liabilities, including debt and tax liabilities, were US$40 million, US$278 million and US$380 million in the years ended 30 June 2005, 2004 and 2003 respectively.

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

Because most 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, financial condition and prospects.

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 was 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 and if compliance is not achieved our reputation may be detrimentally impacted

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. Subsequent negotiations have advanced the flexibility of the proposals with the intention of lessening the

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economic costs to participating countries meeting their emission limitations obligations. 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. Our Petroleum assets in the UK are currently subject to the EU Emissions Trading Scheme. For the rest of our assets, the impacts may be less direct and are more difficult to anticipate.

We may continue to 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.

The European Registration, Evaluation and Authorisation of Chemicals (REACH) system is anticipated to commence operation in 2006. REACH will require manufacturers, importers and downstream users of chemical substances, including metals and minerals, to establish that the substances can be used without negatively affecting health or the environment. The extent to which our operations and customers are impacted by these changes will not be clear until the final form of the regulations is determined. These potential compliance costs, litigation expenses, regulatory delays, remediation expenses and operational costs could negatively affect our financial results.

Despite our best efforts and best intentions, there remains a risk that health, safety and/or environmental incidents or accidents may occur which may negatively impact our reputation and freedom or licence to operate.

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.

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 negatively 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 negatively 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 business

Our business could be adversely affected by new government regulation such as controls on imports, exports and prices, new forms or rates of taxation and royalties.

In South Africa, the Mineral and Petroleum Resources Development Act (2002) (MPRDA) came into effect on 1 May 2004. The law provides for the conversion of existing mining rights (so called old order rights) to rights under the new regime (new order rights) subject to certain undertakings to be made by the company applying for such conversion. These new rights will also be subject to revised State royalties in the case of certain minerals but this is only expected to be introduced in 2009. The MPRDA also required the development of a Broad Based Socio Economic Empowerment Charter, known as the Mining Charter, for the mining industry with the objectives of expanding opportunities, skills, ownership and employment by historically disadvantaged South Africans. The Mining Charter requires that mining companies achieve 15% ownership by historically disadvantaged South Africans of South African mining assets within five years and 26% ownership within ten years. If we are unable to convert our South African mining rights in accordance with the MPRDA and the Mining Charter, we could lose some of those rights.

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 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 terrorism, 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.

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We may not be able to integrate successfully our acquired businesses

We have grown our business in part through acquisitions including our acquisition of WMC Resources Ltd. We 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 recover the funds we spend identifying new mining and oil and gas properties through our exploration programme. 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.

Our non-controlled assets may not comply with our standards

Some of our assets are controlled and managed by joint venture partners or by other companies. Management of our non-controlled assets may not comply with the BHP Billiton Group s health, safety, environment and other standards, controls and procedures. Failure to adopt equivalent standards, controls and procedures at these assets could lead to higher costs and reduced production and adversely impact our results and reputation.

Increased reliance upon the Chinese market may negatively impact our results in the event of a slowdown in consumption

The Chinese market has become a significant source of global demand for commodities. China now represents in excess of 35% of global seaborne iron ore demand, 20% of copper and alumina, 12% of nickel and 8% of oil demand. Chinese demand for these commodities has more than doubled in the last five years but this demand is expected to moderate as the government pursues measures to reduce economic overheating and to increase capital efficiency.

Whilst this increase represents a significant business opportunity, our exposure to China s economic fortunes and economic policies has increased. Sales into China generated just less than US$4 billion or 12.6% of turnover in the year ended 30 June 2005.

In recent times we have seen a synchronised global recovery, resulting in upward movement in commodity prices driven largely by Chinese demand. This synchronised demand has introduced increased volatility in BHP Billiton s commodity portfolio. Whilst this synchronised demand has, in recent periods, resulted in higher prices for the commodities we produce, if Chinese economic growth slows, it could result in lower prices for our products, and therefore reduce our revenues.

Inflationary pressures and shortages of skilled personnel could negatively impact our operations and expansion plans

The strong commodity cycle and large numbers of projects being developed in the resources industry has led to increased demand for skilled personnel, contractors, materials and supplies and increased demands from governments. This has led, and could continue to lead to increased capital and operating costs, and difficulties in developing, acquiring and retaining skilled personnel which may in turn adversely affect the development of new projects, the expansion of existing operations, the results of those operations, our financial condition and prospects.

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INFORMATION ON THE COMPANY

ITEM 4. INFORMATION ON THE COMPANY

A. History and Development of BHP Billiton

Background

We are the world s largest diversified resources group with a combined market capitalisation of approximately US$82 billion as of 30 June 2005 and we generated combined turnover (including our share of joint ventures and associates) and attributable profit (including exceptional items) of US$31.8 billion and US$6.4 billion, respectively, for the year ended 30 June 2005. We hold industry leader or near-leader positions in a range of products, including (after our acquisition of WMC Resources Ltd referred to below) being the:

- 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 second largest producer of copper;
- world s third largest producer of nickel metal;
- world s largest producer of high grade manganese ore;
- world s fifth largest producer of primary aluminium; and
- world s fourth largest producer of uranium.

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

BHP Billiton Limited is incorporated under the name BHP Billiton Limited and is registered in Australia with ABN 49 004 028 077. BHP Billiton Limited was incorporated on 13 August 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 England and Wales with Registration number 3196209. BHP Billiton Plc was incorporated on 9 May 1996.

The registered office of BHP Billiton Limited is at 180 Lonsdale Street, Melbourne, Victoria 3000, Australia and its telephone number is +61 3 9609 3333. The registered office of BHP Billiton Plc is Neathouse Place, London, SW1V1BH, England and its telephone number is +44 20 7802 4000.

On 19 March 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 29 June 2001. BHP Limited changed its name to BHP Billiton Limited and Billiton Plc changed its name to BHP Billiton Plc.

In July 2002, BHP Billiton Limited completed the spin-off of its entire steel flat and coated products business to its shareholders.

In March 2005, we announced a cash offer of A$7.85 per share for WMC Resources Ltd (WMC), an Australian based resources company. On 3 June 2005 BHP Billiton Limited obtained control of WMC. After acquiring over 90% of the issued shares in WMC on 17 June 2005, BHP Billiton Limited commenced action to compulsorily acquire the remaining shares. On 2 August 2005 BHP Billiton Limited completed the acquisition of 100% of the issued shares in WMC at a total acquisition cost of US$7.2 billion.

The major assets acquired through our acquisition of WMC and our Customer Sector Groups (CSGs) of which they now form part are as follows:

- the Olympic Dam copper, uranium and gold mine and related treatment plants located in South Australia (Base Metals);

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- an integrated nickel mining, refining and smelting business with operations located in Western Australia (Stainless Steel Materials);
- the Southern Cross Fertiliser operation (formerly, the Queensland Fertiliser Operation), which consists of an integrated phosphate mine and ammonium phosphate fertiliser production facility in Queensland (Diamonds and Specialty Products); and
- the Corridor Sands mineral sands project in Mozambique (Diamonds and Specialty Products).

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 of BHP Billiton Plc on the London Stock Exchange and BHP Billiton Limited on the Australian Stock Exchange continue to be maintained, as is the secondary listing of BHP Billiton Plc on the Johannesburg Stock Exchange. BHP Billiton Plc and BHP Billiton Limited each maintain an American Depositary Receipt listing 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 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.

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

- Petroleum (oil, natural gas and liquefied natural gas);
- Aluminium (aluminium and alumina);
- Base Metals (copper, silver, zinc, lead and uranium);
- Carbon Steel Materials (metallurgical coal, iron ore and manganese);
- Diamonds and Specialty Products (diamonds, titanium minerals, fertilisers and minerals exploration and technology);
- Energy Coal (energy coal); and
- Stainless Steel Materials (nickel metal, cobalt and, until May 2005, chrome).

In addition, we group the Customer Sector Groups into three broadly related business areas of Non-Ferrous Materials, Energy and Carbon Steel Materials. The Aluminium, Base Metals and Stainless Steel Materials Customer Sector Groups form the Non-Ferrous Materials Group. The Petroleum and Energy Coal Customer Sector Groups form the Energy Group. The Carbon Steel Materials Customer Sector Group forms the Carbon Steel Materials Group. The Presidents of the relevant Customer Sector Groups report to the Group Presidents of the Non-Ferrous Materials, Energy and Carbon Steel Materials Groups respectively. The President of Diamonds and Specialty Products reports to the Chief Commercial Officer of BHP Billiton.

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The table below sets forth the contribution to combined turnover and profit (before tax) of each of these CSGs for the three years ended 30 June 2005.

	Turnover		
	Year ended 30 June		
	2005	2004	2003
	(US$ millions)		
Group including share of joint ventures and associates			
Petroleum	5,970	5,558	3,264
Aluminium	5,265	4,432	3,386
Base Metals	5,071	3,422	1,954
Carbon Steel Materials	7,606	4,857	3,714
Diamonds and Specialty Products	1,544	1,710	1,485
Energy Coal	3,390	2,569	2,089
Stainless Steel Materials	2,274	1,749	1,106
Group and unallocated items	798	725	549
Intersegment	(114)	(79)	(41)
Total	31,804	24,943	17,506

	Profit before tax		
	Year ended 30 June		
	2005	2004	2003
	(US$ millions)		
Group including share of joint ventures and associates			
Petroleum	1,830	1,391	1,178
Aluminium	977	776	581
Base Metals	2,177	1,156	286
Carbon Steel Materials	2,821	1,137	1,045
Diamonds and Specialty Products	417	410	299
Energy Coal	616	234	198
Stainless Steel Materials	758	571	150
Group and unallocated items	(266)	(187)	(256)
Exceptional items(1)	(168)	(468)	(19)
Net interest	(421)	(502)	(537)
Total	8,741	4,518	2,925

(1) Refer note 2 Exceptional items in the 2005 BHP Billiton Group Annual Financial Statements.

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 30 June 2005.

	Turnover		
	Year ended 30 June		
	2005	2004	2003
	(US$ millions)		
Analysis by geographical origin			
Australia	10,415	7,270	6,527
Europe	7,856	6,750	2,798
North America	2,366	2,503	2,186
South America	5,723	4,130	2,727
Southern Africa	5,123	3,882	3,147
Rest of World	321	408	121
Total	31,804	24,943	17,506

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	Profit before tax and net interest		
	Year ended 30 June		
	2005	2004	2003
	(US$ millions)		
Analysis by geographical origin			
Australia	3,845	2,104	1,871
Europe	1,154	756	259
North America	363	(188)	188
South America	2,895	1,719	576
Southern Africa	729	537	558
Rest of World	176	92	10
Total	9,162	5,020	3,462

The table below sets forth the analysis of combined turnover by geographic market for the three years ended 30 June 2005.

	Turnover		
	Year ended 30 June		
	2005	2004	2003
	(US$ millions)		
Analysis by geographical market			
Australia	2,642	1,874	1,775
Europe	10,458	8,941	5,582
Japan	3,739	2,807	2,393
South Korea	1,888	1,598	1,203
China	3,996	2,432	1,216
Other Asia	2,207	1,583	1,172
North America	2,842	2,782	2,389
Southern Africa	1,604	1,363	944
Rest of World	2,428	1,563	832
Total	31,804	24,943	17,506

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Ore Reserves

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 30 June 2005 unless otherwise stated. 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 for traded metals or are based on historical commercial contracts for bulk commodities 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, or test for impairment of, the reserves of traded metals contained in this annual report are as follows:

Commodity	Price US$
Copper	0.938/lb[1]
Gold	361/oz
Lead	0.28/lb
Nickel	4.57/lb
Silver	5.38/oz
Zinc	0.40/lb

(1) All our copper operations have used a copper price at or below the three year historical average copper price to estimate, or test for impairment of, the copper reserves disclosed in this report. The price used for each operation is disclosed in the footnotes to the Base Metals reserves table.

Capital Expenditures and Divestitures

Details of our capital expenditure and divestitures are included in Item 4B and Item 5B of this annual report.

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B. Business Overview

Petroleum

Our Petroleum Customer Sector Group s principal activities are oil and natural gas exploration, production and development in Australia, the United Kingdom, the United States, Algeria, Trinidad and Tobago, and Pakistan; and exploration interests in the United States, Australia, Trinidad and Tobago, Pakistan, Algeria, Brunei Darussalam, South Africa, Canada and the Philippines.

Operating Assets

Australia/Asia

In Australia, we produce oil and gas from Bass Strait, the North West Shelf, the Griffin Project, the Minerva gas field, the Moranbah Coal Bed Methane gas project and from coal mine methane degassing at Illawarra Coal. In Pakistan, we produce gas and a small volume of condensate from the Zamzama gas field.

Bass Strait

BHP Billiton Bass Strait interests are conducted under two separate joint venture agreements: the Gippsland Basin Joint Venture and the Kipper Unit Joint Venture.

Gippsland Joint Venture

The Bass Strait Gippsland Basin Joint Venture oil and gas fields are located offshore southern Australia. Production commenced in 1968. There are 20 producing fields with 21 offshore structures (18 platforms and three subsea developments). Onshore infrastructure includes the Longford Facility, which includes three gas plants and liquid processing facilities as well as the Long Island Point LPG and crude oil storage facilities.

We have a 50% interest in the Bass Strait fields and infrastructure. Esso Australia Resources Pty Ltd (Esso Australia) owns the other 50% interest and acts as operator. Production from most of the fields is subject to an overriding 2.5% royalty payable to Oil Basins Limited.

During 2004-2005, gross oil production averaged 94,000 barrels per day. The majority of produced 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.

During 2004-2005, gas production averaged approximately 650 million cubic feet per day (gross). LPG (liquefied petroleum gases) and ethane extracted from the natural gas are sold in Australia and overseas. During 2004 2005, LPG production averaged 2,900 tonnes per day (gross) and ethane production averaged 570 tonnes per day (gross).

Most of the natural gas produced was sold to GASCOR for on-sale to retailers to meet Victoria s residential and commercial gas requirements. The contract with GASCOR is due to expire on 31 December 2009 or upon depletion of the outstanding contractual volume of 635 billion cubic feet of natural gas, whichever is the earlier. The annual contract quantity is 167 billion cubic feet per annum and the maximum take is 217 billion cubic feet per annum. The contract is a fixed gas price contract with periodic price reviews. Gas prices are escalated in proportion with the Australian Consumer Price Index.

We have also entered into long-term gas sale agreements with retailers AGL and TRUenergy (formerly TXU Australia). Contracted quantities for AGL and TRUenergy are up to 910 and 765 billion cubic feet of natural gas, respectively. We commenced deliveries under both contracts in January 2004 and they are due to expire in 2017. These contracts are fixed gas price contracts with periodic price reviews. Gas prices are escalated in both contracts in proportion with the Australian Consumer Price Index.

We, along with our joint venture partner Esso Australia, continue to seek additional reserves in the Bass Strait in order to enhance existing production levels with high value incremental developments.

Esso Australia operated three drilling rigs in the Bass Strait fields during 2004-2005 with a work programme including drilling infill, development and exploration opportunities. The infill drilling programme across Flounder, Barracouta, Bream A and Tuna fields included 11 wells of which nine wells were successful. The success of these wells is expected to increase production by approximately 6,000 barrels per day (gross). During 2004 - 2005 two well

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work-over programmes were carried out on Bream B. The successful completion of this work-over programme is expected to increase production with initial rate of approximately 2,000 barrels per day (gross). This came online in August 2005.

The delineation and development in the Turrum oil and gas field, in the deep horizon beneath the existing Marlin field included five development wells drilled during the 2005 financial year. First production from Turrum was during late June 2005 at a rate of approximately 1,500 barrels per day (gross).

Kipper Unit Joint Venture

The Kipper field was discovered in 1986 and is located approximately 45 kilometres off the Victorian coastline, in approximately 100 metres of water. It is mapped to straddle the boundary between the Vic/RL2 retention lease and the Vic/L9 production licence. Two wells have been drilled to delineate the field.

The original retention lease for Vic/RL2 was granted in July 1993 and has been renewed once. A second renewal request was submitted in June 2003 but was not granted. Consequently, in June 2005, the joint venturers applied for a production licence which, if granted, will allow the right to develop and operate the field. Esso Australia is the designated operator.

In June 2005, the Kipper joint venturers (BHP Billiton, Santos Ltd, Woodside Energy Ltd and Esso Australia) signed a non-binding memorandum of understanding (MOU) in relation to the development of the field. Under the MOU the project participants have agreed on key terms and conditions for processing gas from the Kipper field through Esso and BHP Billiton s Bass Strait infrastructure and processing facilities. The joint venturers have also signed a separate MOU to unitise the field across the licence blocks.

It is expected that the Kipper field will be developed by installation of a number of subsea wells and associated pipeline infrastructure. First gas is planned for 2009 subject to corporate funding approvals by each of the project participants and receipt of production licences.

North West Shelf

We are a participant in the North West Shelf project, an unincorporated joint venture operated by Woodside Energy Ltd. The project was developed in major phases: the domestic gas phase, which supplies gas to the Western Australian domestic market; and a number of LNG expansion phases, which currently supply LNG (liquefied natural gas) primarily to Japan and will also, from mid 2006, supply LNG to Guangdong in China. The project also produces crude oil, condensate and LPG, primarily for export.

The current domestic gas joint venture participants are Woodside Energy Ltd (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%). Our share of domestic gas production will progressively increase from an 8.33% share to a 16.67% share over the period from 2005 to approximately 2017. When we reach a 16.67% share, all current domestic gas joint venture partners and Japan Australia LNG (MIMI) Pty Ltd (jointly owned by Mitsubishi Corporation and Mitsui & Co.) will have equal 16.67% interests. The six founding participants of the first North West Shelf LNG joint venture include the domestic gas joint venture partners and Japan Australia LNG (MIMI) Pty Ltd, each with a 16.67% interest. A second LNG joint venture (CLNG) has been formed for the purpose of enabling its participants to supply LNG to Guangdong. Each of the six founding LNG participants hold an equal 12.5% interest in the CLNG joint venture with CNOOC NWS Private Limited, a subsidiary of China National Offshore Oil Corporation, holding a 25% interest. While ownership of NWS Project offshore and onshore infrastructure assets remains with the founding LNG and domestic gas venture participants, CNOOC has rights to process its CLNG gas and associated gas liquids products through that infrastructure, on payment of a tariff to the owners.

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 through two trunklines by the offshore North Rankin, Goodwyn, Perseus and Echo-Yodel gas and condensate fields. Production from the North Rankin and Perseus fields is currently through the North Rankin A platform, which has the capacity to produce 2,300 million cubic feet per day of gas and 53,000 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 1,450 million cubic feet per day of gas and 110,000 barrels per day of condensate. Production from these fields will continue to meet current contractual requirements for domestic gas and LNG until mid 2006. Further development of the existing Perseus field has commenced and includes the drilling of seven wells which will be progressively tied in from mid 2006 to early 2007. The currently undeveloped Angel field will also be developed to meet expected market requirements from 2008.

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The North West Shelf domestic gas plant has a current capacity of 615 million cubic feet per day. Debottlenecking work is planned to increase capacity to 720 million cubic feet per day by the end of 2006. The gas is delivered via pipeline to customers in Western Australia under long-term agreements. Production of domestic gas in 2004 2005 averaged 480 million cubic feet per day (gross).

The existing four-train LNG plant has the capacity to produce at an average rate of 33,000 tonnes of LNG per day, or 12 million tonnes per annum. The project currently sells approximately 7 million tonnes of LNG per year under the original long-term contracts to Japanese buyers, which expire in 2009. Further sales to Japan are made under long term contracts that were secured to support the fourth train expansion. These contract periods range from 20 years to 30 years for supply of up to 4 million tonnes of LNG per year with initial deliveries commencing in 2004-2005. Mid term (terms of 5-10 years) contract and spot sales are made to buyers in Japan, Korea and the United States, with the level of spot sales depending on plant and shipping availability. Production for 2004-2005 averaged 30,200 tonnes per day (gross).

In December 2004, an LNG sales and purchase agreement with the Guangdong LNG Project for the purchase and supply of LNG from the North West Shelf became unconditional. The agreement covers 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, with deliveries expected to commence in mid 2006.

In June 2005, the BHP Billiton Board of Directors approved the Group s 16.67% share of investment in a fifth LNG train expansion of the existing LNG processing facilities located on the Burrup Peninsula. Engineering and procurement for the fifth train and associated infrastructure has commenced and first production is expected in the second half of 2008. Negotiations for long term LNG contracts to underpin this investment are progressing.

Condensate is separated from the natural gas in the onshore plant. Condensate production during 2004-2005 averaged 98,000 barrels per day (gross) and our average share of condensate production was approximately 15% over the period. Our share of condensate varies in proportion to our relative interests in condensate production attributable to the domestic gas and LNG joint ventures.

LPG production began in November 1995 and production in 2004 2005 was 2,100 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 gas and condensate field. The oil is produced to a floating production storage and offloading unit, the Cossack Pioneer, and production averaged 96,000 barrels of oil per day (gross) in 2004 2005. An infill well drilling programme for 2005-2006 has been approved to accelerate production. We have a 16.67% working interest in oil production from these fields.

Laminaria and Corallina

We ceased to be a participant in the Laminaria and Corallina joint venture with Woodside Energy Ltd and Shell Development (Australia) Pty Ltd on 14 January 2005 when we completed the sale of our interest to Paladin Oil & Gas (Australia) Pty Ltd.

Griffin

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 2004 2005 averaged 10,600 barrels per day of oil (gross).

We pipe natural gas to shore, where it is exported directly into a pipeline and sold into the domestic market under long term contracts. Gas production in 2004 2005 averaged 16 million standard cubic feet per day (gross).

Minerva

The Minerva gas field, discovered in 1993, is located in the Otway basin offshore southern Victoria. We have a 90% working interest in and act as the operator of the field. Santos (BOL) Pty Ltd owns a 10% share of the joint venture.

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In March 2002 we signed a take or pay gas sales agreement with Pelican Point Power Limited (a wholly owned subsidiary of International Power plc) to provide gas into South Australia and Victoria through the gas fired Pelican Point Power station in South Australia. The contracted quantity is up to 240 billion cubic feet of natural gas to be supplied over a l0 year period from 2004. The contract is a fixed gas price contract with periodic price reviews. Gas prices are escalated in proportion to the Australian Consumer Price Index.

The Minerva gas field was developed with a single flowline transporting raw gas to the coast. The flowline passes through a subterranean shore crossing to an onshore gas processing facility. At the facility, liquids are removed and the gas is delivered into the SEAGas pipeline.

The Minerva gas field commenced commercial production in January 2005. The gas production from commencement of commercial production until 30 June 2005 averaged 101 million cubic feet per day (gross), and condensate production averaged 315 barrels per day (gross).

Coal Bed Methane

We have a 50% interest in the Moranbah Gas Project situated within the Queensland Bowen Basin coalfields.

The project is operated by CH4 Operations Pty Ltd. It comprises the extraction of coal bed methane from surface-to-seam wells using drilling techniques developed by BHP Billiton and CH4.

We and CH4 have signed a Gas Supply Agreement (GSA) with the Queensland Power Trading Corporation (trading under the name Enertrade), owned by the Queensland Government, for delivery of up to a maximum of 290 billion cubic feet (gross) from February 2005 over 15 years, with a take or pay quantity of 8 billion cubic feet per annum (gross) for the first 10 years. Gas deliveries under the GSA commenced during the year and required daily contract volumes have been maintained since April 2005. In May 2005 an amended and restated GSA was signed with CH4 and Enertrade reflecting the agreement also signed in May 2005 between BHP Billiton s QNI and Enertrade for Enertrade to supply gas to QNI s expanded nickel and cobalt refinery at Yabulu near Townsville, North Queensland. 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 initial capital cost of this project was US$31 million. Additional wells will have to be drilled during the contract term as recovery rates from the initial wells decline.

At Illawarra in New South Wales, methane recovery from coal mining operations is continuing. The gas drainage operations are required to reduce the methane content to levels that allow underground coal mining to proceed safely.

In June 2004, we signed an agreement for coal bed methane exploration interests in China with Chevron Texaco and the Chinese Government. During 2004-2005, seven of eight planned appraisal wells were drilled in the Ordos basin. Further development planning will be based on the evaluation of the drilling and resource data obtained from these wells.

On 31 March 2005 we signed a technical services agreement (TSA) with BPI Industries Inc, a Canadian publicly listed oil and gas exploration company, for an initial term of 18 months. We will provide technical services in the areas of drilling and completion of in-seam coal bed methane wells in the Illinois Basin. Pursuant to the TSA, we acquired stock appreciation rights that are only exercisable if a majority in value of the stock or assets of BPI is acquired. The value of this right is based on the excess of BPI s stock price over the closing price on 31 March 2005.

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 Government Holdings 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 programme identified commercial reserves, we commenced production in March 2001 from Zamzama 1 and 2 wells through an extended well test (EWT) phase.

In March 2002, we and our partners approved the Phase 1 development of the Zamzama gas field following the signing of 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 lease (with an option to extend 5 years beyond the 20-year term) for the full field development of the Zamzama discovery.

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The Phase 1 development consists of two additional processing trains, which are located on the existing EWT plant site, and three additional development wells. First gas from the Phase 1 development was produced in July 2003.

In 2004 2005, production averaged 258 million cubic feet per day of gas (gross) and 1,724 barrels per day of condensate (gross).

Two development wells, Zamzama-East and Zamzama-North, were successfully completed in 2004 for US$8 million (our share), resulting in additional proved reserves. Negotiations are currently underway with the Sui Southern Gas Company for the sale of these additional reserves. It is anticipated that a gas sales and purchase agreement will be signed between the parties early in the second quarter of 2005-2006.

Americas

In the United States, we produce oil and gas from the Gulf of Mexico and we also produce oil and gas in Trinidad and Tobago, from the offshore Angostura oil and gas field.

Gulf of Mexico

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

We are the operator of West Cameron 76 and have a 33.8-78.8% working interest (depending on the location of the producing well). The gas field, which is located in shallow water about 20 kilometres offshore from the coast of Central Louisiana, was discovered in 1991 and production commenced in 1992. The field architecture consists of two conventional platforms. In 2004-2005, production from West Cameron 76 averaged 60 million cubic feet of gas per day (gross) and 300 barrels per day of condensate (gross).

We have a 50% working interest in the Typhoon oil and gas development, located in Green Canyon Blocks 236 and 237. Chevron has the other 50% working interest and is the operator. The field is located in 2,000 feet of water approximately 100 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 2001.

We also have a 50% working interest in and operate the Boris oil discovery in Green Canyon Block 282 adjacent to the Typhoon field. Chevron and Noble Energy each have a 25% working interest. Boris was developed as a tie-back to the Typhoon production facility. Production commenced in 2003.

In 2004 2005, production from Typhoon and Boris fields averaged 24,000 barrels of oil and 39 million cubic feet of gas per day (gross).

We have a 4.95% working interest in the Chevron-operated Genesis oil field, located in Green Canyon blocks 160, 161 and 205. In 2004-2005, this field produced an average of 22,000 barrels of oil per day and 36 million cubic feet per day of gas (gross).

We also have a 25% working interest in the Green Canyon 18/Ewing Bank 988 oil field and a 45% working interest in the Green Canyon 60 oil field, both operated by ExxonMobil. In 2004-2005 these fields produced an average of 3,300 barrels of oil per day and 3.1 million cubic feet of gas per day (gross) of which approximately 94% came from Green Canyon 18/Ewing Bank 988.

Mad Dog

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

The initial Mad Dog discovery well, in the Green Canyon area of the Atwater Foldbelt, was drilled in December 1998, followed by three appraisal wells drilled between 1999 and 2001. In February 2002, we and our partners sanctioned Mad Dog for development. The budgeted cost of our share of capital expenditure was US$368 million. The final expenditure will depend on the number of development wells needed to optimise the production of reserves.

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The field is being developed using a truss SPAR facility with an integrated drilling rig, which is permanently moored in Green Canyon Block 782, about 250 kilometres south of New Orleans, Louisiana. Located in approximately 4,300 feet of water, the facility has the capacity to process 100,000 barrels of oil per day and 60 million cubic feet of gas per day (gross), which is an increase over the original design capacity of 80,000 barrels of oil per day and 40 million cubic feet of gas per day (gross). First production began on 13 January 2005. The project is currently ramping up production and we expect to reach oil capacity by mid calendar year 2007. Gross oil production in the period January 2005 to June 2005 averaged 23,000 barrels of oil per day.

An additional well and its sidetracks were drilled in the Southwest Flank of the field in March 2005. The well found hydrocarbons some 1,000 feet deeper on the West flank of the structure than previously encountered. The development programme for this portion of the field is continuing to be assessed.

Caesar and Cleopatra Pipelines

In February 2002, we acquired equity ownership in Caesar Oil Pipeline Company LLC (25%), and Cleopatra Gas Gathering Company LLC (22%), which are limited liability companies that will transport hydrocarbons by pipeline from Mad Dog, Atlantis and, possibly, future discoveries in the proximity. The pipelines are part of a new system in the Southern Green Canyon area.

Our share of capital costs approved by the Board for the construction of the Caesar and Cleopatra pipelines was US$132 million.

The Caesar pipeline has a design capacity of at least 450,000 barrels of oil per day and Cleopatra has a capacity of 500 million cubic feet of gas per day. These pipelines connect with other pipelines to transport product to the United States mainland.

The Caesar and Cleopatra pipelines were placed into service in December 2004. They are currently transporting crude oil and gas from the Mad Dog field and a third party field. An additional lateral will be laid to connect the pipelines to the Atlantis field during fiscal year 2006. Caesar and Cleopatra continue to pursue additional transportation agreements and have entered into a Memorandum of Understanding to transport Neptune production.

Trinidad and Tobago

Angostura

We signed Trinidad and Tobago s first production sharing contract under a new fiscal regime in April 1996 for Block 2(c). Hydrocarbons within a large faulted structure known as the Greater Angostura Structure were encountered with the Kairi-1 exploration well in 2001.

We are the operator of the Greater Angostura development and own a 45% working interest. Other participants are Total (30%) and Talisman Energy (25%). The field is located approximately 38.5 kilometres east of the island of Trinidad. Angostura is located in shallow water depths of approximately 130 feet.

The Angostura development is an integrated oil and gas development. Infrastructure includes a central processing platform with three satellite wellhead protector platforms. A pipeline connects the processing platform to newly constructed storage facilities at Guayaguayare, where an export pipeline has been installed to allow for offloading to tankers in Guayaguayare Bay. First production commenced on 9 January 2005. Gross oil production in the period January 2005 to June 2005 averaged 40,000 barrels per day of oil.

In the first phase, oil is being produced from three wellhead protector platforms via flowlines to the steel jacketed central processing platform. Associated gas is being re-injected to the reservoir to optimise oil recovery. Our share of capital expenditure for the first phase of the Angostura development was US$337 million.

The second phase, gas commercialisation, is currently in the pre-feasibility study stage with Board sanction targeted for the end of calendar year 2006.

Europe/Africa/Middle East

We produce oil and gas from the Liverpool Bay development and the Bruce/Keith fields in the United Kingdom. In Algeria we are entitled to LPG and condensate from the Ohanet development, and oil from the ROD integrated development.

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United Kingdom

Liverpool Bay

The Liverpool Bay oil and gas development is located in the Irish Sea, off the north-west coast of England. We are the operator, and have a 46.1% working interest. Other participants in the joint venture are Eni ULX Limited, which has a 45% interest, and Eni AEP Limited, which has an 8.9% interest. The venture began first production of oil and gas in 1996.

The Liverpool Bay asset comprises the integrated development of the following six offshore oil and gas fields in the Irish Sea: Douglas oil field; Douglas West oil field; Hamilton gas field; Hamilton North gas field; Hamilton East gas field; and Lennox oil and gas field. We produce oil from the Lennox and Douglas fields, which is then treated at the Douglas Complex and piped 17 kilometres to an oil storage barge ready for export by tankers.

We produce gas from the Hamilton, Hamilton North, Hamilton East, and Lennox fields. After initial processing at the Douglas Complex the gas is piped by subsea pipeline to the Point of Ayr gas terminal for further processing. It is then sent by onshore pipeline to E.ON UK plc s combined cycle gas turbine power station at Connah s Quay. E.ON is the sole purchaser of gas from the Liverpool Bay development.

The venture commenced a drilling campaign on the Lennox oil and gas field in 2005. The campaign comprises one sidetrack well and up to five workovers of existing wells.

Production during 2004 2005 averaged 36,000 barrels per day of oil and 200 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.

Gross production from the Bruce field during 2004 2005 averaged 14,000 barrels per day of oil, 400 million cubic feet per day of gas and 976 tonnes per day of LPG. The average production rates were impacted by a 54 day shutdown of the Bruce platform to install the low pressure booster compression module (LPBC). The Low Pressure Booster Compression is a key element of the Bruce field depletion programme. This module will deliver additional compression which will enable the platform operating pressure to be reduced and, hence, reduce reservoir pressure through the field decline period and into late field life. This reduced suction pressure increases recoverable reserves.

We also have a 31.83% interest in the Keith field, which we operate, which is located adjacent to the Bruce field in block 9/8a. The Keith field was developed by a tieback to the Bruce platform facilities. In 2004 2005, production from Keith averaged 1,500 barrels per day of oil and

4 million cubic feet per day of gas (gross).

Algeria

Ohanet

The Ohanet wet gas (LPG and condensate) development is located in the Illizi province of Algeria, approximately 1,300 kilometres southeast of Algiers and 100 kilometres west of Libya.

We have an effective 45% working interest in the Ohanet Joint Venture. The other participants are Japan Ohanet Oil & Gas Co Ltd (30%), Woodside Energy (Algeria) Pty Ltd (15%) and Petrofac Resources (Ohanet) LLC (10%).

The Joint Venture parties together form the Contractor party to the Ohanet Risk Service Contract (RSC), signed with Sonatrach, Algeria s state-owned oil and gas company, in 2000 for the development of four gas and condensate reservoirs in the Ohanet region of Algeria.

The total budgeted costs for the development of the Ohanet reservoirs were US$1,030 million, our share being US$464 million. Actual development costs will not be finalised until the completion of a future drilling campaign included in the original development scope.

Production began in October 2003. Gross liquids production during 2004-2005 averaged 27,000 barrels per day of condensate and 2,100 tonnes per day of LPG.

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The terms of the RSC specify that the total production from the fields is the property of Sonatrach. The RSC Contractor bears the total cost of developing the Ohanet reservoirs, and in return, will recover its 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 is translated into entitlement volumes of condensate, butane and propane that are currently sold to Sonatrach under a marketing agreement with the Ohanet Joint Venture parties.

ROD Integrated Development

In Algeria, we hold a 45% interest in the contractor party that is signatory to the Blocks 401a and 402a production sharing contract with 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 for an exploitation phase duration of 15 years, with an option to extend for an additional 5 years under certain conditions. The blocks are located 900 kilometres southeast of Algiers, near the Tunisian border in the Berkine Basin.

Exploration in Blocks 401a/402a led to BHP Billiton Board sanction in 2000 to proceed with the ROD Integrated Development project. The development activities were undertaken by a joint Sonatrach/BHP Billiton operating organisation (OOC).

The ROD Integrated Development comprises the development and production of six oil-fields, the largest two of which, ROD and SFNE, extend into the neighbouring Blocks 403a and 403d. An agreement is in place to govern unitisation of the ROD and SFNE fields, the sharing of specified costs, operatorship and commercial arrangements for the development. Under this agreement, we estimate that our share of the US$500 million development costs will be approximately US$190 million, still subject to agreement by all parties on the final allocation of capital expenditure between the fields.

The ROD fields are being produced through a new dedicated processing train, constructed adjacent to the existing Bir Ribaa Nord (BRN) production facility located on the Algerian Block 403, operated by a joint Sonatrach/ENI Algeria Exploration B.V operating organisation (GSA). ROD crude is exported through the established pipeline infrastructure to terminals located on the Algerian coast. The associated gas is being re-injected underground. First production from the ROD Integrated Development commenced in October 2004 through an accelerated production system utilising spare capacity in the BRN plant, with production through the dedicated new train following in December 2004. Gross oil production in the period October 2004 to June 2005 averaged 43,000 barrels of oil per day.

Following formal transfer of unit operatorship on 30 June 2005, production operations for the ROD Integrated Development are being conducted by the GSA.

Exploration and Development

We have exploration interests in Australia, Asia, the Americas and Europe/Africa/Middle East. We are participating in developments in Australia, the United States, and Trinidad and Tobago.

Australia/Asia

We have exploration interests in Australia, Brunei Darussalam, the Philippines, and Pakistan.

Australian Exploration

In Australia we have exploration interests in 16 permits offshore Western Australia and one permit offshore Victoria.

Stybarrow   WA-255-P Exploration

We drilled and completed, as operator, an exploration well on the Stybarrow prospect in February 2003. The well encountered hydrocarbons. A Stybarrow-2 appraisal well was drilled and also encountered hydrocarbons. A further two wells, Stybarrow-3 and 4, further confirmed the oil/water contact and encountered hydrocarbons. Based upon the results of these wells, various development concepts have been considered and we expect the Board to consider the final development plan in late 2005.

We own a 50% operated working interest in this permit with the remaining interest held by Woodside Energy Ltd.

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Pyrenees WA-155-P / WA-12-R Exploration

We drilled and completed, as operator, an exploration well on the Ravensworth prospect in July 2003 which encountered hydrocarbons. A Ravensworth-2 appraisal well was drilled in June 2004 and also encountered hydrocarbons.

We own a 40% operated working interest in the WA-155-P permit, with Apache Energy Ltd owning 31.5% and Inpex owning the remaining 28.5%.

In addition to the Ravensworth discovery wells, we also drilled a series of exploration and appraisal wells in the adjoining block WA-12-R during 2003 and 2004. The Stickle-1, Stickle-2, Stickle-3, Crosby-1, Crosby-2 and Harrison-1 wells all encountered hydrocarbons. We own a 71.43% operated working interest in the WA-12-R permit, with Apache owning the remaining 28.57%.

A joint development plan is currently underway encompassing the Ravensworth, Crosby and Stickle discoveries (jointly referred to as Pyrenees development). Harrison is being considered as a potential near-field tie-back following the initial phase of development.

Exmouth Sub-Basin

During 2004-2005, we conducted exploration programmes in the Exmouth Sub-basin of the Carnarvon Basin, in permits WA-255-P (2), WA-155-P (1), WA-12-R, WA-351-P and WA-322-P.

Exploration activity concentrated on integrating the results from the extensive 2003-2004 drilling campaign and rebuilding the prospect inventory. Langdale-1, located in WA-155-P(1), was drilled in April 2005 and was plugged and abandoned as a sub-commercial gas discovery.

We commenced a 3D seismic survey in northern WA-255-P and WA-322-P in June 2005. The acquisition of this survey (covering an area greater than 1600 square kilometres) will enable us to characterise the hydrocarbon potential in the northern part of the sub-basin.

Browse Basin

We are the operator of five permits in the deepwater Outer Browse Basin (WA-301-P, WA-302-P, WA-303-P, WA-304-P and WA-305-P), located immediately to the west of the Brecknock & Scott Reef gas discoveries. During 2004-2005, our efforts were focussed on maturing gas prospects with sufficient volumetric potential for LNG supply. During 2005-2006, we will acquire 3D seismic data over the Dacey prospect and drill the Warrabkook prospect in WA-303-P.

We are also a joint venture participant in the various Woodside-operated retention leases covering the Brecknock, Brecknock South & Scott Reef discoveries, with an equity level varying between 8.33% and 20%. Three wells and two 3D seismic surveys will be undertaken to appraise these discoveries commencing in July 2005.

Additionally, we are the operator of permit AC/P30 in the northern Browse where we have applied for a retention lease over the Argus gas discovery. We have a 67% operated interest in AC/P30 and Encana International (Australia) Pty Ltd holds the other 33%.

Scarborough/Pilbara LNG

We have a 50% non-operated interest in the Scarborough gas field in WA-1-R and hold 100% interest in WA-346-P which covers the northern extension of the mapped gas reservoir. During the first half of calendar year 2004, we obtained 912 square kilometres of 3D seismic data over the field in WA-1-R and its extension into the WA-346-P permit. Subsequently, under agreement with our partner, Exxon, we operated the drilling of three appraisal wells in WA-1-R between December 2004 and February 2005. Scarborough-3, Scarborough-4A and Scarborough-5 all encountered hydrocarbons and were plugged and abandoned. Evaluation of the drilling results and the 3D seismic data acquired in 2004 are in progress. We are conducting a pre-feasibility study into development options for the field and a proposed LNG plant and export facilities to receive and process feedstock from the Scarborough gas field in the Carnarvon Basin, 280 kilometres north-west of Onslow, Western Australia. We have selected a site near Onslow as our preferred location for the LNG processing plant and export facilities. The project is examining a number of concepts for the field development that would connect to a single train with capacity of approximately 6 million tonnes per annum.

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Gippsland

During 2004-2005, we drilled the West Moonfish -1 exploration well in Vic/L10 which was plugged and abandoned as a sub-commercial gas and oil discovery. We also exited the VIC/P45 permit, which we had previously operated.

Philippines Exploration

In April 2005, we exited SC-41, an offshore permit in the Sulu Sea after drilling two wells in mid 2004, Zebra-1 & Rhino-1. Both wells failed to encounter hydrocarbons and were subsequently plugged and abandoned.

We were also part of a bidding consortium with Unocal, Occidental and Amerada Hess Corporation (25% each) that won two deepwater permits. The service contract (SC56) was signed in August 2005.

Brunei Exploration

We have a 25% working interest in Block J, offshore Brunei Darussalam. The remaining interests are held by Total (60% and operator), and Amerada Hess Corporation (15%). The joint venture executed a production sharing contract with the government of Brunei Darussalam in March 2003. The government of Malaysia subsequently claimed this block formed part of their territorial waters and awarded the same acreage to a competing joint venture. The dispute remains unresolved.

Pakistan Exploration

In April 2005 we acquired a 37.5% working interest in the Jhangara block in the Sindh province of Pakistan, approximately 40 kilometres from our Zamzama operated asset. Premier Oil Pakistan Offshore BV is the operator with 18.75% working interest. The remaining working interests are held by OMV (18.75%), Pakistan Exploration Limited (10%) and Oil & Gas Investments Ltd (15%). We have a one-well commitment and seismic option. The first exploration well spudded in August 2005.

Americas

In the Gulf of Mexico, we are developing the Atlantis and Neptune oil and gas fields. In addition, we have extensive exploration interests in the Gulf of Mexico, Trinidad and Tobago and smaller interests in Canada, Colombia and Mexico.

Gulf of Mexico

We have been acquiring leasehold interests in the deepwater Gulf of Mexico since the early 1990s. At 30 June 2005 our offshore portfolio consisted of 368 leases, 241 of which are in deepwater and 127 of which are on the shelf in the Gulf of Mexico and cover various prospects within this area.

Atlantis Development

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

The initial Atlantis discovery in the Green Canyon area was drilled in 1998. As of June 2005, a total of five appraisal wells, three with major sidetracks, have been drilled on the Atlantis structure. All five wells encountered oil bearing sands. In addition, four successful development wells have been drilled to date.

In February 2003, the BHP Billiton Board approved a total of US$1.1 billion as full funding for the development of the Atlantis oil and gas reserves. In November 2004, the Board agreed that the US$1.1 billion approved in 2003 would be used to develop the South portion of the field only and that funding for the North portion of the field would be sought at a later date. The majority of the reserves for the Atlantis field are located in the South portion of the field. It is anticipated that additional funding for the North portion of the field will be requested during fiscal year 2006. The final expenditure for Atlantis will depend on the number of development wells needed to optimise the production of reserves. 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. Gross daily capacity is expected to be 200,000 barrels of oil per day and 180 million cubic feet of gas per day. First oil is expected from the field in the third quarter of calendar year 2006.

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Neptune Development

In 1995 we farmed into the Neptune prospect, 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 in April 2002 with partners Woodside Petroleum Ltd and Marathon Oil Company, we, as operator, drilled and completed the Neptune-3 appraisal well and encountered hydrocarbons. The fourth appraisal well on the prospect was drilled in December 2002. It was non-commercial and has been plugged and abandoned.

In May 2003, we farmed-out a portion of our interest in the Neptune prospect to Maxus (US) Exploration Company, a subsidiary of Repsol (YPF). 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%).

In July 2003, we drilled the Neptune-5 well and encountered hydrocarbons. In January 2004, an integrated project team was formed to evaluate development alternatives and select a preferred concept. In April 2004, the Neptune-7 appraisal well was drilled and encountered hydrocarbons (Neptune-6 was drilled but due to drilling complications was abandoned and Neptune-7 was drilled in its place).

In June 2005, the Board approved the capital expenditure for our share of the costs to develop the Neptune field. The Neptune facility will have a design capacity to produce up to 50,000 barrels of oil and 50 million cubic feet of gas per day with gross costs for the development estimated at approximately US$850 million (BHP Billiton share approximately US$300 million). The Neptune field is located in the deepwater Gulf of Mexico approximately 120 miles from the coast of Louisiana. The production facility will be located in approximately 4,250 feet of water. A standalone, tension leg platform (TLP) has been selected for the development, with seven initial subsea wells tying back to the TLP. First oil is expected by the end of calendar year 2007.

Starlifter Development

We hold a 30.95% interest in the Starlifter project with Newfield Exploration (operator with 45%), Houston Exploration (13.75%) and Ridgewood Energy Corp. (10.3%). It is located in West Cameron Blocks 77 and 96. First production from a single gas well commenced in July 2005. A second well is expected to be drilled in the first half of calendar year 2006.

Shenzi Green Canyon Exploration

In December 2002 we drilled an exploration well on the deepwater Shenzi prospect. The well was drilled in 4,400 feet of water and encountered hydrocarbons. Four successful appraisal wells have since been drilled on the Shenzi prospect. The Shenzi-2 appraisal well drilled to a total depth of 25,500 feet also encountered hydrocarbons, and was followed up by several successful sidetracks. The Shenzi-3 appraisal well was subsequently drilled to test the western side of the structure, reaching a total depth of 28,300 feet. The Shenzi-3 appraisal drilling operations were completed in December 2004 after several successful sidetracks. The Shenzi-4 appraisal well finished drilling in March 2005 after reaching a total depth of 28,000 feet. The Shenzi-5 appraisal well finished drilling in June 2005, after reaching a total depth of 28,500 feet and successfully testing the down dip limits of the structure.

An integrated project team was formed to further define the range of reservoir uncertainty, evaluate development alternatives and select a preferred concept. In July 2005, the Shenzi project progressed to the feasibility phase, having selected a concept based on a 100,000 barrels of oil per day nominal capacity TLP with subsea wells. The project scope, costs, and schedule are being finalised as a part of the front end engineering and design prior to sanctioning the project.

Based on the preferred development concept and the wells drilled to date, a small quantity of reserves were booked in 2004-2005.

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

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Mustang Exploration

In June 2005, we drilled a successful gas exploration well in West Cameron Block 77. We are the operator with a 43.7% working interest with partners Dominion Exploration (22.4%), Houston Exploration (19.4%) and Ridgewood Energy Corp. (14.5%). Development activities are underway, with first gas expected during calendar year 2006.

Puma Green Canyon/Western Atwater Foldbelt Exploration

The Puma-1 exploration well was drilled in January 2004. The well was drilled in 4,130 feet of water and encountered hydrocarbons in both the original hole and in two subsequent sidetrack bores. The operator (BP) is currently drilling the first appraisal well, with a second appraisal well planned to spud late calendar year 2005.

We hold a 33.3% working interest in Puma with BP owning 51.7% and Unocal owning the remaining 15%.

Cascade / Chinook Walker Ridge Exploration

In June 2002, we (as operator) drilled an exploration well on the ultra deepwater Cascade Prospect and encountered hydrocarbons. The well was drilled in waters approximately 8,200 feet deep to a total depth of 27,979 feet. The Cascade 2 appraisal well is currently drilling and is expected to be finished late calendar year 2005.

We hold a 50% working interest in Cascade, with Petrobras and Devon Energy Corporation each holding a 25% interest.

In January 2001, we (as operator) drilled an exploration well on the ultra deepwater Chinook Prospect. The well was drilled in water depths of approximately 8,830 feet and failed to encounter hydrocarbons. A second exploration well targeting a deeper reservoir section was subsequently drilled in June 2003 and encountered hydrocarbons. Further appraisal will be required to evaluate the economic viability 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.

Some significant exploration wells drilled in the Gulf of Mexico during 2004-2005 included:

Mad Dog Deep

Drilling operations are proceeding on the Mad Dog Deep well, a 27,300 feet wildcat located in Green Canyon Block 826 in 6,741 feet of water. The well was spud in May 2005 and is targeting the Pre-Miocene section (Eocene and Paleocene) on the Mad Dog anticline. It reached final depth in August 2005 and logging operations are continuing. We hold a 23.9% working interest, with partners BP (operator) 60.5% working interest and Unocal 15.6% working interest.

Makalu

The Makalu-1 exploration well in the Atwater Valley was spudded in the fourth quarter of 2004, and was subsequently plugged and abandoned in the second quarter of 2005 as a dry hole. Chevron operated the well with a 37.5% working interest, while we participated at a 40% working interest level. Other partners were Devon (12.5%) and Murphy Oil who farmed-in to our position at a 10% working interest level.

Bonsai

We are currently participating with a 35% working interest in a planned 29,500 feet deep exploratory test on the Bonsai Prospect in the Atwater Valley. BP is operating the well with a 65% working interest, and will also operate any subsequent appraisal operations.

Joseph

We participated with a 20% working interest with Shell as operator (30%) in an exploration well on the Joseph prospect in High Island Block 10L in Texas State waters, spudded in early September 2004. Partners in the well included Devon (20%) and Total (30%). The well reached a total depth of 25,552 feet in late June 2005 and has been temporarily abandoned.

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Blackbeard

We are currently participating with a 5% working interest with Exxon as operator (25%) in an exploration well on the Blackbeard prospect in South Timbalier Block 168 in Lousiana Federal OCS waters, spudded in early February 2005. Partners in the well include Newfield (23%), BP (20%), Petrobras (20%) and Dominion (7%). As of mid 2005, the well was at a depth of 12,872 feet. The planned total depth of the Blackbeard well is 32,000 feet and total depth is anticipated to be reached in early calendar 2006.

Knotty Head

We are currently participating with a 25% working interest in an exploration well on the Knotty Head Prospect located in the Green Canyon area close to the existing Tahiti discovery. Partners in the well include Nexen (25% operator), Anadarko (25%), and Unocal (25%). Unocal spudded the well in March 2005 and has encountered hydrocarbons. Drilling operations are continuing with the well expected to reach final depth in mid-October 2005.

Significant Acreage Activity / Changes in Ownership in the Gulf of Mexico during 2004-2005 included:

Vortex and Bass Lite (Atwater Valley)

In November 2004 we divested our interest in the Vortex gas discovery in the eastern Atwater foldbelt area. An additional divestment was made of the Bass Lite gas discovery and more than 60 OCS blocks in the same area in April 2005.

Trinidad and Tobago Exploration

Block 2(c) REA Exploration

In April 2002, at the end of the Second Exploration Phase, we relinquished acreage as required under the production sharing contract , and retained approximately 16,120 hectares in the southern portion of Block 2(c), offshore Trinidad. The retained exploration area (REA) is a subset of the broader Block 2(c) PSC which was signed on 22 April 1996 and which comprised 51,766 hectares. We own a 64.28% working interest with Talisman Energy holding the remaining 35.72%. As the operator we drilled the Howler-1 well in June 2003 and encountered hydrocarbons. The well was drilled in waters approximately 190 feet deep to a total depth of 10,170 feet. It is being evaluated as part of the Angostura gas commercialisation study. During 2004-2005, mapping of the remaining prospectivity within Block 2(c) REA was completed and the final commitment exploration well (Gypsy) was spudded in July 2005.

Block 2(c) Producing Area

Kairi A1-A05 (K1-OG) was spudded in December 2004 to test a deeper pool exploration follow-on to a deviated field development well within the Block 2(c) Producing Area. We operated the well with a 45% working interest, with other participants being Total (30%) and Talisman (25%). In January 2005, we and Talisman agreed to drill to a deeper depth which Total opted out of leaving us with a 64.28% working interest and Talisman having the remaining 35.72% in this well. We encountered sub-commercial quantities of hydrocarbons and the well was plugged and abandoned as a dry hole in late June 2005.

Block 3(a) Exploration

The Block 3(a) PSC was signed on 22 April 2002. Block 3(a) is located 40 kilometres off the east coast of Trinidad in water depths ranging from 100 to 300 feet and comprises 612 square kilometres adjacent to the east of Block 2(c). We own a 30% working interest in block 3(a) with BG Trinidad and Tobago and Talisman Energy each holding 30% and Total holding 10%. As the operator we drilled two exploration wells in block 3(a) in September and October 2003. The wells were on the Bimurraburra and Delaware prospects. It was subsequently found that the Bimurraburra prospect was non-commercial and the cost was written-off in March 2005. The Delaware discovery is being assessed to determine its economic potential. During 2004-2005, mapping of the remaining prospectivity within Block 3(a) was completed and the first of a maximum of three commitment exploration wells is planned to be spudded in late calendar 2005.

Galera Block Exploration

We farmed into BP s Galera Block during 2003-2004 under an agreement which required us to fund a seismic programme over the block in order to retain an option to earn a working interest by funding a future exploration well. We are currently deciding whether or not to exercise our option to participate in an exploration well on the block. Should we participate, the post-well interests in the Galera Block would be BP (50% operator), BHP Billiton (32.5%) and Talisman (17.5%). Our farm-in to this block remains subject to Government approval.

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Maritime Canada

During 2003, we negotiated a farm-in arrangement with ConocoPhillips to participate in its Laurentian Basin acreage. The agreement, concluded in 2004, gave us access to ConocoPhillip s operated acreage with Murphy Oil Company as its joint venture partner. The acreage includes existing exploration licences (offshore Newfoundland 7 licences, Nova Scotia 1 licence/pending and St Pierre Miquelon 1 licence), with the farm-in giving us various participating interest earning options, with a maximum participating interest earning rights ranging from 32.5% to 40% depending upon the particular area earned and exploration work programme completed. The work programmes to date have included a 3,800 kilometre 2D seismic programme (completed during July through November 2004) and a 2,100 square kilometre 3D seismic programme (in progress in 2005 with completion targeted for early in the second quarter of 2005-2006). An exploration drilling programme targeting one or more exploration wells (depending upon seismic results) is scheduled to begin in 2007.

Colombia

During 2004-2005, we negotiated a 100% participating interest in the offshore Fuerte Technical Evaluation Agreement (TEA), which became effective 16 May 2005. The TEA covers an area of approximately 1.5 million hectares and gives us the right to technically study the area for a period of 18 months. On or before the end of the study period, we have the preferential right to convert the TEA to an exploration licence, the term and work commitments of which are negotiable with the Colombian National Hydrocarbon Agency.

Mexico

During 2004-2005, we entered into an agreement with PEMEX (Mexico s state oil company) to assist them in evaluating the petroleum system and prospectivity of the Lamprea Profundo area. This Joint Collaboration Project started in March 2005 and concluded in August 2005. We have conducted geological and geophysical evaluations of seismic and well data and are assisting PEMEX with basin modeling, structural restoration and production facility selection studies.

Brazil

In June 2002, we acquired a 100% interest in offshore block BM-C-24 that covers 603 square kilometres. Following an evaluation of the block s prospectivity, a decision was made to exit. Therefore, following the required transfer of reprocessed seismic data to the government, we relinquished the block in August 2005.

Europe/Africa/Middle East

We have exploration interests in the UK North Sea, Algeria and southern Africa.

UK North Sea Exploration

In October 2004 we farmed into the Davan prospect located in the UK northern North Sea in Blocks 9/5aS, 9/10a, 9/5c and 9/4c. Partners in the blocks include Total (operator), Marathon and Amerada Hess, with the equity held by each partner varying across the four blocks. We have working interests of 27%-35% in the Davan blocks. The Davan prospect is located in 350 feet of water 17 kilometres north-east of the Bruce platform and if successful could potentially be developed as a subsea tieback to Bruce. The current commitment is to drill one exploration well which spudded in September 2005.

Algeria Exploration

During 2004 and 2005, we participated in two international exploration licence rounds in Algeria (the fifth round awarded in August 2004 and the sixth round in April 2005), with the blocks being awarded under production sharing contracts. We were successful in both of these rounds, being awarded the Ksar Hirane permit in the fifth round and the Hassi Bir Rekaiz and Oudoume permits in the sixth round.

Ksar Hirane (Blocks 408a/409) is located onshore to the north of the gas field Hassi R Mel. We have a 50% operating interest, with Woodside Energy Ltd holding the remaining 50%. The expected work programme is 1,200 kilometres of 2D seismic and one exploration well during the initial three year period. Seismic acquisition commenced in September 2005, with the first exploration well planned for late 2006.

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Hassi Bir Rekaiz is located onshore in the Berkine Basin, approximately 190 kilometres north-west of the ROD Integrated Development. We have a 100% operating interest in this permit which includes the existing Semhari oil discovery. The expected work programme includes both exploration and appraisal activities (2D seismic on the exploration potential and 3D seismic on the appraisal area, with wells on both) over the initial three year period, but work is yet to start as the licence is yet to be formally gazetted.

Oudoume is located onshore in the Illizi Basin, approximately 100 kilometres west of the Ohanet wet gas development. We have a 100% operating interest in this permit which includes two small existing gas discoveries. The expected work programme includes both exploration appraisal activities (2D seismic on the exploration potential and 3D seismic on the appraisal area, with wells on both) over the initial three year period, but work is yet to start as the licence is yet to be formally gazetted.

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. In February 2004, we farmed out half of our interest in Block 3B/4B offshore South Africa to Occidental Oil and Gas Corporation whilst retaining a 45% working interest and operatorship. The joint venture then acquired 3D seismic data and we are currently planning to drill an exploration well in the fourth quarter of calendar year 2005.

In November 2004, we and Occidental applied to the South African Government Agent (PASA) for an exploration right over a large tract of acreage (approximately 52,000 square kilometres) to the west of Blocks 3B/4B, referred to as the Western Margin Deepwater Block and this application is currently being processed.

In March 2005, we farmed into Block 3A/4A, acquiring a 90% working interest and resuming operatorship from Sasol Petroleum International (Pty) Ltd. We are currently reprocessing the 3D survey prior to deciding whether to proceed with the next licence phase.

Namibia

In March 2005, we applied for two exploration licences in offshore Namibia and negotiations with the Government are currently underway.

Marketing

Oil and Condensate

Our global trading and marketing teams based in Houston, Melbourne, The Hague and Singapore manage the marketing and risk associated with our crude oil, condensate 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, North West Shelf Australia LNG Pty Ltd, 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 and Korea.

We are seeking approval to construct and operate the Cabrillo Port, a Floating Storage and Re-gasification Unit (FSRU) approximately 34 kilometres off the California coast. This deepwater port would be the receiving terminal for shipments of LNG bound for the west coast markets of the United States. Cabrillo Port is designed to store 270,000 cubic metres of LNG. Natural gas production would average 800 million cubic feet per day with design capacity of the FSRU and downstream pipelines allowing maximum deliveries of 1.2 billion cubic feet per day into the SoCal Gas pipeline system. The Cabrillo Port project is in the midst of a thorough permitting process involving federal, state and local government agencies. The project is currently in the pre-feasibility study stage with Board sanction targeted for 2007.

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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. We make some spot sales when LPG produced exceeds our term commitments.

Energy Marketing

Energy Marketing (EM) was set up in July 2002, with the responsibility of co-ordinating our marketing activities in the energy commodity markets, namely coal, gas, emissions credits and electricity. The group is based in The Hague, The Netherlands and is part of our Marketing function.

EM is currently active in purchasing and selling third party physical gas and small amounts of electricity in the UK and emissions credits in Europe. EM has also participated in gas storage capacity to facilitate its gas sale and purchase activities. Where required, EM also buys or sells pipeline capacity to transport gas onto the UK gas grid called the National Transmission System. Most products are transacted over the counter and are principal-to-principal transactions in the wholesale market. The emissions strategy is largely defensive to meet internal asset requirements as well as to facilitate increased coal sales into Europe.

Reserves

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (i.e. prices and costs as of the date the estimate is made). Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Estimates of oil and gas reserves are inherently imprecise, require the application of judgement and are subject to future revision. Accordingly, financial and accounting measures (such as the standardised measure of discounted cash flows, depreciation, depletion and amortisation charges, the assessment of impairments and the assessment of valuation allowances against deferred tax assets) that are based on reserve estimates are also subject to change.

Proved reserves are estimated by reference to available seismic, well and reservoir information, including production and pressure trends for producing reservoirs and, in some cases, to similar data from other producing reservoirs in the immediate area. Proved reserves estimates are attributed to future development projects only where there is a significant commitment to project funding and execution and for which applicable governmental and regulatory approvals have been secured or are reasonably certain to be secured. Furthermore, estimates of proved reserves only include volumes for which access to market is assured with reasonable certainty. All proved reserve estimates are subject to revision, either upward or downward, based on new information, such as from development drilling and production activities or from changes in economic factors, including product prices, contract terms or development plans. In certain deepwater Gulf of Mexico fields proved reserves have been determined before production flow tests are conducted, in part because of the significant safety, cost and environmental implications of conducting those tests. In these fields other industry-accepted technologies have been used that are considered to provide reasonably certain estimates of productivity.

The table below details estimated oil, condensate, LPG and gas reserves at 30 June 2005, 30 June 2004 and 30 June 2003, with a reconciliation of the changes in each year. 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 include quantities of oil, condensate and LPG which will be produced under several production and risk sharing arrangements that involve the BHP Billiton Group in upstream risks and rewards without transfer of ownership of the products. At 30 June 2005, approximately 12 % (2004: 17 %; 2003: 19 %) of proved developed and undeveloped oil, condensate and LPG reserves and nil per cent (2004: nil; 2003: nil) of natural gas reserves are attributable to those arrangements. Reserves also include volumes calculated by probabilistic aggregation of certain fields that share common infrastructure. These aggregation procedures result in enterprise-wide proved reserves 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 [(a)]	Australia / Asia	Americas	UK/Middle East	Total
		(millions of barrels)		
Reserves at 30 June 2002	329.0	160.7	108.9	598.6
Improved recovery			0.1	0.1
Revisions of previous estimates	52.2	(12.2)	12.2	52.2
Extensions and discoveries	0.5	10.1	3.9	14.5
Purchase/sales of reserves				
Production [(b)]	(55.1)	(6.6)	(11.7)	(73.4)
Total changes	(2.4)	(8.7)	4.5	(6.6)
Reserves at 30 June 2003	326.6	152.0	113.4	592.0
Improved recovery				
Revisions of previous estimates	20.2	(2.6)	(9.5)	8.1
Extensions and discoveries	0.4	11.0	1.1	12.5
Purchase/sales of reserves		(4.0)		(4.0)
Production [(b)]	(46.3)	(7.6)	(14.1)	(68.0)
Total changes	(25.7)	(3.2)	(22.5)	(51.4)
Reserves at 30 June 2004	300.9	148.8	90.9	540.6
Improved recovery				
Revisions of previous estimates	24.5	(1.7)	(1.3)	21.5
Extensions and discoveries	7.2	43.5		50.7
Purchase/sales of reserves	(9.2)			(9.2)
Production [(b)]	(38.7)	(7.6)	(14.7)	(61.0)
Total changes	(16.2)	34.2	(16.0)	2.0
Reserves at 30 June 2005 [(c)]	**284.7**	**183.0**	**74.9**	**542.6**

Proved developed oil, condensate and LPG reserves [(a)]				
Reserves at 30 June 2002	233.1	15.9	30.2	279.2
Reserves at 30 June 2003	227.8	9.9	24.5	262.2
Reserves at 30 June 2004	201.9	5.4	54.8	262.1
Reserves at 30 June 2005	**180.5**	**18.3**	**74.5**	**273.3**

(a) In Bass Strait, the North West Shelf, Ohanet and the North Sea, LPG is extracted separately from crude oil and natural gas.

(b) Production for reserves reconciliation differs slightly from marketable production due to timing of sales and corrections to previous estimates.

(c) Total proved oil, condensate and LPG reserves include 11.3 million barrels derived from probabilistic aggregation procedures.

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Proved developed and undeveloped natural gas reserves	Australia / Asia (a)	Americas	UK/ Middle East	Total
	(billions of cubic feet)			
Reserves at 30 June 2002	4,500.8	154.0	489.2	5,144.0
Improved recovery			16.7	16.7
Revisions of previous estimates	404.1	4.9	(7.0)	402.0
Extensions and discoveries	188.9	10.2		199.1
Purchases/sales of reserves				
Production [(b)]	(189.2)	(21.8)	(79.9)	(290.9)
Total changes	403.8	(6.7)	(70.2)	326.9
Reserves at 30 June 2003	4,904.6	147.3	419.0	5,470.9
Improved recovery				
Revisions of previous estimates	114.6	2.2	(10.0)	106.8
Extensions and discoveries	51.6	4.6		56.2
Purchases/sales of reserves		(32.8)		(32.8)
Production [(b)]	(222.9)	(20.5)	(77.0)	(320.4)
Total changes	(56.7)	(46.5)	(87.0)	(190.2)
Reserves at 30 June 2004	4,847.9	100.8	332.0	5,280.7
Improved recovery				
Revisions of previous estimates	237.3	3.1	(29.9)	210.5
Extensions and discoveries	177.0	27.6		204.6
Purchases/sales of reserves	(165.8)			(165.8)
Production [(b)]	(275.7)	(14.6)	(57.6)	(347.9)
Total changes	(27.2)	16.1	(87.5)	(98.6)
Reserves at 30 June 2005 [(c)]	4,820.7	116.9	244.5	5,182.1

Proved developed natural gas reserves				
Reserves at 30 June 2002	2,455.1	79.9	481.9	3,016.9
Reserves at 30 June 2003	2,560.4	64.8	397.1	3,022.3
Reserves at 30 June 2004	2,539.7	20.1	310.0	2,869.8
Reserves at 30 June 2005	**2,621.4**	**15.1**	**239.3**	**2,875.8**

(a) Production for Australia includes gas sold as LNG and as liquefied ethane.
(b) Production for reserves reconciliation differs slightly from marketable production due to timing of sales and corrections to previous estimates.
(c) Total proved natural gas reserves include 190.6 billion cubic feet derived from probabilistic aggregation procedures.

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Production

The table below details our Petroleum business historical net crude oil and condensate, natural gas, LNG, LPG and ethane production by region for the three years ended 30 June 2005, 2004 and 2003. We have shown volumes and tonnages of marketable production, after deduction of applicable royalties, fuel and flare. We have included in the table average production costs per unit of production and average sales prices for oil and condensate and natural gas for each of those periods.

	Year ended 30 June		
	2005	**2004**	**2003**
Crude Oil and Condensate Production (millions of barrels)			
Australia/Asia	31.1	38.9	48.0
Americas	7.6	7.5	7.1
Europe/Africa/Middle East	12.1	11.6	10.8
Total	50.8	58.0	65.9
Natural Gas Production (billions of cubic feet)			
Australia/Asia (Domestic)	189.8	165.3	126.4
Australia/Asia (LNG) (leasehold production)[1]	83.1	60.8	62.0
Americas	15.0	20.6	20.6
Europe/Africa/Middle East	57.8	77.6	72.2
Total	345.7	324.3	281.2
Liquefied Petroleum Gas (LPG) Production[2] (thousand tonnes)			
Australia/Asia (leasehold production)	640.1	652.8	644.2
Europe/Africa/Middle East (leasehold production)	220.0	200.7	98.9
Total	860.1	853.5	743.1
Ethane Production (thousand tonnes)			
Australia/Asia (leasehold production)	101.5	94.3	94.9
Total Petroleum Products Production			
(millions of barrels of oil equivalent) [3]	119.0	122.5	121.8
Average Sales Price			
Oil and Condensate (US$ per barrel)[4]	47.16	32.24	28.14
Natural gas (US$ per thousand cubic feet)	2.98	2.62	2.21
Average Production Cost[5]			
US$ per barrel of oil equivalent (including resource rent tax and other indirect taxes)	9.89	7.78	8.01
US$ per barrel of oil equivalent (excluding resource rent tax and other indirect taxes)	4.16	3.27	3.55

(1) LNG consists primarily of liquefied methane.

(2) LPG consists primarily of liquefied propane and butane.

(3) Total barrels of oil equivalent (boe) conversions based on the following:

6,000 scf of natural gas equals 1 boe; 1 tonne of LPG equals 11.6 boe; 1 tonne of ethane equals 4.4667 boe.

(4) No commodity hedging of oil and condensate prices occurred during the periods presented.

(5) Average production costs include direct and indirect production costs relating to the production and transportation of hydrocarbons to the point of sale. This includes shipping where applicable. Average production costs have been shown including and excluding resource rent tax and other indirect taxes and duties. Average production costs also include the foreign exchange effect of translating local currency denominated costs and indirect taxes into US$.

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Regulatory and Fiscal Terms

Australia

Oil and natural gas belong to the government, and rights to explore and produce oil and natural gas are granted by the relevant State, Territory or Commonwealth Government of Australia. The Commonwealth Government has legislative responsibility for Australian offshore petroleum exploration and production beyond the three-mile territorial sea limit, which encompasses the area of most relevance to us in Australia. Our operations in this area are governed by the Petroleum (Submerged Lands) Act 1967 (PSLA). Within the three-mile limit, petroleum operations are governed by the adjacent State or Northern Territory legislation, which is similar to the PSLA. Most production licences we hold in the North West Shelf and Bass Strait regions have been issued under the PSLA.

An exploration permit authorises the holder to explore for, but not produce, petroleum in the area that is the subject of the permit. Offshore exploration permits are awarded based on either cash bidding or work programme bidding for an initial period of six years. The holder of a permit granted under the work programme bidding system is required to complete a minimum guaranteed dry-hole work programme for the first three years of the permit and secondary work programme for the subsequent three years. Under the cash bidding system, permits are awarded to the highest cash bidder and applicants are not required to submit exploration programmes.

Exploration permits may be renewed for five-year periods in respect of half the number of blocks contained within the existing permit. A retention lease may be applied for if a petroleum discovery is currently non-commercial but has the potential to become commercial within 15 years. The initial term of a retention lease is five years and it may be renewed provided it still meets the required commerciality criteria. A production licence may be applied for after a discovery is made. Production licences granted prior to 30 July 1998 authorise the licensee to recover petroleum and explore for petroleum in the licence area for a term of 21 years with a further term of 21 years upon the first renewal. All production licences granted after 30 July 1998 and the second renewal of production licences granted prior to that date remain in force indefinitely. Such production licences will expire if no production operations are carried on for a continuous period of five years.

The expiry dates of our existing production licences in Australia are as follows:

Licence Name	**Field (s)**	**Expiry Date**
VIC/L1-2	Barracouta, Whiptail, Tarwhine and Whiting	24 August 2009
VIC/L3-4	Marlin, Batfish and Turrum	24 August 2009
VIC/L5-6	Halibut, Mackerel, Yellowtail and Gudgeon	19 September 2010
VIC/L7-8	Kingfish	19 September 2010
VIC/L9	Tuna	12 July 2016
VIC/L10	Snapper, Moonfish and Sweetlips	28 May 2018
VIC/L11	Flounder	28 May 2018
VIC/L13-14	Bream	15 December 2006
VIC/L15-16	Dolphin	13 June 2010
VIC/L17	Perch	13 June 2010
VIC/L18	Seahorse	13 June 2010
VIC/L19	West Fortescue	12 July 2016
VIC/L20	Blackback/Terakihi	1 January 2019
VIC/L22	Minerva	31 October 2023
WA-1-L to WA-6-L	North Rankin, Goodwyn and Angel	29 September 2022

WA-9-L	Wanaea and Cossack	11 April 2012
WA-11-L	Wanaea	30 September 2014
WA-16-L	Hermes and Lambert	11 September 2018
WA-30-L	Perseus Extension	5 years after the end of production
WA-10-L	Griffin, Chinook and Scindian	18 February 2014
WA-23-L to WA-24-L	Echo Yodel	5 years after the end of production
PL191 (Coal Bed Methane)	N/A	21 March 2032
PL196 (Coal Bed Methane)	N/A	21 December 2034

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Secondary taxes   Australia

A petroleum resource rent tax applies to offshore areas, with the exception of the North West Shelf project. The petroleum resource rent tax, which applies at a 40% rate, is calculated on the excess of assessable receipts over certain deductible expenditures as outlined in the Petroleum Resource Rent Tax Act 1987. The North West Shelf project is subject to excise and royalty on oil production and royalty on LNG, domestic gas, LPG and condensate production.

The petroleum resource rent tax is assessed before company income tax. The amount of petroleum resource rent tax paid is a deduction for the purpose of calculating company income tax.

The petroleum resource rent tax is payable when project cash flows become positive, after taking into account all allowable exploration, development and operating costs, and after a stipulated return on the project has been achieved. Exploration expenditure has a stipulated return of 15% plus the Australian government long-term bond rate, and project expenditure has a stipulated return of 5% plus the long-term bond rate. The long-term bond rate for this purpose for the year ended 30 June 2005 was 5.42%.

Pakistan

Onshore oil and gas interests in Pakistan are held under concession agreements which provide for exploration, development and production operations to be carried out under petroleum exploration licences, with interest holders being entitled to apply for the grant of a development and production lease in the event of a commercial discovery. Our rights in the Zamzama field are held under the concession agreement relating to the 2667-1 Dadu block, and the associated development and production lease. A royalty equivalent to 12.5% of the wellhead value of the petroleum won and saved under this lease is payable to the government, with production bonuses also payable when cumulative levels of production reach specific pre-set levels. Income tax liability is charged at the higher of 55% of taxable profits (after charging royalty as an expense) and 50% of profits before charging royalty. Royalty payments are adjustable against the final income tax liability.

Americas

Our current operations in the Americas principally fall under two separate fiscal regimes, namely, the United States, and Trinidad and Tobago. In the United States, operations are predominantly in Federal offshore waters in the Gulf of Mexico. Revenues from this area carry royalty interests of 16.67% in water depths up to 400 metres and 12.5% in water depths greater than 400 metres. In addition, a 35% tax rate is also levied on taxable income. Under the United States Outer Continental Shelf Deep Water Royalty Relief Act of 1995, certain deepwater outer continental shelf tracts in the central and western Gulf of Mexico have been leased with automatic suspension of the royalty payment obligation as to certain volumes of production, depending on the water depth of the wells. In addition to automatic royalty relief, the government can also grant discretionary royalty relief where prospect development would be otherwise uneconomic.

The lease conditions for our existing production in the Gulf of Mexico are such that each lease shall continue from the effective date, for the initial period, and for so long thereafter as oil or gas is produced from the leased area.

In December 2000, the US Minerals Management Service (MMS) granted discretionary royalty relief for up to 87.5 million barrels of oil equivalent on production from the Typhoon field, subject to commodity price thresholds which, when reached, trigger royalty payment obligations. The Boris field qualifies for automatic royalty relief, but MMS has, arguably incorrectly, imposed price thresholds, which trigger the royalty payment obligation. The Mad Dog Field is not eligible for any form of royalty relief.

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As at 30 June 2005 we have 19 producing leases in the Gulf of Mexico:

Block	Area	Field	Expiry Date
282	Green Canyon	Boris	As long as oil and gas is producing in paying quantities .
18	Green Canyon	Green Canyon 18	As long as oil and gas is producing in paying quantities .
944, 988	Ewing Bank	Green Canyon 18	As long as oil and gas is producing in paying quantities .
160-161, 205	Green Canyon	Genesis	As long as oil and gas is producing in paying quantities .
738, 781-783, 825-826	Green Canyon	Mad Dog	As long as oil and gas is producing in paying quantities .
236-237	Green Canyon	Typhoon	As long as oil and gas is producing in paying quantities .
60	Green Canyon	Green Canyon 60	As long as oil and gas is producing in paying quantities .
60-61, 76-77	West Cameron	West Cameron 76	As long as oil and gas is producing in paying quantities .

In Trinidad and Tobago, the production sharing contracts allow the contractor to recover its cost from revenue from production in Block 2(c) and Block 3(a). The remaining production is deemed to be profit crude oil or profit natural gas which is split between the Government and contractor according to a formula based on daily production levels and the respective oil or natural gas prices.

The present expiry dates of our existing production sharing contracts in Trinidad and Tobago are as follows:

Block	Field (s)	Expiry date
2(C)	Angostura	21 April 2021
2(C) Retention	Exploration phase	21 February 2006
3(A)	Exploration phase	21 April 2006

United Kingdom

In the United Kingdom, the Crown owns all petroleum under land, the territorial sea and the UK continental shelf. A licence is required for exploration or production. The Secretary of State for Trade and Industry is empowered to grant licences, on conditions approved by the Secretary, and has wide powers of regulation of all aspects of exploration and production. The UK corporate tax rate, applicable to offshore Petroleum production, is 40% (30% primary tax plus a surcharge of 10%).

The present expiry dates of our existing production licences (which are capable of extension in accordance with their individual licence terms) in the United Kingdom are as follows:

Licence Name	**Block**	**Field (s)**	**Expiry date**
P.710	110/13a and 110/13b	Douglas, Douglas West, Hamilton, Hamilton North and Hamilton East	18 July 2007
P.791	110/15b	Lennox	12 June 2009
P.099	110/14b	Lennox and Hamilton East	8 June 2016
P.276	9/9b	Bruce	11 April 2015
P.209	9/8a	Bruce and Keith	15 March 2018
P.090	9/9a	Bruce	24 November 2011

Algeria

Oil and gas are owned by the Algerian state. Mining licences are granted to Sonatrach, the state-owned oil company. Sonatrach, in turn, is empowered by Algerian legislation to enter into contractual arrangements with non-Algerian enterprises covering the exploration and/or exploitation of oil and gas fields. Where the contractual form is either that of a production sharing or risk service contract, the non-Algerian enterprise is liable to Algerian tax, but Sonatrach pays this on their behalf. The ROD Integrated Development partly located in Blocks 401a/402a is under a production sharing contract with an exploitation phase duration of 15 years, plus an option for a five year extension under certain conditions. The Ohanet development is under a risk service contract 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.

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The 401a/402a production sharing contract allows the Contractor to recover its costs out of a maximum of 72.5% of the annual production of crude oil and natural gas liquids from the fields that are covered by the production sharing contract. The remaining production is split as between Sonatrach and the Contractor according to a formula based upon daily production levels. Sonatrach s share of such production ranges from 28% to 57%, out of which Algerian taxes and royalty are paid on behalf of the Contractor, provided that the Contractor is not entitled to more than 49%, in aggregate, of the annual production of crude oil and natural gas liquids, except in the first and second calendar years of production. This may be adjusted in the sixth calendar year of production.

With regard to Ohanet, the risk service contract provides that the Ohanet field shall be developed by the Contractor, the cost reimbursement of which is capped at approximately US$928 million (excluding payments made for Algerian taxes and duties). The Contractor is entitled to the reimbursement of the cost of development, Algerian taxes and duties paid, and operating costs. A level of remuneration set at 106.9% is applied to the recoverable development costs and Algerian taxes and duties incurred. Total recoveries and remuneration is from the production of LPG and condensate. The recoverable and remunerable volumes cannot exceed 49% of the combined annual production of LPG, condensate, and dry gas from the Ohanet field. Sonatrach is entitled to the remainder of the production, from which Algerian royalty and taxes are paid on behalf of the Contractor.

Aluminium

Our Aluminium Customer Sector Group is principally involved in the production of aluminium and alumina. The principal raw materials required for our aluminium production are alumina, petroleum coke, liquid pitch and electricity.

Hillside

We own the Hillside aluminium smelter, which we commissioned between July 1995 and June 1996. Hillside is located in Richards Bay, 200 kilometres north of Durban, KwaZulu-Natal, South Africa. In 2003 2004, we increased the capacity of Hillside by 132,000 tonnes per annum at a cost of US$411 million. In fiscal year 2005 Hillside produced approximately 685,000 tonnes of aluminium using the Aluminium Pechiney AP30 technology. Hillside mostly produces primary aluminium. We sell most of our primary aluminium in standard ingot form, principally to export markets in Asia, Northern Europe and the United States. Hillside also sells aluminium in liquid metal form to our Bayside operations, which casts it into products for the manufacture of aluminium value-added products such as alloy wheels.

We own all of Hillside s property, plant and equipment, including the land on which it is located. In addition, we own silos, buildings and overland conveyors at Richards Bay Port which sit on leased land. Our leases are for 10 years and expire in 2009. Other than the lease of the silo site, the leases have options to extend for up to 10 years. We have to reline the pots we use in our reduction process every five to six years and are currently in our second relining cycle for potline 1 and 2.

Hillside s annual alumina requirements of approximately 1,326,000 tonnes are sourced from our own refinery product and third party sources. Hillside consumes approximately 257,000 tonnes per year of calcined petroleum coke and approximately 56,000 tonnes of liquid pitch each year sourced from a number of overseas suppliers. Hillside purchases electricity from Eskom, the local state-owned power generation company, under a long-term contract with pricing linked to the aluminium price on the London Metal Exchange (LME).

Bayside

We own the Bayside aluminium smelter, which was commissioned in 1971. Bayside is located at Richards Bay. Bayside currently produces approximately 180,000 tonnes of aluminium per year. The smelter uses Alusuisse pre-bake and Soderberg self-bake technologies.

Bayside purchases liquid aluminium from Hillside, which is utilised in addition to the liquid metal produced by Bayside in the manufacture of value-added products.

Bayside generates approximately 80% of its sales revenue from the domestic market, which consists of South Africa and the surrounding countries. The main products produced at Bayside include wheel rim alloy, for use in the manufacturing of vehicle rims, extrusion billets, for use in the building industry, rods, for use mainly as electrical cables and rolling ingot, for use mainly in the production of aluminium sheeting.

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Bayside s annual alumina requirements are sourced from our own refinery product and third party sources. Bayside purchases approximately 70,000 tonnes per year of calcined petroleum coke primarily from American suppliers and approximately 24,000 tonnes of liquid pitch each year from primarily a locally based manufacturer. Bayside purchases electricity from Eskom under a long-term power supply agreement which links the cost of electricity to the aluminium price on the LME.

Mozal

We own a 47.1% interest in the Mozal aluminium smelter, which was commissioned in June 2000. The remaining interest in Mozal is owned by Mitsubishi, which owns a 25% interest, Industrial Development Company of South Africa Limited, which owns a 24% interest, and the government of Mozambique, which owns a 3.9% interest. The smelter is located in southern Mozambique, on the east coast of southern Africa, 17 kilometres from Maputo. It is located approximately 13 kilometres from the nearest port facilities. The smelter uses the Aluminium Pechiney AP30 technology.

Mozal produced its first metal from Phase 1 in June 2000 and from Phase 2, which added a second potline at a cost of US$660 million, in April 2003. The nameplate capacity of the smelter is 506,000 tonnes per year. Our share of production for 2004-2005 was 260,000 tonnes. The joint venture produces standard ingots. We export most of our share of Mozal s production to Europe.

We furnish approximately 1,000,000 tonnes of alumina per year to Mozal, which represents its entire alumina requirements. Mozal purchases most of its petroleum coke requirements from American suppliers. The joint venture purchases its electricity from the South African grid from Motraco, a joint venture between Electricidade de Mozambique, Eskom and the Swaziland Electricity Board, under a power supply agreement which in the first 12 years (through 2012) is at a fixed tariff and thereafter is linked to the aluminium price on the LME.

Worsley

We own an 86% interest in the Worsley joint venture, an integrated bauxite mining and alumina refining operation located in Western Australia. The other participants in the venture are Sojitz Alumina Pty Ltd, which owns a 4% interest, and Japan Alumina Associates (Australia) Pty Ltd, which owns a 10% interest. The refinery is located approximately 55 kilometres north-east of Bunbury and the bauxite mining operation is linked to the refinery via a 51 kilometre overland conveyor.

The open-pit mine produces approximately 12 million tonnes of bauxite per year from extensive near surface deposits. The venture operates its mine on a 2,600 square kilometre mining lease. At the end of the initial 21-year lease granted by the Government of Western Australia, the joint venture renewed the lease for a further 21 years in 2004. There is a further 21-year renewal option available and a possibility that the joint venture may benefit from a third 21-year renewal under renegotiated terms. At current production rates, the venture expects the mining life of the reserves at Worsley to be approximately 26 years.

The refinery, utilising the Bayer process, currently produces approximately 3.27 million tonnes of alumina per year. The joint venture produces metallurgical grade alumina, which is used as feedstock for aluminium smelting. Our share of alumina production at the refinery is approximately 2.81 million tonnes per year. Our alumina is railed to a shared berth facility at the port of Bunbury, and dispatched from there by ship directly to end-use customers.

In May 2004, we announced the approval of the US$192 million (US$165 million our share) Worsley Alumina Development Capital Projects (DCP). The DCP is designed to take advantage of latent capacity in the plant through a series of 28 packages of work. The result will be an increase in alumina production of 250,000 tonnes per annum (215,000 tonnes per annum our share) to a capacity of 3.5 million tonnes per annum (3.01 million tonnes per annum our share). Commissioning and completion of DCP is expected by the first quarter of calendar year 2006 with the resulting production ramp-up to be achieved by the end of the second quarter of calendar year 2006.

The principal raw materials required for alumina production at Worsley, apart from bauxite, are caustic soda, natural gas used for calcination and steam generation and coal for the power station. The power and steam needed by the refinery are provided by a venture owned onsite coal fired power station and a non-venture owned onsite gas fired power station.

Suriname

In August 2003, we announced the restructuring of our joint venture arrangements with Suriname Aluminium Company, L.L.C (Suralco). Under the new arrangement, BHP Billiton Maatschappij Suriname manages all mining operations while Suralco continues to manage the alumina refining in the restructured 45% (BHP Billiton) - 55% (AWAC) venture. The mining joint venture exploits the Lelydorp and Coermotibo deposits, carries out exploration work and new mine development for future bauxite supply. The mining joint venture produces metallurgical grade bauxite, which is processed by the refining joint venture s alumina plant at Paranam.

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The Lelydorp III mine, an open-pit mine located in the coastal plain of Suriname, is situated approximately 25 kilometres south of Paramaribo and 17 kilometres west of the Paranam Refinery. The mine has a nominal production capacity of 2.1 million tonnes per annum.

The Coermotibo operations, a surface strip mine located 150 kilometres east of the Paranam refinery produces 2.1 million tonnes of metallurgical grade bauxite ore per annum. The ore is hauled to the Coermotibo crushing and loading facility and subsequently barged to the Paranam refinery.

Exploration and Exploitation rights

We hold exploitation licences with respect to the Para and Kankantrie deposits, which were recently extended to 2026. Suralco holds exploitation licences over the current Lelydorp III deposit as well as over the bauxite deposits in the Coermotibo operations. Suralco also holds exploitation licences over a number of deposits in eastern and central Suriname. These licences expire in 2032. Furthermore, BHP Billiton and Suralco jointly hold the exploration licence over the Bakhuis region in western Suriname. The rights over this 2,780 square kilometres terrain were granted in November 2003 for a period of 25 months with options for extension. Currently the development of the Kaaimangrasie and Klaverblad deposits across the Suriname River is in the execution phase. It is expected that mining of these deposits will commence in 2006 on depletion of the reserves at the current operations.

All the above mentioned bauxite rights were made available to the new mining joint venture.

Refining joint venture

The refining joint venture operates an alumina refinery and port facilities located at Paranam, at the Suriname River. Alumina exports take place from the Paranam port.

The refining joint venture s alumina plant is a low temperature plant which uses standard Bayer plant technology. The refinery produces approximately 1.95 million tonnes of alumina per year. Our share was 874,000 tonnes in 2004-2005.

In August 2003, we, along with Suralco, approved the expansion of the refinery by 250,000 metric tonnes per year to a capacity upon completion of approximately 2.2 million metric tonnes per year. The US$65 million (100% terms) expansion is complete and although the commissioning process is challenging, it is expected that the target capacity will be achieved in late calendar year 2005.

All alumina produced is exported to Europe. The refinery has three thermal generators, which provide the steam and electricity necessary for the process.

Alumar

The Alumar Consortium (Alumar) is an unincorporated joint venture comprised of an alumina refinery, an aluminium smelter and support facilities. We own a 46.3% interest in the aluminium smelter and Alcoa Aluminio S.A. (Alcoa) owns the remaining 53.7%. We own a 36% interest in the alumina refinery, an affiliate of Alcan Aluminium Limited (Alcan) owns 10%, Alcoa owns 35.1%, and Abalco S.A. (owned 60% by Alcoa and 40% by Alumina Limited) owns the remaining 18.9%. The alumina and aluminium plants are integrated, located in the industrial district of São Luís, the capital of the state of Maranhão, in northern Brazil.

Total annual smelter production, using Alcoa technology, is approximately 380,000 tonnes of aluminium per year. Alumina arrives by conveyor from the adjoining refinery and electricity generated at the Tucuruí hydroelectric dam arrives via two transmission lines. The venture purchases its electric power requirements from Central Elétricas do Norte (Eletronorte) under a long-term contract that was renewed in June 2004 and will expire in December 2024. Most of the production is standard ingots. In 2004-2005, we sold approximately 50% of our share of the ingots to domestic customers with the balance sold on the export market.

The refinery began production in 1984. Subsequently it has been expanded several times. Total production has now reached approximately 1.4 million tonnes per year. The required raw materials, caustic soda, coal, and bauxite, are delivered by ship to the Alumar port. In 2004-2005, approximately 80% of our share of the alumina was allocated to the Alumar and Valesul smelters with the balance sold on the export market.

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We own 14.8% of Mineraçao Rio do Norte S.A. (MRN), a Brazilian mining company jointly owned by affiliates of Alcoa, Alcan, Companhia Brasileira de Alumínio (CBA), Companhia Vale do Rio Doce (CVRD) and Norsk Hydro. MRN extracts, processes and supplies bauxite. We have long-term contracts with MRN to supply the Alumar refinery. MRN has bauxite production capacity of 15.5 million tonnes per annum. Currently, MRN has total proven ore reserves that would allow it to produce 15.5 million tonnes of bauxite per annum for approximately 5 years. The mine is actively pursuing an evaluation programme of bauxite plateaus within the remaining lease area to establish the overall life of the project. MRN holds valid mining rights to all its reserves until exhaustion of the reserves.

During 2001-2002, we joined two consortia with the objective of participating in auctions being held by the Brazilian Electricity Regulatory Agency (ANEEL) for concessions to build and operate proposed Hydropower Plants The first is made up of affiliates of Alcoa, CVRD, Votorantim and Camargo Correa Energia S.A. We own a 20.6% interest in this consortium. In 2001, the consortium won the auction for the Santa Isabel Baixa concession and later signed the concession contract. The Federal Environmental Agency (IBAMA) has declared the project not viable as presented, therefore the consortium has requested ANEEL to return the concession guarantees and to revoke the concession agreement.

Our partners in the second consortium are affiliates of Alcoa, CVRD, Tractebel and Camargo Correa Energia S.A. We own a 16.5% interest in this consortium. This consortium won the auction for the Estreito concession in July 2002 and the Estreito concession contract was signed in December 2002. We are awaiting further definition of requirements from IBAMA regarding environmental issues before the project can be progressed further.

Valesul Aluminio SA

We own a 45.5% joint venture interest in Valesul Aluminio SA, an aluminium smelter located in Rio de Janeiro, Brazil. The balance is held by CVRD. The port of Sepetiba is less than 40 kilometres away and the Port of Rio de Janeiro is less than 60 kilometres away. Valesul began production in 1981 and currently produces approximately 95,000 tonnes of aluminium per year based on P19 Reynolds technology. Valesul draws power primarily from local hydroelectric plants in which it has an ownership interest.

Marketing

Our global trading and marketing team based in The Hague manages the marketing and risk associated with our product. We also purchase product from third parties and some of our joint venture partners in Mozal.

Reserves and Production

The table below details our bauxite-ore reserves in metric tonnes, and is presented in 100% terms as estimated at 30 June 2005.

Bauxite	Ore Type	Proved Ore Reserve	Probable Ore Reserve	Total Ore Reserve	BHP

Deposit[1, 2, 3, 4]		Tonnes (millions)	% $A.Al_2O_3$	% $R. SiO_2$	% Fe_2O_3	Tonnes (millions)	% $A.Al_2O_3$	% $R. SiO_2$	% Fe_2O_3	Tonnes (millions)	% $A.Al_2O_3$	% $R. SiO_2$	% Fe_2O_3	Billiton Interest %
Australia														
Worsley	Laterite	297	30.9	1.73		22	30.10	1.8		319	30.8	1.73		86
Brazil														
MRN[5]	MRN Crude	98								98				14.8
	MRN Washed	72	51	3.5						72	51	3.5		14.8
Suriname														
Coermotibo	Laterite	3.4	45.1	3.1	15.9	0.5	40.2	3.3	20.6	3.8	44.5	3.1	16.4	45
Onverdacht[6]	Laterite	8.5	51.5	4.41	4.98	6.9	49.2	4.2	9.9	15.4	50.5	4.3	7.2	45

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(1) Approximate drill hole spacings used to classify the reserves are:

	Proved Ore Reserve	Probable Ore Reserve
Worsley	maximum 100m	maximum 200m
MRN	A maximum bauxite intersection grid of 200 metres. Mining and metallurgical characterisation (test pit/bulk sample), plus a reliable suite of chemical and size distribution data.	Those plateaux with a bauxite intersection grid spacing of less than 400 metres and/ or a 400 metre spaced grid with a 200 metre offset fill in, plus a reliable suit of chemical and size distribution data.
Coermotibo	61m x 61m	122m x 122m
Onverdacht	61m x 61m	122m x 122m

(2) Metallurgical recoveries for the operations are:

	% Anticipated Metallurgical Recovery Al_2O_3
Worsley	90
MRN (based on Alumar refinery)	94
Coermotibo	93.5
Onverdacht	93.5

(3) All reserve tonnages and grades include dilution and are quoted on a dry basis.
(4) No third party reserve audits were conducted specifically for the purpose of this disclosure.
(5) Mineração Rio do Norte (MRN) annual reporting moisture basis has been changed from Wet/Semi Dry in 2004 to Bone Dry.
(6) In addition to the reserves of the Lelydorp III the 2005 statement includes an additional 10.8Mt of reserves made up of 3.9Mt of proved reserve from Klaverblad and 6.9Mt of probable reserve from Kaaimangrasie.

The table below details our alumina and aluminium production for the three years ended 30 June 2005, 2004 and 2003. Production data shown is our share unless otherwise stated.

BHP Billiton Group Interest	BHP Billiton Group Share of Production Year ended 30 June 2005	2004	2003
	(thousands of tonnes)		

Alumina				
- Worsley	86%	2,813	2,799	2,742
- Suriname	45%	874	918	879
- Alumar	36%	495	507	471
Total		4,182	4,224	4,092
Aluminium				
- Hillside	100%	685	622	534
- Bayside[(1)]	100%	166	184	185
- Mozal	47.1%	260	250	134
- Alumar	46.3%	176	156	178
- Valesul	45.5%	43	44	43
Total		1,330	1,256	1,074

(1) During 2005, Bayside experienced a total potline freeze at the end of April, which impacted on the production capacity of the facility.

Regulatory and Fiscal Terms

Australia - Western Australia

In Western Australia, minerals in the ground belong to the government, and rights to mine are granted by the state. The Worsley joint venture operates under a State Agreement made under the Alumina Refinery (Worsley) Agreement Act 1973 (as amended). The Worsley joint venturers are permitted, under the State Agreement, to explore for and mine bauxite and to refine it into alumina.

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Market Conditions

The aluminium market was firm throughout fiscal year 2005, with visible stocks continuing to decline. For example, LME aluminium stocks declined by 168,600 tonnes in the six months ending June 2005. As a consequence, the ratio of visible global stocks to global consumption is at its lowest level for 30 years. Towards the end of the fiscal year, some signs emerged that the market had moved closer to balance rather than deficit, mainly due to an abatement in demand growth.

The smelter grade market remained strong throughout the period. The Metal Bulletin spot alumina price averaged US$395 per tonne in fiscal 2005 versus US$369 per tonne in fiscal 2004. China remained a large and growing buyer of alumina. Measures by the Chinese authorities to lessen the pace of smelting production growth might see the rate of growth of China s appetite for alumina slow in the future. However, smelter production growth elsewhere in the world should be supportive of alumina.

The outlook for the aluminium and alumina markets remains sound, with ongoing demand and high effective utilisation rates.

Base Metals

Our Base Metals Customer Sector Group comprises our assets and interests in copper, silver, lead, zinc, uranium and gold. We provide base metals concentrates to smelters worldwide and copper cathodes to rod and brass mills and casting plants.

Copper

We are the world s second largest producer of copper. The Escondida copper mine in northern Chile is the world s largest source and a low cost producer of copper. During the year, as part of the acquisition of WMC, we acquired the Olympic Dam mine in South Australia, which has a significant copper and uranium reserve. Our other key Base Metals assets include the Cannington silver, lead and zinc mine in Australia, the Cerro Colorado copper mine in northern Chile, and the Tintaya copper mine and Antamina copper and zinc operations in Peru. We also have a number of greenfield and brownfield expansion opportunities.

Escondida

We hold a 57.5% interest in Escondida, a copper mine consisting of two open-pits accessible by road and located in northern Chile s Atacama Desert, at an altitude of approximately 3,100 metres, 160 kilometres south-east of the port city of Antofagasta. The other owners are affiliates of Rio Tinto plc, which hold a 30% interest, JECO, which holds a 10% interest, (Mitsubishi Corporation, 7%, Mitsubishi Materials Corporation, 1%, Nippon Mining and Metals Company Limited, 2%), and the International Finance Corporation, which holds a 2.5% interest.

Escondida is a large porphyry copper deposit with current mine dimensions of 2.4 kilometres in an east-west direction, 3.2 kilometres in a north-south direction and a depth of 464 metres. The ultimate pit limits are estimated to be 3.5 kilometres by 4.8 kilometres, with a depth of 750 metres.

Original construction of the operation was completed in 1990 at a cost of US$836 million (100% terms) and the project has since undergone four phases of expansions at an additional cost of US$2,125 million (100% terms) plus US$451 million (100% terms) for the construction of an oxide plant. The operation has two conventional processing streams, with high quality copper concentrate being extracted from sulphide ore through a flotation extraction process and pure copper cathode obtained in a plant applying leaching and subsequent solvent extraction and electro-winning to oxide ores. An open pit mine services both operations, with a current total movement of approximately 375 million tonnes of material each year, while dedicated pipeline and port facilities as well as a private railway are used to transport output.

The Escondida Norte expansion was approved in June 2003, with an investment of US$400 million (100% terms) required to bring Escondida Norte mine into production. In April 2004, the US$870 million (100% terms) Escondida Sulphide Leach copper project was approved. The project has the capacity to produce up to 180,000 tonnes of copper cathode per annum and is scheduled to begin production during the second half of 2006. The project will utilise a bacterially assisted leaching process on low-grade run-of-mine sulphide ore from the existing Escondida pit and the currently in-development Escondida Norte pit. The resulting solutions from the leaching will then be treated in solvent extraction and electro-winning plants to produce copper cathode.

The Escondida mine life is based on the production rate of feed to the combined flotation plants and is currently estimated at 27 years. Escondida Norte will provide a portion of the production to the flotation and sulphide leach plants for 19 years, concurrently with Escondida.

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Escondida has the right of indefinite exploitation (mining) concessions for the mining of the Escondida ore body as well as exploitation and exploration rights for some territory surrounding the existing operation. Exploitation concessions allow the concession holder to mine the area indefinitely contingent upon the annual payment of corresponding licence fees.

Separate transmission circuits provide power for the Escondida mine complex. These transmission lines, which are connected to Chile s northern power grid, are company-owned and are sufficient to supply Escondida post Phase IV. Electricity is purchased under contracts with local generating companies, Norgener S.A. and GasAtacama Generación S.A.

Escondida has committed its forecast annual copper concentrate production under long-term sales contracts ranging in duration from 5 to 10 years. Expiration of these contracts varies, with the earliest being at the end of calendar year 2006 and the latest in 2012. Forecast production is fully committed (though not 100% priced) through to the end of calendar year 2006 under these long-term sales contracts. Approximately 85% of annual cathode production is sold under annual contracts to end-users and traders located primarily in Europe, Asia, the United States and Brazil and the remainder of production is sold on a spot basis.

Tintaya

The Tintaya deposit is owned by BHP Billiton Tintaya S.A., a Peruvian subsidiary of BHP Billiton Limited. Tintaya is an open-pit copper mine located in the Southern Andes in Peru at an altitude of approximately 4,000 metres. We hold a 99.95% interest in Tintaya with the remainder held by Peruvian shareholders. The deposit is a copper gold skarn system associated with a low-grade porphyry copper body and is approximately 3 kilometres long by 2.5 kilometres wide. We hold mining rights over 3,600 hectares and surface rights over 5,930 hectares on which the Tintaya mine and operations and provisions for future projects are located. These rights can be held indefinitely, contingent upon the annual payment of corresponding licence fees and the supply of information on investment and production to the authorities in due course. Mine operations consist of conventional truck and shovel operations from multiple pit locations. Electricity for the Tintaya operations is sourced from the Peruvian power grid and supplied under contract with three Peruvian power companies, San Gabán S.A., Enersur S.A. and Eléctrica MachuPicchu S.A.

Production commenced in 1984 and currently consists of a conventional flotation extraction process producing copper in concentrate from sulphide ore. Tintaya s total annual production capacity is 90,000 tonnes of copper contained in concentrate along with gold and silver credits. An acid leach plant for oxide ore commenced commercial operation in June 2002 with a design capacity of 34,000 tonnes of copper cathode per year. With recent improvements to this plant, cathode production is now 38,000 tonnes annually. We expect annual production to remain stable until 2010 and then decrease as sulphide ore mining ceases and low grade stockpiles are processed to the end of the life of the mine, which we estimate will be between 2012-2014.

Approximately 65% of Tintaya s cathode production is committed under annual contracts with rod mills in Peru and North America with the balance allocated to the spot market. For calendar year 2005, approximately 60% of Tintaya s anticipated copper concentrate output is committed against long-term contracts with the balance allocated to a variety of spot sales. Operations were suspended from 25 May 2005 until 20 June 2005 after a period of local political unrest culminated in protesters briefly entering the facility. As a precautionary measure to guarantee the safety of employees and to defuse the situation, management suspended operations and evacuated personnel. Operations were resumed when the government re-established public order and management assessed that it was safe to return to work. Lost production during this period was 8,700 tonnes.

Cerro Colorado

The Cerro Colorado mine is owned by Compañia Minera Cerro Colorado Limitada, a Chilean wholly owned subsidiary of BHP Billiton Plc. The open-pit copper mine is located in the Atacama Desert at an altitude of 2,600 metres, approximately 125 kilometres by road, east of Iquique, Chile. Cerro Colorado holds mineral rights over 16,582 hectares and surface rights over approximately 845.6 hectares on which the mine and plant are located. These rights can be held indefinitely contingent upon the annual payment of corresponding licence fees.

The Cerro Colorado deposit is approximately 2 kilometres long east-west and 1.5 kilometres wide north-south. Two main zones are present. Mineralisation is from 50 metres to 250 metres thick and is covered with 50 metres to 150 metres of leached cap and post-mineral rocks. The east deposit contains multiple layers of oxide and sulphide mineralisation with complex shapes. The west deposit generally consists of one oxide layer overlying one sulphide layer, but locally exhibits some of the complexities present in the east deposit.

At Cerro Colorado, we produce finished cathode copper by crushing, agglomeration and heap leaching followed by a solvent extraction-electrowinning process.

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We source water requirements from an underground aquifer at Pampa Lagunillas, the rights to which we hold by grant from the state. Two suppliers, Edelnor S.A. and Compañía Electrica Tarapacá S.A, supply power under long-term contracts to the facilities through the northern Chile power grid.

Construction of the facilities was completed in 1994 at a total cost of US$287 million and commercial production at Cerro Colorado commenced in June 1994. An expansion of annual production capacity to 60,000 tonnes was completed in 1995 at a cost of US$49 million and in 1998, a second expansion of Cerro Colorado was completed, at a cost of US$214 million increasing the mine s annual production to a nominal 100,000 tonnes of refined copper. Plant modifications were completed during calendar year 2004, at a cost of US$62 million, to increase the mine s crushing capacity, leach pad area and mine fleet in order to maintain annual production capacity at a level of 120,000 tonnes per year for the next five years. With these modifications, we estimate that the remaining mine life will be 11 years.

The majority of Cerro Colorado production of cathode copper is committed for sale under annual contracts to customers in Europe and Asia.

On 13 June 2005, an earthquake measuring 7.9 on the Richter scale affected the region in which the Cerro Colorado mine is located. Normal road accessibility for heavy trucks was suspended for two weeks, but was re-established by the end of June. Production on one of the two plants suffered damage and its production was halted for two months until it was rebuilt. Production of cathode was approximately 50% of capacity during the month of August and will gradually ramp up to full capacity over the next few months. Some other minor damage affected the mine but with no serious consequences.

Spence

In October 2004, following the completion of an updated feasibility study, we approved the development of the US$990 million Spence copper project in Chile. This porphyry copper deposit lies within BHP Billiton s (100%) land holding of 46,744 hectares of mineral rights with an associated 20,145 hectares of surface rights. The project is located 150 kilometres north-east of the port city of Antofagasta and 50 kilometres south-east of the mining city of Calama at an elevation of 1,700 metres above sea level in the Atacama Desert of northern Chile.

The Spence orebody consists of in situ copper oxide mineralisation that overlies supergene sulphide, transitional sulphide, and lower-most primary (hypogene) sulphide mineralisation. The copper contained within both the oxide and supergene sulphide mineralisation is recoverable by heap leaching and solvent extraction/electorwinning processes (SXEW), whereas copper contained within the primary sulphide mineralisation (principally chalcopyrite) is not. The deposit will be developed by open-cut mining methods and heap leaching of crushed ore on dynamic (on-off) leach pads. Chemical (acid) leaching of oxide ores and bacterial leaching of supergene sulphide ores will be applied. Collected leach solutions will be sent to separate oxide and sulphide solvent extraction (SX) plants followed by a single electro-winning (EW) plant to produce copper cathode. The project will have a nominal capacity to produce 200,000 tonnes of copper cathode per annum when completed, and has an estimated mine life of approximately 19 years. First cathode production is scheduled for the fourth quarter of 2006.

BHP Billiton has the right of indefinite exploitation (mining) concessions for the mining of the Spence ore body as well as exploitation and exploration rights for some territory surrounding the existing operation. Exploitation concessions allow the concession holder to mine the area indefinitely contingent upon the annual payment of corresponding licence fees.

Access and transportation of supplies to the project is via the primary highway connecting Antofagasta and Calama, which, prior to the project passed directly over the deposit. Electrical power will be supplied to the project via a 70 kilometre high-voltage transmission line connected to Chile s northern power grid. Spence will own this transmission line and purchase electricity under contracts from a local generating company.

As of 30 June 2005 the overall project was at 29% completion with 4.5 million hours worked. Project and operations staffing ramp-up has also been accomplished on plan. Pre-mine waste stripping operations commenced on schedule in May 2005.

Copper-Uranium

Olympic Dam

The Olympic Dam operations in South Australia became a part of Base Metals through the acquisition of WMC. The operations are a significant producer of both copper and uranium oxide. It currently ranks as the fourth largest copper deposit and the largest uranium deposit in the world.

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During 2002, Olympic Dam completed an optimisation project which delivered the capacity to plate 235,000 tonnes of copper per year and the ability to mill slag. Following successful commissioning of the new copper solvent extraction plant in the first quarter of 2004, production in calendar year 2004 was 224,731 tonnes of copper. Production in the year ended 30 June 2005 was 231,257 tonnes of copper.

Due to the size of the Olympic Dam ore body, there is potential to further increase the size of the operation over and above the 235,000 tonnes of copper capacity. We are currently examining a substantial increase in production via an open-pit mine. However, this expansion of Olympic Dam will require completion of feasibility studies and subsequent Board approval as well as various regulatory and governmental approvals covering a range of operational matters.

The Olympic Dam copper, uranium, gold and silver deposit was discovered in 1975 and production of copper began in 1988. It is located 560 kilometres north-west of Adelaide in South Australia. It comprises a large number of discrete ore zones throughout an area of several square kilometres ranging in depth from 350 metres to approximately one kilometre. The Olympic Dam underground mining operation is highly mechanised, with automated rail transportation and underground crushing. The primary method of ore extraction is long hole open stoping with cemented aggregate fill. This method allows for large equipment to achieve high productivity and maximum ore recovery.

Ore is hoisted to the surface where it is fed to two grinding circuits in parallel. After grinding, the resultant slurry passes to a flotation circuit where a series of flotation stages and a further regrinding stage produce a copper concentrate. The concentrate then passes through a leaching circuit which is principally designed to extract uranium from the copper minerals. Uranium is extracted in a solvent extraction plant, producing yellow-cake, which is subsequently calcined to produce uranium oxide concentrate and then packaged in drums for export sales.

After drying, copper concentrate is fed to an Outokumpu flash furnace, which produces blister copper and flash furnace slag. Blister copper is transferred to anode furnaces for further fire refining. Anode copper is transported to the refinery where the ISA electro-refining process is used to produce copper cathodes. The slimes from this process are treated separately to recover gold and silver.

Approximately 95% of copper sales from Olympic Dam are made under short to medium-term contracts with major customers. Approximately 75% of the copper sold during 2004 was exported. The bulk of uranium production is committed under long-term sales contracts with well-established overseas electricity generating utilities.

Power for the Olympic Dam operations is supplied via a 275kV power line from Adelaide, with power supplied currently under contract until July 2006 by TXU and transmitted by Electranet in accordance with the National Electricity Code and the Electricity Act 1996 (SA) (as amended).

Water supply for Olympic Dam is accessed from bore fields which draw from the Great Artesian Basin in South Australia. The operation has licences from the relevant authorities to allow a drawdown (aquifer pressure) estimated to be the equivalent of 42 megalitres per day, of which 33 megalitres per day is currently used.

The Olympic Dam operations produce both LME accredited ER (electro-refined) copper cathode and EW (electro-won) copper which is not LME accredited. Production commenced at Olympic Dam in 1988 at a rate of 45,000 tonnes per year of refined copper. Between 1989 and 1995, the production rate was increased, ultimately raising the ore mining capacity to approximately 3 million tonnes per year to supply a copper production capacity of approximately 85,000 tonnes per year. In 1999, a major expansion of operations was completed at Olympic Dam with production capacity increasing to approximately 200,000 tonnes of refined copper, 4,300 tonnes of uranium oxide, 75,000 ounces of refined gold and 850,000 ounces of refined silver per year. A further optimisation project in 2002 has taken our refined copper production capacity to 235,000 tonnes per annum. However, production in 2003 was 160,080 tonnes due to the plant shutdown to reline the smelter, the rebuild of the copper and uranium solvent extraction plants and a failure of a heat exchanger in the acid plant.

The currently accepted mine life for Olympic Dam underground operation is in excess of 20 years. Studies are underway to re-examine the underground mine plan.

We hold a special mining lease relating to the Olympic Dam operation that was granted by the Government of South Australia by an Act of Parliament for the period of 50 years from 1982, with a right of extension for a further period of 50 years.

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Copper-Zinc

Antamina

The Antamina copper-zinc deposit is owned by Compañía Minera Antamina S.A. (CMA), in which BHP Billiton holds a 33.75% interest. Noranda Inc. holds a 33.75% interest, Teck Cominco Limited holds a 22.5% interest and Mitsubishi Corporation holds the remaining 10% interest. The deposit is located in the Peruvian Andes at an altitude of 4,300 metres, approximately 270 kilometres north of Lima, Peru.

The Antamina project achieved mechanical completion in May 2001 and commercial production began in October 2001. The total development cost, including financing costs, working capital and sunk costs was US$2,228 million. The principal project facilities include a 115 kilometre access road, a truck-shovel pit operation, a nominal 70,000 tonnes per day concentrator, a 300-kilometre concentrate pipeline with a single stage pumping station to transport concentrates in slurry form from the mine to the de-watering, drying, and port facilities at Huarmey, and housing for operating employees and their families in the City of Huaraz, located approximately 200 kilometres by road from the mine.

The property comprising the Antamina mine area consists of mining concessions, mining claims and surface rights covering an area of approximately 14,000 hectares. The project company also owns sufficient surface rights for mining infrastructure, the port facility at Huarmey and an electrical substation located at Huallanca. In addition, the project company holds title to all easements and rights of way required for the concentrate pipeline from the mine to the project company s port at Huarmey. All of the rights can be held indefinitely.

Power to the mine site is being supplied under long-term contracts with individual power producers through a 58-kilometre, 220 kilovolt transmission line constructed by the project company, which is connected to the Peru national energy grid. In late 2002, an additional third party owned transmission line was connected to the project s substation, significantly increasing power supply reliability.

CMA entered into 19 long-term copper and zinc concentrate sales contracts with 16 smelting companies, which, in aggregate, cover approximately 75% of the project s expected annual production. All but two of the contracts are for terms extending to 2012 or 2013. The remainder of production is sold to project sponsors prorated by each partner s equity stake in CMA.

The Antamina deposit is a large copper skarn with zinc, silver, molybdenum, lead, arsenic and bismuth mineralisation. It has a south-west to north-east strike length of more than 2,500 metres and a width of up to 1,000 metres. The deposit sits at the bottom of a U-shaped glacial valley surrounded by limestone ridges. Mineralisation is associated with pervasive replacement by calcium silicate minerals of both a centralised intrusive body and a thick limestone formation that hosts the intrusive. A well defined zonation consists of high-grade copper sulphides occurring in the centralised intrusive and in limestone immediately adjacent to the intrusive. High grade copper-zinc sulphides overprint the copper-only style of mineralisation in a narrow doughnut-shaped zone at the outer margin of skarn formation. Like other skarn deposits, the Antamina deposit is highly erratic in form and grade.

During calendar years 2003 and 2004, 30,000 metres and 114,000 metres, respectively, of additional diamond drilling was completed. Because of the erratic nature of the ore types and grades within ore zones, a change in reserve classification has been adopted effectively tightening the criteria for Proven and Probable ore. As a result some of the previously reported Proven ore is now reported as Probable.

Following the drilling programme, a new pit design was completed utilising updated parameters more closely reflecting actual operating experience. This new pit design forms the basis of the current reserve. The reserve has been grouped into two major ore types, copper only and copper-zinc ores since they undergo different treatment processes and in order to add clarity for reporting purposes. Zinc contained in copper only ore is not recovered and molybdenum contained in copper-zinc ores is not recovered. The Antamina mine has an expected life of 15 years at current production rates.

Silver, Lead and Zinc

Cannington

Cannington is a mining and concentrating facility that is 100% owned and operated by us, and is the world s largest single mine producer of both silver and lead. The Cannington silver, lead and zinc deposit is located in northwest Queensland, Australia, and is accessible by sealed road 300 kilometres southeast of Mount Isa. The Cannington deposit is entirely contained within mining leases granted to us in 1994 and which expire in 2029. The deposit consists of a shallow, low grade northern zone and a deeper, higher grade and more extensive southern zone. The southern zone contains a broadly zoned and faulted sequence of silver-lead-zinc, zinc and silver-lead lodes.

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We use transverse, long hole open stoping for the extraction of the main, thicker, hanging wall orebodies of the deposit. Production commenced in October 1997 at a cost of US$250 million. Underground mine production for the year ended 30 June 2005 was 3.4 million tonnes. Work on the Cannington Growth Project which was approved in February 2003 was completed during the year at a total cost of US$56 million to improve mill throughput and increase metal recovery. We are continuing an ongoing programme of incremental mill improvements. Nominal capacity is now 3 million tonnes per annum. A power station, comprising 18 x 1.03MW and 6 x 1.915MW gas-fired engines and 4 x 1.4MW diesel-fired engines located at Cannington is operated under contract to supply power solely to Cannington.

Approximately 85% of Cannington s lead and zinc concentrate production for the year ending June 30, 2006, is fully committed under long-term contracts with smelters in Australia, Korea, Japan and Europe with the balance being allocated to the spot market, primarily China and Korea.

The reserve life as currently stated is approximately seven years. Surface exploration is continuing on a number of geophysical and geochemical anomalies in the mine lease area.

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Reserves and Production

The table below details our copper, zinc, silver, gold, molybdenum and lead reserves in metric tonnes, and are presented in 100% terms as estimated at 30 June 2005.