BHP BILLITON LTD
Form 20-F
September 25, 2006
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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C.

FORM 20-F

¨ **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 2006

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	**Commission file number: 001-31714**
BHP BILLITON LIMITED	**BHP BILLITON PLC**
(ABN 49 004 028 077)	**(REG. NO. 3196209)**

(Exact name of Registrant as specified in its charter)	**(Exact name of Registrant as specified in its charter)**
VICTORIA, AUSTRALIA	**ENGLAND AND WALES**
(Jurisdiction of incorporation or organisation)	**(Jurisdiction of incorporation or organisation)**
180 LONSDALE STREET, MELBOURNE, VICTORIA 3000 AUSTRALIA	**NEATHOUSE PLACE, VICTORIA, LONDON, UNITED KINGDOM**
(Address of principal executive offices)	**(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	3,495,949,933	2,468,147,002

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. Yes ¨ No x

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes x No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See

definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨

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1. KEY INFORMATION

Selected financial information

The selected financial information for BHP Billiton reflects the combined operations of both BHP Billiton Limited and BHP Billiton Plc and has been derived from the 2006 financial statements. The selected financial information should be read in conjunction with, and is qualified in its entirety by reference to the 2006 financial statements and notes thereto. For the first time in 2005-06, the BHP Billiton Group s financial statements are prepared in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union and, as such, the basis of preparation is different to that of the most recent comparative year s annual financial report. The 2004-05 comparatives have been restated accordingly. IFRS differ in certain aspects from US Generally Accepted Accounting Principles (GAAP). Details of the principal differences between IFRS and US GAAP are set out in note 39 US Generally Accepted Accounting Principles disclosures in the financial statements. The BHP Billiton Group publishes its consolidated financial statements in US dollars.

One of our jointly controlled entities, Minera Escondida Limitada meets the definition of a significant unconsolidated subsidiary in accordance with Rule 3-09 of Regulation S-X. Accordingly, the financial statements of Minera Escondida Limitada will be filed with the SEC as soon as available, but no later than 31 December 2006.

Amounts in accordance with IFRS	**30 June**	
US$M except per share data	**2006**	**2005**
Consolidated Income Statement		
Revenue together with share of jointly controlled entities revenue	**39,099**	31,150
Less: share of jointly controlled entities external revenue included above	**(6,946)**	(4,428)
Revenue	**32,153**	26,722
Profit from operations	**14,671**	9,271
Profit attributable to members of BHP Billiton Group	**10,450**	6,396
Dividends per ordinary share paid during the period (US cents)	**32.0**	23.0
Dividends per ordinary share declared in respect of the period (US cents)	**36.0**	28.0
Earnings per ordinary share (basic) (US cents) [a]	**173.2**	104.4
Earnings per ordinary share (diluted) (US cents) [a]	**172.4**	104.0
Number of ordinary shares (millions)		
- At period end	**5,964**	6,056
- Weighted average	**6,035**	6,124
- Diluted	**6,066**	6,156
Consolidated Balance Sheet		
Total assets	**48,516**	41,843
Share capital	**3,242**	3,363
Total equity attributable to members of BHP Billiton Group	**24,218**	17,575

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Amounts in accordance with US GAAP	**30 June**				
(US$M except per share data)	**2006**	**2005**	**2004**	**2003**	**2002**
Consolidated Income Statement					
Sales revenue	32,153	26,722	22,887	15,608	13,552
Operating income	9,043	6,554	3,489	2,780	1,698
Net income total	9,783	6,388	2,716	1,581	1,249
Net income from continuing operations	9,783	6,388	2,716	1,576	1,513
Net income/(loss) from discontinued operations				5	(264)
Per ordinary share [(a)]:					
Net income attributable to members					
- Basic from continuing operations (US cents)	159.7	104.3	43.7	25.5	25.1
- Diluted from continuing operations (US cents)	158.9	103.7	43.5	25.4	25.0
- Basic from discontinued operations (US cents)					(4.4)
- Diluted from discontinued operations (US cents)					(4.4)
- Basic total (US cents)	159.7	104.3	43.7	25.5	20.7
- Diluted total (US cents)	158.9	103.7	43.5	25.4	20.6
Per American Depositary Share (ADS):					
Net income attributable to members					
- Basic total	319.4	208.6	87.4	51.0	41.4
- Diluted total	317.8	207.4	87.0	50.8	41.2
Consolidated Balance Sheet					
Total assets	53,317	46,861	36,675	35,001	35,795
Share capital	3,242	3,363	3,603	3,537	4,895
Total equity attributable to members of BHP Billiton Group	27,839	22,004	18,802	16,832	17,147

(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) On 1 July 2005, we changed our US accounting policy for pension and other post retirement benefits. Details of the impact on the 2005-06 year, and pro forma disclosures for the 2004-05 year had the policy been applied, are set out in note 39 US Generally Accepted Accounting Principles disclosures in the financial statements. Had the change in policy been applied to previous years, the impact on net income would not have been material in the 2003-04, or 2002-03 years, and would have had an impact of US$200 million in the 2001-02 year. The impact on earnings per share would have been an increase of 0.6 US cents per share in 2003-04, and decreases of 1.4 and 3.3 US cents per share in 2002-03 and 2001-02 respectively.

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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 the BHP Billiton Group.

Fluctuations in commodity prices may negatively impact our 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. The influence of hedge and other financial investment funds participating in commodity markets has increased in recent years contributing to higher levels of price volatility. 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 rates 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, Chilean peso, Brazilian real 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 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.

Failure to discover new reserves or enhance existing reserves could negatively affect our 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.

Health, safety and environmental exposures and related regulations may impact our operations and reputation negatively

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 greenhouse gas emission targets for developed countries that have ratified the Protocol. The European Union Emissions Trading System (EU ETS), which came into effect on 1 January 2005, has had an impact on greenhouse gas and energy intensive businesses based in the EU. Our Petroleum assets in the UK are currently subject to the EU ETS as are our EU based customers. Elsewhere there is existing and emerging regulation, such as the mandatory renewable energy target in Australia (which puts the onus on power producers to ensure that the national grid has 2 per cent renewable energy by the year 2020) that will affect energy prices. From a medium and long-term perspective, we are likely to see changes in the margins of our greenhouse gas intensive assets and energy intensive assets as a result of regulatory impacts in the countries where we operate. These regulatory mechanisms may be either voluntary or legislated and may impact our operations directly or indirectly via our customers. Inconsistency of regulations may also change the attractiveness of the locations of some of our assets. Assessments of the potential impact of future climate change regulation are uncertain given the wide scope of potential regulatory change in the 25 or more countries where we operate.

The European Registration, Evaluation and Authorisation of Chemicals (REACH) system is anticipated to commence operation in the first half of 2007. 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 draft legislation, which is currently

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undergoing review as it proceeds through the European Parliament for potential enactment, contemplates a registration and authorisation process for identified uses of products. The extent to which our operations and customers are affected 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.

Our operational processes and geographic locations may be subject to operational accidents or natural catastrophes such as earthquakes, hurricanes and tsunamis.

We may continue to be exposed to increased operational costs due to the costs and lost workers time associated with the HIV/AIDS infection rate of our southern African workforce.

Because we operate globally, we may be affected by potential avian flu outbreaks in any of the regions in which we operate. The effects of avian flu may manifest themselves directly on employees, offices and operation or indirectly on customers and markets.

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

Land tenure disputes may negatively impact our 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 (BBSEE) Charter, known as the Mining Charter, for the mining industry with the objectives of expanding opportunities, skills, ownership and employment for historically disadvantaged South Africans. The Mining Charter requires that mining companies achieve 15 per cent ownership by historically disadvantaged South Africans of South African mining assets within five years and 26 per cent ownership within 10 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.

Additional risks associated with emerging markets may negatively impact some of our 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, renegotiation or nullification of existing contracts, leases, permits or other agreements, and changes in laws and policy as well as other unforeseeable risks. If one or more of these risks occurs at one of our major projects, it could have a negative effect on our operating results or financial condition.

We may not be able to successfully integrate our acquired businesses

We have grown our business in part through acquisitions. 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.

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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 program. Increasing requirements relating to regulatory, environmental and social approvals can potentially result in significant delays in construction and may adversely impact upon the economics of new mining and oil and gas properties, the expansion of existing operations and our results of operations.

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 41 per cent of global seaborne iron ore demand, 22 per cent of copper, 22 per cent of aluminum and 16 per cent of nickel demand. China s 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 US$6.6 billion or 16.8 per cent of revenue, including our share of jointly controlled entities revenue in the year ended 30 June 2006.

In recent times we have seen a synchronised global recovery, resulting in upward movement in commodity prices driven partly by China s 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 China s 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 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 and our financial condition and prospects.

Forward looking statements

This Annual Report contains forward looking statements, including statements regarding:

- estimated reserves
- trends in commodity prices
- demand for commodities
- 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

provisions and contingent liabilities.

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Forward looking statements can be identified by the use of terminology such as intend , aim , project , anticipate , estimate , plan , believes may , should , will , continue or similar words. These statements discuss future expectations concerning the results of operations or financial condition or provide other forward looking statements.

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 some 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 above. 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. Except as required by applicable regulations or by law, the Group does not undertake any obligation to publicly update or review any forward looking statements, whether as a result of new information or future events.

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2. INFORMATION ON THE COMPANY

History and development of BHP Billiton

We are the world s largest diversified resources group with a combined market capitalisation of approximately US$122.8 billion as of 30 June 2006 and we generated revenue, together with our share of jointly controlled entities revenue and profit attributable to members of BHP Billiton of US$39.1 billion and US$10.5 billion respectively for the year ended 30 June 2006.

Since June 2001, we have operated under a Dual Listed Companies (DLC) structure. Under the DLC structure, the two parent companies, BHP Billiton Limited (formerly BHP Limited, and before that The Broken Hill Proprietary Company Limited) and BHP Billiton Plc (formerly Billiton Plc) operate as a single economic entity, run by a unified Board and management team. More details of the DLC structure are located under Organisational structure .

BHP Billiton Limited was incorporated in 1885 and is registered in Australia with ABN 49 004 028 077. BHP Billiton Plc was incorporated in 1996 and is registered in England and Wales with registration number 3196209.

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, UK, and its telephone number is +44 20 7802 4000.

We divide our business into seven business units, or Customer Sector Groups (CSGs):

- Petroleum, which explores for, produces, processes and markets hydrocarbons including oil, gas and liquefied natural gas

- Aluminium, which explores for and mines bauxite and processes and markets aluminium and alumina

- Base Metals, which explores for, mines, processes and markets copper, silver, zinc, lead, uranium, and copper by-products including gold and molybdenum

- Carbon Steel Materials, which explores for, mines, processes and markets metallurgical coal, iron ore and manganese used in the production of carbon steel

- Diamonds and Specialty Products, which explores for and mines diamonds and titanium minerals, and also includes our recently-sold fertiliser operations

- Energy Coal, which explores for, mines, processes and markets energy coal for use in electricity generation

- Stainless Steel Materials, which explores for, mines, processes and markets nickel, which is used in the production of stainless steel.

In addition to the seven CSGs, we also have a minerals exploration group, a technology group and a freight, transport and logistics operation. The tables below list the contribution to revenue from each of these CSGs and by geographic market for the years ended 30 June 2006 and 30 June 2005. Further details of the contribution from each of these CSGs to our revenues and profits are outlined in the Operating and financial review and prospects section.

Analysis by CSG	**Revenue 2006 US$M**	**Revenue 2005 US$M**
Petroleum	**5,871**	5,967
Aluminium	**4,977**	4,571
Base Metals	**4,901**	2,329
Carbon Steel Materials	**9,134**	7,168
Diamonds and Specialty Products	**886**	731
Energy Coal	**2,881**	2,971
Stainless Steel Materials	**2,955**	2,266
Group and unallocated items	**548**	719
Total	**32,153**	26,722

Analysis by geographical market	Revenue 2006 US$M	Revenue 2005 US$M
Australia	**3,507**	2,626
North America	**2,344**	2,122
Europe	**10,027**	9,352
South America	**729**	55
Southern Africa	**1,426**	1,308
Japan	**3,959**	3,118
South Korea	**1,689**	1,662
China	**5,294**	3,413
Other Asia	**2,496**	1,851
Rest of World	**682**	1,215
Total	**32,153**	26,722

Business Overview

Petroleum Customer Sector Group

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. We group our petroleum assets for reporting purposes into the following regions: Australia/Asia, Americas, and Europe/Africa/Middle East. We produce and market crude oil and condensates, natural gas, liquefied natural gas, liquefied petroleum gas and ethane.

Total production in 2005-06 was 116.0 million barrels of oil equivalent, compared with total production in 2004-05 of 119.0 million barrels of oil equivalent.

Australia/Asia

In Australia, we produce oil and gas from Bass Strait, the North West Shelf, the Griffin Project, the Minerva gas field and the Moranbah Coal Bed Methane (CBM) gas project with the Bass Strait and North West Shelf being the major fields. In Asia, we produce gas and a small volume of condensate from the Zamzama gas field in Pakistan.

The majority of our Bass Strait crude oil and condensate production is dispatched from the Bass Strait fields to refineries along the east coast of Australia. The majority of the natural gas produced was sold to GASCOR, under a long-term Consumer Price Index (CPI) indexed contract with periodic price reviews, for on-sale to retailers to meet local residential, commercial and industrial requirements. The GASCOR contract is due to expire on 31 December 2009 or upon depletion of the outstanding contractual volume, whichever is the earlier. Similar contracts have been executed with AGL and TRUenergy that will extend gas supply to these two retailers until 2017.

The domestic gas phase of the North West Shelf Project delivers gas via pipeline to the Western Australian domestic market under long-term contracts. Significant portions of the LNG expansion phase production are sold per year to Japanese buyers under long-term contracts, which expire at various periods in three to 28 years. Medium-term (terms of three to five years) contract and spot sales are made to buyers in Japan, Korea and the US, with the level of spot sales dependent upon plant and shipping availability. 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 and sales under the contract commenced in mid 2006.

Americas

Our operations in the Americas consist of interests in five producing assets in the Gulf of Mexico operations and the Angostura project off Trinidad and Tobago. Our operating fields in the Gulf of Mexico are Mad Dog, West Cameron 76, Mustang, Genesis and Starlifter. We also own 25 per cent and 22 per cent respectively in the companies that own and operate the Caesar oil pipeline and the Cleopatra gas pipeline, which transport oil and gas from the Green Canyon area to connecting pipelines that transport product to the US mainland. During the year, we sold Green Canyon 18/Ewing Bank 988 and Green Canyon 60 blocks with effect from 1 September 2005. The transactions closed in December 2005 and January 2006 respectively.

Our activities in the Gulf of Mexico were affected by the severe hurricanes in September 2005. Both Hurricanes Katrina and Rita interrupted production for several days and Rita severely damaged our Typhoon facility. We decided not to redevelop Typhoon, Boris and Little Burn tie-back field but rather pursue divestiture options. On 18 August 2006, Energy Resource Technology, a wholly-owned subsidiary of Helix Energy Solutions, acquired a 100 per cent working interest in the Typhoon, Boris and Little Burn oil fields. The agreement is subject to regulatory approval.

Europe/Africa/Middle East

Our Europe/Africa/Middle East producing assets include our fields off the UK coast and two operations in Algeria. In the UK, we produce oil and gas from Liverpool Bay and Bruce/Keith fields. In Algeria, we produce wet gas from Ohanet and oil from ROD integrated development.

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Information on Petroleum operations

Detailed descriptions of our producing assets by geographical region are listed in the tables below. These tables should be read in conjunction with the production and reserve tables.

Name, location and type of asset	Ownership and operation	Title/lease	Facilities
AUSTRALIA/ASIA			
Bass Strait Offshore Victoria, Australia Oil and gas production	We hold a 50% interest in the Bass Strait fields. Esso Australia owns the other 50% interest and is the operator.	The venture holds 19 production licences issued by the Commonwealth of Australia with expiry dates ranging between 2009 and 2018.	There are 20 producing fields with 21 offshore developments (14 steel jacket platforms, 3 subsea developments, 2 steel gravity based mono towers and 2 concrete gravity based platforms). Onshore infrastructure includes the Longford Facility, which includes 3 gas plants and liquid processing facilities as well as the Long Island Point LPG and crude oil storage facilities. The Bass Strait production capacity is as follows: Crude 500 Mbbl/d Gas 1,075 MMcf/d LPG 5,150 tonnes per day Ethane 850 tonnes per day
North West Shelf (NWS) gas and gas liquids (LPG and condensate)	We are a participant in the North West Shelf (NWS) Project, an unincorporated joint venture.	The venture holds 9 production licences issued by the Commonwealth of Australia, of which 6 expire in 2022 and 3 expire 5 years after the end of production.	Production from the North Rankin and Perseus fields is currently through the North Rankin A platform, which has the capacity to produce 2,300 MMcf/d of gas and 53 Mbbl/d of condensate.

North Rankin, Goodwyn, Perseus, Echo-Yodel and Angel fields offshore, Dampier in northwestern Australia Gas, LPG and condensate production and LNG liquefication	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 primarily to Japan and also supply LNG to Guangdong in China. We hold 8.33% of the original domestic gas joint venture, 16.67% of the LPG domestic gas joint venture, 16.67% of the original LNG joint venture, 12.5% of the China LNG joint venture, 16.67% of the LPG joint venture and approximately 15% of current condensate production. Other participants in the respective NWS joint ventures are subsidiaries of Woodside Energy, Chevron, BP, Shell, Mitsubishi/Mitsui and the China National Offshore Oil Corporation. Woodside Energy is the operator of the project.	Production from the Goodwyn and Echo-Yodel fields is through the Goodwyn A platform, which has the capacity to produce 1,450 MMcf/d of gas and 110 Mbbl/d of condensate. Further development of the existing Perseus field has commenced and includes the drilling of additional wells tied into the Goodwyn A platform. An onshore gas treatment plant at Withnell Bay has a current capacity to process 615 MMcf/d of gas for the domestic market. An existing 4 train LNG plant has the capacity to produce an average rate of 33,000 tonnes of LNG per day.

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Name, location and type of asset	Ownership and operation	Title/lease	Facilities
North West Shelf crude oil Approximately 30 kilometres northeast of the North Rankin gas and condensate field, offshore Western Australia, Australia Crude oil production is from the Wanaea, Cossack, Lambert and Hermes oil fields	We hold a 16.67% working interest in oil production from these fields. The other 83.33% is held in equal 16.67% shares by Woodside Energy, BP Developments Australia, Chevron Australia, Shell Development, and Japan Australia LNG (MIMI). Woodside Energy is the operator of the project.	The venture holds 3 production licences issued by the Commonwealth of Australia with expiry dates ranging between 2012 and 2018.	The oil is produced to a floating production storage and offloading unit, the Cossack Pioneer, which has a capacity of 140 Mbbl/d and a storage capacity of 1.15 million barrels of crude oil.
Griffin Carnarvon Basin, 68 kilometres offshore Western Australia, Australia Comprises the Griffin, Chinook and Scindian offshore oil and gas fields	We hold a 45% interest in the project. The other 55% is held by Mobil Exploration and Producing Australia (35%) and Inpex Alpha (20%). We are the operator of the project.	The venture holds a production licence issued by the Commonwealth of Australia that expires in 2014. The licence may be renewed on expiry for a period expiring 5 years after production	Oil and gas are produced via the Griffin venture, a floating production, storage and offloading facility. We pipe natural gas to shore, where it is delivered directly into a pipeline. The Griffin venture has the capacity to produce 15 MMcf/d of gas and 8.175 Mbbl/d of crude oil.
Minerva Approximately 10 kilometres offshore in the Otway Basin of Victoria, Australia Single offshore gas reservoir with 2 compartments. Gas plant is situated approximately 4 kilometres inland from Port Campbell	We hold a 90% share of Minerva in a joint venture agreement. The other 10% is held by Santos (BOL). We are the operator of the field.	The venture holds a production licence issued by the Commonwealth of Australia that expires in 2023. The licence may be renewed on expiry for a period expiring 5 years after production ceases.	The Minerva development consists of 2 subsea well completions in 60 metres of water. A single flowline transports gas to an onshore gas processing facility with a gas capacity of 150 MMcf/d and 600 bbl/d of condensate.
Moranbah Bowen Basin, Queensland, Australia	We had a 50% interest. On 21 June 2006, we agreed to sell our Australian CBM interests	The venture held 2 production licences issued by the State of Queensland that expire in 2032 and 2034.	The project consists of approximately 70 gas wells and surface facilities including a pipeline gathering system and compressors.

Coal bed methane coal seam	to The Australian Gas Light Company (AGL) for US$68.7 million. The transaction closed on 21 August 2006.		
AMERICAS			
West Cameron 76	We hold a 33.76% working interest in the joint venture.	The venture holds a lease from the US as long as oil and gas are produced in paying quantities.	The production facility consists of 2 conventional gas platforms with a capacity of 100 MMcf/d of gas and 500 bbl/d of condensate.
Gulf of Mexico, 15 kilometres offshore, Central Louisiana, US	The other owners are Dominion Exploration and Production (40%), Merit Management Partners (15%) and Ridgewood Energy Company (11.24%).		
Offshore gas and condensate fields			
	We are the operator.		

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Name, location and type of asset	Ownership and operation	Title/lease	Facilities
Typhoon (Green Canyon 236 and 237) Gulf of Mexico, approximately 100 kilometres offshore of New Orleans, Louisiana, US Deep water oil and gas field	We had a 50% working interest. As described above, an agreement to sell the Typhoon field was executed on 18 August 2006.	The venture holds a lease from the US until September 2006, at which time a plan for redevelopment is required to retain the lease.	The field consists of 4 subsea wells tied back to a local host mini tension leg platform. The platform was severely damaged by Hurricane Rita in September 2005 and has since been taken out of service.
Boris (Green Canyon 282) Gulf of Mexico (adjacent to the Typhoon field) approximately 100 kilometres offshore of New Orleans, Louisiana, US Deep water oil and gas field	We hold a 4.95% working interest. The other owners are Chevron (56.67%) and ExxonMobil (38.38%). Chevron is the operator.	The venture holds a lease from the US as long as oil and gas are produced in paying quantities	The production facility consists of a floating cylindrical hull (spar) moored to the seabed with integrated drilling facilities and a capacity of 55 Mbbl/d of oil and 72 MMcf/d of gas.
Genesis (Green Canyon 205) Gulf of Mexico, approximately 100 kilometres offshore of New Orleans, Louisiana, US Deep water oil and gas field	We hold a 4.95% working interest. The other owners are Chevron (56.67%) and ExxonMobil (38.38%). Chevron is the operator.	The venture holds a lease from the US as long as oil and gas are produced in paying quantities.	The production facility consists of a floating cylindrical hull (spar) moored to the seabed with integrated drilling facilities and a capacity of 55 Mbbl/d of oil and 72 MMcf/d of gas.
Starlifter (West Cameron 77) Gulf of Mexico, 15 kilometres offshore, Central Louisiana, US Offshore gas and condensate field	We hold a 43.66% working interest in the joint venture. The other owners are Dominion Exploration and Production (22.4%), Merit Management Partners (19.4%) and Ridgewood Energy Company (14.54%).	The venture holds a lease from the US as long as oil and gas are produced in paying quantities.	The field development consists of a single conventional gas platform with a capacity of 40 MMcf/d of gas and 600 bbl/d of condensate.

	We are the operator.		
Mustang (West Cameron 77)	We hold a 43.66% working interest in the joint venture.	The venture holds a lease from the US as long as oil and gas are produced in paying quantities.	The field development consists of a single conventional gas platform with a capacity of 40 MMcf/d of gas and 600 bbl/d of condensate.
Gulf of Mexico, 15 kilometres offshore, Central Louisiana, US	The other owners are Dominion Exploration and Production (22.4%), Merit Management Partners (19.4%) and Ridgewood Energy Company (14.54%).		
Offshore gas and condensate field			
	We are the operator.		
Mad Dog (Green Canyon 782)	We hold a 23.9% working interest in Mad Dog.	The venture holds a lease from the US as long as oil and gas are produced in paying quantities.	The field development consists of an integrated truss spar equipped with facilities for simultaneous production and drilling operations, permanently moored in 4,300 feet of water.
Gulf of Mexico, approximately 320 kilometres offshore of New Orleans, Louisiana, US	The other 76.1% is held by BP (60.5%) and Chevron (15.6%).		
Deep water oil and gas field	BP is the operator.		The facility has the capacity to process 100 Mbbl/d of oil and 60 MMcf/d of gas.

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Name, location and type of asset	Ownership and operation	Title/lease	Facilities
Greater Angostura Approximately 38.5 kilometres east of Trinidad island, Trinidad and Tobago Shallow water oil and gas field	We hold a 45% working interest in the joint venture. The other 55% is held by Total (30%) and Talisman Energy (25%). We are the operator.	The venture has entered into a production sharing contract with the state of Trinidad and Tobago that entitles it to operate Angostura until 2021.	The Angostura development is an integrated oil and gas development. The infrastructure consists of a steel jacketed central processing platform with 3 satellite wellhead protector platforms and flowlines. 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. The facility has the capacity to process 100 Mbbl/d of oil.
EUROPE/AFRICA/ MIDDLE EAST			
Liverpool Bay Douglas and Douglas West oil fields, Hamilton, Hamilton North and Hamilton East gas fields, and Lennox oil and gas fields in the Irish Sea, approximately 10 kilometres off the northwest coast of England	We hold a 46.1% working interest in the joint venture. The other 53.9% is held by Eni. We are the operator.	The joint venture holds 3 production licences issued by the Crown of the United Kingdom. One of these licences expires in July 2007. However, this will be extended in accordance with licence terms. The other licences expire in 2009 and 2016.	The Liverpool Bay asset is an integrated development of 6 fields. Oil from the Lennox and Douglas fields is treated at the Douglas complex and piped 17 kilometres to an oil storage barge ready for export by tankers. Gas from the Hamilton, Hamilton North, Hamilton East and Lennox fields is initially processed at the Douglas complex then piped by subsea pipeline to the Point of Ayr gas terminal for further processing. The facility has the capacity to produce 308 MMcf/d of gas and 70 Mbbl/d of oil and condensate.
Bruce/Keith North Sea, approximately 380 kilometres northeast offshore of Aberdeen, Scotland	We hold a 16% interest in the Bruce field. The other 84% is owned by BP (37%), Total (43.25%) and Marubeni (3.75%). BP is the operator of Bruce.	The joint venture holds 3 production licences issued by the Crown of the United Kingdom, which expire in 2011, 2015 and 2018.	Production is via an integrated oil and gas platform. The throughput of the Bruce facility has, since 2002, been increased to 920 MMcf/d through de-bottlenecking and revising operating envelopes.

The Keith field is located adjacent to the Bruce field Offshore oil and gas fields	We hold a 31.83% interest in the Keith field. The other 68.17% is owned by BP (34.84%), Total (25%) and Marubeni (8.33%). We are the operator of Keith. As part of our normal portfolio management process, we are marketing our interests in the Bruce field, the Keith field and associated acreage. The asset was classified as Held for sale in the financial statements.	The Keith field was developed as a tie-back to the Bruce platform facilities.

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Name, location and type of asset	Ownership and operation	Title/lease	Facilities
Ohanet Approximately 1,300 kilometres southeast of Algiers and 100 kilometres west of Libya, Illizi province, Algeria Four wet gas fields	We have an effective 45% working interest in the Ohanet joint venture. The other 55% is held by Japan Ohanet Oil and Gas (30%), Woodside Energy (Algeria) (15%) and Petrofac Resources (Ohanet) (10%). The project is operated by a Sonatrach/BHP Billiton jointly-staffed organisation.	The venture is party to a risk service contract with the title holder Sonatrach that expires in 2011 with an option for a 4-year renewal under certain conditions.	Ohanet is a wet gas (LPG and condensate) development consisting of 4 gas and condensate reservoirs and a gas processing plant with the capacity to treat 20 MMcf/d of wet gas and 61 Mbbl/d of associated liquids (LPG and condensate).
ROD integrated development Berkine Basin, 900 kilometres southeast of Algiers, Algeria Six oil fields	We hold a 45% interest in the joint venture contracted under the 401a/402a PSC, with ENI holding the remaining 55%. However, we have an effective 36% interest in ROD unitised integrated development. ENI owns the remaining 64%. This interest is subject to a contractual determination to ensure that interest from participating association leases is accurately reflected. Future redetermination may be possible under certain conditions. A joint Sonatrach/ENI entity is the operator.	The venture is party to a production sharing contract with the title holder Sonatrach that expires in 2016 with an option for a 5-year renewal under certain conditions.	Comprises the development and production of 6 oil fields, the largest 2 of which, ROD and SFNE, extend into the neighbouring blocks 403a and 403d. The ROD fields are being produced through a new dedicated processing train, with the capacity to process approximately 80 Mbbl/d of oil.

Development projects

Australia/Asia

Stybarrow

In November 2005, our Board approved the development of the Stybarrow oil field in the Exmouth Sub-basin, off the northwest coast of Western Australia. At a water depth of approximately 825 metres, Stybarrow will be Australia s deepest oil field development. Project costs are approximately US$600 million (US$300 million our share) and first production is expected during the first quarter of 2008. The Stybarrow project consists of a subsea development and a floating production, storage and offshore loading facility, which will be used to process, store and offload oil to export tankers. The vessel will be disconnectable, double-hulled and able to process approximately 80,000 barrels of liquids a day. We own a 50 per cent operated working interest in this permit with the remaining interest held by Woodside Energy.

North West Shelf Train 5 expansion

In June 2005, our Board approved our 16.67 per cent share of investment in a fifth LNG train expansion of the existing LNG processing facilities located on the Burrup Peninsula, which will increase total LNG production capacity to 43,500 tonnes per day. The project is progressing on schedule with all major construction contracts awarded. Our share of development costs, based on the operator s (Woodside

Energy) estimate, is approximately US$250 million with first production expected by late 2008. The project cost and schedule are under review.

North West Shelf Angel development

In December 2005, our Board approved our share of development costs for the North West Shelf venture s Angel gas and condensate field. The development will include the installation of the venture s third major offshore production platform which will have a capacity to produce 800 MMcf/d of gas from the North West Shelf and associated infrastructure, including a new subsea 50 kilometre pipeline, which will be tied in to the first trunkline at the North Rankin platform. Our share of development costs, based on the operator s (Woodside Energy) estimate, is approximately US$200 million with development expected to be fully operational by the end of 2008.

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Zamzama Phase 2

Phase 2 of the Zamzama plant facility upgrade project is currently under construction after being approved by our Board in November 2005. Capacity is expected to increase by approximately 50 per cent (by 150 MMcf/d of gas and 800 bbl/d of condensate) by the end of September 2007 at a cost of US$120 million (US$46 million our share). We signed a gas sales and purchase agreement in November 2005 with the Government of Pakistan and Sui Southern Gas Company Limited. The agreement covers the supply of up to 150 MMcf/d of gas over the life of the field.

Americas

Atlantis South

We have a 44 per cent working interest in Atlantis South in the deepwater fields in the Gulf of Mexico. The facility will be a moored, semi-submersible platform with a capacity of 200 Mbbl/d of oil and 180 MMcf/d of gas. We have approved a budget of US$1.1 billion (our share) for the development of these reserves. However, the project is experiencing cost and schedule pressures as a result of heated market conditions and additional quality assurance and regulatory certification processing in response to the last year s Gulf of Mexico hurricane season. Cost pressures are likely to result in a capital cost increase of more than 30 per cent in excess of the currently approved budget. BP owns the other 56 per cent and operates the project. The project and cost schedule presently remains under review.

Neptune

We have a 35 per cent interest and will operate the Neptune oil and gas project in the deepwater Gulf of Mexico. Other members of the joint venture are Marathon Oil (30 per cent), Woodside (20 per cent) and Repsol (15 per cent). The project will construct a stand-alone tension leg platform with a nameplate capacity of 50 Mbbl/d and 50 MMcf/d of gas. Estimated development costs are US$850 million (US$300 million our share). First oil is expected by the end of calendar year 2007.

Shenzi

We have a 44 per cent interest and will operate the Shenzi oil and gas project in the deepwater fields of Gulf of Mexico. Other members of the project are Repsol (28 per cent) and Hess Corporation (28 per cent). The project will construct a stand-alone tension leg platform with a design capacity of 100 Mbbl/d and 50 MMcf/d of gas. Gross costs for the full field development through to 2015 are estimated at approximately US$4.4 billion (our share US$1.94 billion). First oil is expected by mid 2009.

Other developments

Americas

We are seeking approval to construct and operate Cabrillo port, a floating storage and re-gasification unit (FSRU), located in the Pacific Ocean approximately 22 kilometres offshore from Ventura County, California. This deepwater port would be the receiving terminal for shipments of LNG for the west coast markets of the US. Natural gas production would average 800 MMcf/d with design capacity allowing maximum peak deliveries of 1,500 MMcf/d. The Cabrillo port project is progressing through a permitting process involving US federal, state and local government agencies.

Exploration and appraisal

We are focused on finding significant discoveries through wildcat drilling that will add substantial resources. We have exploration interests throughout the world, particularly the Gulf of Mexico and Western Australia. During the year, our gross expenditure on exploration was US$447 million. Our major exploration interests are as follows:

Australia/Asia

Scarborough/Pilbara LNG

We have a 50 per cent non-operated interest in the Scarborough gas field in WA-1-R (ExxonMobil holds the remaining 50 per cent and is the operator) and hold 100 per cent interest in WA-346-P, which covers the northern extension of the mapped gas reservoir. The project is still examining a number of concepts for field development.

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

Pyrenees is a joint development plan encompassing the Ravensworth, Crosby and Stickle discoveries. We own a 40 per cent operated working interest in the WA-155-P permit (Ravensworth discovery in this area), with Apache Energy Ltd owning 31.5 per cent and Inpex owning 28.5 per cent. We also own a 71.43 per cent operated working interest in the WA-12-R permit (Crosby and Stickle discoveries in this area), with Apache Energy Ltd owning the remaining 28.57 per cent. The project is currently in feasibility with development options still under evaluation.

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Americas Gulf of Mexico

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 first appraisal well was suspended short of the primary objective by the operator (BP) in August 2006 and will be re-entered in mid fiscal year 2007. Further appraisal is scheduled for 2007.

Following an interim equity agreement, we hold a 29.805 per cent working interest in Puma. The other 70.195 per cent is held by BP (46.195 per cent), Chevron (21.75 per cent) and Statoil (2.25 per cent) subject to future re-determination.

Knotty Head

We currently own a 25 per cent working interest in an exploration well on the Knotty Head Prospect located in the Green Canyon area. Partners in the well are Nexen (25 per cent owner and operator), Anadarko (25 per cent) and Unocal (a wholly-owned subsidiary of Chevron) (25 per cent). Unocal spudded the exploration well in March 2005. The initial well was completed in mid December 2005 followed by a sidetrack operation, which was completed in early March 2006 to further evaluate the results of the discovery well. The well was drilled in 3,570 feet of water to a total depth of 34,189 feet and encountered hydrocarbons in both the original hole and the subsequent sidetrack. Additional appraisal work will be required to further evaluate the economic potential of the prospect.

Cascade/Chinook Walker Ridge exploration

On 9 August 2006, Petrobras and Devon purchased our 50 per cent working interest in the Cascade blocks. Petrobras and Total EandP USA, Inc acquired our 40 per cent working interest in Chinook. We received cash and a right to future contingent consideration, as well as maintaining an overriding interest in these blocks.

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Aluminium Customer Sector Group

Through operations in Australia, Brazil, Mozambique, South Africa and Suriname, our Aluminium CSG mines bauxite, refines bauxite into alumina and smelts alumina into aluminium metal. The principal raw materials required for aluminium production are alumina, electricity, liquid pitch and petroleum coke. Alumina production requires bauxite, caustic soda and electricity. Most of the alumina we use to produce aluminium metal is sourced from our own operations. We buy caustic soda, liquid pitch and petroleum coke from a number of producers around the world.

We sell part of our bauxite and alumina production to other refiners and smelters, and sell aluminium in the following forms: primary aluminium; foundry alloy; extrusion billet; rolling slab and wire rod.

We are the world s sixth largest producer of primary aluminium with a total operating capacity of approximately 1.3 mtpa of aluminium. We also have a total operating capacity of approximately 14 mtpa of bauxite and 4 mtpa of alumina. We sell aluminium metal to customers around the world, generally at prices linked to the London Metal Exchange (LME) price. Our alumina and bauxite sales are governed by a mixture of contract and spot sales.

The Aluminium CSG s operations comprise the following:

- The fully owned and operated Hillside and Bayside aluminium smelters, located at Richards Bay, South Africa.
- A 47.1 per cent interest and operator of the Mozal aluminium smelter in Mozambique.
- An 86 per cent interest and operator of the Worsley joint venture, consisting of the Boddington bauxite mine and the Worsley alumina refinery, both located in Western Australia, Australia.
- A 45 per cent interest and operator of the Suriname Mining joint venture operating the Lelydorp III, Kaaimangrassie, Klaverblad and Coermotibo mines in Suriname, and a 45 per cent interest in the refining joint venture, comprising an alumina refinery and port facilities at Paranam in Suriname.
- Interests in the Alumar consortium and Mineração Rio do Norte SA (MRN). The Alumar consortium operates an integrated alumina refinery and aluminium smelter in São Luís, Brazil. As a result of our joint venture partner s investment (Alcoa, Inc.) in a new smelter line, our share in the Alumar smelter was reduced from 46.3 per cent to 40 per cent during the year. Our share in the Alumar refinery remains at 36 per cent. The Alumar consortium purchases bauxite under long-term contracts from MRN, an operation of three open-cut mines in northern Brazil of which we own 14.8 per cent.

In August 2006, we completed the sale of our 45.5 per cent interest in the Valesul Aluminio SA Joint Venture to our joint venture partner Companhia Vale do Rio Doce (CVRD).

Information on the Aluminium CSG s bauxite mining operations

Detailed descriptions of our producing assets are listed in the tables below. These tables should be read in conjunction with the production and reserve tables.

Name, location and type of mine and access	Ownership, operation and title/lease	History	Facilities and power source
Boddington bauxite mine	We own 86% of the Worsley joint venture. The other 14% interest is	The Boddington mine opened in 1983 and was significantly	The mine has a crushing plant with the capacity of 13 dry mtpa

123 kilometres southeast of Perth at Boddington, Western Australia, Australia Open-cut mine The mine is accessible by sealed public roads. The ore is transported to Worsley alumina refinery via a 51 kilometre overland conveyor.	owned by Sojitz Alumina (4%) and Japan Alumina Associates (10%). Worsley Alumina Pty Ltd is the manager of the joint venture on behalf of the participants. Worsley Alumina Pty Ltd has the same ownership structure as the Worsley joint venture. We hold a 2,716 square kilometre mining lease from the Western Australian Government. In 2004, we renewed the lease for a second 21-year term. A further 21-year renewal is available.	extended in 2000.	of bauxite. Power is supplied from the Worsley alumina refinery site via a joint venture-owned powerlines. A description of the Worsley alumina refinery can be found below.

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Name, location and type of mine and access	Ownership, operation and title/lease	History	Facilities and power source
Lelydorp III mine (Onverdacht)	We own 45% of the Refining and Mining Joint Venture. The other 55% interest is held by Suralco (a subsidiary of Alcoa World Alumina and Chemicals (AWAC), a venture of Alcoa and Alumina Limited).	The Lelydorp III mine started operations in 1997. The mine will close down in February 2007.	Lelydorp III mine has a nominal production capacity of 2 mtpa; there are no beneficiation or processing facilities.
25 kilometres south of Paramaribo and 15 kilometres west of the Paranam refinery, Suriname	We manage all mining operations.		Electricity is sourced from Suralco and fuel sourced from an external provider.
Open-cut mine	Suralco holds exploitation licences, issued by the Government of Suriname, over the Lelydorp III deposit. These licences expire in 2032.		
The mine is accessible by joint venture-owned haulroads. The ore is hauled by truck over a distance of 15 kilometres to the Paranam refinery.			
Kaaimangrasie mine (Onverdacht)	We own 45% of the refining and mining joint venture. The other 55% interest is held by Suralco.	The development of the Kaaimangrasie mine started in November 2005.	Kaaimangrasie mine has a nominal production capacity of approximately 2 mtpa of bauxite; there are no processing facilities at the mine.
38 kilometres southeast of Paramaribo and 24 kilometres east of the Paranam refinery, Suriname	We manage all mining operations.	Operations/delivery of bauxite to the refinery will commence in July 2006. The mine is scheduled to be operated until August 2010.	Electricity is sourced from Suralco and fuel sourced from an external provider.
Open-cut mine	Suralco holds the exploitation licences, issued by the Government of Suriname, over the Kaaimangrasie deposit. These licences expire in 2032.		
The mine is accessible by a joint venture owned haulroad. The ore is hauled by truck over a distance of 28 kilometres to the Paranam refinery.			
Klaverblad mine (Onverdacht)	We own 45% of the refining and mining joint venture. The other 55% interest is held by Suralco.	The development of the Klaverblad mine started in July 2005.	The development of the Klaverblad mine started in July 2005. Operations/delivery of bauxite to the refinery will commence in May 2007. The mine is scheduled to be operated until August 2010.
23 kilometres southeast of Paramaribo and 11 kilometres east			

of the Paranam refinery, Suriname	We manage all mining operations.	Operations/delivery of bauxite to the refinery will commence in May 2007. The mine is scheduled to be operated until August 2010.	
Open-cut mine	Suralco holds the exploitation licences, issued by the Government of Suriname, over the Klaverblad deposit. These licences expire in 2032.		
The mine is accessible by a joint venture- owned haulroad. The ore is hauled by truck over a distance of 17 kilometres to the Paranam refinery.			
Coermotibo	We own 45% of the Coermotibo joint venture. The other 55% interest is held by Suralco.	The Coermotibo mine started operations in 1991. Based on reserves the mine will be depleted in 2007. Remnants mining will continue after that time.	Coermotibo mine has a nominal production capacity of 1.7 mtpa; there are primary crushing and barge loading facilities but no beneficiation or other processing facilities.
150 kilometres east of Paranam, Suriname	We manage all mining operations.		
Surface strip mine	Suralco holds exploitation licences over the bauxite issued by the Government of Suriname. These licences expire in 2032.		Coermotibo generates its own electricity from power generators that run on diesel fuel.
The mine is accessible by joint venture-owned haulroads.			
The ore is hauled to the Coermotibo crushing and loading facility and subsequently barged along the Commewijne river to the Paranam refinery.			

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Name, location and type of mine and access	Ownership, operation and title/lease	History	Facilities and power source
MRN Oriximina, State of Pará, Brazil Open-cut mines The mine is accessible by joint venture-owned haulroads. A joint venture-owned railroad connects the 28 kilometres between the plant and the port.	We own 14.8% of MRN. The other 85.2% is owned by affiliates of Alcoa (18.2%), Alcan (12%), Companhia Brasileira de Alumínio CBA (10%), CVRD (40%) and Norsk Hydro (5%). MRN holds valid mining rights to all its reserves until exhaustion of the reserves.	Production started in 1979 and the last expansion occurred in 2003.	MRN beneficiation facilities consist of a crushing unit and a washing unit and a conveyer belt that transports the ore between the 2 units. The bauxite nominal production capacity is approximately 17 mtpa.