BHP Billiton

Petroleum Business Briefing

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Growth & Project Updates

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I. Introduction

I am pleased to be here today. As you know, my name is Philip Aiken and I am the President and CEO of BHP Billiton Petroleum. Joining me in the presentation today here in London is Greg Robinson, who is the CFO of Petroleum, and Steve Bell, who is the Head of Exploration and Business Development.

To assist with questions and also to be with us in South Africa is David Walker. David is the President of our UK, North Africa & Middle East Operations and Development. He is in South Africa to take some questions down there.

Today's presentation is really to give you some insights of the strategies that BHP Billiton Petroleum business is pursuing, and will continue to pursue in search of growth. We have a very impressive slate of projects that will continue towards the growth of this business, and we also have a number of opportunities – which we will talk about today – which we believe will give us the next series of opportunities to grow this business overall.

What I would like to do is start off by just giving the context of where Petroleum fits in BHP Billiton overall.

II. BHP Billiton

1. Outstanding Diversification

As you are aware, BHP Billiton was formed in June last year, following the merger of BHP and Billiton, and is now a leading international diversified resources company with a market capitalisation of about $33 billion.

BHP Billiton is broken down into seven customer sector groups, each responsible for the clear operating and financial objectives. Each of the customer sector groups is a substantial business in its own right, and several are in fact leaders are in their field. The Petroleum business is a very significant contributor to the Company, generating over $1 billion of EBIT in 2002, and in that year represented 29% of the Corporation's overall EBIT. This year, as you know, in the first quarter it was an even higher figure: more like about 45%.

2. Market Capitalisation

Let me also put the energy industry into perspective. In particular, this slide shows the order of magnitude of super-majors in the energy industry overall. You will see when looking at energy companies, BHP Billiton rates about number ten in terms of market capitalisation. This is very important for our Petroleum business because it means, being part of a larger Group in the top ten energy companies, we have the financial strength which allows us to punch above our weight. Therefore, it gives us the opportunity to be a much larger contributor in projects than if we were a stand-alone E&P company just by ourselves.

III. BHP Billiton Petroleum

1. Our Role within BHP Billiton

Let me now talk about the Petroleum business. As you know, at the top of this slide you will see that BHP Billiton has identified a set of six value drivers that distinguish us from the other resources companies. One of those value drivers is the Petroleum business itself.

Petroleum actually provides a breakout from BHP Billiton's traditional peer group. We provide BHPB with diversification and significant growth opportunities that might be more easily achieved and sustained than, say, with the minerals customer sector groups.

In the lower section of the slide you will see the Petroleum business value drivers as they relate to BHPB. Firstly, we have world-class assets; particularly the Bass Strait and the North West Shelf. Our innovative approach is evidenced by our activities in the Gulf of Mexico deepwater and our approach to contracts. I think in the GoM deepwater, and some of the contract renewals we have done in Liverpool Bay and Bruce, we have taken very innovative approaches towards the way we do business. Our marketing is very customer-focused and we have an excellent inventory of projects going forward. I will cover these in some detail today.

Finally of course, our portfolio is both geographically spread and diversified. We also have a very efficient business. We rank in the top quartile amongst our peer group in terms of net income per barrel of oil equivalent, and we rank in the top quartile when it comes to return on capital.

As a finding and development company, we would rank at the top of the second quarter in our F&D costs, and we would also be in about the second quartile when you look at our finding costs. You can see that Petroleum fits very well into BHP Billiton's overall drivers, and you can see the areas which we are pursuing.

2. Financial Year 2002

Well let us look at the business last year. This slide shows you that last year we had about 65% of our production in terms of liquids and 35% in terms of gas. About 70% of our production was sourced in Australia last year, and about 69% of our proved reserves are in Australia.

Organisationally, Petroleum employs about 1,600 people globally – with offices in Melbourne, Perth, London, and Houston. The organisation which I lead is supported by the Petroleum Executive Committee, which in turn is supported by global asset resource teams. We have processes and portfolio management organisation in place, which means we operate as a truly global company, which has its significant strengths.

Our processes have been very much streamlined on a global basis and the management team is charged with accountability for the global nature of the business.

3. Petroleum Executive Committee

The next slide shows you the Petroleum Executive team and where they are located. There are six members in the group overall. There are also two members of the BHPB Executive Committee – Chief Legal Officer John Fast and the Chief Marketing Officer Marius Kloppers – who act in a role similar to like independent directors of the Petroleum Executive Committee.

The Petroleum Executive Committee has very clear responsibilities. It is responsible for providing the high level strategic direction and clarity for the business. It provides leadership to the asset and resource teams, it oversees the business development opportunities, and it makes the key investment decisions going forward, which are then passed up to the Executive Committee or the Board, depending on their magnitude.

We also establish performance measures for the business and provide liaison with the Group overall. Whilst the Petroleum Executive Committee is collectively responsible for overseeing the global operations for the business, each member of the group also has individual responsibility to oversee the teams in their direct line of responsibility. As I said, you can see the members of the team and where they are located in that slide. You will be hearing from two of the members later on in these presentations.

4. Current Operations & Exploration

The next slide shows our major areas of focus, which we will explain in more detail today as we move through this presentation. Our major producing assets are located in Australia, the UK, the GoM, Pakistan, and Bolivia. We also conduct an international exploration and development programme around three areas of business focus aimed at securing our medium- to long-term growth.

These business areas are based on High Margin Exploration, where we are likely to explore deepwater basins; the Commercialisation of Gas resources; and what we call securing 'Access to Discovered Resources' through the development of enduring alliances with host governments and their agencies.

5. Growth Highlights

a. High Margin Exploration

What I would like to do now is show you what progress we have made during the last 12 months in each of those areas. Firstly, in High Margin Exploration we sanctioned the Mad Dog project during the year and detailed engineering is well underway. First production is expected from this field in 2004.

The Atlantis development was also sanctioned, with partial funding to align with BP's pre-sanction process. Detailed engineering work is also underway with this project, and we expect to have full project sanction later this year. We increased our exploration acreage in the GoM and Trinidad, and we also entered new deepwater acreage offshore Brunei, offshore Brazil, and also offshore South Africa.

Our appraisal drilling programme continued in the Greater Angostura area offshore Trinidad, following the discovery of the Kairi well in August, and of course in the GoM we have had more discoveries which we will appraise in the coming year: at Cascade, and more recently with Boris and Neptune.

The Company also acquired interests in the Caesar/Cleopatra oil and gas pipelines which will transport hydrocarbons from Mad Dog and Atlantis in the GoM. This is expected to commence in about 2004. So you can see in the High Margin Exploration we had a number of milestones and projects sanctioned during the year.

b. Commercialisation of Gas Resources

With regards to the Commercialisation of Gas Resources, the Minerva gas field development offshore Port Campbell in Victoria was approved and will commercialise a static gas resource. Design engineering and construction contracts have now been awarded and first gas is expected around 2004.

The North West Shelf joint venture brought together this year a number of contracts in Japan, which led to the sanctioning of the fourth train. More recently, as you are probably aware, we won the contract to supply the first LNG into China. Finally, in Pakistan we sanctioned the full field development of Zamzama. This will supply some 320 million cubic feet of gas a day for 20 years, from 2003. This project is currently being executed on a fast-track basis and should be in production later next year. So a number of major, significant projects were sanctioned in our Commercialisation of Gas Resources during the year.

c. Discovered Resources

The third area in which we are seeing growth is in Discovered Resources. During the year the Ohanet wet gas project continued on track and is now about 89% complete. We expect first production round about the middle, second half of 2003. After a slow start, the ROD integrated oil development is now on track and engineering work is underway. We expect production from this in about April 2004. At the moment, that project is about 21% complete.

6. Producing Assets Highlights

a. Liverpool Bay

A bit later we will cover in production in more detail - Greg Robinson will cover that, but I would like to just make a couple of comments about our producing assets during 2002.

As you many of you who have followed BHP Petroleum in the past and now BHP Billiton Petroleum, one of the assets we had some significant issues with over the years was Liverpool Bay. Liverpool Bay was a troublesome asset which we have spent a lot of time and effort on in recent years. In the last 12 months we produced some 24 million barrels of oil, which was ahead of the record we set in 2000 of 17 million barrels, and we have produced something in excess of 90 billion cubic feet.

This exceptional year's performance was driven by good topside facility reliability in both the process and utility systems. This year this asset has focused on a commitment to maintain its improved reliability and stability of production, and has reaped the benefit of the number of initiatives which were put in place last year to further reduce operating costs and improve margins.

b. Typhoon

The other highlight I would like to talk about is Typhoon. Typhoon is our first development in the deepwater GoM. It came on-stream in July last year, and after setting a new standard for deepwater GoM – taking a project to discovery and development – it is currently producing fairly close to its design capacity of 40,000 barrels a day.

I know many people have got concerns about how we can go with developments in deep and ultra-deep water, but I think Typhoon is a very good start; having come on-stream so well and having produced so well in its first year of production.

As I said before, Greg Robinson will cover the producing assets in much more detail when he presents.

c. Proved Reserves

Let me now turn to reserves – a very important figure in any petroleum business. The total proved reserves at the end of June 2002 were 1,456 million barrels of oil equivalent. During the year we booked reserves in the GoM, Pakistan, Trinidad, and also Minerva, offshore Australia.

There has been considerable comment in various market reports about our reserve numbers and the status of our proven and probable reserves. The figures I quoted to you before were what we call our 1P or our P90 reserves.

d. P50 Reserves

Whilst we only report our P90 reserves externally, internally we carry a most likely P50 – i.e. the proven and probable reserves – of 2,066 million barrels of oil equivalent. These are made up of 990 million barrels of liquids and 1,076 million barrels of oil equivalent of gas. The P50 is – if you like – our expected outcome, and this reflects the potential upside of our commercial reserves base. You will see from this slide that if you look at our P90 reserves, our reserves-to-production ratio is about 11 years, but if you look at our P50 reserves that actually increases to about 15 years.

e. Full-Year 2002 Reserves and Contingent Resources

In addition to these proved and probable reserves, we also carry most likely contingent resources – or statics – of 1,479 million barrels equivalent of gas and 337 million barrels of liquids. 73% of these contingent gas resources are located off the North West Shelf, with additional volumes in Bass Strait, Pakistan, and Trinidad.

These gas resources are ones where we do not have any specific gas contracts in place, but we know technically we do have these resources. These are obviously the subject of our Gas Commercialisation Strategy.

If you look overall – and this has been a question asked in the past – you can see on that slide our 1P reserves, our 2P reserves, and if you throw in all the contingent resources, you will see a total there of something like about 3.9 billion barrels of oil equivalent, if you take all of the reserves and also the contingent resources.

7. Health, Safety & Environmental Performance

Let me now talk briefly about our Health, Safety, and Environmental (HSE) performance. BHP Billiton has an overriding commitment to HSE responsibility and sustainable development. Our goal is zero harm to people and to the environment. During 2002, Petroleum's HSE performance improved and there were no significant environmental incidents, fines or prosecutions.

Over recent years we have been working continuously to improve our HSE performance. Last year, our operations in Australia – production, drilling, exploration and the office – received the Australian Producing and Exploration Association (APPEA) Safety Improvement Award for the best improvement in the total injury frequency rate of all oil and gas companies in Australia.

Also during the year, our Australian Operated Asset Team achieved ISO 14001 accreditation for environmental management systems. The Australian Operated Asset Team is the first offshore oil and gas producer in Australia to obtain this certification, and follows on the accreditation at Liverpool Bay the year before. We will continue to pursue ISO 14001 accreditation with all our operations.

8. Social & Community Activities

a. Overview

BHP Billiton is also committed to upholding the fundamental human rights of people with whom we work, consistent with United Nations Universal Declaration on Human Rights. At the outset of our projects, an analysis of social risks and issues is undertaken, which forms a part of our community relations plans. Let me talk about three particular areas.

b. Pakistan

In Pakistan, we are building effective relationships with local communities in the Dadu and Johi areas of the Sindh province in Pakistan. We are participating in a number of local development projects, including two community health clinics, a primary school for girls, a vocational centre for women, a computer training centre for both genders, and a microcredit scheme for women. Construction of a boys' school is also taking place near the Zamzama gas field, and two additional schools for girls are also being looked at.

We will continue to develop this programme in consultation with local community groups. We see this being a very important part of our development in Pakistan.

c. Liverpool Bay

In Liverpool Bay, we have made a significant contribution to North Wales and the northwest of England through our community programme. The programme covers a broad spread of initiatives based on providing employment, bolstering the local economy, and supporting education. This year our visitor centre at Point of Ayr was upgraded and the asset has plans to launch a dedicated website for local schools by the end of this year.

d. Minerva

The Minerva development is off the coast of southwest Victoria in an area of environmental significance. Although construction has only just commenced, a community programme is already underway. The community programme for Minerva includes sponsorship of local projects which benefit the widest possible community, provision of job training opportunities for students in the local school, and career orientation seminars given to local students by BHP Billiton professional staff.

So you can see, no matter whether we are in a third world country or a first world country, we do work very hard in the community programmes. We see ourselves as very much part of the communities for a long time going forward.

IV. Growth Strategies

1. Strategic Priorities

Let me now talk and refer back to our future growth. This is a slide many of you have seen before, but it still remains valid today and shows the consistency of the strategy we have had in place in the business for some years. We have categorised our portfolio into three areas of business growth – with one of cash generation – each having a complementary role in the global portfolio. Let me just take a few minutes to explain what each of these strategic priorities is about.

2. High Margin Oil Exploration & Production

The High Margin Oil Exploration and Production area comprises projects with high potential returns, frequently characterised by high sub-surface or technological challenges, but in environments of generally low political risk. For better-than-average players who can successfully manage these at times complex sub-surface and technological risks, returns can be high. In addition, we can usually obtain exposure to oil price upside in these regimes. The GoM is the prime area where we will be pursuing this particular strategy.

3. Discovered Resources

With Discovered Resources, we are really talking about low risk, already discovered hydrocarbons in resource rich countries which may offer significant growth options in the longer term. The trade-offs are a relatively fixed rate of return, limited exposure to oil price upside, and limited exposure to downside. An additional trade-off is often country risk. Our main activities here have been our oil and gas projects in Algeria.

4. Gas Commercialisation

The third area is Gas Commercialisation, which provides exposure to a high growth industry sector that is robust to environmental and greenhouse pressures. Whilst some existing LNG contracts link price to crude oil, some gas contracts do actually provide an opportunity for commodity price diversification. We continue to expand our gas portfolio and we will talk in more detail about some of these projects shortly.

5. Cash Generation

Finally there is the cash generation area, which comprises our producing assets whose primary strategic driver is to generate cash, since their business growth potential and contribution to organisational capability is basically limited. These assets underpin our short-term financial performance and boost our financial capacity to fund our growth projects longer-term.

V. High Margin Oil Exploration & Production

1. Overview

a. Gulf of Mexico

Let me first turn to High Margin Oil Exploration and Production. The GoM is an area where we have built a strong position over a number of years and we now rank in the top ten leaseholders in the deepwater areas. We believe the GoM is a premier basin in which to grow our business. The Gulf has world-class potential, very attractive fiscal terms, and access to a premium oil and gas market.

Our projects and prospects offer both near- and long-term value. Our exploration programme has delivered some success. In the last two years, we have announced approval of the Mad Dog, Atlantis, and Boris developments, and we have an active exploration programme underway. Last year we spent $162 million on exploration activities in the GoM. We continue to look to expand our portfolio there, and in the last year we were awarded another 26 leases in a range of water depths. Later on Steve Bell will spend some time talking through our exploration portfolio in the GoM.

b. Trinidad

The second area we are working hard in this area is in Trinidad. This is an exploration province which has the potential to quickly become another core area for Petroleum. The area is relatively shallow water and we are growing our position. To date we have completed eight exploration wells, making four discoveries – both oil and gas.

Detail sub-surface mapping and facilities engineering and design work is currently underway. We expect to sanction our first development project in about the next six months – probably around March next year – and we expect to have our first production in Trinidad in 2004. Also in Trinidad, we took more acreage during the last 12 months to consolidate our position in that province.

c. Australia

We continue to have good opportunities in Australia, and we are hoping to grow our activities through an exploration programme in the offshore Carnarvon, Beagle and Browse basins, and we are also continuing to explore offshore Gippsland in Bass Strait.

d. Africa

In Africa we have another area where we have some interests. We have recently farmed into a very large block offshore South Africa. This acreage is in deepwater and will complement our other acreage in the region.

e. Brazil

In Brazil we have also been awarded an exploration block in water depths ranging from 100-1,500 metres. We have been interested in establishing a position in offshore in Brazil for some years, and this block represents a good opportunity as an entry point which we can build on and look at other quality opportunities as they become available.

f. Southeast Asia

In Southeast Asia, we expanded our portfolio during the year by being awarded a 25% interest in a deepwater block offshore Brunei. An extensive 3D seismic survey has already been conducted over this area and has provided some high quality data for accelerating the initial phase of this exploration programme. We anticipate spudding our first well in this block in the next 12 months.

2. Mad Dog Development

As I said, later on Steve Bell will address it in more detail, but let me firstly spend some time talking about the development projects we currently have in this part of our growth strategy.

The first of these is Mad Dog. Mad Dog will be developed using Spar technology, similar to the Genesis field. The production facility will be a massive structure, equivalent to about a 50-60 story skyscraper. It will have a capacity of 80,000 barrels of oil a day, and 40 million cubic feet of gas a day. In addition to local wells drilled directly beneath the Spar by the Spar rig, provision will also be included for the future tie back of remote sub-sea well clusters. Produced oil and gas will flow through separate risers to an export pipeline system.

The situation at the moment with this project is that lump sum contracts are being negotiated for the hull and risers with Aker. Contracts for fabrication of the topsides and installation are being negotiated, and labour rate contracts are being put forward based on target incentives. A lump sum contract for the Spar rig is also being negotiated. As I said before, production from this facility is expected in 2004.

3. Atlantis Development

The other major project in the GoM is the Atlantis project. At the moment detailed engineering is underway and we expect full sanction of this project later this year. This project remains one of the largest fields in the GoM and when in production it will produce 150,000 barrels of oil a day and 180 million cubic feet of gas a day. We still expect the first oil from this project to occur towards the end of 2005 or early 2006.

4. Caesar/Cleopatra Transportation Infrastructure

The Mad Dog and Atlantis projects are very important to us, but another project which we sanctioned during the year was our involvement in the Caesar and Cleopatra pipelines. This slide shows the existing crude oil infrastructure in green, with the proposed El Paso Cameron Highway pipeline in blue. It also shows the deepwater oil leg which will connect Mad Dog, Holstein, and Atlantis to the markets.

BHPB has committed about $100 million to this project to purchase a 25% interest in the Caesar oil pipeline and a 22% interest in the Cleopatra gas pipeline. Each of these is approximately 190km long, including the laterals. Participation in these pipelines allows BHPB to secure transportation solutions for production from Mad Dog and Atlantis, and will also give us the opportunity to transport any other discoveries we have in the Atwater Foldbelt area. It also means that we will be able to add value from the transportation of any third party volumes from other companies that have developments in the area.

We are all aware that being established in the early infrastructure is very important in these projects, and I think this is an investment which in years to come will be something which we will be pleased we have made. Commissioning is scheduled in 2004, on a parallel timeframe with the Holstein and Mad Dog developments. Weather permitting, it is expected that pipeline laying will commence in December of this year.

5. Neptune Development

Mad Dog and Atlantis represent projects in the pipeline that we have already sanctioned. But let us talk about some of the projects which we hope we will see developed in the near future. In July this year we announced the results of the Neptune well. This was an appraisal well at the original discovery we made in the Western Atwater Foldbelt.

Neptune-3 followed a reshuffling of the equity position on this asset. We have now assumed a 50% ownership, being the designated operator, with our partners Marathon Oil Company and Woodside Petroleum. This well was a success, encountering a 450-foot gross hydrocarbon column. The other data we collected from this well is also very encouraging, and we are planning another appraisal well, which will spud in the next few weeks, to further delineate this field and also collect more data.

Neptune-4, as that well will be known, is planned to commence after the Shenzi well, which we are currently drilling with our drill ship the *CR Luigs*. Coinciding with this drilling, initial development studies are underway to determine how best to produce hydrocarbons from this resource. We will be looking for a fast-track development of Neptune once we determine that it is actually a commercially viable field.

6. Trinidad Development & Exploration

Let me now talk about Trinidad. As you might know, we got involved in Trinidad back in the early 1990s and signed a PSC for two blocks back in 1995. In 1999 we made our first gas discovery at Angostura in Block 2(c), and in the same block we made a significant oil discovery in 2001. We have wrapped up our appraisal programme earlier this year, and are now going on to look at the development.

We have a 45% working interest in Block 2 (c) with our partners being TotalFinaElf with 30%, and Talisman Energy with 25%. Currently the detailed sub-surface mapping and facility design work is underway, and we expect to make an investment case for a development project on this block. Once the appropriate approvals are received from the partners, local authorities, etc., we would hope to make an announcement of this project with more detail. As I said before, we expect this probably around about the end of the first quarter of the next calendar year.

On top of the development project in Angostura, we have also acquired acreage adjacent to this discovery. We have a 30% working interest in Block 3 (a) and we are the operator, with our partners being British Gas and Talisman, both with 30% each, and TotalFinaElf with 10%. The PSC for this was signed last April. We are currently working with our partners on exploration plans for this block, including a 3D seismic survey which will commence next month.

After this data is collected and analysed, we expect to begin an exploratory drilling campaign, with the first wells expected to spud by the end of the current fiscal year. Like the acreage in the adjacent block, we are pursuing both oil and gas targets in what are relatively shallow zones here, being drilled in relatively shallow water.

So in Trinidad, it really now is about getting on with the development of the first project and then looking at what other discoveries we can make when we review the exploration programme later this fiscal year.

VI. Gas Commercialisation

1. Overview

Let me now turn to our second growth strategy, which is Gas Commercialisation. This is really all about bringing gas to market. Of course, in this area we have had a number of projects around for some years but let me just briefly talk about the North West Shelf.

The North West Shelf has two phases: the domestic gas phase and the LNG phase – or the export phase. The domestic gas plant has a production capacity of about one billion cubic feet per day, last year it produced about 450 million cubic feet per day, and hence there are opportunities to grow this business.

The most likely next growth opportunity for the North West Shelf domestic gas business is based on a conditional sales and purchase agreement we signed earlier this year with Methanex to supply 180 million cubic feet of gas a day for 25 years from 2005, for their proposed methanol plant to be located on the Burrup Peninsula. There are a number of other opportunities to grow the domestic gas business, and as I said before we have plenty of capacity on the Burrup for future growth.

But it is really the LNG – or export phase – which commands most attention. At the moment, we supply somewhere between 126 and 130 LNG cargoes per annum to Japan, and we usually supply two to four spot cargoes either to Japan or the USA. The Japanese customers are Japan's largest electricity and city gas providers, all of whom have current contracts for 20 years which expire in 2009.

Earlier this year we approved the expansion of the next phase of the North West Shelf, which is a 4.2 million tonne train, which will come into operation round about 2004. Earlier this year – a few months back – we announced the winning of the first contract into China, but the North West Shelf also sees opportunity to grow our business not just in China, but also in other areas of Japan and potentially in Korea and Taiwan.

2. China LNG Supply

Let me spend some time talking about the contract we have signed in China. On the 18th of October the North West Shelf Joint Venture signed Sales and Purchase Agreements for the Guangdong LNG project. The agreements were signed with the six LNG partners for the supply of approximately 3.3 million tonnes per annum of LNG for the first phase of the Guangdong project. This will commence in late 2005-06 and the contract has a life of 25 years. The contract value is something between about $12-20 billion, depending on the overall oil price.

This is a most important contract for the North West Shelf. Winning the first contract with China was really a great success story, not just for the North West Shelf but also for Australian LNG. Also as part of this contract, besides the LNG contract, there are two other important contracts being negotiated.

The first is an opportunity for the China National Offshore Oil Company (CNOOC) to acquire a participating interest in the North West Shelf Project gas reserves, which will supply gas to the China project. The second – and least developed at this stage – is also an opportunity to enter into an agreement with Chinese shipping companies – COSCO and China Merchant – to establish a ship-owning and ship management company to transport LNG to Guangdong. Two or three LNG carriers will be required for this contract, and the details of those contracts are still being worked through.

As I said before, supplying China is very important, but in the Chinese LNG market this is the first contract, which will only be 3.3 million tonnes per annum. But there are a lot of people who believe the China LNG business could be 20 million tonnes within the next 10 years. This is obviously a market which the North West Shelf will be targeting for further growth.

3. Zamzama

Another example of our success in our Gas Commercialisation area has been what we have done in Pakistan. Back in April 2000 BHPB signed a Gas Sales and Purchase Agreement for what was known as the Extended Well Test, where we contracted to supply for the sale of 70 million cubic feet of gas a day for a 21-month period to the Sui Southern Gas Company Ltd. Commercial production commenced on the 26th of March 2001, and last year we averaged 92 million cubic feet of gas a day.

This Extended Well Test has been very important as it enabled us to capture market share via an innovative low-cost development, while minimising the inherent political risk and testing the market's ability to pay. Now we are going ahead with a full-field development. To make this possible, a Gas Sales and Purchase Agreement, which will underpin the full-field development, was completed and the project has been sanctioned by BHPB.

The agreement covers the supply of up to 320 million cubic feet a day over the expected life of the project, which is some 20 years. The gross reserves are estimated at 2 Tcf on a P50 or 2P basis. The capital and drilling cost of Phase One of this full-field development is expected to be approximately $40 million (our share), and we expect the first sales to take place round about in the first half of 2003. Once again, on this project BHP Billiton is the operator and has a 38.5% share of the project.

4. Eastern Australia Gas Overview

a. Bass Strait

Well let me now turn – in talking about our Gas Commercialisation – from one of our newest to our oldest asset: the Bass Strait. Gas from Bass Strait currently supplies around 50% of the market in southeast Australia. It actually supplies about 90% of the Victorian market and we now also supply about 20% of the gas market in New South Wales – that is about 20 petajoules per annum.

The last few years have seen great changes in gas infrastructure in Australia, particularly in southeastern Australia. Gas from Bass Strait has been supplied into New South Wales by Duke Energy's Eastern Gas Pipeline since August 2000. Supply into Tasmania started in September this year via another pipeline owned by Duke Energy. Additionally, we will be providing gas into South Australia from the Minerva project, and have only in the last 24 hours announced an MOU with TXU for the supply of another 20 petajoules per annum into the South Australian market.

We have been very much at the forefront of realising the opportunities afforded by reforms taking place in the energy sector in southeastern Australia. But let me make this comment: we still have significant uncommitted reserves of gas from the Bass Strait, and we will eventually look at developing other fields in the Bass Strait, such as the Kipper field.

5. Bass Straight Potential Revenues

Obviously the Bass Strait asset is very important to BHPB. The next slide shows you why we see Gas Commercialisation activities as being most important. This chart has been shown in presentations like this before – it shows BHP Billiton's share of revenues from Bass Strait.

Bass Strait is now a very mature province from a crude oil point of view, and the crude oil production is forecast to decline by around about 17% per annum over the next six years; hence, the importance of increased gas production. You can see here the gas projections; these are based on securing about 30 petajoules per annum into New South Wales and 20 petajoules into Tasmania.

The importance of these extra gas sales is tied to the increased condensate and LPG production associated with this gas sale. What is also nice about this particular development is that the capex requirements to produce this extra gas is quite minimal, with only a very minor amount of capex required for increased gas production at Longford. The only real major investment will come when we bring on new fields such as Kipper.

This slide shows that Bass Strait, although it is a very mature asset, will still be important to BHPB in 10 years' time. You can see there significant revenue going out into the next decade.

6. Minerva Development

One of the other projects we are going to supply into this southeastern market, is the development at Minerva. In March this year the Company approved the development of the Minerva field, which will commercialise a static gas resource offshore Port Campbell in Victoria.

This shows a simple diagram. It actually is a very simple project involving two vertical subsea wells in shallow waters, tied back to an onshore gas plant via a single pipeline. The total estimated project cost is

$136 million, with our share being about 90% or $123 million. The first gas is expected to flow ashore in 2004. The gas from Minerva will be sold on an ex-plant basis via a greenfield 680 km pipeline, which will terminate in Adelaide.

We have signed a Gas Supply Agreement with the Pelican Point power station, a wholly-owned subsidiary of International Power. The gas will be consumed in their existing 500 megawatt combined cycle power station. The pipeline to Adelaide is being built by the SEAgas consortium. As I said before, that will also be used for other supplies coming out of Bass Strait into South Australia. We have a 90% interest in the Minerva field – and are the operator – with the other 10% being owned by Santos.

VII. Discovered Resources

1. Overview

The third and final area of our growth strategy is what we call our Discovered Resources Development and Production strategy. This is really where we get involved in areas where there are very low risk resources, which offer moderate financial returns and very few technology challenges.

In this particular area, most of BHPB's activity to date has been in North Africa, where we have two significant projects: the Ohanet wet gas development and the ROD integrated oil development. We continue to look at other areas to expand our business in North Africa and the Middle East, where there are significant discovered resources.

As you all know, the Indian sub-continent is a growing energy market – particularly for gas. The Middle East is the logical place from which to supply this. We have identified a number of opportunities; we have various points of discussion with relevant authorities, and we hope in the future that some of these projects will come to hand. Certainly our priority at the moment is bringing on-stream the two projects we have in Algeria.

2. Algeria

a. Ohanet

The first of these is the Ohanet project. Ohanet is a project in which BHP Billiton is the operator and has a 45% working interest. This is being developed under a risk service contract, in which we agreed back in 2000 to develop a field with 3.2 Tcf of gas and 210 million barrels of liquids. BHPB's entitlement under the RSC is for about 67 million barrels. The indicative cost of this project is round about $1 billion (US).

Just to give you an idea where we are with this project: all of the 3D seismic data acquisition has now been completed and the data is being processed and incorporated into the reservoir models. By the end of September 2002, a total of 22 new wells had been drilled and completed, and 11 existing wells had been re-completed. Facilities engineering is complete and all equipment – and most of the bulk materials – are now onsite. Overall construction progress at the moment is about 89% complete, and we do expect the first production on schedule in the second half of 2003.

I visited this site recently. It is about 1,500km inland from the Mediterranean and it is quite an amazing site, in that everything has had to be brought in by road train. The one area we are particularly proud of in this project is that we have now worked some eight million man hours without a lost-time injury. Considering we have had 2,700 people onsite throughout this project, that is quite a significant achievement in the conditions we are working in.

Anyway, the Ohanet project is well on schedule to be not just on time, but also in line with budget.

b. ROD

The second project in Algeria is the ROD project. This is an integrated oil project with AGIP. Overall, BHPB has a 38.75% interest, following the alignment of all the interests. Our partners here are AGIP and SONATRACH. The premise of this project at the moment is 36 development wells will be required, ten of which will be re-completions of already drilled wells. The first development well commenced drilling in November 2001 and at the end of September the rig was working on its eighth development well. The overall project is about 21% complete.

All the critical long-lead engineering items are progressing on schedule, and the EPC contractor is now progressing the engineering and procurement. Site preparation commenced in October 2002. The gross reserves of this project are some 299 million barrels, with BHPB's entitlement being 60 million barrels. The gross capital cost is about $500 million, our share about $200 million, and we now expect first oil round about the end of the first quarter of 2004.

VIII. Growth Overview

So that gives you an idea of the projects we are currently working on in the three areas where we see our growth. Just to summarise those: this slide shows you the nine projects we are currently working on. These are currently all under construction and all are in good shape. Overall you will see here some $2.5 billion of projects which are under construction at the moment, and this money will be spent over the next three to four years. As I said before, all these projects are proceeding to plan at this stage.

IX. Petroleum Production Forecast

What happens when we complete all of these projects? Well this next slide gives you an estimate of BHPB Petroleum's production levels going out to 2008. You will see at the top there the oil projects in green and the gas projects in red, and the approximate dates we expect them to come on-stream.

If we actually look at this overall – and I make this caveat: this is subject to all things being equal and all the projects coming forward as we expect. This does not carry out any assumptions on future exploration success, and the only project we have included in there which is not already sanctioned today is the Trinidad project.

You will note that this represents an increase from our current production level of about 130 million barrels of oil equivalent in 2001 to around about 180 million barrels of oil equivalent in 2007. We are currently in the middle of a fairly flat spot in our production, and over the next couple of years you might actually see some slight decline in our production. This is due to the natural decline in Bass Strait, and also the decline in the Laminaria field in Western Australia.

However, from 2003 through 2004 we will see the start-up of the Ohanet and the ramp-up of the ROD project. Obviously, post-2004 we will see the full impact of the development of Ohanet and ROD, and then we will see Zamzama, Atlantis, and Minerva coming on-stream.

I must make the point: this slide is based on our current or planning assumptions and is very much a forecast and subject to change as we redefine our development plans. But certainly all things being equal in the current environment, this is the sort of growth we are looking at from our business coming out over the next five years.

Well, Ladies and Gentlemen I would like to now stop at this stage and pass over to Greg Robinson, who will give you some more information about our production and about our performance.

Production & Performance

Greg Robinson

CFO, Petroleum

I. Petroleum Financial Overview

1. Production

Good morning; it is a pleasure to be here this morning. I would like to start with a financial overview. Phil has already touched on some of this, but really most of our financial performance is dominated by price, production, and costs.

During the 01-02 year, you can see that we had a very strong performance in production; production was up substantially. Our financial result was substantially lower, and that was really reflecting the much lower prices that we got in the 02 year. Having said that, the prices were still very attractive for us on a net back per boe basis, and I will talk about that a bit later in the presentation.

2. Prices

Lower prices pretty much gave us almost a $500 million revenue swing in that year. Our cost base – and I am going to talk about that later in the presentation – does not swing as much as our price. For everyone here, I think you would be fully aware that we do not actually hedge our prices. We are fully exposed to the liquid prices.

Gas is a little different; gas is more stable. Our Victorian gas sales and our gas sales in Western Australia are pretty much CPI-linked, and so we get a much more stable revenue stream there.

Over the last three years it has been a very strong financial and operational performance from Petroleum. We have had a good price environment over those years and certainly from an operational point of view we have not seen any major hiccups. As a CFO, it is always a pleasure to stand up here and know that your operational performance has been very strong in a high price environment.

3. Returns on Capital

It really reflects in our returns on capital. Over a three-year period our return on capital has been greater than 25% average, and so that is I think a very good performance for the Group. Our free cash flows have been very high and we have been a significant contributor on that basis back to the Corporate Group.

4. Capital Expenditure

2001 represents a little bit of a benchmark year for us. Up to that period our reinvestment rate was pretty much in line with our DD&A: approximately $500-550 million. From 2002 to 2005, our capital expenditure will outstrip our depreciation rates quite substantially as we reinvest heavily into the business. Phil has already talked about the fact that the nine growth projects – excluding Angostura – represent $2.5 billion worth of capex over that period.

Just to give you an idea: in 03 and 04 we will be spending capex at about $1 billion a year. To put some light on that: from a cash flow perspective, we expect to fund all of that capex within the Petroleum group. Our capex to cashflow will be relatively tight in 04 but we still anticipate funding it within Petroleum.

5. Exploration

You can see the exploration number there in 02. Again, I will talk a little bit about that later in the presentation, but that was a high expenditure year. We would not expect to spend that much in 03; our expenditure rates should be around the $240 million mark. And we usually look at a capitalisation rate of around 30%.

6. Quarterly Comparison

The quarterly performance that you can see on the chart here is down a little on production, generally due to the performance of Liverpool Bay. We had a scheduled maintenance shutdown, and that is what caused some of that production decline. We had a very strong sales performance; it does not necessarily show there in the production but we had some early shipments from the North West Shelf which caused that EBIT result to be very strong for the quarter, and we had a slight price increase.

The exploration number there – it looks like we are not actually spending much on exploration during that quarter, but we actually had three wells in progress. We do not expense them until we actually see the result to the well. Steve will talk a bit more about that later on.

II. Full-Year 2002 Production by Asset

Let us look at production. I would like to illustrate the 01 to 02 production by asset. We have three key assets within our portfolio: Bass Strait, which began production in the 1960s; North West Shelf, which began production in the 1980s; and Liverpool Bay, which began production in the 1990s. These three assets make up greater than 70% of our production base at this point.

There are two new assets on the chart: Typhoon, which is in the GoM – is an oil and gas development and the first of our deepwater developments in that area, and Pakistan, which started gas production essentially right at the end of 01, and you can see the pick-up in 02. As Phil mentioned, Pakistan is actually being expanded at the moment – tripled in size in terms of production.

Two assets there are in steep decline: Laminaria and Griffin have both had successful in-fill programmes over the last couple of years. I will talk about that a little further on. Both are in quite steady decline at this point.

As Phil mentioned, we expected Bass Strait to have about a 17% decline rate. The in-fill programmes there have been very good and we have been sustaining production levels higher than our own expectation. Again, I will talk about that a little further on.

Phil showed you a production chart further out; the GoM, Algeria, and other growth projects will replace the declining production that I am talking about here at the moment.

III. Quarterly Production Comparison by Asset

Just a quick look at quarterly production. As I said, Bass Strait really had a very good performance in that first quarter. We really have seen a very successful in-fill programme there. North West Shelf also had very strong production. You can see Liverpool Bay had a reduction - that was the planned maintenance shutdown. Laminaria and Griffin in-fills performed strongly on a quarter-by-quarter basis, but as I said, I think you can expect quite a strong decline on those going forward.

IV. Production by Product

Just a quick look at how our products actually break down. I am not going to spend too long on this slide. Really the main point here is that 65% of our production comes from liquids and 35% from gas – that is gas and LNG. That mix will move a little bit towards gas over the ensuing years, but you can see the importance of the liquids to the profitability.

V. Bass Strait

1. Overview

I wanted to start talking about the real engine room of the business at the moment, which is our Australian asset base – starting with our largest asset, Bass Strait which started production back in the 1960s. Cumulative production to June 2002 – our share only – is about 2.1 million barrels of liquids and nearly 3 Tcf of gas, so you can see it has just been a tremendous asset for the BHPB Group.

Average gross daily crude and condensate production during 02 was around 160,000 barrels a day, and gas production was 532 million cubic feet a day. Gross LPG production about 2,500 tonnes per day. Again, it was above our expectations at the start of the year.

Bass Strait accounts for around 40% of Australia's petroleum liquids production. It supplies about 90% of Victoria's natural gas requirements and around 20% of the New South Wales markets. The gas is sold under long-term contracts. The crude is primarily sold to local refineries and has a floating price fixed to it.

As Phil mentioned, the aim here is to really look at the gas side and try to pick up more eastern Australia gas contracts. To give you an idea: we have produced – all-up with our partner – more than 5 Tcf of gas. That only represents about 50% of the proved reserves, so I have plenty of upside here to capture new contracts.

2. Financials

Let us have a look at the financial performance for Bass Strait. This is an extremely high returning business for us. It is a very old asset so it is heavily depreciated; we really do get a tremendous return on capital here. The 01 to 02 you can see that there was a very large reduction in price that I have talked about before, but you can see that we have really maintained our production level.

A lot of the aim here is to make sure we tackle that decline and maximise the value of this asset. The quarter one 02 versus quarter one 03, we had a small price increase, but again you can see that we have managed to maintain our production level. Let me just turn to what is actually going on in the asset at the moment and what we are doing to tackle that decline and look at these gas contracts.

3. Highlights

We have upgraded infrastructure at Bass Strait. We have put $300 million gross over five years into the Longford plant restoration. Long Island Point, which is where we export the crudes and where we export our LPG, is going under a $100 million gross refurbishment programme.

We are mitigating the liquids decline, which is the principle aim. We are putting $100 million gross into a new gas pipeline from Bream. That accelerates around 30 million barrels of liquids from that asset. That will be on production by first quarter 2003. That project is on time and on budget.

The in-fill programmes I have been talking about are at West Tuna; it is marked up there up in the right top box. We initially aimed to do about four wells there; we ended up doing about 13 and finished that in-fill programme around June. Every one of those wells was very successful. We will be moving on to Tuna and Flounder. You are never quite sure how in-fill programmes are going to turn out, but we would hope they are going to be very successful and maintain our attack on that decline profile.

4. Future Growth Opportunities

The purplish area you see there is where we have recently spent $28 million with our partner acquiring 3,900km of 3D seismic. Now we have not actually done some sophisticated 3D seismic in this area for over 10 years – it has really been a long while. We would hope that we are going to identify prospects there to drill. We will be looking at results post-April next year.

We have also acquired 3D seismic at Vic/P45, down to the south there you can see in the little tan box. Again about another 900km of 3D seismic, so we are going to actively look for new prospects there. Phil has mentioned Kipper; it is under review, it is a gas development, and you will probably hear more about that as time goes on.

VI. North West Shelf

1. Overview

The North West Shelf project began production in the 1980s and is Australia's largest resource development project. BHPB has a one-twelfth share of domestic gas production and a one-sixth share of production of all other products from the North West Shelf venture. Our share of reserves you can see there at the bottom; we have marked in the 2P reserve base at 590 million barrels of oil equivalent.

Phil has already covered a lot of the gas side here. Needless to say, large, long-life assets often have a way of getting better, and this is one of them. It is producing at a level of 630,000 barrels of oil equivalent per day. It is broken into different product streams: LNG, natural gas, condensate, crude, LPG. Phil has already mentioned the LNG side, that we have seen significant expansion in the last couple of years: for the Japanese contracts we have picked up of 4.2 million tonnes and the China contract which we have recently won of 3.3 million tonnes.

There is also the domestic gas contract with Methanex, which we are looking to supply at 200 terajoules per day, which again is a substantial contract.

2. Financials

Let me turn to the financial performance for the North West Shelf. It is again a very high returning asset for us; it has had a very strong performance in 02 on a production basis – stronger than 01 – due to very low maintenance downtimes. We did not have any cyclones through the period in WA, so that benefited both this asset and our Griffin asset. In LNG we had 7.7 million tonnes of production. We had record oil production due to Cossack Pioneer's performance. We developed the Echo-Yodel condensate development, which is tied back to the Goodwyn-A platform.

You can see the capex growing in 02. That is related to the Train 4 development for the Japanese contracts. That is on time, on budget, and our share of capital costs there is gross $235 million. As Phil mentioned – I will not go into it – the Chinese contract added to the back end of this.

The first quarter 03 was very strong. This is where we picked up some extra sales early in July. We had a couple of extra shipments there, so it is a bit stronger than our production base – making the result look stronger than it would have been.

VII. Laminaria/Corallina

Now let us turn to Laminaria and Corallina. The Laminaria and Corallina oil fields are located in the Timor Sea about 550km northwest of Darwin. Oil production from Laminaria and Corallina began in November 1999. Oil production in financial year 02 was 34.9 million barrels gross, or an average of 96,000 barrels a day.

In June production commenced from our in-fill programme, which was Laminaria Phase Two, which involved two in-fill wells on the Laminaria field. The initial production contribution from those wells was 70,000 barrels a day. It is pretty much as we expected. Now what we are seeing is the field going into decline, so we would expect it to much more rapidly decline over the next 12 months.

VIII. Other Australia/Asia Region Financials

Wrapping up the Australian/Asian region financials, this includes Laminaria/Corallina, a smaller production facility we have – Griffin, the Pakistan asset, and Buffalo, which we sold in 01. That is part of the reason you see the EBIT reduction from 01 to 02. The Laminaria and Griffin fields – as I mentioned – are in decline – they are very mature assets.

On the other hand, we are tripling production in Pakistan so we will see a good contribution from that asset going forward. The quarterly result again for Laminaria and Griffin again looks very strong but that was a result of the in-fill wells. Pakistan is going from 100 million cubic feet a day to roughly 320 million cubic feet of gas a day, so we are roughly tripling that production level.

Over time we would hope to bring our production levels in Western Australia back up. We have a number of exploration programmes in that area. In the deepwater Browse, as Phil mentioned, and in the Carnarvon basin – not far from our Griffin production – we have two leases: WA-155 and 255, and we will be drilling some wells on that next year. Steve will comment more on that later.

IX. UK

1. Liverpool Bay

Turning now to the UK. Liverpool Bay is our largest operated asset. It is located in the Irish Sea off the Welsh coast. It is a mature, low cost asset. Operating costs have continued to reduce as we have really focused on the asset over the last three years. Before that period, it was a problematic operation for us. The performance in the last three years has been a real credit to the team there. And we have continued to look at ways of reducing that operating cost – we have recently moved our operating team out of London, up to Point of Ayr, close to the asset. So we are looking at all ways of reducing that.

It has had a very good safety performance. It has a large 2P reserve position still – 93 million barrels of oil equivalent – so it will be a very good contributor to the Group in the years ahead. The oil production for 02 was very strong. We had 23.9 million barrels gross against last year's record, which was only 17 million barrels. Also, the gas production was strong at 90.6 Bcf. That gave us a total production profile for the year of 39 million barrels, which was a very strong performance and a record for Liverpool Bay.

2. Bruce & Keith

Let me move on to Bruce and Keith. The Bruce field is located northeast of Aberdeen. It is one of the largest gas condensate fields in production in the UK North Sea. Gross liquids production was 17.1 million barrels for the year and gross gas production 183 Bcf. It had a pretty successful in-fill programme over 01 and part of 02, and we will be looking to do more of that in 03.

One of the really important things about Bruce is that we had some production restrictions with the type of gas contract we had in the Group. Our asset group and our marketing group in The Hague were able to unlock that contract, which allows us not to be restricted by demand by Centrica on the gas side. We are now able to develop the reserves a lot more effectively.

Bruce and Keith still have a 2P reserve level of 52 million barrels of oil equivalent, and again will be a good contributor to the Group over the next couple of years.

X. UK / Middle East / Africa Region Financials

Rolling up the results for the UK, the Middle East, and the African region, it has been a good performance. Most of the earnings are driven by Liverpool Bay and Bruce. Liverpool Bay has been affected a little bit in the 03 first quarter through the planned maintenance shutdown, as I mentioned. The capex numbers look extremely high there, but that picks up Algeria – it does not have it in a footnote, but it does actually pick up the Algerian capex. $243 million of that $289 million are the Algerian projects for 02. That represents about 34% of our total capex for the year.

XI. Typhoon

1. Overview

Let us move on to Typhoon in the GoM. Production began from the Typhoon field in the GoM in July 2001 and it is the first of our deepwater developments in that area. It is in about 600 metres of water and approximately 100km from the Louisiana coast. Gross production from Typhoon for 2002 averaged 31,000 barrels of oil a day and 35 million cubic feet of gas a day.

We have been conducting a lot of work around Typhoon. Following the discovery at Boris, a small asset just to the southeast of Typhoon, we took an action to develop that as fast as possible and tie it back to the infrastructure we have with Typhoon. We managed to do that in 13 months and we expect that to come on production in December this year.

When you have infrastructure like Typhoon, you like to target as many of these small prospects you have around and tie them back as quickly as possible. Typhoon has been very good for us from that perspective. Our share of capex on the Boris development was about $65 million.

2. Near-Field and Other Opportunities

This gives you an idea of what I am talking about when I talk about the Typhoon mini-basin. Maximising returns from our deepwater assets includes the exploitation of near-field opportunities. As the map shows, BHP Billiton has a direct interest in some 30 exploration blocks within a 40 km radius of the Typhoon platform. Our aim will be to find more Boris's. We will be drilling some of these prospects in the 03 financial year. Steve will talk a little bit about that in his presentation.

XII. Americas Region Financial Performance

Obviously, we are going to expect much stronger growth longer term here with Mad Dog and Atlantis coming into this sub-section. You can see the 01 to 02 performance is largely driven by the Typhoon start up. The other assets we have in production within this sub-division are Green Canyon, West Cameron and Bolivia. They are all mature assets, so they are all on the decline, as are Griffin and Laminaria.

We will be looking to further exploit the Typhoon mini-basin just in production. as we have just been talking about. Mad Dog is expected to come on late 04. Atlantis early 06. So we would expect this group to be a major contributor to the Group over the next five to six years onwards.

XIII. Petroleum Financial Details

1. Petroleum Full-Year 2002 EBIT by Producing Asset

Let us wrap up the total EBIT profile. If we look at the total EBIT profile, I mentioned North West Shelf, Bass Strait and Liverpool Bay as the three key drivers of the business. You can see that in the performance here. Of that $252 million, Liverpool Bay roughly contributes about $180 million.

The decline that I have been talking about in some of the mature assets will be replaced by the Gulf of Mexico, Algeria, North West Shelf, Pakistan and Trinidad; projects that Phil gave you an outline of earlier on.

2. Efficiency Targets

This is just to give you an idea of the sort of efficiency we set ourselves. The second column has got a 06 target, but it is not actually an 06 target. We set ourselves these targets for all our projects. We look for finding costs of $1.50, finding and development costs of $4.50 and EBIT margins of greater than $6.00. Over a three-year average we have been able to outperform those metrics. That puts us in pretty much the top quartile of the industry.

3. Exploration – Capitalised Versus Expensed

Exploration looks like it is building from 2000 through 2002 with $288 million spent in 2002. As I mentioned, 2002 was an unusual year in the sense that we had a lot of appraisal drilling around Atlantis, Mad Dog and Trinidad. We do not expect to be spending at quite that rate in 03. We would expect it to be about $240 million and we would aim at a capitalisation rate of about 30%.

Going forward also, when you think about reserve bookings - and this is one thing I think the analysts have difficulty predicting with us - we go into more wildcatting and away from just pure appraisal drilling. When you are doing wildcat wells you really need to wait for the appraisal process before you start booking the reserve base. So it may not be at the same pace that the analyst community expects.

4. Operating Margin

I mentioned earlier that price and production sort of dominate our profitability. I just want to show you the opex per boe. Our opex per boe is roughly about $2.50 per boe. There is a high component of fixed costs within that. Our DD&A per boe, for example, runs at about $4.60. So it shows that it is almost double what our opex per boe is. I guess the analogy I am trying to give you is if you get your capex wrong on these projects upfront, you can pretty much jeopardise the operating profile of the project going forward. It is very important to get that right.

The secondary tax piece is also a significant part of our operating expenditure and it slides with prices. As prices go high, quite often the secondary taxes increase, and that would roughly be about $3.50 per boe.

5. EBIT Margin Versus Production

So this gets us into our net back. It shows the very strong performance the business has had over the last three years. EBIT has been very strong through this period. The first quarter is a little bit skewed as I mentioned. We get lumpy sales with our shipments, and we had very good sales in that first quarter so it makes that margin look a little more attractive.

The important bit about 1999 is it shows the very low price environment we were in - $13.20. We still managed to have quite a good EBIT net back even in that sort of environment, and that was including some problems at Longford in Bass Strait. So it shows you our business is actually very profitable at very low oil price environments.

6. Development Expenditure Versus Depreciation, Depletion & Amortisation

I mentioned earlier that 01 was a bit of a banner year in the sense that we are changing to our reinvestment programme going forward. If you look at 01 DD&A and capex spend they were roughly in line. From 02 onwards, we are going to be spending at much higher rates of capex. This is the nine development projects Phil mentioned, without including Angostura.

For 03 and 04, we would expect to spend greater than $1 billion a year in capex funded by the cash flow within Petroleum.

7. Margin Analysis – FY 2002

I have another margin chart here but I am not going to talk to this today, the data is there for everyone to have a look at. It is very consistent with the boe margins that I was talking about on the prior charts.

XIV. Petroleum Relative to Industry Players

Just a quick benchmark to the industry players. We rank around eighteenth in the world in size of reserves and about nineteenth in production. The interesting thing is the assets or the companies around us at that level. In our view their asset quality is vastly different to what we have. We see our asset profile closer to what the majors actually have.

1. Peer Group Benchmarking

I have put that up just so I can show you where our three-year average performance has been. We have had a very strong performance over those three years. The mixture of these benchmarks is exploration, production and finance benchmarks. The peer group is the global players I had on the page before. Overall, we have ranked pretty well in the performance data.

We are in the top quartile for production per unit of production and in the return on capital. We would hope to improve on the reserves replacement with our growth projects and our exploration programme going forward.

At this point I would like to turn it over to Steve Bell to talk about exploration. Thank you.

Exploration & Business Development

Steven Bell

President, Exploration & Business Development, Petroleum

I. Introduction

Thank you Greg. Good morning everyone. For the next 20 minutes or so I am going to cover the exploration piece of this presentation.

When done properly and well, exploration can create great leaps in value for our shareholders. Clearly we can create tremendous value to the business. Cash flows and income measured and scrutinised so carefully would not be possible without the discoveries made by explorers.

When I have spoken to the investment community throughout my career I have often had to explain, and at some times actually defend, the purpose of exploration.

II. Exploration Turns Ideas Into Money

So I aim to clarify my brief remarks this morning with a simple cartoon on the first slide and describe how the function is creating and adding value to BHPB shareholders. The points on the chart are basically the principle nodes of value creation as we go through the piece, how we create value over time.

Ideas, such as deepwater potential in the Gulf of Mexico, have very little value by themselves. But when tested with exploratory drilling and verified with discoveries these ideas can quickly add value to our company.

Successful appraisal is the next leap up when going from the ‘D’ to the ‘A’. Successful appraisal provides the greatest leaps in value, as we have seen with the Atlantis and Mad Dog projects. Developments, such as at Typhoon, can take it up another notch, with reserves additions from near-field opportunities as was just mentioned with Boris and North Boris. Otherwise adding more reserves creates even more value. By the time these fields are depleted new ideas are being tested and more value is created. Finally, to the point where one gets to cash destruction, which I think is really a point the industry could focus on a bit more. We put more money into the ground than we are ever going to get back. I mention this to you so that you keep this in mind during the review of the Company’s exploration programme.

In the Gulf of Mexico and elsewhere we have a number of ideas that we are pursuing to create value for our shareholders.

III. Current Exploration Acreage Portfolio

Our portfolio is focused on high-growth opportunities. These are high-margin oil plays that at times are high risk, but they have the potential to add significant value to the Company. When you look at the map you may ask how do we manage this portfolio. The execution of the exploration business is facilitated by quarterly business reviews. These are designed to ensure that:

- We achieve our targets – that we actually deliver what we promise.
- Business milestones are delivered and cycle times are shortened.
- The portfolio is constantly high-graded.
- Capital and human resources are best allocated.
- A significant portion of the exploration community is involved in this discussion and these decisions. So, at times, I have the best minds around the table in making sure these decisions are met.
- We also make sure we challenge prevailing views and that new ideas are heard.

So the focus areas for our business are in the Gulf of Mexico, in Trinidad and in Australia. These areas are where the primary dollars go for exploration. A significant franchise has been and continues to be built in these areas through exploration discoveries.

We are also selectively expanding into new areas that include Brazil, Brunei and South Africa.

IV. Challenges Unique to Our Portfolio

We have a fairly unique portfolio when you compare us to other independent oil companies. We are indeed a different kind of wildcatter. One of the challenges we face, and it is one of the aspects that sets us apart, is that our portfolio is indeed unique, but I think it provides an opportunity for shareholders. We are a different kind of explorer.

Our portfolio is heavily weighted towards prospects in deep and ultra-deep offshore frontiers. These are enormous structures covering thousands of acres. Exploration here is not just technically challenging but deepwater wells are also very expensive with higher rig rates and longer drilling schedules than other wells. That said, we are one of the most efficient drillers in the Gulf of Mexico in deepwater. We will participate in half a dozen of these wells in the Gulf of Mexico this year.

But the prospects in our portfolio have tremendous value. Discovering, appraising and developing them takes quite a bit of time and careful analysis. To offset this we have near-field and other opportunities, but again, the better prospects are in deepwater. The larger prospects are in deepwater.

A thirteen-month turnaround like we have seen at Boris is a world class achievement. The point I want to make here is that, in some respects, we are conducting a 10- to 20-quarter business inside of a four-quarter environment. You want to measure on four quarters, but as Greg mentioned before, from discovery to appraisal to the point where we can get to bookings it actually takes quite a bit more time. So what I would suggest is the best to measure us over time is to look at us on a rolling three-year average to properly track our progress.

V. Deepwater Gulf of Mexico Potential – Still a Long Way to Go

To better understand our exploration strategy I am really going to focus on the Gulf of Mexico where much of our effort is currently being focused. The largest part of our exploration efforts are directed in this basin. You may be asking why. A few years ago, the basin was considered the 'dead sea' with little exploration potential. In fact, at the last meeting I pointed out there is a number of famous landmark papers in the 1930s, 1940s and 1950s, all of which pronounced the Gulf of Mexico dead – nothing left to find. The great paper by the US GS in the late 60s pronounced that there was nothing left to find. I think the last one was in the 80s. There is a great paper again with nothing left to find in the Gulf of Mexico.

What it is truly showing is that rather than running out of oil, it is usually explorers running out of ideas. The basin still has significant upside potential as shown by this slide. The graph on the left shows the cumulative hydrocarbons in billions of barrels of oil found to date in the deepwater over the last quarter century. Approximately 15 billion barrels of oil equivalent have been found to date. As you can see by the slope of the curve it is still rising. Hardly a mature basin. As the basin is maturing that slope would curve over and flatten. As you can see, it is not.

Many estimates have the Gulf of Mexico yielding between 30-50 billions of barrels of oil equivalent recoverable out of the deepwater. Similarly, the chart on the right shows an average discovery size of slightly less than 100 million barrels of oil equivalent without displaying any trend to smaller fields, which is again another indicator of a maturing basin.

VI. Indicative Margin Analysis

When you take a look at the indicative margin analysis as shown on this chart, the main point is well, great, we can find oil and gas in the deepwater, but can we make any money at it? The industry has shown that we can find the hydrocarbons. But how profitable are these barrels? Besides being productive, the Gulf of Mexico is very profitable with direct access to the US oil and gas market.

This slides illustrates the very large fields in deepwater. In this case it is a field in 6,500 feet of water and a half a billion barrels recoverable. It represents really the core of the opportunities in our portfolio.

On the first bar you can see that returns are in excess of $3.00 per barrel at a flat nominal $18.50 WTI after all costs, including a notional $1.00 per barrel exploration costs deducted. At low oil prices here by the second bar at $14.50 WTI US, investors' returns are still acceptable at greater than $1.00. Then a $25.00 per barrel case, which is an environment we have continually found ourselves in for the past four to six quarters. Cash margins are an impressive $7.00 per barrel.

Given our current environment with the oil prices fluctuating between $25.00 and $30.00 a barrel, these types of assets can be very profitable to the bottom line. What is different about the Gulf of Mexico is that indeed we really can share in the upside when prices move upwards.

VII. Gulf of Mexico Exploration Programme Has Delivered

The other point to make to you is that the Gulf of Mexico exploration programme has delivered. This chart gives a snapshot of the results of the exploration drilling programme since 1994. We have drilled 40 wells in total, of which 24 are exploration wells and 16 were appraisal wells. Four of the exploration wells were in the shallow flex play early in the trend and really are hardly what we are aiming at right now.

The highlights that you can see are:

- A 21% commercial success rate in exploration drilling. That increases to 38% with the inclusion of discoveries that are currently under evaluation, currently being considered for further appraisal.

- We have completed one project, Typhoon, and in the last fiscal year we sanctioned Mad Dog and Atlantis fields, Caesar and Cleopatra pipelines and the Boris tieback project.

- Of the 16 appraisal wells delivering projects, we have basically been able to book P50 reserves of 342 million barrels of oil equivalent and P90 reserves of 133 million barrels of oil equivalent.

The exploration group, wherever we have been in the world, has been successful when we have recognised good basins early and emerging technologies early. When we have moved quickly to capture a position and moved decisively to capture that position. We have competed strongly where we have learnt the game, and we have leveraged both the people and our positions. Finally, where we have delivered value reserves and growth. Indeed, the Gulf of Mexico is a basin where we moved very quickly early on to establish a significant position.

VIII. Gulf of Mexico Lease Acquisition Costs Versus Peers

In terms of our lease acquisition costs, this chart really shows how we stack up against our peers. Acquiring land early in the cycle of a play is important. Firstly, because that is when it is available, but that is because it is cheaper.

We have always tried to obtain quality at the lowest possible cost. Generally, we have been able to do so. Now the plays are much more competitive and one would think that our prices are moving up significantly. But still we have been able to obtain land at very competitive rates in this basin.

We participate in an annual Ernst & Young Gulf of Mexico exploration benchmarking survey. The survey shows our acreage cost per block over the past three years is the lowest of the benchmark companies, as you can see.

IX. Deepwater Performance Post-1995

As far as our performance since 1995, basically internal rate of return versus net present value, the sum total of early recognition and capture of quality acreage, competitive costs for land drilling, is that we have a very strong absolute and relative performance in the Gulf of Mexico.

This graph is from an extensive deepwater Gulf of Mexico industry report prepared by Wood McKenzie late last year. 'WoodMac' maintains and updates an exhaustive deepwater Gulf of Mexico field database with reserves, costs and economics.

This particular graph plots the full-cycle NPV adds since 1995 on the *x* axis, with the full-cycle internal rate of return on the *y* axis. I would like to draw your attention to the stand-out position where BHPB is located. With only one other company we are unique among the independents in that we have achieved both competitive returns and material value creation.

X. Gulf of Mexico Deepwater Leasehold Ranking

Access to, and control of, quality acreage has been and will continue to be a critical differentiator for us in the deepwater Gulf of Mexico. We have a very strong acreage position in the deepwater as shown by this graph. Our assets are primarily concentrated in the central Gulf of Mexico region. We have a very good quality lands' position over the plays we really want to be in.

XI. Upcoming Drilling Activities in the Next 12-18 Months

Just to give you a quick summary of what we are doing in the basin and what is coming up in the next 18 months. It is located on a fairly busy slide here but I will try to guide you through it. We are participating in three exploration wells that are currently drilling.

- As Phil mentioned, the *CR Luigs* is currently drilling the Shenzi prospect in the Atwater Fold Belt, which is in the centre of the slide.

- We are being carried on the Kansas well, which is being drilled by Marathon and will test the north-eastern extension of the Western Atwater Fold Belt. Again, that is just to the north-east of Shenzi as I pointed out.

- We are also being carried on the Kerr McGee-operated Vortex well, which is in the Eastern Atwater fold belt. We will be the operator of this prospect, if indeed it is a discovery and that it appraises out to be a field.

Other potential wells in the next 18 months include:

- An appraisal well at Cascade, another at Walker Ridge at Chinook.

- A near-field Green Canyon mini-basin well at Tiger. Tiger is in the upper left corner. Again, this is the area Greg was talking about. You can see a significant number of blocks around Typhoon and this is where we can get our medium-cycle time and even short-cycle prospects tied back into Typhoon.

- We also have a Mississippi Canyon test at the Habanero prospect.

It is very important to note that our future activity has a much higher concentration of operated prospects than in the past. You can note on the map anything noted in red is what BHPB operates. So we are the designated operator at Neptune, Shenzi, Cascade, Chinook, Vortex (but as I said not for the exploration well), Tiger and Habanero.

Our Gulf of Mexico programme has now evolved from being a non-operating partner at developments such as Typhoon, Mad Dog and Atlantis, to one where the bulk of our future prospects will be BHPB operated. Importantly, we will be able to control our production, our reserves and the pace at which a lot of these projects will move ahead. So it is a significant shift for the organisation.

So our skills are growing; our capabilities are growing. What I would like to do is just take a few moments and show you where we have gone elsewhere in the world to take these skill sets into the deepwater in similar basins.

1. Brunei Block J Offshore Acreage

In addition to the Gulf of Mexico activities, we have recently announced the acquisition of Block J in offshore Brunei. This slides actually shows two blocks – Block J is the one to the north-east, so it is the upper right-hand block.

This was only one of two blocks offered in the country's bid round and we were part of a consortium that was awarded this property. We hold a 25% equity position, TFE is the operator with a 60% working interest, and Amerada Hess has the remaining 15%.

A 3D seismic survey was shot over the acreage prior to the bid, so we were actually able to look at the prospects and size of these things. They are very well controlled with very high quality seismic. We will spud our first well early in the next fiscal year on this play.

2. Brazil Offshore Acreage

In June we also acquired a 100% working interest in Block BM-C-24 in the Campos Basin, offshore Brazil. We have been wanting to enter this basin for quite a while and with the feeding frenzy that had gone on down there in the past number of years it was quite difficult to actually move in to get the quality land without having to overpay for it.

So this really provides us with high-quality acreage with a material equity position that we can either use to trade in to other people's acreage, or leverage to have someone drill a well for us. This was also controlled by a 3D survey. This was controlled by the Roncador field 3D survey that we were able to identify the prospect. For those of you that may not be aware, Roncador is a three-billion barrel field in Brazil. So if you are going to have some control that is not a bad name to be tossing out.

3. West Africa/South Africa Exploration

Lastly, we are continuing our work in West Africa. We are exiting Angola and abandoning Block 21. The results of both wells drilled on the block were very disappointing and the contractor group will honour its obligations to Sonangol for both of the undrilled wells under the terms of the PSC, so we are pulling out of that block.

Finally, we farmed into a block with the dominant acreage position off the coast of South Africa. We acquired a 90% interest in Block 3B/4B for a capture cost of about $5.5 million. The licence cover is a term of seven and a half years with an effective date from 1 February 02 and is divided into four periods. The first period covers 18 months and has a work obligation of 2,500 km of 2D seismic data. The remaining three periods are optional. So for those of you that know the language, this is really a seismic option that we have taken on this block.

So, like the new ventures in Brazil and Brunei, this plays to the strengths we have built over the years in deepwater exploration, where we can use our expertise and proprietary knowledge to create growth and value for the Company.

XII. Summary – On Track to Adding Value

So, in summary, I would like to leave you with just a few points here.

- Our exploration programme is very focused on high quality, material value-adding prospects.
- We have been successful in generating value by turning ideas into valuable projects - Boris and Typhoon, Mad Dog and Atlantis in the Gulf of Mexico and the Angostura field in Trinidad, to just name a few examples.
- We have built a strong competitive position in the Gulf of Mexico, one of the premier basins in the world for deepwater exploration.
- We are currently pursuing new ideas that we believe can make other significant contributions to the portfolio value, both in the Gulf of Mexico and also in Australia, Trinidad and new regions as I have just shown. As an aside, I will just point out that in Trinidad we will begin drilling again in April of this year - more wildcats. We have got three scheduled for the next year in Trinidad.
- In the Outer Browse we will begin drilling in the first quarter of 03. A very large series of prospects in offshore Australia.
- Again, in the Bass Strait, Greg mentioned it is the first exploration 3D ever conducted in the basin. It is amazing for such a prolific basin to get its first exploration 3D in the year 2003. We are looking forward to getting the data and taking a look at what we have to drill.

- Our exploration team is highly talented and skilled, particularly in the technologies we use to analyse deepwater opportunity.

At this point I will turn it over to you Phil.

Summary

Philip Aiken

I. Business Priorities

Thanks Steve and thanks to Greg. I hope that gives you an idea of our activities now and where we see things going to in the future.

Let me just conclude by saying our business priorities going forward are pretty simple. They can be summarised by these five bullet points:

- We certainly intend to keep our producing assets performing efficiently and effectively. Obviously, that is one of our main priorities – to keep on running our existing producing assets as efficiently as we can.

- We see it as very important that we deliver our projects on time. We have a lot of sanctioned projects. As I said, nine projects and about a $2.5 billion BHP Billiton share. Obviously keeping those projects sanctioned and delivering on time and to budget is important.

- We see it also important that we deliver more projects. Trinidad is one we have talked about which we will be trying to pursue and get approved early in the New Year.

- We are also looking to the future. I think Steve has talked about that quite strongly. We are not just about what we have got today. We certainly see it as important to keep on growing this business into the future.

- Obviously, we want to continue to operate safely. We certainly take into account BHP Billiton's commitment to HSEC in our performance going forward.

II. Conclusion

In conclusion, I suppose my comment would be that I think you can see today we have a position as a very well-established oil and gas business with good growth prospects for the future. As such, we think will remain a very important contributor to BHP Billiton into the future.

We have got a very strong portfolio of assets. All our production assets are producing well.

We have very strong margins and we have very good exploration success and really a pipeline of projects that we think will continue to see this business grow into the future.

Questions and Answers

Robert Marshall-Lee, Newton Investment Management, London

Can you give us a feel for your views on OPEC and their ability to control the market going forward?

Philip Aiken

The question of oil prices is always extremely difficult. In recent times I think that we have seen that OPEC has been trying to operate in this $22-28 basket environment. Really, I think that although OPEC non-conformance has blown out recently, I am certain if oil prices did reduce you would see a bit better discipline in OPEC overall. So without trying to ever suggest to be an expert on predicting oil prices and the role of the OPEC, I think that the OPEC discipline has been quite reasonable in recent times and I think it is likely to see prices stay in that range of $22-28.

Obviously, if the issues in the Middle East do lead to some uncertainty, then prices might spike, but I do not think they are going to spike for a long period of time.

Russell Skirrow, Merrill Lynch, London

Congratulations on the 2P reserves, Phil.

Philip Aiken

Thank you.

Russell Skirrow

It is good to see them. You have mentioned opening the development of the Trinidad field and yet it still sits within contingent resources. Could you just outline what you have allocated in contingent resources and what the historical reserve translation ratio is from resources to 2P reserves? That was my first question. I do have a follow up after that.

Philip Aiken

I think actually we booked oil reserves in Trinidad last year. We have not booked any gas reserves. The situation in Trinidad is the project we will sanction next year will basically be an oil project. We are probably not looking at producing gas for another five or six years after first production. At this point in time, all we have booked have been the P90's. I cannot tell you exactly what they are. We can find them later I would have thought.

The fact is in Trinidad that it is a very complex block we are working - quite a faulted block. Really we decided to cease the appraisal programme because, basically, we had enough reserves to commercialise the project. Longer term, I think you will probably find we will book a lot more reserves in Trinidad.

Again, this was one of those projects where continuing to appraise was just going to destroy value. So we ceased the appraisal programme and going forward we will go ahead. But, at the moment, we have booked some oil reserves. We obviously have more in the P50's and at this stage the gas is contingent resources.

Russell Skirrow

The second question. We have seen other companies come under some pressure recently in terms of not quite reaching production targets. How has your own reconciliation gone with your Typhoon experiences versus forecasts? I am particularly looking at the impact of hurricane-related or maintenance-related production losses.

Philip Aiken

Picking up a comment I think Steve made about reserves, as a company I do not think we have ever gone out with very high projections about our production targets, 3, 4 or 5%. In fact, if you look at our business over the last few years our production has been pretty flat. Obviously, if you look right through over about the last ten years, we have produced between 125-130 million barrels of oil equivalent.

The strategy we brought into place around about 1995/96, which was really based on the deepwater Gulf of Mexico, was to try and make the discoveries to replace the Bass Strait. But we had Bass Strait coming down quite strongly and, therefore, we had to look at an opportunity. Really the entry into deepwater Gulf of Mexico was really to try and replace the Bass Strait decline in production.

The figure I have given today of going from around 130 to 180, if you just take all our projects which we currently have sanctioned plus Trinidad and you add them all and look at natural decline coming out of the fields, we are going from about 130 to 180. But that is not a production forecast. That is an estimate of where we believe we will be in five years' time if all those projects go as projected.

So I do not think we are really in the business of giving a production forecast, so much percent per annum, because we do not think it is really applicable to us.

We are slightly different to a lot of our competitors. We are part of a portfolio company. Therefore, I think BHP Billiton gives us the ability to look at opportunities when petroleum prices are good and petroleum projects are there. There is a time will come in the future when probably we will not have the projects and you will probably find other CSG's going ahead. So I do not think we are quite in the same situation as a stand-alone E&P company.

Andrew Hollins, Dresdner Kleinwort Wasserstein, London

You kind of alluded to tax regimes and tax issues as an important determinant for profitability in this division. Now I know obviously North Sea taxes have been raised. In addition, just looking at one of your slides on your indicative margin in the Gulf of Mexico - the profit margin at $18.50. Comparing the slide this year to the one last year then you have lost $1 a barrel on profit. It is down a quarter and it is all in the tax take.

Can you talk about sort of tax regimes in the different regions around the world, how that might be going forward, and particularly how in the Gulf of Mexico that has affected your focus and development programme over the next three to four years?

Philip Aiken

Well let me just address one of the points you raised there. Last year and in a couple of other presentations we have given some generic numbers on what we thought a 500 million barrel field in the Gulf of Mexico would be. I think we always said it was a generic – this was in order of magnitude. The figures you see today are actually based on the projects we have sanctioned at Mad Dog and Atlantis. I think you will actually find the biggest change is not the tax. I think it is actually in the transportation and the opex cost. I think that is where the area has actually gone up. Sorry, is that right? I think it is the opex and the transportation. That is the area which has actually increased.

The tax situation in the Gulf of Mexico is very interesting for BHP Billiton. As you are probably aware, we have considerable tax losses in the US. One of the areas which makes the US production very attractive to us is that we will not be paying tax on any profits there for many years to come. So the figures you have got there today show that before taking into account the net operating losses that we have as a Group overall.

The Gulf of Mexico is an area where the fiscal regime is very good. Therefore, you are in a situation in the Gulf of Mexico which we see number one very good fiscal terms. You are very close to the largest market, and actually taking into those pipelines. As we have said before, we can virtually access every refinery in Texas and Louisiana. So we see it as an area where it is not just about the tax regime; but it is the position of the market overall.

So, really we would like to target areas where the fiscal terms are best for us. But, obviously, it depends on the prospectivity that you have overall. But really for us the Gulf of Mexico adds not just the opportunity of a good tax regime, but obviously we have also got the ability there of accessing very, very liquid markets and also the opportunity of liberalising our NOL's.

I probably have not answered the question as you wanted. That is the sort of rationale behind the Gulf of Mexico.

Greg Robinson

In the Gulf of Mexico, the reason the fiscal regime is very good in the ultra-deepwater, is the royalty rate falls to about 12% from 16%. Greater than 400 m of depth water you get that advantage.

The second thing is when we picked up the leases we were able to get the first 87 million barrels royalty free and that is a significant advantage. Typhoon picked up that advantage. Now you have to apply to the US regulatory authorities to get that but, in general, most of our projects will be looking to apply for it. So the good thing about the US is you get quite a linear relationship to the oil price, where you do not get that relationship in other tax regimes.

Some of the other tax regimes that we are looking at are production sharing contracts and risk service contracts and buyback contracts through the Middle East and in Trinidad and these parts of the world. They actually cap and floor your profitability. So you will see less volatility in the earnings, but you will not see the same sort of high returns in the very high prices.

I saw some statistics recently which said the industry in general you are going to see maybe more price volatility but you will see lower earnings volatility because the industry is moving more towards these PSC structures. So it is an area you could go on for a long while.

Steve Sheppard, JP Morgan, South Africa

I was very interested to see the slide you presented sourced to Wood MacKenzie about the internal rates of return, net present values. First question would be do you support their findings?

Then could you perhaps give us a sense of the way you look at the risk in these very deepwater projects, or projects costing $350 billion? What sort of returns would you expect? What sort of long-term pricing assumptions are you making?

Steve Bell

I will comment on the first one. In general we do. We have run our own internal sets of numbers. While I would not say it is so accurate I could lay a ruler down and say we will arrive at the exact same point on that curve, in a relative sense, we are very, very close to that both in terms of our peer relations and in terms of the value. So we are quite comfortable with where we sit on that chart and we think it represents our position fairly.

In terms of the risks in deepwater, they range from across a whole series of risks from geotechnical risks sub-surface, to development risks at the surface moving this crude on to shore. From our standpoint, the way we have really managed the risk is to have a fairly robust portfolio and to aim our capital as best we can to projects that have the lowest geotechnical risk, while perhaps having the largest perceived value that we can create.

We have also leveraged the Company's reputation for being successful in this trend and having high acreage by effectively using other people's money to drill wells. So we have really been able to leverage our own technical work with the perception - I think it is an accurate perception – that we have some of the better lands and better prospects and people are willing to pay a premium to access that by coming along with us.

Philip Aiken

I will ask Greg to comment. I think the last part of your question was the economics, what sort of oil prices and what sort of returns.

Greg Robinson

Our weighted-average cost of capital that we deal with internally in the business is 9%. Generally, we look for thresholds of trying to get projects north of 15% before we feel we can compete with the other CSG's within BHP Billiton.

The sort of oil price forecasts that we build in, we do not try to crystal ball the first couple of years. We just take the forward curve and then we extrapolate out to about 2006. In 2006 the oil price forecast we have in real dollars is about $20.20. Then we have a real decline of 1.5% per annum from that point on. All our projects get run through high-price scenarios and low-price scenarios, usually around the range of plus or minus $4.00.

Philip Aiken

I think the last comment I would make on that is really it does not matter what price you run these at. We run across a whole series of scenarios, both deterministic and probabilistically. What happens with all our projects is we try to make sure that at least we return our cost of capital at the low-oil price tests we do. So it is a very rigorous process which is gone through in this whole area.

Hilton Ashton, BoE, South Africa

In fact, my question is quite similar to the previous one but I would like to explore in a bit more detail perhaps. You showed the return on capital of 24.9% I think on one slide. Given these heavy capital expenditures and also certain fields that are dying and will be closing over the next couple of years, I am trying to get a sense of the profile of the return on capital that you expect over the next five years.

Philip Aiken

I suppose the comment I would make is that this is a business that if you actually looked at it over the last ten years you would probably say we have under-invested. In fact, at some stages, our return on capital has been in much higher figures than 25. The fact is that if we do not invest in this business over the next few years, basically this business would be liquidating itself. Therefore, we are going to see our return on capital decline. But I still think we will be well and truly north of the corporate target, even with the investment programmes we have in place over the next few years.

So the targets which have been put down for BHP Billiton as a whole, we will more than exceed in the Petroleum business. But, yes you are correct. The fact is that we have some very, very strong legacy assets, which are obviously a huge amount of cash now and have very high return on capital. We are going to see a decline in this business overall.

David Fleming, BoE, South Africa

I just note that over the last few years the Petroleum business has been a great diversifier for Billiton. As you have mentioned, in the last quarter it was 45% of EBIT. If prices do go down, which I am sure they will do one day, can you just give us some indication of how much flexibility, certainly in protecting margin? I cannot imagine there is an awful lot.

Secondly, with respect to the Billiton goal of the $270 million of cutting costs and also the $500 million going forward, how much of that is attributable to the Petroleum division?

Greg Robinson

Can I take the second question first? Essentially, our business is not going to contribute significantly to that $500 million. If you look at Petroleum there are not a great deal of operational synergies between the two groups. I tried to show you where the opex per boe was on our business. Roughly about $2.50 per boe. It is a very low operating cost business as it stands. On top of that you build the depreciation, depletion and amortisation rates of about another $4.50. You have got an enormous amount of fixed cost.

In general, with petroleum assets what you want to do is to get the capex right. If you get the capex right, you will get your operating cost profile pretty right going forward.

Philip Aiken

What was the first question?

David Fleming

I think you have answered it to some extent. It is in terms of how much flexibility there is if prices do come off.

Greg Robinson

Certainly, you like to keep your production at capacity. So there will not really be that much flexibility as prices come off. We could hedge but we do not. Effectively, our gas prices give us some stability. Essentially, if you look at the Australian domestic gas it is all CPI-linked to prices. So at the moment we are getting $2.60 a gigajoule in Victoria and we have got CPI increases. Out in Western Australia we have similar pricing formulas.

So all parts of our business are linked to liquid volatility. But, at the moment, the view of the Group is that we are a very low-cost producer. We make margin in low-cost environments and we prefer to be exposed to that oil price.

Philip Aiken

I knew there was one point I wanted to make. I think a good example for how we try to manage our portfolio was what happened with the Buffalo venture. The Buffalo venture was an FPSO we had offshore Western Australia, which came on stream. We actually sanctioned the project when the oil price was very low and brought it on stream when the oil price was quite high. We ran that asset very hard for 18 months. Basically, we actually took the production out in 18 months. Of course, we took the opportunity of a spike in the oil price.

If the oil price went lower, the fact remains that all of our assets make money at very low oil price because we have got a very low-cost set of assets. So, obviously if the oil price goes down to the low teens for any period of time, we would have to look at how we operate the business overall. We have got some flexibility, but basically, even at those low prices, our asset is still actually cash flow positive and would generate a positive EBIT.

Greg Robinson

I should just add one other point Phil, that we do focus on operating costs enormously with all the assets. Every one has performance indicators that they have to reach. A good example is Liverpool Bay moving its operational team up to Point of Ayr. So even though you do have a significant amount of fixed costs in that operating expenditure, we do spend an enormous amount of time looking at it.

Philip Aiken

I suppose just to finish it off the only comment I would make is that, obviously, when we had the merger of BHP and Billiton, Billiton did not have an oil and gas business. Therefore, to some degree there were not quite the opportunities that there were say in our mineral CSG's where there was some overlap.

The fact also remains that in 1998/99 the old BHP Petroleum had a huge cost reduction programme. In fact, at that stage, I think we employed 3,500 people and we actually cut back to about 1,600. We cut out our regional structure. We made some big changes to our business. Therefore, a lot of the cost savings that were available were actually taken out pre the merger of BHP and Billiton in the case of Petroleum overall.

Mike Bedford, Barnard Jacobs & Mellet, London

Some of your new projects are in areas of very high political risk and you do have a primary listing in London. Is it becoming increasingly difficult for you to do business in those areas?

Philip Aiken

The area we are investing in most is Algeria of course. As you probably know, Algeria has had some political issues for a number of years. But the oil and gas industry has continued to operate right through all those times. Really, although you might say there is a country risk in Algeria, you would probably say that the risk for the upstream oil and gas industry is quite low. That is not an area which we have seen any issues with, either with the market here or the market in Australia.

As I said, Pakistan is a good example of where we took a very managed process to enter that country as a gas supplier. We basically went in with a project that was just an extended well test and now we are going ahead with a full field development which will recover our costs quite quickly.

So there is no doubt that being listed both here and in Australia has got issues with regard to country risk, but I think they are manageable. In the areas we are in we are not the only European company based in those countries and I think the risk is accepted by the market overall.

Nick Hatch, Investec, London

Really a follow-up question to that last one. Can you update us on what may or may not be happening in Iran? Then perhaps gives us some sort of flavour on what management and sort of internal mechanisms you can put in place to protect yourself from some of that type of country risk? Particularly, given events that may unfold just over the border over the next few months.

Philip Aiken

As you know, we have spent a number of years looking at opportunities in Iran. We have actually done a lot of work on the Iran to India pipeline, which will be built one day but I do not think it will be built next year. But, for some time, we have also been looking at the opportunity of buyback projects. The one we were looking at was the Foroozan project. At the moment, with the Foroozan we are providing aid to the Iranians, to NIOC and their contract to PetroIran. But, in the current environment, I do not really see us making a major investment in Iran. I think we will wait and see what political events transpire in the next year or so.

We would like to keep our opportunity in because, longer term, we do believe there will be good opportunities for us to invest in Iran. But, at the moment, we recognise that now is obviously not the optimum time to make an investment in that country. But we are certainly keeping our involvement as a supplier of technical aid to that particular project.

I think really our attitude to North Africa and the Middle East is to take a fairly managed role. I say that quite seriously. As a corporation we really do believe that the exposure we have got, say in Algeria, is very small compared to the total balance sheet of BHP Billiton.

To some degree, we really do like to go into a country, operate there for some time, understand what the opportunities are and then we make our investments in the longer term. The only country we are really making an investment in that part of the world is Algeria. We are looking at other countries but really we would not enter into those opportunities until we thought we had mitigated all the risks and done all the overall planning. We certainly do see the opportunity where we can go in with quite a small investment, understand how it works, and then look at longer term as a larger investment where we understand the political situation.

Jonathan Copus, SG, London

Just returning to an earlier question about your production forecasts. You have spoken a lot now about the Gulf of Mexico, and the fields there are obviously very important. You also spoke a bit later about the amount of production you will be operating going forward. In the near term though, two of your big fields, Atlantis and Mad Dog are operated by BP, who are currently reviewing their production targets going forward. What are the chances that your roll out of those projects will be impacted by that review process?

Philip Aiken

Well you have really got to ask BP that. But, at this point in time, I have no reason to suggest that those two projects are not still viable projects for BP. I mean Mad Dog is well down the road of construction now and I do not think there are any issues with that. I know BP are reviewing all their projects. But, at this stage, I have nothing to suggest that they would not be very important. I mean Atlantis is one of the largest fields in the Gulf of Mexico. It is a very, very robust project.

I know BP is doing these reviews but, at this point in time, I am not aware of any changes. The fact remains that if there are that will obviously put some difference to what our projection is out to 2007, the figure I gave before. Obviously, if Atlantis did not come in on time or came in later, obviously we would have a different profile there. But, at this stage, I have nothing to believe that there is anything changed in their thinking.

Michael Wang, Dow Jones, London

You talked about an impressive suite of organic growth. Can you tell us what your thoughts are on bolstering your portfolio through acquisitions? And if you can give us an idea that if acquisitions are a priority or an interest of BHP Billiton, what size of company would you be looking at?

Philip Aiken

Firstly, obviously, talking about M&A is always a very market-sensitive issue, so let me answer that question very much in a generic sense. A few years back when we had the old BHP, we obviously had the huge net operating losses in the US. Our primary consideration in those days was trying to acquire some production in the US. We were not successful in doing that and to some degree that priority has now gone because we are actually sanctioning these projects and they will come online over the next few years.

Therefore, anything we did in that sort of area would be really only about accelerating our ability to liberate those tax losses.

Because we are part of BHP Billiton, we are not quite driven like an E&P company. Therefore, I would make the comment as I made on Friday, that making an acquisition for just acquiring production has no interest to us at all. We really do see our focus strategy as being important. Therefore, just going out and making an acquisition of production just makes no sense to us at all.

If we were going to make an acquisition it would have to be strategic. It would have to be something which added to our deepwater, our discovered resources or our gas commercialisation strategy. I would see it important to either grow the business or give us more growth options going forward. So if we do an acquisition in this business I think it would be very much along the lines of something which we saw as strategically important to making our existing business better in the future.

Now having said that we are always in the market for opportunities, but we are not going to go out and do an acquisition for doing an acquisition's sake. We do not think it is necessary and that is why, to some degree, we do say the same of a company who was a stand-alone company in its own right about the same size as ourselves.

With regards to size, the right asset transaction would be great. If you could pick up an asset which gives you another boost in your production and gives you more resources that would be good. I do not see it being a major issue. We really would look at it as it came along. It could be reasonably small, it could be reasonably large.

Daniel Major, JP Morgan, London

Two questions, the first one quite simple. You are looking at finding a development target going forward of $4.50. Gulf of Mexico you have got at $4.95. Where is the cheap find in development coming through to average that out?

The second one really follows on from that. It is really the cash flow at risk argument. Petroleum brings a lot of growth, a lot of margin, a lot of strength. You talk about the right deal, but how do you tie that in to this cash flow at risk argument and stability of the growth of BHP Billiton?

Philip Aiken

Let me answer the first question. I will flip the second one to Greg. You said $4.50 as the target. We are currently $4.08 or whatever it was. You have got to remember there are brown field and there are green field developments. In a lot of cases as we put in green field developments, as we improve up reserves and the P50's become P90's, you start booking reserves for very little capital. Also a lot of our investments will be marginal investments to brown field.

So the target of $4.50 is the sort of target we would like to look at as longer term. It really will depend on the mix going forward. Now that does not mean that if a great opportunity comes along and it does not make the $4.50 because the margins are so strong you would not do it. But it is more of a target for the business internally to achieve top quartile performance as an E&P company.

With regards to the cash flow at risk I think I might pass that to Greg.

Greg Robinson

With cash flow at risk, we have run the internal models every time we look at all our growth projects. With all the other CSG's it is bundled up at the corporate level to look at what their sensitivity actually looks like, new projects etcetera.

The fact is our influence actually falls over time if you look at the growth of the other CSG's. They are actually dealing in low-price environments at the moment. Over time, even with our growth projects coming on, if we see metals' prices recover you will see the cash flow at risk issue just still quite balanced. We never actually force ourselves above that 35% EBIT margin which we were two years ago.

Andrew Mugs[?], AMC, South Africa

You will withdraw from Blocks 21 and 22 offshore Angola. Does that represent a complete exit from the country? Also, given the heightened interest in Equatorial Guinea over the last few years, is this a country that might feature on your development agenda at some stage?

Philip Aiken

Let me answer the first. I will give the second one to Steve. Basically, when we went into Angola a few years back we had a commitment programme which we have now either met or will meet very shortly. When we have completed that we will totally withdraw from Angola. The reason behind that is Blocks 21 and 22 have not turned out to be prospective and we do not see any other opportunities for us in Angola. So it will be a total withdrawal.

Steve Bell

Well, with Equatorial Guinea you are right that there is a lot of activity there in the industry. But as I pointed out by way of example with the Gulf of Mexico, if one is going to succeed and actually going to get fairer returns for their shareholders, an early entry into the basin is probably one of the prerequisites. At this point, it is fairly overheated and I would not expect that we would enter that arena at this time. At some point in the future, five, ten years from now, that is completely different, but right now it is not in the crosshairs.

James Allen, Barnard Jacobs & Mellet, South Africa

With regard to China, can you give us an indication of the current offtake of LNG in the Guangdong province and how you see this growing into the future?

Philip Aiken

This is the first LNG to go into China. This is the first project and, as I said, initially it will be about 3.3 million tonnes. That will be the build up over the first couple of years. This is phase one of Guangdong and phase two could come fairly quickly after it and it will be the same again basically. So it really is quite a build up.

The LNG going into the first phase of the Guangdong project, quite a bit of it is actually flowing back into Hong Kong. But there are three new gas-fired power stations being built as part of it and they will take about half the volume going forward.

The second LNG in China is the project in Fujian. I think you are going to find that whole south-eastern part of China is a market that is going to grow quite significantly. So I think this is the first of what will be a series of contracts you will see in China over the next decade.

Andrew Hollins

Can I just ask one further question on being an operator or a non-operator. Firstly, is that a value driver within the business? As the run rate, can you give me the current level of output where you are operator? Of the projects that are on in 2007 what percentage may that increase to?

Philip Aiken

This has always been a very interesting question for us to look at. If you look at BHP Petroleum as it was, we started off as a non-operator in Bass Strait and North West Shelf. We then got involved as an operator of FPSO's off Western Australia. Actually we were one of the first people to operate FPSO's. I think there is argument whether we were first or Petrobras, but whoever it was we were very early in the piece.

As an organisation we believe we will be the operator where it is appropriate and where we think it makes sense. For example, in Brunei we have gone in as a non-operator, a TotalFinaElf is operator there and we have taken a 25% interest. We thought that was really the sensible thing to do. But, in other parts of the world such as the Gulf of Mexico, there is no doubt the operator drives the agenda and drives the timetable.

Now our situation in the Gulf of Mexico, just to try explain our rationale, was in going into deep/ultra-deepwater in the first place we wanted to partner with a mega major. So our major partners in the Gulf of Mexico have been BP. BP then bought Amoco so we finished up much more with BP. But you have got to remember that our first operation there, or first producing role there, has been with Chevron in Typhoon.

In the Gulf of Mexico we have been operating the exploration and drilling phase of a number of wells now. In fact, our performance has been as good as or better than some of the people we have partnered with. Now we think it is about time we actually look at taking a role as the producing operator. Hence, if Neptune is successful, if Shenzi is successful, if Cascade is successful, then we would be the operator. But there are also other projects there where we are not going to be the operator overall. So we will take the opportunity to operate where we think it is appropriate and where we think we are capable of doing it.

Where it stands today I cannot give you an exact figure, but at the moment our operated production is probably less than 20%. I would say that is where it is at the moment. In 2007 I would say that is probably going to be about 25%. That is probably slightly more than it is today but you have got to remember that Mad Dog and Atlantis are operated by BP. We are the operator in Algeria. We will be the operator in Trinidad. So I think it increases but I could not tell you off the top of my head what it is. I do not think you will find it is going to be a lot more than it is today, although I think it would be slightly higher.

Nick Hatch

Just following up on the Chinese LNG, does this now mean that the fifth train will be developed? Or do you have enough flexibility with the existing structure?

Philip Aiken

The simple view is that hopefully the Chinese contract will underpin the fifth train but no decision has been made yet on the fifth train. We probably have not got to make a decision for at least 12 months, possibly even longer.

The reason we would like to delay that a bit further is you have got to remember that we have 7.5 million tonnes or trains one to three coming out of contract in 2009. Now, depending on what happens to those contracts in Japan (and you would have to assume we will re-sign most of that), you probably would build a fifth train. But, at the moment, we can supply the China contract in its early years from the existing infrastructure of trains one to four.

So really it depends what happens over the next 12 months or so with the existing contracts, whether we fast track the fifth train or whether we actually leave it for longer until there is more certainty about the Japanese extensions and re-contracting.

Closing Remarks

Philip Aiken

Well, Ladies and Gentlemen, I think I have completed the questions. I would like to thank you all for attending today here in London and also in South Africa, and also for those people on the telephone. As you leave here today there is a copy of our 2002 Financial and Operating Performance document.

Thank you very much for joining us today and we hope you now know more about BHP Billiton's Petroleum business. Thank you.

This Commercial Verbatim transcript was produced by Ubiqus Reporting
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