BHP Billiton
Petroleum Business Briefing
Friday, 23 November 2001
London

PHILIP AIKEN [President and Chief Executive Officer, Petroleum]: Good morning and welcome. I would like to take this opportunity to also welcome those who are listening in from Johannesburg.

It is a few months since we had presentations on BHP Petroleum and I am pleased to be back here to give a presentation that I hope will give you some more detail and update you on our business. This is the first of a number of presentations from the BHP Billiton customer sector groups.

Assisting me this morning is Keith Hunter. Keith is President of Project Development and Operations for the Petroleum business. There are also a number of others here from the Petroleum business; I will not introduce them individually, but you will have an opportunity to meet them and ask them any questions during the morning.

The presentation today is in six parts. We plan to cover the first two and then have a break. We will start off with an overview and then talk about our producing assets. After the break we will then talk about our growth strategies - high margin exploration, gas commercialisation and access to discovered resources.

So let me start off with an overview of the Petroleum business. BHP dates back to its incorporation in 1885 in Broken Hill. Billiton was incorporated in 1860 in The Hague. BHP Billiton was formed this year and is a global leader in the natural resources industry with a capitalisation of about US$31 billion.

The Petroleum business is an important contributor. Last year, assisted by oil prices, it contributed about 35% of the BHP Billiton group's EBIT.

BHP Billiton Petroleum is a significant oil and gas exploration and production business, which was founded on successful exploration in Australia, in the mid-to late 1960s.

We are recognised by the market as a high-performance, focused, upstream petroleum business that generates consistent above-average returns and has the organisational capability for ongoing value creation. Our core purpose is to create shareholder value through the discovery, acquisition, development, production and marketing of petroleum natural resources.

Today we have production in five countries and exploration in nine countries.

We have an extensive exploration and development portfolio, which we believe will generate value for the Company by achieving efficient and competitive growth. Our growth strategy, as I said before, involves exploration acreage and growth projects in nine countries and is aimed at securing medium to long-term growth from three key areas. The first of those is the exploration and development of high margin oil production. This is primarily in the deep water of the Gulf of Mexico and West Africa, and the Canarvon Basin offshore Western Australia. The second area is the commercialisation of gas resources in Australia, and in other countries like Trinidad and Pakistan. And we are securing resources in North Africa and in The Middle East. We will talk today about Algeria, and a little bit about Iran.

1. Petroleum Financial Year 2001

This slide shows the performance of BHP Billiton Petroleum last year. Just to give you an idea of the size of the business, BHP Billiton Petroleum would rank about number 15 in terms of both production and reserves amongst the world's oil and gas companies, that excludes those companies with partial or full state ownership.

Being part of a much larger company brings advantages of scale characteristic of many of the super-majors. Petroleum Finance Corporation, a Washington-based energy consultant, did a ranking of the top 50 energy companies, and BHP Billiton ranks 15th, in terms of market capitalisation.

We now have processes and portfolio management organisation in place which means we operate as a truly global company which has many specific strengths. Last year we produced about 131 million barrels of oil equivalent, with about 60% liquids, and 40% gas.

Our main office locations are London, Houston, Melbourne, and Perth. We also have offices in eight areas in which we operate, such as in the Middle East.

2. Petroleum First Quarter Financial Year 2002

This slide shows the strong performance of the Petroleum business during the first quarter of fiscal 2002. During this time, our average realised oil price was US$24.86, and our production was split about 64% liquids, and 36% gas.

Obviously, the outlook for the remainder of the financial year will depend very much on oil prices, which, as you know, have been rather volatile recently.

3. Petroleum EBITDA FY 2001 (Before exceptionals) US$ Million

This slide indicates the sources of EBITDA for BHP Billiton Petroleum for fiscal 2001. You can see that a significant amount of our profitability comes out of Australia [Bass Strait] and the North West Shelf. We also have a significant EBITDA coming out of Liverpool Bay. There are a lot of people who thought at the time of the merger, that BHP Petroleum, was really a couple of non-operated assets in Australia. Whilst these assets are still very significant to us, I think you can see from this slide that we also have some significant other business, which I think will be growing in the future.

4. Realised Oil Price – West Texas Intermediate (US$bbl)

I would like, for a few moments, to talk about the oil price. In the first six months of last fiscal year, prices maintained great strength after their strong run up during fiscal 2000.

By September 2000, WTI prices had reached $35. At this point OPEC attempted to cool the overheated market and announced an increase of about 800 thousand barrels a day of production. This had limited impact on prices, which were supported by surprisingly strong US demand.

By December last year, the supply/demand fundamentals were weakening, a contra-seasonal build in inventories occurred, and Iraqi exports resumed after rollover of the Oil for Food program; prices dropped quite sharply from the mid-$30s to around $27. OPEC acted at that stage, by cutting production by 1.5 million barrels a day. Prices firmed slightly, supported by winter demand.

But mid-March saw a seasonal fall in demand, and estimates of future demand growth were progressively cut. As a result, OPEC announced another cut, of about 1 million barrels a day of production.

Over the last six months of the financial year, prices stayed fairly well within the OPEC price range of $22 to $28, in fact averaged at the higher end of that range. There was a high degree of price stability during that period. In more recent times, prices have moved down, and in the last couple of days moved up again as there have been some signs that some of the non-OPEC producers might cut their production.

The price discussion above refers to the WTI, or West Texas Intermediate, market. A lot of BHP Billiton's crude, in fact most of our crude coming out of Western Australia, is actually sold against the TAPIS market. The actual price we realise is more a function of quality than the regional demands for the product we sell.

If you look at last year, when we averaged just over $28 a barrel, WTI averaged slightly over $30, so our oil price was a $2 discount to WTI. More recently, in the first quarter of this year, with slightly better demand in Asia, we actually had a realised oil price of $24.86, while WTI averaged $26. So the actual discount to WTI was about $1. So you have got to be careful in just looking at WTI; it also depends on where products are being sold, and what actual prices we are getting for our blends and crudes.

5. Petroleum Organisation

Let me now talk about organisational and management capabilities.

The Petroleum organisation currently comprises 1 700 staff and contractors spread across four main locations [London, Houston, Melbourne, and Perth] with representation in a number of other locations such as Iran, Japan and Pakistan.

The organisation is led by a President and Chief Executive Officer, myself, and I am supported by a leadership team, which we call the Petroleum Executive Committee. The Petroleum Executive Committee is supported by local asset teams who run our businesses, and global resource teams.
The organisation is based upon key stages of the business' exploration and production value chain. A clear distinction has been made between the value creation and value delivery stages of the

business, with business process/capability and financial management underpinning these important functions. The value creation and delivery functions represent the two primary cylinders of the business, with a natural hand-over at the stage of project sanction.

6. Petroleum Executive Committee

The seven member Petroleum Executive Committee reports into the BHP Billiton Executive Committee, which has ultimate responsibility for directives. The Petroleum Executive Committee has seven members who are responsible for the management of the Petroleum business as a whole. When I gave the last briefing in March, there were a number of positions which had not been filled. I am now pleased to say that all positions have been filled. Missing from this slide is Mike Herret, who is the Head of Human Resources.

The Executive Committee basically has six functions: it provides high-level strategic direction for the business, it provides leadership to the asset teams, resource teams and advisory leaders, it oversees the business development opportunities and recommends appropriate key capital investment decisions, it establishes and monitors business performance, and provides the liaison between the BHP Billiton Executive Committee and the other external stakeholders.

If we consider the list of the executives who are on the Executive Committee, you can see they are based in Melbourne, London, and Houston. Steve Bell, the Head of Exploration, only joined us a few months ago. He is a geologist, with a long history in the oil business, with Apache, and more formerly with Alberta Energy. Keith Hunter is responsible for technology and operations, he has a long history with BHP Petroleum, before that he was in the UK with Britoil and Total.

Mike Weill, who is responsible for business development, is based in Melbourne. He joined us a number of years ago. He is a petroleum engineer who joined us from Shell. Greg Robinson, the Chief Financial Officer, joined us from Merrill Lynch, after a career in investment banking. Chip Goodyear, BHP Billiton's Chief Development Officer, also sits on the Petroleum Executive Committee, and provides a very useful link into the broader BHP Billiton group. We also have Mike Herret, who is our Head of Human Resources.

7. Petroleum International Activities

This map shows our major areas of focus, including production, which we will be explaining in more detail, as we move through the presentation today. Petroleum currently derives the bulk of its production from OECD-type countries, although we will be moving more of our production in the future, into non-OECD countries. I mentioned before that Petroleum conducts an international exploration and development program around three key areas of focus aimed at securing medium to long term growth. These are also shown on the map.

8. Recent Petroleum Highlights

In the 2001 financial year Petroleum generated an EBIT of US$1.4 billion, booked reserves in excess of 130% of production and sanctioned a number of substantial projects. The highlights of recent times include the approval of the Ohanet wet gas project in Algeria (net investment to BHP Billiton of US$430 million) and the approval of the fourth train expansion of the North West Shelf LNG project (investment by BHP Billiton of US$260 million). Another two areas that we are very pleased about is the commencement of contractual gas sales from the Zamzama gas field in southern Pakistan, and our activities in the Gulf of Mexico where we have strengthened our leaseholding, and progressed a number of opportunities.

So there are certainly a number of things that we have achieved in the last 12 months, which are very good for the growth of the business moving forward.

9. Petroleum Proved Reserves

Total proved reserves at the end of fiscal year 2001 were 1 409 million barrels of oil equivalent.

Efficient reserve additions to replace production, is one of the key business drivers for an oil and gas company. In the last fiscal year, we actually booked 160 million barrels of oil equivalent in new reserves, while producing 131 million barrels. As such, we have more than replaced our production, by a reserve/replacement ratio of 127%. During that year, we booked our initial reserves for Atlantis and Mad Dog in the Gulf of Mexico. We booked our reserves associated with the Ohanet project, and Echo/Yodel in Australia. We also bought reserves when we purchased Genesis (Gulf of Mexico).

During the current year, we will book additional reserves from Atlantis and Mad Dog and, subject to commerciality, we will also book reserves from Zamzama in Pakistan, and Minerva in Australia.

Whilst we only report externally our P90 (proved) reserves, internally we also carry a most likely P50 reserve of 1 886 million barrels of oil equivalent, which is made up of 920 million barrels of liquids and 966 million barrels of oil equivalent of gas. In addition, we carry most likely contingent resources (statics) of 1 640 million barrels of oil equivalent of gas and this is the focus of our gas commercialisation strategy., This, to some degree, is where we have a company waiting to happen, because we have as many static reserves as we have reserves. A lot of these contingent gas resources are located off the North West Shelf, with additional volumes in Bass Strait, Pakistan and Trinidad. So we have significant opportunities to grow our business by commercialising static resources that we have in place.

I said before that our replacement ratio last year was 127%. Over the last 3 years, we have averaged 112% per annum.

10. Petroleum Exploration by Location

In replacing reserves we have to spend money on exploration, and a key element of our growth strategy is to deliver growth through exploration success. Last year we spent US$196 million on exploration, a substantial proportion of which was in the Gulf of Mexico. This expenditure was made up of about 84% exploration and 16% appraisal. In fiscal 2002, we are going to spend more like US$250 million on exploration, with additional monies for appraisal, as we move forward in appraising and delineating the discoveries we have made in the Gulf of Mexico, and more recently, offshore Trinidad.

11. Petroleum Cost Base

One of the areas that BHP Petroleum has worked hard on over the past few years is our cost base and this will continue as part of BHP Billiton. There are three areas that we look at very strongly. The first is our finding and development costs. Our finding and development costs, in period through 1999 to 2001, were US$4.13 per barrel of oil equivalent. This marks very well against the peer group that we measure ourselves against, which consists of a group of 24 international Exploration and Production companies including mega-majors and independents. In the same period of time our peer group had a finding and development cost of US$5.33, so we performed extremely well.

We tackle finding and development costs by maintaining a focused exploration program in specific areas where significant prospectivity is recognised. We also partner with major leading companies in order to gain best practice experience and outcomes. The US$4.13 of finding and development cost, can be broken down into a finding cost of US$1.35 and development cost of US$2.88.

12. Operating Costs (excludes RRT)
The second area that we focus on is our operating costs. Our operating cost, in the same period (1999-2001) of US$3.16 also compared favourably to our peer group which averaged US$3.69. Our focus is on operating costs at operated assets, particularly Liverpool Bay and the Griffin Venture. These will be covered later. Liverpool Bay has been extremely successful in reducing operating costs over the past two years. We also seek to work very closely with the operators of our non-operated assets to reduce operating costs.

The third area area of costs is G&A costs (general and administration costs), or what some people would see as overheads. This is primarily manpower. A few years ago BHP Petroleum employed over 3 000 people. As a result of the organisational changes we have made, we have reduced our overhead cost from over US$25 million per month to US$15 million per month. The 2001 results were impacted by both redundancies and the transition to shared business services but I think we have achieved some good reductions in general and administration cost over the past few years.

I hope that these three statistics give you an idea that, besides growing the business, we continue to have a very strong drive to keep costs down going forward.

13. Petroleum Production Forecast
The next slide is an estimate of BHP Billiton Petroleum's production levels going out to the year 2008. At this point in time it is very much an estimate, but it does provide a picture of how we see our business going forward. In this particular projection we have taken both our 'approved' projects, which will come on stream and a view on other projects which we believe will come on stream. It does not carry any assumptions on future exploration success. As a caveat, it is also based on our current oil price-planning scenario and is very much a 'forecast' and subject to change as we refine our development plans.

You will notice that this represents an increase from our current production of 130 million barrels of oil equivalent in 2001, to 180 million barrels per year in 2007, or a 5.5% increase per annum over that period. That would be very much at the leading edge of what an upstream E&P company would hope to achieve.

There are a lot of projects that have to be brought on line and this is very important because we do have decline in some of our existing businesses. For example, Laminaria will decline from 2003 to 2004, and it is important that the projects we are currently working on come in on time. In particular, you will know that this year we have brought Typhoon on-stream, which will give us production in its peak year of 6.9 million barrels. In 2003, we hope to bring on the 401/402 ROD oil project in Algeria, and the full-field development of Zamzama in Pakistan. Those two projects will bring 7.6 and 6.4 million barrels/year of production at their peak.

2004 is going to be a big year for us. We hope to bring on-stream Ohanet, Minerva, Mad Dog, and also the next phase in Bass Strait, when we complete the Bream pipeline, so there are four projects due to come on stream in that year.

In 2005, we hope to bring on-line the fourth train of the North West Shelf and the Atlantis project. This is also the most likely time for Trinidad coming on-stream.

I think that this is quite an impressive suite of projects, and there is obviously going to be a lot of work making sure the projects all come on-stream, on time, and on cost.

14. Petroleum – Strong Margins, Impact of Lower Oil Prices

These projects will assist us to continue to be a very strong business in terms of margins. We have very strong margins, and the above slide shows this and the relative robustness to lower oil prices. On the left, you can see our 2001 results, overall petroleum margins over the year were US$7.48 per barrel of oil equivalent. You can see the North West Shelf with a very high margin, at US$12.84, and the two other major assets Bass Strait at US$7.28, and Liverpool Bay at US$7.88.

On the right the slide shows sensitivity to oil price. You can see oil prices of US$30, US$18, and US$12 a barrel. At US$18, we would still expect to achieve a margin in excess of US$4 per barrel. That again, would be a very robust margin versus most of our peers in the business. You can see that oil prices can decline to almost $10 a barrel before we get a negative situation.

15. Peer Group Benchmarking

This slide provides information on BHP Billiton Petroleum's performance on key business drivers and selected financial measures, relative to a peer group that covers the major players in the oil and gas industry. As I have said before, this covers some 24 companies, and includes mega-majors, and a number of independents in Europe and in the USA.

We have to be a bit careful with the comparisons, because BHP Billiton's performance is for the period to 30 June, whereas for all other companies it is for the period to 31 December. We should also note that a number of these companies have different reserves and booking policies. Our review suggests that BHP Billiton is probably one of the more conservative companies when it comes to reserve bookings, and this may slightly understate our performance in some of these measures.

Overall, BHP Billiton Petroleum has ranked well on the performance data. The summary diagram shows, in a simplified form, the movement of the main performance measures over the period 1996/97 to 2000/2001. In all measures except reserves replacement the company has improved its performance relative to the industry over this four-year time frame, and is positioned in the top quartile for Finding and Development Unit Costs, Profit per Unit of Production and Return on Capital. Overall, you can see our performance improving, and looking very good relative to the industry as a whole.

16. Petroleum Financial Year 2001 HSE Performance

One of the most important areas for an offshore E&P company is its safety performance, and we have a philosophy that it is safety first, production second, and costs third.

Our Lost Time Injury Frequency Rate, and oil spill performance was good, with results showing improvements in both areas and targets being exceeded. Our Lost Time Injury Frequency Rate of 1.09, is at the leading edge of this industry.

In the last few months we have achieved ISO 14001 accreditation for Liverpool Bay and Australia Operated Asset Teams' offshore and onshore operations. This is a significant achievement in this industry. We also carry out a significant number of internal audits. Major audits last year were focused on Algeria and Pakistan. These audits are carried out against our Global HSE Management Standards. The audit findings are now being closed out.

More recently, we have established a program of HSE leadership meetings in each of our key locations. These are held quarterly and are chaired by an Executive Committee member. They provide a very useful way for senior management to focus on and action HSE issues.

17. Petroleum within BHP Billiton

Where does petroleum fit, within BHP Billiton? The BHP Billiton merger allows the new group to enjoy an outstanding diversity of commodities.

The Petroleum business, which incorporates both oil and gas is a significant part of the new group, and also provides a tremendous range of brown field and green field opportunities for growth. Petroleum is also expected to provide significant growth for the group going forward, particularly from developments in the Gulf of Mexico, North Africa and the Middle East.

For those of you who attended yesterday's portfolio risk management presentation here, you will know that if Petroleum was removed from the BHP Billiton portfolio, and the proceeds from the sale or spin-off were re-invested into the metals or mining sector, the cash flow at risk of the portfolio would increase significantly. So we believe that Petroleum is a very significant and very important part of BHP Billiton going forward. It is a great business, with some great growth opportunities.

18. Petroleum Growth Strategies

At this stage I would like to make a comment about the speculation regarding our discussions with Woodside. We are being quite open in saying that we have had discussions with Woodside and Shell, and these have been very useful, but have ended with little likelihood of any transaction taking place. We have always said that if we did anything with Woodside, it would need to add value to all three parties. At this point in time, we do not think this is possible.

We have categorised our portfolio into three areas of business growth and one of cash generation. Each has a complementary role in the global portfolio, which has significant scope to deliver growth options at an acceptable risk, and to deliver earnings quality in terms of margins and robustness to risk the external business environment.

Our producing assets have been called the cash generation portfolio group. These are very much about generating cash, since these businesses are where we really get our license to operate, and our credibility to be part of the E&P industry. These assets are very important, and we will spend some time on those in just a few minutes.

The three areas of growth that we are concentrating on can be summarised by the slide.

The first is high-margin oil exploration and production (E&P) projects. This comprises of projects with high returns, frequently characterised by high sub-surface or technological challenge. For these, the better-than-average players can successfully manage the complex technical aspects, and returns can be quite high. In addition, we can usually obtain exposure to oil price upside from these regimes. The Gulf of Mexico is a very good example of a high-margin oil E&P play.

The Discovered Resources Group represents low risk, already-discovered resources in resource-rich countries that may offer significant growth options for BHP Billiton longer term. The trade-offs are a relatively fixed moderate rate of return, little exposure to oil price upside, and limited exposure to price downside. An additional trade-off is country risk. An example is an Iranian buyback contract.

The Gas portfolio group provides exposure to a high-growth industry sector that is robust to environmental and greenhouse pressures. While some existing LNG contracts link price to crude oil, gas contracts may provide further commodity price diversification.

The rest of this presentation will cover these four particular areas; producing assets, and the three growth strategies.

Production

1. Petroleum Production

We produce in five countries: Australia, United Kingdom, United States, Bolivia, and Pakistan. I am going to cover the two non-operated assets in Australia, Bass Strait and North West Shelf, and then I will hand over to Keith Hunter, who will cover the rest of our producing assets.

2. Bass Strait – Slide 1

Bass Strait is the largest asset in which BHP Billiton Petroleum has an equity. It is located off the southern coast of Australia, between Tasmania and Victoria, and has produced over 4 billion barrels of liquids and over 5.1 trillion cubic feet of gas.
Current production is in excess of 190,000 barrels gross of liquid per day. That is 100%, so our production is half of this. That is made up of about 160,000 barrels of crude and condensate, and 32 000 barrels of LPG. We are also producing over half a billion cubic feet per day of gas on a 100% basis. So the net share for BHP Billiton is about 95 000 barrels a day, and 250 billion cubic feet of gas. Liquids production this financial year has been maintained as a result of a successful infill drilling program, which I will touch on in a moment.

Bass Strait is very important for Australia. It accounts for around 40% of Australia's petroleum liquids production. It also supplies around 90% of Victoria's natural gas requirements and around 20% of the New South Wales gas market. So overall, it accounts for about 23% of Australia's gas consumption.

BHP Billiton Petroleum is working to commercialise gas from Bass Strait. Whereas about 89% of the oil reserve base has been produced, less than 50% of the gas reserves have been produced. Petroleum now delivers gas to New South Wales customers, including Sithe Energies, BHP Steel and OneSteel sites including Newcastle and Port Kembla, and we are also supplying gas to the Tomago Aluminium Smelter. Communities along the pipeline route between Sydney and Melbourne are also receiving gas.

In the last 12 months we have also had a significant change in our situation in Victoria where the 'D' market gas price, which goes back a number of years came to an end. That has added about $25 to $30 million a year revenue to our gas sales in Victoria.

3. Bass Strait – Slide 2

Although Bass Strait is a relatively old asset, there are some opportunities going forward. We have been holding the production profile of Bass Strait liquids above the forecast over the last 12 months. We have been producing at around 160,000 barrels a day of crude oil and condensate versus a forecast of 17% decline. This has been made possible by the West Tuna / Tuna Infill program, which has accelerated oil production. This programme of wells comprises 6-8 wells for West Tuna and 4 wells for Tuna. The program commenced mid-2001 and is expected to be completed by mid-2002. It is expected to capture about 9 million barrels of gross reserves, with an NPV for us of about US$30 million for the 12-well programme. So it has been a very significant programme for us.

There is also the development of a gas pipeline, which is know as the Bream Gas Cap Development Project. It was approved in October of this year. It is an investment of US$125 million gross, and consists of a 46 km offshore pipeline and a 5 km onshore pipeline, bringing about 200 million cubic feet per day from the Bream-A platform to the shore. The new pipeline will allow the production of gas reserves currently being re-injected into the Bream reservoir. It will also accelerate the current production of around 30 million barrels of hydrocarbon liquids over a ten-year period.

The third major activity is a new Seismic survey of the Northern Fields of the Gippsland Basin. We are primarily looking at new plays in an old basin with much improved 3D seismic technology. This play was approved, and work commenced in October of this year to shoot 3,900 square km of 3D seismic to identify hydrocarbon targets over a range of geological horizons. It is expected to result in a new round of drilling activities that could add to the asset's proven reserves.

So, although Bass Strait might appear, on the surface, to be a fairly mature and ageing asset, it is still going to be important to BHP Billiton for some years to come.

4. North West Shelf / Laminaria Production by Product

Let me now turn to our second major asset in Australia; the North West Shelf. Combined North West Shelf and Laminaria production capacity is 700 000 barrels of oil equivalents per day (100% terms). BHP Billiton's share is around 130 000 barrels per day.

The majority of revenue to last year was from oil due to high oil prices, record production levels and low exchange rates. However, as oil reserves decline the revenue gap will be filled by LNG expansion. In the coming year revenue contribution from oil will decrease, at current prices both oil and LNG will each contribute about 37% of the total revenue.

The project is very important, as it delivers between 126 and 130 LNG cargoes to Japan each year with between 2 to 4 cargoes to USA. Japan customers include Japan's largest electricity and city gas providers with current 20-year contracts expiring in 2009. The 4th train has contracts with 6 Japanese customers (3.9 milliton tonnes per annum). All those contracts are expected to be concluded in 2002.

In addition to oil and the LNG, the North West Shelf also supplies around 70% of the Western Australia's domestic gas market with major customers comprising large mining/processing companies and electricity utilities. Feedstock gas opportunities continue to emerge for more domestic gas sales. Conclusion of contracts with Methanex (methanol), and Syntroleum, will represent a 50% increase in domestic gas volumes.

5. North West Shelf Venture

The North West Shelf Venture is an unincorporated joint venture. The onshore plant is located 1 200 km north of Perth, (Western Australia) with gas/condensate and oil fields located between 100-150 km offshore. I will not go through the history of the NWS venture; it goes back to 1984, when the first domestic gas was delivered, and 1989 when the first LNG was delivered. The North West Shelf has enough gas to fulfil its existing contracts, assuming extensions through to 2024, and has enough gas for the 4th and 5th trains.

Oil production will probably reach a plateau in 2001 but will continue through to field wide expiry in 2014. Looking at the region as a whole, there is considerable gas exploration planned, but oil prospectivity is limited.

What is the strategy going forward in the North West Shelf? Well, it is to certainly commercialise remaining gas resources. This is for the domestic plays that I spoke about before, and obviously for volumes for the 5th train. We will continue to accelerate liquids by developing static resources such as Echo/Yodel and Angel. We will continue to engage with other resource owners in the area, to bring further gas onto the North West Shelf. For example, we own half of a gas field called Scarborough, which could eventually be a gas source on the North West Shelf.

You will be aware that, some months ago, we announced the approval of the 4th train. The 4th train is a 4.2 million tonne liquefaction processing train and a 42-inch gas trunkline to be installed over a distance of 135 kilometres from existing production platforms to the onshore processing plant.

As part of that project, there is an additional LNG carrier, with a capacity of 137 200 cubic metres, that has also been ordered to deliver some of the sale volumes associated with the expansion project. So North West Shelf is a very important project for us, and I will spend a bit of time later on about some of the opportunities to grow that business.

6. Laminaria / Corallina

In our North West Shelf Asset Team we also have the Laminaria/Corallina project. Laminaria and Corallina are oil fields which located in the Timor Sea about 550 km west-north-west of Darwin and 160 km south of Timor, in offshore Production Licence AC/L5.

BHP Billiton Petroleum has a 32.6% working interest in Laminaria and a 25% working interest in Corallina. Other joint venture participants in Laminaria and Corallina are Woodside Energy Ltd and Shell.

The Laminaria and Corallina oil fields have been developed using the FPSO the Northern Endeavour, which is permanently moored between the two fields in 390 metres of water. The Northern Endeavour has a storage capacity of around 1.4 million barrels. Oil production commenced from Laminaria and Corallina in November 1999. Gross production levels peaked at around 180 000 barrels per day, with an average of 141 000 barrels per day this year. Our record production was achieved during 2001, with BHP's share of production being of 14.8 million barrels.

Field production rates commenced their predicted decline from plateau during the year and in 2001 the Laminaria Phase 2 infill project was approved. Production from that development is expected to commence by mid 2002 at an initial rate of 65 000 barrels a day (gross). The project will enable access to additional undeveloped oil reserves, resulting in an additional 21 million barrels of addition production over the first two years of production. The capital cost for the project is approximately US$60 million, of which our share is about US$20 million. Once again, it is a very good way of boosting our production, by getting access to incremental reserves.

That covers the first two of our major producing assets, the Bass Strait and the North West Shelf. At this stage, I would like to pass over to Keith Hunter, who will alk about our other producing assets.

KEITH HUNTER [President Project Development and Operations, BHP Billiton Petroleum]

7. Griffin

Thank you. I am gong to talk a little bit about the Griffin Aaset, which actually consists of three fields, Griffin, Chinook and Scindian, which are all linked together by an FPSO facility.

We started off producing Griffin in 1994, and at the time of sanction it was thought to contain about 80 million barrels. We have actually produced about 130 million barrels; that is about 58% net million barrels to us. We have a 45% interest in Griffin and we operate the asset.

Current oil production has declined from its peak of 80 000 to about 25 000 barrels a day. Having said that, we have one well, Scindian 3, closed in at the moment, and it is worth about 15 000 barrels a day. It is being repaired, so if we bring that back on, production will be back to about 40 000 barrels. Again, like with some of our other fields, we have been very successful at infill growth. Last year we infilled Griffin 8, which is a well in the main Griffin field itself, and for a while, we actually restored production to about 65 000 barrels a day at capacity. As I speak, we are just about to spin another well, Griffin 9. If that is successful, that will probably put another 15 000 back on to our total. So, with any luck, this field will be back at around 55 000 barrels a day by February of next year.

Of course, it is a pool that has heavily depreciated, and in fact, it is one of the highest margin pieces of business that we have got. The margin on this is about US$9.90 per barrel. So this is a nice cash generating piece of business.

8. Liverpool Bay

Moving now to the UK, I will talk a little about our Liverpool Bay Field. Here again, we are the operator with 46%. It is our largest operated asset. We produce about 2.4% of the UK's oil, and about 2.8% of the UK's gas. In fact, it is not one field, but it is five fields, two oil fields, Douglas and Lennox, and three gas fields, Hamilton, Hamilton East, and Hamilton North. The gas is produced and sent to the shore terminal, where we remove hydrogen sulphide from it and it is cleaned up before it is shipped to PowerGen's power station at Connor's Key.

It has been a very difficult asset to operate over the years. As you can see, we are in close proximity to the shore, in fact you can see the facilities from the shore. It is a facility that you have to operate with a great deal of care, to avoid any kind of odours, spills, and any such things as that. So it has required an enormous amount of attention, first and foremost from an HS&E perspective.

Liverpool Bay hadinitial reserves of something like 115 million barrels. They currently stand at 150 million barrels. So we have been very successful over the years in building the production up, and building the reserves up, so basically we lower our depreciation costs. This has been largely a function of some very good reservoir management at Lennox, but in particular at Douglas. In fact at Lennox and Douglas, we are still able to produce at capacity, of about 45 000 barrels a day. I checked the production reports this morning; we have been consistently averaging 72 000 to 73 000 barrels per day of oil from the complex, and about 300 million cubic feet of gas. During the past three months, I think we have met 100% of the nominations of gas from the customer.

9. Liverpool Bay – Performance Improvements

Petroleum is continuing to focus on maintaining improved reliability and stability of production at Liverpool Bay. This slide shows a record of oil sales. You can see that last year, and in the first and second quarters of FY01, we were making about 1.7 or 1.8 million barrels our share per quarter. We took a very large shut down last year to fix a number of persistent engineering problems, and since then, I think you can see that production has been up to 2.6 million barrels our share per quarter. So, the first primary focus has been on improving reliability, so we can get the volumes up.

We have also been working very hard to get our lifting costs down. Now the managed costs for our liftings run at less than one cent a barrel. That is something I am very proud of. We have also been attacking the operating cost base.

10. Liverpool Bay – Future

This slide provides a snapshot of what we think production will look like over the next few years. As you can see, production remains fairly constant through 2002 to 2003.

This is not a field where there is huge scope for adding reserves by drilling nearby targets, although recently we have brought on Hamilton East, which did increase our gas reserves. There is limited prospectivity in the basin, but there has been considerable effort, and considerable success by grouping more reserves by infill drilling, and by building up our understanding of the geology of the existing fields. More importantly, we do this by improving the way in which we have depleted the Lennox reservoir. The Lennox reservoir is one of the few fields in the UK that is depleted using multilateral horizontal wells, and it has been a huge success story.

11. Bruce / Keith Fields

The Bruce and Keith fields are located in the North Sea and operated by BP. We have a 16% interest in Bruce which commenced production in 1993, and has a nameplate capacity of about 875 million cubic feet a day in gas and about 60 000 barrels a day in liquids.

The initial reserves of oil and gas together were about 800 million barrels. We have about 430 million barrels remaining, so we have just reached the end of the production plateau for the field. We have been adding reserves as we have gone and have tried to extend the plateau by subsequent development phases. The Western Area development was started about a year ago. As we speak, we are still drilling infill wells, and new wells on the Western flank of Bruce to see if we can prolong the production plateau.

The Keith field is a very interesting, small development which came into production in November 2000. We have actually had that field in our portfolio for 17 years. We took advantage of the dip in oil prices about two years ago to actually bring it to production. We also took advantage of the fact that the rig rates came right down. It is a single well development that accesses about 10 million barrels. It is connected back to Bruce via a single flow-line, which is operated by subsea electronic hydraulic controls. It is currently producing about 7 000 barrels a day. It was at a peak at about 12 000 barrels a day. We have capacity for about 15 000 barrels a day down the flow-line. In fact, we plan to make Keith phase 2, which will start early next year. It will be another single well, which will access another 10 million barrels, and will probably take us to the capacity of the flow-line. There will also be a geological side-track to access one other block of the Keith field, and if that is successful, we will tie that in at a later date. All in all, it has been a very successful piece of add-on business.

12. Gulf of Mexico Net Production

I would like to turn now to the USA Gulf of Mexico. This shows the estimated production profile over the next few years. You can see we basically had production from only two fields until 2002, West Cameron, which is a gas field hat we operate, and Green Canyon which is an oil and gas field operated by Chevron. In fiscal 2002, we have subsequently brought on production from Genesis, and Typhoon. So we have production in the Gulf increasing from 5 000 barrels a day equivalent a few years back to 30 000 barrels a day equivalent.

13. Typhoon

The Typhoon field is a highlight for us. Typhoon is located in about 2000 feet of water. It has been developed using a mini TLP. We own a 50% non-operated interest in Typhoon. Chevron holds the remaining 50% interest and is the operator. It has a capacity of 40 000 barrels of crude per day, and 60 million cubic feet of gas per day. We are currently producing at a maximum rate, and we are producing from four wells.

The project was brought on under budget and ahead of schedule. The budget was US$256 million, we brought it on at US$228 million. The project was delivered roughly 18 months after it was sanctioned by our Board, and 3.2 years after we made the initial discovery. So a very fast-tracked project that demonstrates that deepwater need not necessarily mean waiting for a long time to get production to the market place. That is a very important lesson that we learnt there, and we have been able to commercialise a field of over 50 million barrels reserve gross, quite comfortably, with a unit development of about US$4 per barrel. It is a pretty good effort.

Typhoon will serve as a hub for a number of blocks that we have around the Green Canyon area.

14. Genesis

Genesis is a field in which we acquired a 5% interest in September last year. It is operated by Chevron. The production vehicle is a deepwater SPAR.

We took this interest for a number of reasons, one of which was to gain access and know-how about SPAR's. It has been highly successful to-date, and currently produces approximately 52 000 barrels of oil and 90 million cubic feet per day of gas.

It is a drill and production platform; we are busy drilling at the moment. There is no reason to believe that this will not be a highly successful venture. There will be lessons that we can take from this and transfer them on to Mad Dog.

15. West Cameron and Green Canyon

West Cameron, and Green Canyon are the two existing fields which I mentionioned. West Cameron extends over four blocks; we have a 44% working interest. We are currently producing about 102 million cubic feet of gas, and 600 barrels of condensate per day. This was a field that, until a few years ago, was basically on its last legs, and which we have revived through extensive infill drilling. This has actually turned out to be a very profitable venture for us, because we caught the increased gas production within about 30 million cubic feet. We caught the peak gas prices of the last couple of years. West Cameron continued to do about 100 million cubic feet for a while. We have just recently built a very interesting well, the A5 well. It was brought on a couple of weeks ago with about 22 million cubic feet a day. The initial production of the well suggests that there is scope to drill another well to the south west.

Green Canyon 18 is a field that is coming to the end of its life. It is able to do about 12 000 barrels a day at the moment, and about 17 million cubic feet a day of gas. There have been a number of infilling projects conducted over the years on Green Canyon. It is amazing that we are able to squeeze 12 000 barrels a day from it. It has been like this for the last five or six years. It is an interesting piece of business, but it is not one of our stars.

16. Bolivia

BHP Billiton has interests in three producing fields in the Mamore area of central Brazil: Paloma, Surubi, and Bloque Bajo. The p50 initial values for the field were 100 million barrels, and we have a 50% interest in partnership with Repsol the operator. To date we have produced about 24 million barrels from the field. During fiscal year 2001, the average production from the field was 10 700 a day in barrels of oil and condensate.

We also started selling natural gas from our Bolivia assets last year, and gas production has increased substantially, from an average of 14 million cubic feet per day in 2000 to 26 million during fiscal year 2001.

We have added enormously to reserves by infill drilling, and making the most out of the existing asset. It is a field in which the margins are pretty good.

17. Zamzama
Lastly, I would like to talk about the Zamzama field. The Zamzama field was discovered in 1998, with Zamzama 1. We started producing gas in March of this year. It was a project that was fast-tracked through our system very quickly indeed. The first gas was produced 12 months after the project was first sanctioned.

BHP Billiton is the operator and Lasmo, Premier, and ENI are our partners. We are producing, from two wells, 100 million cubic feet per day. The reservoir has reserves between 1 and 2 trillion cubic feet of gas, and it is very close to the existing infrastructure. The main challenge for this field is not to produce the gas; it is to get the gas to the market. In that respect it has been very successful. Basically, what we were trying to do was to test the marketplace, and the market's ability to pay for our production on time. We have satisfied ourselves of that. Our share of the plant was US$8 million, and that was paid out within a couple of months of production.

The second thing we wanted to do was to introduce medium-calorific value gas to the Pakistani market. The gas has a rather high nitrogen content. In both respects we have been highly successful. We hope to be shortly signing a contract to take that production up to 350 million feet per day for the second phase at Zamzama. We are delighted with what we have been able to achieve in Pakistan. We hope it will be a cornerstone of what is to come in the future.

High Margin Exploration

1. High Margin Exploration
I would like to spend the next few minutes talking about high-margin exploration, which is one of the growth arms of the business. We basically have high-margin exploration going on in two main areas the Gulf of Mexico and West Africa.

2. Green Canyon Area
This map shows our acreage in the Gulf of Mexico. You can see the production assets I talked about, Typhoon and Genesis, highlighted at the top of the map. You can see that, in the Green Canyon area, we have some 30 blocks within a 40km radius of the Typhoon platform.
The other trend is in the southern part, where you can see Mad Dog, Atlantis, and Neptune. Those are the two big focus areas for us.

The importance of this is that when you have your exploration acreage tightly held, like this, it enables you to make the most of it when you make discoveries. As we speak, in one of the adjacent blocks to Typhoon, we have made a discovery a few weeks ago called Boris, which we will tie back into the Typhoon field.

3. Mad Dog and Atlantis – Areal Extent – Miocene Depth Map
The big news for us was the discovery of the Mad Dog, Neptune, and Atlantis fields. This is a 3D visualisation of that main trend. The red parts represent the structural highs. You can see where we have actually intercepted the reservoir with the yellow lines, which show actual interceptions with the drill bits. So we have made quite a few wells, and side tracked both into Mad Dog, and Atlantis.

These reservoirs are predominantly tertiary plays; they are middle and lower miocene, and they extend over several blocks. We have several hundred acres under license; they are very large.

4. Deepwater Production Systems – Gulf of Mexico Progression 1989 – 2000

This slide shows the evolution of the oil industry into deep water. It is interesting to note that it took 15 years to get production from 1 000 feet up to 3 000 feet at Auger. However, it has taken us only four years to move from 3 000 feet to 5 000 feet at Mensa. What you see happening is a shortening of the time-scales, and a maturing of the technology to allow us to produce comfortably in very deep water. The record for deepwater production is currently held by Petrobras, which is producing from a field in 6 000 feet of water offshore Brazil.

Our view is that developments in water depths ranging from 7,000 to 10,000 feet will be technically and commercially feasible within the next few years. The hull forms at the surface are known and are well understood. The sub-sea well systems and the drilling technology is available right now. The challenge, in these water depths, is how to moor the hulls and connect the wells to the surface. Essentially, we are comfortable with what we are going to put in the water at the surface, and we are also comfortable with what is going to be on the seabed. We can therefore move forward with confidence producing some of these rather large discoveries.

5. Mad Dog SPAR Facility

Mad Dog was one of the fields that I showed you in the Green Canyon area. We have been working in the field in conjunction with BP and have drilled four wells and four side tracks. The appraisal programme is now complete. We expect to sanction a development project for Mad Dog in the next few weeks. Mad Dog is a major field, with reserves estimated between 200 to 450 million barrels of oil equivalent.

Like the Genesis field, Mad Dog will be developed using SPAR technology. It will feature a massive production facility, equivalent in size to a 50-60 storey skyscraper, with capabilities for producing 80 000 barrels of oil per day and 40 million cubic feet of gas per day. Our combined take of that will be about 18 300 barrels equivalent a day.

First production is expected by the end of calendar 2004, and our working interest is 23.9%. It is a big rig, and we will have 18 500 tonnes of topside load, and probably 16 wells.

6. Atlantis Development Concept

Another field which has been very successful, is Atlantis. The Atlantis straddles a huge, submarine escarpment. The water is about 8 000 feet and about 4 000 feet on the escarpment. It will be produced using a very large semi-submersible. This field is somewhat larger that the ones we have been talking about. It has recoverable reserves of between 400 to 800 million barrels of oil equivalent. The facilities will be engineered to produce 150 000 barrels of oil a day, and 60 million cubic feet of gas. Our share of production will be just north of 61 000 barrels a day equivalent. There will be further disclosure, once we have finished our screening studies and all the engineering work. We would expect this project would be sanctioned some time in 2002, for production in 2005. Our development cost is currently scheduled to look like something under US$4 per barrel, so it is a very large piece of business for BHP Billiton.

7. Gulf of Mexico Deepwater Producers > 1 500' WD

This slide shows where BHP Billiton is in deepwater production, by which I mean more than 1 500 feet deep. Until last year, we did not have Typhoon on production and we were virtually just producing on Genesis. With the introduction of Typhoon we have moved up. When we add production from Atlantis and Mad Dog, we will be in the top few of the producers in the Gulf of Mexico. I think it has been a terrific success story for BHP Billiton so far.

8. Gulf of Mexico Production Forecast Range

This slide shows our production from the Gulf of Mexico stepping up above 20 000 barrels of oil equivalent per day with the onset of Typhoon this year. By 2005/2006, our total production from the Gulf is expected to be somewhere around 80 000 to 160 000 barrels a day.

9. Indicative Margin Analysis

So the question really is, can we make any money from this production? And we are asked this question often. These basically show the margins available to us for given oil prices. You can see that, at US$18.50, we make US$4.24. Even if the oil price drops to US$14.50 we still make a couple of dollars a barrel, at margin, which is perfectly acceptable. Should we get back into the anticipated range of US$25, we will be making US$8 a barrel margin. It is a very attractive piece of business for us.

Most of the leases we have in deepwater are subject to royalty but they are also subject to royalty exemptions. In the US, the deepwater royalty is 12.5%. On most of the leases that we have, we either have royalty exemption on the first 87 million barrels, or we can apply for it, if we can make an economic case. The effect of that exemption is to reduce the government's take from 43% to 35% of taxable income, which is the US corporate tax income rate.

10. Gulf of Mexico – Exploration Strategy

Let me talk about our exploration strategy. BHP Billiton's successful exploration strategy in the Gulf of Mexico has been based on three key drivers. The first is that you have to be very focused to be successful. You will notice the pattern of our acreage; it is basically focused in two main play fairways. We are not all over the map; we are in two areas that we think we understand well. You can work those areas and improve your knowledge. The second thing you have to do is ensure that you have the right capabilities. As we have found out, the key competencies in the Gulf are depth imaging and pressure prediction for the drilling. To be successful in drilling, and to get the cost down, the most important thing is to be able to predict pore pressures.

The last part is that we have to work together with other people, who also know what they are doing, and use our commercial nouse to extract value from the acreage positions. What that means in the industry is that you have to be in first, at a cheap time, and then leverage your position so other people basically pay for your exploration. That is what we have been trying to do.

11. Gulf of Mexico Deepwater Potential

This graph, which is pinched from BP, shows the pattern of discoveries with time in the shelf area. As you can see, it is characterised by a very steep rise, and then a flattening off. What is plotted here is what we have discovered over an equivalent time, or number of fields drilled in the deepwater. So, you can see that in deepwater, we are still very much in the early days in the Gulf of Mexico. It is showing no sign of turning over yet. Where it will turn over, we just do not know, but if it follows this shelf pattern, we have certainly have a few more years of large discoveries being made, and good times to be had.

12. Gulf of Mexico Exploration – Industry Deepwater Wells
One of the other ways to look at the maturity of a basin is to consider how many wells have been drilled, in terms of depth. This map of the Gulf of Mexico shows the distribution of deepwater well penetrations, obviously out of scale, but they appear as red circles. The green is the salt canopy that shadows much of the tertiary zone in the Gulf of Mexico. Notice how the penetrations are concentrated in the relatively shallow parts of the deepwater, nearer to the shelf. Virtually all of them have been drilled through apertures through which you can image through the salt.

Also note how the penetrations are predominately in areas which do not have a salt canopy -- which is shown in green. The salt is not a hindrance to the formation of oil and gas fields but it does present a more challenging environment in which to find them. Advances in drilling and seismic technologies are opening up these areas as well. This suggests that there are a lot more wells to be drilled out in deeper water yet, and if you can image successfully through salt, it would open up a whole new world of exploration to you that is not available to anybody else.

The deepwater Gulf of Mexico is a magnificent playground and we intend to continue to be a significant player for the foreseeable future. There is no reason why BHP Billiton will not have abundant investment opportunities going forward where we will be able to apply our accumulated knowledge and capabilities to advantage.

13. Gulf of Mexico Exploration – Play Types / Exploration Focus
In the left hand part of this slide are established shallow water plays. They are all tertiary plays, and upper miocene and pliocene plays.
As we move out to deep water, now you can see plays in upper and lower miocene, and plays in the cretaceous and the oligocene. The play types look substantially different, with much more structure available. Most of what we have discovered is classic, fall away type closures. We still see classic plays of the ground having been shifted by the presence of salt. The point is that we are seeing additional play types, and the number of targets is potentially larger than what we are seeing back up on the shelf. We have to be able to exploit these, and the ability to image is very important, as is the ability to drill the wells.

To that end, we commissioned a rig to drill these very deep water plays; the CR Luigs came out of Belfast a year and a half ago. The results to-date have been extremely impressive, including the drilling of a well in record-setting water depths 8 835 feet in Chinook, in the Gulf, as well as world-class performance in drilling rate and other efficiency metrics.

14. Gulf of Mexico Deepwater Leasehold Ranking – September 2001
BHP Billiton remains one of the largest leaseholders in the deepwater Gulf of Mexico. Obviously, we do not have as much acreage as people who have been in the Gulf for a long time. Going into the second-quarter of this fiscal year, we had interests in 218 lease blocks in deep or ultra-deep water.

These are concentrated in the central Gulf of Mexico play fairways, where we have focused our exploration efforts, created a targeted, dominant acreage position, and can leverage experience and proprietary knowledge of the area to our advantage.

15. Gulf of Mexico Exploration – Program Result FY94 – FY02 to Date
This chart gives a quick picture of the results of our exploration program since 1994. We have drilled 34 wells in the deepwater, 22 have been exploration wells and 12 have been appraisal wells. We have made a number of discoveries, two which are truly giant (Atlantis and Mad Dog). Typhoon is not so giant, but is very profitable for us. We have an 18% commercial success rate in exploration drilling. This increases to 36% with the inclusion of discoveries that are under evaluation as tie-back opportunities. Looking at the drilling leverage, 27% of all the wells that we have drilled, we have been able to get significant promotes. It is a very good record indeed.

The last remark I want to make on this slide is that for the past three years BHP Billiton has participated in a deepwater Gulf of Mexico Exploration Benchmarking study. Among our peers who also are a part of this study, we have had top-quartile performance in finding and completing costs. These were US$1.07 per discovered barrel for 2001, on a three-year, moving average basis.

16. Gulf of Mexico Exploration Current Inventory
This map shows the prospects that will be drilled over the next few years. The writing tells you something of the sense of the size, in terms of the colour. You can see that some of them are truly large fields. A health warning here, these are just expectations at this point. We have to drill them before we know if there is anything in them. However, there are large structures with the ability to hold large amounts of oil and gas.

Just notice the focus is around the play fairways that we have been working in. These are areas where we already have a very good working knowledge.

17. Angola and Gabon
I want now to talk briefly about our position in Angola. We have acreage in both Gabon and Angola. In Angola we have blocks 21 and 22, and we have the Tolo blocks in Gabon.

It is early days for West Africa. We have drilled a couple of wells in Angola, and a couple in Gabon. At the moment, we are just looking at what those results have been, before we initiate proper drilling.

That has given you a feel for what is going on in exploration, and with that I will hand you back over to Philip.

Gas, Access to Discovered Resources & Summary

PHILIP AIKEN [President and Chief Executive Officer, BHP Billiton Petroleum]

1. Gas
I will cover the last three sections of the presentation, starting with our gas business and then what we call our access to discovered business.

I think we are all aware that gas is going to play a larger part in the energy picture in this decade and going forward. At the moment, if you look at the world's energy mix, oil supplies about 40% of the world's energy requirements. Coal is about 27%, and gas is somewhere around 20%. Somewhere over the next 20 years, around 2015, gas will probably become a bigger source of the world's energy market than coal. I was at the OPEC conference in Vienna a few weeks back, and it was interesting to see the OPEC ministers devote about a third of their time at the conference to talk about gas. Ten years ago, I would not have thought that OPEC would have talked about gas at all. So there is no doubt that gas is a very important business going forward, and one where we see we have a big role to play.

There are four areas I am going to talk about today. Two are well known to us, Bass Strait and the North West Shelf. But I will also talk a little bit about Pakistan and developments there, and also where we stand in Trinidad.

2. Bass Strait Resource Position

Bass Strait has traditionally been an oil province, but we have now produced about 89% of the oil in Bass Strait. We are hoping that our new, 3D seismic programme will bring some more opportunities, but really, the focus on Bass Strait going forward will be on gas.

Gas sales are very important to us, because the gas fields of Bass Strait are quite liquid rich, so as we produce more gas, we also produce more liquids. In September 2000, the Duke Energy International Eastern Gas pipeline running from Longford to New South Wales was completed and it now supplies Bass Strait gas to our customers in New South Wales.

In April 2001, BHP Billiton and Esso signed a long-term supply agreement with Duke Energy International enabling the introduction of natural gas to Tasmania. The supply agreement has provided the underpinning volumes for a pipeline to be constructed from Longford to Bell Bay with Laterals to Port Latta and Hobart.

3. Eastern Gas

It is really the eastern seaboard of Australia where things are taking place. Eastern gas is very important to us, as it offers an opportunity to win new customers. BHP Billiton will still be the most competitive gas supplier for Victoria with our existing infrastructure and reserves, and we are in a great position to benefit from gas/electricity convergence. For those of you who are not so familiar with Australia, until the Eastern Gas pipeline was built between Sydney and Melbourne, there was no way of connecting the supplies of Bass Strait with the supplies out of the Cooper Basin. As these pipelines are now made, more and more opportunities will arise for us to sell gas into other markets.

4. Eastern Gas Today – 2001

An exciting new proposed development is the Duke pipeline from Longford to Launceston. It will offer natural gas to Tasmania for the first time and will provide a significant new market for Bass Strait gas.

In the downstream area, BHP Billiton and ExxonMobil have commenced supply to BHP Steel in Port Kembla and also to the Smithfield power project in the outer suburbs of Sydney. We are also in the process of selling gas into the New South Wales domestic market via our agreement with

Duke Energy. We are now supplying 20% of the New South Wales market, and we are confident that we can continue to grow the sales in those markets.

5. Upstream

In the upstream area there is feasibility work continuing on the discoveries of Kipper and Minerva. In May 2001, BHP Billiton signed a Memorandum of Understanding with Australian National Power for a ten year supply of Minerva gas. This will underwrite ANP's plans to build a 680km underground gas pipeline to Adelaide, South Australia, in a joint venture with Origin Energy. The development of the Minerva field, including the transport of the gas by pipeline to an onshore gas processing facility, is under full feasibility review with first production expected in 2003.

Minerva is in a very environmentally sensitive area, offshore Victoria. It is a field we have looked at for a number of years now, but it does appear that this is the best opportunity we have had, and we are fairly confident that this project will go forward sometime over the next 12 months.

Considerable geological and geophysical study over the past year has helped in better defining the volume of hydrocarbons in the Kipper Field. The studies have further assessed prospects and leads in the greater Kipper area which resulted in the maturing of the East Pilchard prospect, which was drilled in the second quarter of 2001 with the well being suspended as a potential gas/condensate producer. Development opportunities are currently being assessed for the Kipper gas field. So, after many years of producing in the Bass Strait, we are looking at other opportunities, and other areas near the Bass Strait.

6. Bass Strait Potential Revenues

This slide shows where we think Bass Strait will go in the future. Bass Strait oil production has been declining by about 17% per annum, and will continue to do so over the next six years. However, as the revenue from crude oil decreases, increased gas sales, and the condensate and LPG produced with this gas will assist. This slide assumes that gas sales in the developing markets of New South Wales and Tasmania go ahead as planned. We are looking at about 35 petajoules a year into New South Wales, and 20 petajoules into other markets. That is the equivalent, in terms of growth of gas sales, of about 116 billion cubic feet by 2003.

This is ambitious, but achievable, and I think it shows that Bass Strait is going to remain very important in its revenue and profits for BHP Billiton for many years to come.

7. North West Shelf

The second major area in Australia is the North West Shelf. There are uncommitted reserves of gas available for extension of existing LNG contracts for a further 15 years as well as volumes for a possible 5th train. The current Japanese contracts for the first three trains expire in 2009, and we hope that they can be extended to 2024. The 4th train, when it comes on-stream, in a couple of years' time, is a series of 20 to 25 year contracts. The LNG market focus for these volumes is Japan, China, Korea and Taiwan. I was in China last weekend, and on behalf of North West Shelf joint ventures, signed a Heads of Agreement with CNOOC, which is China's offshore oil company, for the potential participation in New South Wales LNG supply. This is a positive first step in our LNG supply bid to the Guangdong project in China. It is a part of the bid process and the details are confidential. It is not intended to be a pre-emptory deal and is conditional. The Agreement is consistent with long-stated Chinese Government policy, which encourages Chinese equity in upstream supply.

Australian LNG still has a very strong position, due to the security of supply, and the stability of Australia. We are very confident that the LNG market will continue to grow out of the North West Shelf.

As I commented before, there is more than just export gas. There are some significant domestic gas opportunities, using gas as feedstock, which are being pursued. Recently, the North West Shelf participants signed a Memorandum of Understanding with Methanex Australia Pty Ltd for the supply of gas to a proposed methanol plant on the Burrup Peninsula, Western Australia. The agreement involves the supply of 200 terajoules of gas a day over a 25 year period from 2005. Under the agreement, there is also a provision for the North West Shelf Venture to supply a further 200 terajoules a day should Methanex proceed with plans to double production.

We see a lot of growth opportunities in Australia with our assets in the Bass Strait and in the North West Shelf.

8. Zamzama

One new asset we have is Zamzama, in Pakistan. In April 2000 BHP Billiton signed the Extended Well Test gas sales and purchase agreement for the sale of 70 million cubic feet of gas per day over a 21 month period to Sui Southern Gas Company Limited. Commercial production started on 26th March 2001. Over the past 3 months the plant has maintained an average daily production of over 90 million cubic feet of gas per day. To end October 2001, sales from the Extended Well Test were 18 billion cubic feet of gas and 117 000 barrels of condensate.

Letters of Intent from customers identified by BHP Billiton and an allocation letter from the President for gas sales totalling 320 million cubic feet of gas per day have now been received. The Gas sales and purchase agreements which will underpin Phase 1 of the full field development are currently being negotiated. The capital and drilling cost of Phase 1 of the Full Field Development is expected to be approximately US$40 million BHP Billiton share. Financially the Zamzama project is very robust. First gas sales from Phase 1 are expected in the second half of 2003. So Zamzama, which has started off on a small scale, with an Extended Well Test, now has the opportunity of being the major supply of energy into the Pakistan market.

9. Trinidad

Now I am going to discuss Trinidad, which has the potential to quickly become another core area for BHP Billiton. Located off the coast of Venezuela in South America, this small island has a long and storied hydrocarbon pedigree. It is the world's leading exporter of methanol and has a sophisticated petroleum infrastructure.

Following a continuous and significant drop in Trinidad's daily oil production, which peaked at about 240 000 barrels per day in 1978, the government of Trinidad and Tobago wanted to generate more foreign company interest in its offshore acreage by revising its contractual regime to more internationally accepted standards. In 1995, it invited foreign companies to bid on acreage offshore the eastern coast of Trinidad under revised fiscal terms that included the implementation of a new production sharing contract model.

We conducted basin studies in the area in the late 1980s, but with the new financial incentives, the company revisited the country in 1995 to renew old friendships and to strengthen the relationship it had developed previously with Trinidad's energy personnel.

10. Trinidad – Blocks 2(c) and 2(ab) Drilling Results

In 1996, after filing successful applications, BHP Billiton signed 25-year Production Sharing Contracts for two continuous exploration tracts. These are now in the 5th year of six-year exploration terms. The two blocks, originally approximately 450 000 acres in size, are located immediately off the east coast of Trinidad in water depths that range from 15 to 60 metres. An initial seismic shoot was conducted to acquire proprietary data on the blocks, and a drilling program was initiated in 1999, with discoveries at Angostura that year, Aripo in 2000, and Kairi in 2001. In total we have completed five exploration wells, making three discoveries in both oil and gas.

Our latest exploration well, Canteen-1, is nearing completion, as announced earlier this month. We have another discovery, which, with the results from Kairi, confirms the oil potential in the area. The Canteen-1 well is at TD, and as previously advised encountered hydrocarbons, further supporting the oil and gas potential found at Kairi-1.

A testing program has commenced. This in itself signals that significant hydrocarbons have been found. A full release will be made when the testing program is complete and approved by our partners. We expect that within the next few weeks. We are very excited about this emerging significant project. It is very hard to put any firm reserves on what we have discovered, but we would believe that what we have discovered so far could have the potential of an oil play of about 300 to 400 million barrels. There is a series of fault blocks in relatively shallow water, which would make this block relatively easy to develop. There would be the possibility that we could have this on stream, possibly within a couple of years. You will hear a lot more about Trinidad from us in the future.

11. Trinidad Block 3(a) Awarded

As in the Gulf of Mexico, our strategy here has been to achieve success, that is, deliver shareholder value, by focusing our exploration efforts. This has been executed by acquiring a dominant acreage position in a targeted area and leveraging proprietary knowledge and expertise in those plays. Trinidad is poised for growth. An appraisal drilling program will begin on Block 2c discoveries as soon as Canteen-1 testing is completed, and studies have begun on development projects for these assets.

Also, as announced earlier this month, we have been awarded exploration block 3a, which is adjacent to Block 2c where we have made our gas and oil discoveries. Negotiation of a Production Sharing Contract with Trinidad's energy ministry is underway, with execution expected in the next few weeks. Block 3a provides us with highly prospective acreage, and our knowledge in the adjacent areas can only enhance our efforts in the newly awarded block. Trinidad's political stability and attractive petroleum geology, together with its improved contract terms, make it one of the most attractive exploration areas for us to pursue in the Latin American and Caribbean region.

12. Access to Discovered Resources

Let me finish off this section on strategies, by what we call our access to discovered resources. As I mentioned earlier, where as in our exploration programmes we are looking at relatively high technical risk, in this area we are looking at low technical risk, because we are getting access to resources that are already discovered. But there are other risks involved, such as commercial risk and political risk, which we need to make sure we mitigate.

Our success to-date has been driven by Algeria. The Middle East gives lots of development opportunities for BHP Billiton. As you all know, the Middle East has significant discovered resources, and we are evaluating a number of opportunities, like a number of other companies. Of particular interest is Iran. Iran has huge reserves, 9% of the world's proven oil and 18% of the world's gas reserves. There are opportunities to enter into "buy back" projects. Australia and BHP Billiton have good relationships with Iran. Iran also wants to develop minerals sector. Hence, there is an opportunity for BHP Billiton, with its unique mixture of petroleum/mineral skills, to be successful. We have been in discussion with Iran for some time now around possible buy–back opportunities. We are currently at an advanced stage of discussion over the rejuvenation of the Foorozan field to enhance production levels. The field has been in production since 1975, and the production would be rejuvenated through a 'technology package'. This investment would be the first Petroleum project in Iran and with our excellent relationships would be a significant platform on which to build future growth. The Indian subcontinent has a growing energy demand, particularly for gas. Iran is a logical place to supply from.

Iran is the country where we can identify the most potential for the medium-term huge gas resources. Iranian authorities are seeking an industry perspective on the planning of the development of the gas resources, and BHP Billiton in involved in a 9 company consortium to carry out a study for NIOC on gas utilisation on the South Pars field over the next 25 years. The study will take nine months.

So we are continuing to look at Iran and other countries in the region. One country is Syria, but we do take quite a detailed look at opportunities as they come along in North Africa and the Middle East.

13. Algeria

There are several areas of interest for BHP Billiton in Algeria. Our main priorities at the moment are the two projects we have in execution, ROD and Ohanet.

14. ROD Integrated Development

ROD comprises an Integrated development adjacent to AGIP BRN facility in Block 403. This involves the development of six accumulations in 401a/402a. and 403 AGIP. BHP Billiton has 45% equity, AGIP 55%. These have separate production sharing contracts. The utilisation agreement is in progress between Blocks 401/402 and Block 403, with gross reserves of 299 million barrels of oil equivalent, which gives BHP Billiton, a p50 entitlement of 60 million barrels. The indicative Capex gross is US$500 million, so our cost is about US$200 million. All drilling contracts have been awarded and civil engineering for the drilling campaign is well under way. The drilling of the first of 19 wells is scheduled to begin in mid November. We expect to award the EPC contract in the near future, and first oil is expected in 2003.

15. Ohanet Development

The second project is the very large Ohanet gas project. This is a Risk Service Contract (RSC) that we agreed in 2000 with SONATRACH, and the RSC was gazetted in November 2000. The total field reserves are 3.2 trillion cubic feet of dry gas, and 210 million barrels of liquids. This is consdensate and LPG. The liquids production will be about 60 000 barrels per day gross, with the BHP Billiton share about 25 000 barrels per day.

Our entitlement under the Risk Service Contract, p50 liquids, is about 67 million barrels of oil equivalent. About 55% of that is condensate, 45% LPG. Our investment is about US$430 million, with the total indicative gross capex of US$1 billion. All sub-contracts have been let by the EPC. Development drilling has commenced and facilities engineering is approaching 80% completion. Most major construction sub-contracts have been awarded. We will drill 32 new wells and recomplete 15 previously drilled wells, and currently we have two drilling rigs, a work over rig, and a rigless testing unit all in the field and active. The first production is scheduled for the third quarter of 2003.

So I think the progress to-date, since I spoke to you last on these projects, has been very good, and we are very pleased on the implementation we have made on those two projects in Algeria.

16. Summary – Petroleum Projected Capital Expenditure $ Million

I would like to conclude by showing you a slide of the projects that we have lined up over the next few years. The bubble size is relative to the capital expenditure on each project. In 2003, we expect Zamzama in Pakistan, and ROD in Algeria to come on stream. The Bream pipeline in Bass Strait, Ohanet, Minerva, and Mad Dog, should come on-stream in 2004. In 2005, we would expect our fourth train from the North West Shelf, and the first production from Trinidad. Shortly after that we would expect production from Atlantis. All things being equal, we would hope to have the 5th train of the North West Shelf coming on-stream somewhere in 2006.

If you add all those projects up, from BHP Billiton's point of view, we are looking at about US$2.5 billion, going forward. They have very good returns, and they are very robust projects.

17. Summary: Business Focus –

So what is the business focus going forward? We talked about our desire to maximise the value from our existing production, and I hope you saw that we are well down the track of making sure we maximise that value.

We are also striving to deliver our projects on time. Again, in Algeria, the 4th train of the North West Shelf, and the Bream pipeline, these projects will come on-stream over the next three years.

18. Summary: Business Focus – Slide 2

We also hope to sanction and develop projects which will come on-stream over the next 3 to 4 years. The major ones there are Mad Dog, Atlantis, Trinidad, and Zamzama.

The fourth part is how we create new opportunities and maintain a quality portfolio, making sure we have meaningful sized projects, and making sure we maintain our very careful geographical focus.

19. Summary
Ladies and Gentlemen, today I have presented to you, what I believe shows where we are going. BHP Billiton is a leading global resources company. BHP Billiton Petroleum is an important part of BHP Billiton, contributing significantly to the company's profits and return on capital. BHP Billiton Petroleum also has good growth prospects for the future and as such, will remain a major contributor to the Group into the future. I trust today that you have a better understanding of what our business drivers are, and where we are today.

Question and Answer Session

Q. Russian oil is very much in the news these days. Do you have any ambitions in that direction?

Philip Aiken: No, we had a project in Russia, which we withdrew from about two years ago. One of the things that was done in the mid-1990's, was decided that a company of our size had to be very focused, we were at one time exploring in 19 countries around the world. Russia was a country that we withdrew from, and we have no intention, at this stage, of going back into Russia.

Q. One of things that has been mentioned in the past, with respect to Billiton, may be a little bit less with respect to BHP, is an opportunity to try and capture additional margins. This would be looking at the synergies between the oil business and other areas of the group that use oil or use energy. Are you thinking about moving downstream in some of your gas production?

Philip Aiken:. We have no intention of going downstream. We certainly think that, as an oil company, we will stay upstream. In LNG, we are probably in midstream, by getting into LNG liquefaction, and I think that as the LNG market gets more diverse in the future, there is the possibility that we might go further downstream in LNG.

If you look at BHP Billiton's Energy Coal business, I think we supply 30 of the major 60 power utilities in the world. If you look at our natural gas sales, we certainly supply some of the larger natural gas using power utilities in the world. We have spent a considerable amount of time trying to see where we can add value downstream. At this point in time, whether we got into being a power generator would be most unlikely. It would be more about trading opportunities, and how we use our diverse range of coal and gas assets.

Q. In light of the failure to do a merger with Woodside, can you give us your outlook on whether you see BHP Billiton as being a resolutely independent oil and gas player, or whether there are opportunities for a merger with another partner?

Philip Aiken: I do not consider it a failure that we have not merged with Woodside. As I have said before, we would have only done something with Woodside if it had added value for our shareholders, and we could not see that it had value, so we did not proceed.

If I look at the upstream oil and gas business, I think it will probably polarise into the mega-majors, and the specialist players like ourselves. I think there are some good opportunities for smaller players like us, such as in Pakistan and, to some extent, in Trinidad. These are projects that would not be large enough for the mega-majors, so I think there is very good opportunity for us to operate as an independent E&P company.

We think that we have some significant green field and brown field opportunities going forward, to grow this business internally. We will always look at M&A opportunities, and we have a screening process. It has to be an acquisition which adds value to the group overall. We are a little bit different to a lot of the companies of our size; because we are part of a larger, diversified group, there is not the imperative to go out and do an acquisition for acquisition's sake.

Q. Given the focus right now on oil prices, would you feel any need to reduce your output? Could you give us your view on where you see oil prices going this year? My second question refers to your peer group benchmarking graph. The fact that you show that your reserve replacement was actually worse than your peer group, was that of any concern to you?

Philip Aiken: I think that the world consumes something like 75 million barrels a day of oil. We produce about 360 000 barrels a day, or about 130 million barrels a year. So, if we were supplying the world, we would be sold out by lunchtime on the 2nd of January, so we are fairly insignificant, when it comes to size. There is really no intention for us to reduce our output, because our output is so small, there is no significance.

The Russians have just announced they will cut 150 000 barrels of oil, and I gather the oil price has moved down again in the last couple of hours. I really feel that I have no ability to project oil prices, and I think anybody who does, in the current environment, is a very brave person, so I would rather not comment on the oil prices. I will just make the point though, that we have very high margin assets, and therefore we are very robust to low oil prices.

Your second question about reserves replacement. I made the comment that we possibly have a rather conservative treatment on how we book reserves, and we are usually six months out of line reporting relative to the companies that we compare ourselves with. I will also make the comment that we have spent quite a lot of money in the Gulf of Mexico in recent years, but we have only booked our initial reserves from Atlantis and Mad Dog. Therefore I think, that though we might be slightly behind at the moment, we understand why, I and think there are good opportunities to catch up and improve our performance over the next two years.

Q. Could you just say what the mechanism is for the price of those commodities, and what the lag might be with the oil prices?

Philip Aiken: Let me talk about LNG first. In North Asia, we sell LNG against a basket of Japanese crudes. That basket has a minimum and maximum, so it is an 'S' curve. So it actually maximises out at about $27, and minimises out at about $15. So, although it is linked to crude oil prices, it actually has a cap. It is normally done a quarter after, so at the moment, you would not have an impact; decreasing prices would hit you a quarter after. However, they are not as dramatic, because of the effect I have mentioned.

LPG is very similar to oil. In Australia, our major contracts with our users are set against the Saudi posted price, but LPG has a considerable spot market. LPG prices do not necessarily go in concert with oil prices, they do to some degree, but LPG has different prices.
When it comes to natural gas, it is very much about local markets. Most countries have long-term contracts, though there are very big spot markets in the US, and here in the UK. However, the spot

market in Australia is relatively unsophisticated, and very low at the moment. Natural gas prices are much more in tune to local energy prices than to global oil prices.

Q. Do you see a spot market developing in LNG?

Philip Aiken: That is a difficult question. I attended LNG13 this year and you hear about the potential new suppliers who talk very strongly about the LNG market going spot. I think there will be a bigger spot market. If you look at the current world market, less than 2% is sold on the spot market, but people project that will go to 5% over the next few years. I think that longer term, trains will be justified on long-term contracts, and people will be opportunistic on the spot markets. So yes, I think it will grow, but it will be some years before it gets sizeable.

Q. Early in your presentation you highlighted that you were going up from 130 million barrels of oil equivalent a year, to about 180 million barrels, a 40% rise in the next five to six years. Can you say how much will be operated within that mix, then versus now? Going on from that, how will the margin change, as a result of going deepwater Mexico, less Bass Strait, less North West Shelf? Is that volume growth, or is there a margin position as well?

Philip Aiken: I think we equated our margin as being about $7, and I think you saw the margin for the Gulf of Mexico. In the Gulf of Mexico, we will have very good margins, and they will be very similar. Obviously, in the regulated-return type margins, you are not going to achieve those margins, and therefore you will see a decline. In our total area, we would not see our margin decline significantly over that time; there will be some, but it will not decline significantly, because we will still be producing a large amount out of Bass Strait and North West Shelf. With the Gulf of Mexico being quite high margin, our margins should be relatively robust.

Keith Hunter: Looking at the mix of operated and non-operated projects, there are clearly two big projects in the Gulf of Mexico: Mad Dog and Atlantis. They account for 80 000 barrels a day equivalent, between them. They are non-operated. On the other hand, Zamzama, ROD, Ohanet, they are all operated by us and Angostura will be operated by us. To go to the issue of margin, the two projects we currently have on the go in the Gulf of Mexico return margins comparable to what have at the moment. That is somewhere between $4 and $8. Angostura would be somewhere north of $4 or $5. Zamzama is very high margin and the two Algerian projects would have a lesser margin.

Q. Healthy margins are really only part of the question. It is the return on capital that is very important. The return on capital at Bass Strait, which is your major asset, is quite phenomenal. You had $600 million EBITDA on assets of $400 million, although it was an exceptional year. Looking at it from the other point of view though, many shareholders and investors do have a problem with oil in your business. It is a problem related to the asset mix. I think they are missing the point, in that they should be looking at the returns on the assets, and not where the returns are coming from. Could you talk to us about the general kinds of returns on capital that you see in the business, and the kind of oil prices assumptions that you use to make returns that are acceptable?

Philip Aiken: Just to comment on returns, it is obvious that we have probably the highest return on capital of any oil and gas company, because of the high percentage of our production that is from legacy type assets, like Bass Strait. Our return on capital is currently much higher that you would expect for a much bigger oil and gas company. However, if we get our finding and development costs right, we have a finding and development target of below about $4.15. At that rate, you can work out that you would get a return on capital in excess of 20%. If you continued to do that, it would compare fairly well to what you would expect out of the average resource stock. That is assuming an oil price of about $18 to $20. When we look at our projects, we make sure that they are robust enough, and we drive very strongly to at least recover our cost of capital at our low oil price test. The low oil price test is a flat figure in the low teens; it is a pretty harsh test. It is most unlikely that a project would stay at $14 right through that timetable.

Keith Hunter: A simplistic way of looking at returns, and why we focus on margin so much. You can calculate the approximate return on a project by taking the margin, say $4 a barrel, and divide by the unit depreciation cost, say $3 a barrel. Multiply that by your reserves production ratio. That would give you the returns in the first year, which would be your worst year. Numerically, if you had $4 margin over a $3 development cost, and with a reserve production ratio of ten to one, it would give you a 30% to 40% in your first year in which you had production. Every year from that would improve the margin, because you have got a depreciating asset base.

Q. I am wondering if there are any possibilities of further acquisitions with any of the other players?

Philip Aiken: I mentioned before that we believe we have a very strong mix of brown field and green field opportunities, but there is no doubt that, if we found the right opportunity to grow our business, we would be very keen. Quite seriously, we have found nothing as yet, that we believe would add value to BHP Billiton. I make the comment again that, unlike a pure play E&P company, who might be quite concerned in the current environment, we are part of a larger, diversified group.

Q. Do you intend to take a more operational role in future projects?

Keith Hunter: Yes, we have got a number of blocks that we operate at 100%. We have learned a lot, but we have also contributed a lot. The lead role in the subsea of the Typhoon project was actually undertaken by BHP people seconded into Chevron. When we actually entered into the Gulf of Mexico, it was already on a good knowledge base and good experience in the company of floating production and subsea.

Philip Aiken: So, if there are no further questions, I would like to thank everybody in Johannesburg, and everybody here in London for attending. I trust you now know more about our business, and that you have found the morning informative. Thank you very much.