BHP Billiton Petroleum
Customer Sector Group Briefing

3 December 2004

<u>Introduction, Overview, Growth and Project update</u>

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Slide 3 - Overview of today's briefing

Thank you for joining us this morning. For me it's always nice to come back to Sydney. As most of you know I was actually born and bred in Sydney and it's always nice to come back and spend at least 24 hours in your old home town. As you well know I'm Philip Aiken, I'm the Group President of Energy for BHP Billiton and joining me in the presentation today I've got Greg Robinson and Steve Bell. The format of today's presentation, I'll start off giving you an overview; talking about strategy; tell you about our projects and where the growth's coming from. Greg will then take over and talk about the production, the financial figures, a little bit about bench-marking etc. And then we'll talk about the exciting bit. Steve will talk about exploration – what we're doing and what we thinks going to happen over the next period of time. I'm going to do a last section then on gas, and I'm sorry today that Rebecca McDonald, who is our new President of Gas and Power, can't be here today, but she's actually in California where she's been at the public hearings for the Cabrillo Port Project. Obviously that's a very important project for us and I'll give you a bit of a run-down on what's happening there as well as a little bit on the gas business. And then hopefully we'll have time for some questions and then lunch is available after the presentation. We intend to end around 12 o'clock or just after that.

Slide 4 – BHP Billiton Energy

Just very quickly, I think you're all aware that in March this year we brought together the Petroleum and Energy Coal businesses to form the BHP Billiton Energy Group. The presentation today is purely about Petroleum but we'll be coming to you in March next year with a presentation on Energy Coal. That's a tentative date but today is about Petroleum. While the operations of Petroleum and Energy Coal are very different, we believe that the BHP Billiton Energy Group has made the company more able to respond in a flexible and timely way to changes in the energy industry. From a customer perspective we also now have the opportunity of having a one-stop shop. So although the businesses are very different we see energy as one of the very important areas for the future of BHP Billiton, and we now have the opportunity of bringing all our businesses together under the one management. We've now got an Energy Executive Committee but the Petroleum Executive Committee is in fact still the body that runs the petroleum business. Petroleum is managed by the Petroleum Executive Committee and they're supported by global assets and resource teams based around the world. Just to let you know the members of the Petroleum Executive Committee. I have played my role for ten years. Steve Bell as you know here is the President of Exploration and Business Development. Steve's based in Houston. Rebecca McDonald, who's Gas and Power, is based in London. Greg Robinson who's Chief Financial officer for the Energy Group also looks after Petroleum sites based in Melbourne, and then there's two operational guys: David Walker who's based in London, who looks after the UK, North Africa and the Middle East, and Mike Weill who's based in Houston, looks after the Americas which includes Trinidad and also the Australian operations.

Slide 5 – Petroleum - Overview

Well, let's get into the presentation. Firstly, this first slide shows you the last couple of financial years. Our production breakdown is about 55% liquids, which is our oil and condensate, and 45% is gas. About 65% of our production is based in Australia and about 72% of our proved reserves are in Australia. But also as I think you know, we're becoming a much more international group and that percentage will change quite dramatically over the next five years. We work as a global organisation. We employ about 1800 people in total and we're located in four major offices – Melbourne, Perth, Houston and London. The offices have all got their own areas of importance. Houston was obviously the hub for our Gulf of Mexico business but it's also our major office for exploration. It's also where our Trinidad & Tobago business is run. London is very much about Europe or Africa and the Middle East, and we also have the assets from Algeria, Pakistan, Liverpool Bay etc run out of the London office. The Perth office has really become our operational centre for Australia with the North-West Shelf, the Australia Asia Exploration Group and the Australian operated business out of there. In Melbourne these days it's very much our sort of corporate function and also the home for our Bass Strait and Minerva projects. So we've got four offices these days in very much a global structure, which we've worked on over the last few years. We really have what I'd say a seamless global organisation.

Slide 6 – Reserves Trends

Looking at reserves. We've spent a lot of time on this. I think you know the background. Our crude reserves actually decreased last year. Our reserves replacement from all sources was only 39% of production, but over the last three years our average reserves replacement has been 106%. Our current crude reserves are 1,421 million barrels of oil equivalent and that represents a very healthy reserves to production ratio of about 11.6 years. Our proved and probable reserves actually increased last year and they're now 2.184 million barrels.

I might make the comment here that our exploration programme is very much focussed on large, long-life fields and bookings will be lumpy and play-out over a period of time. Looking at individual years can be very misleading and I think you've really got to look at what's happening to both the proved and probable reserves, and what's happening over a period of time, say three years or more, rather than worry about annual bookings. Our exploration programme is very much about long-life assets and as they play-out over a period of time, you won't get the bookings in the year you actually start up a project.

Slide 7 – Petroleum FY2004 Health, Safety & Environment performance

An area which is very important to the whole of BHP Billiton is HSEC. As stated in our HSEC policy we have an ultimate goal of zero harm to people and the environment, and our performance therefore is driven very much by our commitment to continuous improvement. During the last fiscal year we actually exceeded all our targets with regards to the health, safety, environment and community index. You can see some of the highlights there during the year. Obtaining ISO14000 accreditation for our producing assets, and also our community programmes. We see it as very important that we adhere to our HSEC policies, and during the last year we had no major oil spills or environmental incidents and only had three smaller loss of containment incidents. We did not receive any prosecutions or environmental breaches and our HSEC performance during the year met all of our targets overall.

Slide 8 – BHP Billiton Petroleum – Core purpose/Core values

Having given you a little bit of background, I'd like to move on and talk about our strategy firstly. BHP Billiton Petroleum's core purpose is to create value through the discovery, appraisal, the acquisition, development, production and marketing of petroleum resources. This slide I think is a very important slide because it really sums up the strategy which we took to the Board earlier this year, and received their endorsement of our way forward. We're very much committed to that set of core values and principles by which we run our business. As well as adhering to the BHP Billiton Charter, they include maintaining a high level of asset quality and focus to drive top quartile financial performance. Project delivery is very important. It's a core value. And for example, in the Gulf of Mexico the successful completion of ultra deep water projects will be critical in delivering our short to medium term growth. We aspire to build our business around a set of existing and emerging new core businesses with the scale and scope to provide multiple opportunities for reinvestment going forward.

Slide 9 – BHP Billiton Petroleum – Core business

The concept of a core business is something I'll just spend a moment on. A core business to us is a coherent area of business that is material to BHP Billiton. It meets our financial objectives and offers a long-term span of activity and many options for reinvestment. This can be developed organically or through acquisition or a combination of both, and it's not restricted to a single asset or an initial entry point or upstream resource positions. So these businesses must have sufficient scale to create options for growth and be material in the BHP Billiton portfolio overall.

So in summary a core business is something that is material to BHP Billiton; delivers against our financial objectives; involves critical mass - multiple investment opportunities through multiple vehicles; plays to our capabilities with strategic aspirations; and involves control and asset liquidity. We can control critical activities and decisions but we must have a reasonable freedom to manage optimally the asset portfolio. We will continue to seek core businesses to which we can apply our inherent capabilities and competitive strengths. We certainly seek to control critical activities and decisions, and seek a level of participation that allows us to influence important outcomes. So looking at our business overall, we believe at this point in time we have two core businesses. One is in the Bass Strait, the Eastern Australia Gas business, and we have another one in Western Australia with our Pacific Basin LNG and West Australian Oil and Gas business.

Slide 10 – BHP Billiton Petroleum – Goals & Aspirations

If we look at our goals and aspirations at the moment, the first of them is really to fully exploit those two existing core businesses and I'll spend some time talking about them shortly. The second priority we've got is to turn the Gulf of Mexico into our third core business. We've talked about the Gulf of Mexico deep water activities now for a number of years, but as you know in the next few weeks we'll be commencing the first production from Mad Dog, and you'll hear from myself and Steve of the opportunities which we believe will make the Gulf of Mexico the third core business for BHP Billiton. We'd like also to add a fourth core business, and over a period of time in the next decade we hope we'd be able to add a fourth core business. It could come from exploration, could come through a major resource holding opportunity or it could come from gas. There are a number of assets we have at the moment, things like Algeria, Trinidad etc, which at the moment are not defined as core businesses, but we have the ability to win new opportunities in those countries and turn them into core businesses. And then, while we're continuing to operate our two core businesses well, developing a third core business and looking for the fourth one, we'll also have as a priority to pro-actively manage our other high quality assets in order to optimise value, or longer term to turn them into core businesses overall. This is a little bit different to the strategy that I would have spoken to this group about five or six years ago when we had a much more Petroleum centric-type strategy. This really is about a strategy within the whole BHP Billiton portfolio and really shows, I think, a maturity of how our business has come over the last few years.

Slide 11 – Petroleum – core business and current operations

Let's now have a look at where we are based. As you can see from this map you will see circled the core or emerging core businesses. We have a significant oil and gas exploration and production business. We have the three core businesses with the principal activities being in Australia, the United Kingdom, US, Algeria, Trinidad and Tobago, and Pakistan. Later on Steve Bell will touch on some of the areas where we have exploration interests which we hope will turn into businesses in the future. The exploration activities at the moment are very much based in the US, Australia, Trinidad and Tobago. There are also opportunities in areas like Pakistan, Algeria, Brunei, the Philippines, South Africa and Brazil. So we're looking for where the next opportunities will come.

We're always looking at what's going to be our business in ten years time.

Slide 12 – Petroleum – Growth highlights

I thought I'd move on to some of the highlights in the last 12 months. Let me commence by saying that over the last 12 months we've brought on new production at the Ohanet wet gas development in Algeria; at Zamzama Phase One in Pakistan; and we also brought on Boris North, which was our first operated deep water development in the Gulf of Mexico. More recently, as you are aware, the fourth train of the North

West Shelf was successfully completed, and in October we brought on our first production from the Rod Project in Algeria.

It's been a very big year for our exploration people and we've enjoyed considerable success in the Gulf of Mexico and Australia. In the Gulf of Mexico we spent over US$220 million on exploration activities. We had positive results in the Gulf at Shenzi, Neptune and Puma, and in the Exmouth Sub Basin and in Australia with Stybarrow, Ravensworth, Crosby and Stickle. Exploratory drilling in the Greater Angostura area in Trinidad and Tobago also delivered some promising results. We also during the year strengthened our position in the Gulf with the acquisition of interests in more than 90 blocks, and we currently have in the Gulf of Mexico interests in over 430 blocks.

We've also pursued growth with considerable success with long-term gas contracts being signed with AGL and TXU for the flow of gas into eastern Australia, and we commenced the largest drilling programme in the Bass Strait since the 1980s. We announced the proposal to develop Cabrillo Port, an innovative LNG receiving terminal off the coast of southern California and we're currently seeking regulatory and government approval for that. I'll comment about that when I talk about gas. As you also know, as part of Cabrillo Port, we also started working on the commercialisation of the Scarborough Gas Field in Western Australia. During this very busy year for us from an operational point of view, the development projects – Minerva, Angostura, Mad Dog and Atlantis, have also been continuing. And I'll spend some time just going through the status of all those projects.

Slide 13 – Petroleum – Gulf of Mexico projects

BHP Billiton originally approved development of the Mad Dog oil and gas field in February 2002. The field has estimated gross reserves of 200 to 450 million barrels of oil equivalent and BHP Billiton's interest is 23.9%. The production facilities will be able to produce 100,000 barrels of oil a day and 60 million cubic feet a day of gas. This is an increase over the production capacity when we sanctioned the project, which was 80,000 barrels a day. We've spent a bit more money on this project and BHP Billiton's share now is $368 million - but that has really been about increasing the output, and also some inflationary pressures on the project. First production is scheduled later this month. I was actually in the Gulf of Mexico about three weeks ago and you can see a photograph there of the Mad Dog spar. I can assure you it's there. It's ready to produce and it's really a matter of the first development well being completed. We're expecting production to come somewhere towards the end of December.

BHP Billiton's second major project in the Gulf of Mexico is Atlantis and you can see the hull there in Korea where it's currently being constructed. This project was originally sanctioned in February 2003. The current gross reserves estimates for Atlantis is some 635 million barrels of oil equivalent. Atlantis will be developed using a moored semi-submersible production system. Our share of the total project was $1.1 billion but recently we added another $120 million in response to a capacity enhancement facility and the operator's cost review. Atlantis when it comes on-stream now will have a gross capacity to produce 200,000 barrels a day of oil. This was previously 150,000 and it'll also produce 180 million cubic feet a day of gas.

This has come at a cost, and a cost review highlighted some additional costs relating to the flowline installation, topside fabrication and hull engineering, all related to inflationary pressures in the current market we're working in. BHP Billiton has a 44% interest in the Atlantis field and when it comes on stream in the third quarter of 2006 our total share of production will be slightly in excess of 100,000 barrels a day. So hence it's a very major project for us.

Soon after the company sanctioned the Mad Dog field for development, we also announced that we would participate in the transportation systems in the deep water Gulf of Mexico. We actually approved $132 million for a 25% interest in the Caesar Oil pipeline and a 22% interest in the Cleopatra Gas pipeline. These pipelines are part of a new grid system being built in the Southern Green Canyon area for the transportation of gas from Atlantis plus some other third party fields. The construction of these pipelines has now been completed and the connection to Mad Dog is currently taking place. The risers have been installed on the hull of the Mad Dog production system and the project, which will come in under budget, will be carrying the first product from Mad Dog and another field nearby, Holstein, as soon as they come onstream in the next few weeks.

Slide 14 – Petroleum – Other projects

Turning now to Trinidad. In February 2003 following the completion of appraisal drilling in Trinidad, we committed some $327 million for the development of the first phase of the Angostura Integrated Oil and Gas Development Project located off the north-east coast of Trinidad and Tobago. This project has a nominal nameplate capacity of 100,000 barrels a day and is consistent with our strategy of pursuing growth through exploration and production that we can provide good returns from. At the time of sanction, the gross recoverable oil reserves from Angostura were estimated at between 90 and 300 million barrels. We also had a range on the gas reserves of somewhere between 1 and 2.3 TCF. The range of recoverable oil reserves was a reflection of the strategy of advancing the development and using the development drilling phase to finally define the oil reserves. The drilling programme is now well advanced and we're looking at the impact of these results on the reserve numbers for oil. While it's too early to be specific, it seems that the oil reserves will more than likely be at the lower end of the 90 to 300 range that I quoted before. The Angostura field is one of the most complex we've encountered.
Until we actually have dynamic data and a test of all the fault blocks, it's very difficult for us to put a final figure on the reserves. However we do believe they will be at the lower end of that figure ie. less than about 100 million barrels. In light of that, as we said at the time of sanction, we will probably accelerate the gas commercialisation. If you take a figure of about 1.5 TCF in total with the oil, you're still looking at a resource in excess of 250 million barrels but with the lower oil reserves we will probably look at bringing the gas on-stream earlier. Just also for guidance, it's expected in the first two or three years of start up we'll probably run the facility at about 60,000 barrels a day of oil. The initial development phase of Angostura sees oil being produced by three well-head protector platforms via flow lines to a steel jacketed central production platform. The associated gas will be reinjected into the reservoir to optimise the oil recovery. The produced fluids will be taken to the central processing platform and oil will then be transported via pipeline to an onshore storage facility. The project remains on budget and on schedule with first

oil production again during the month of December. In fact I think it's just before Christmas. So although we have a difficult drilling situation here, we still have a very robust project and we are expecting production in December.

Another project on the slide there you can see is the Minerva Project, which was approved in May 2002. The final part of the Minerva development, the gas plant, is now approaching completion. Construction is well advanced and pre-commissioning has started. All other parts of the Minerva development are now ready to produce with the Minerva 3 and 4 wells completed, and the onshore and offshore pipelines installed, and all the tie-ins have been made to the gas plant. Initial production is again expected towards the end of December. BHP Billiton's share of the capital remains unchanged at about $150 million.

Slide 15 – Petroleum – Sanctioned/delivered projects

I'd just like to give you a slide now which I hope is of interest to you. This slide shows the projects we're delivering over this period. The first five are actually operating and the next four will be operating this month or thereabouts and of course Atlantis is due to come on stream in 2006. I've attempted here to give a comparison of scale of the projects. These are nameplate capacities and are not corrected for down time. Actual production obviously will be lower, and will depend on a number of factors. For example in Ohanet it's a risk-sharing contract where our production is dependent on the oil price. As I said before, in Angostura until we get dynamic data, what the production will actually be will depend on the performance of the reservoir. Minerva will depend on customer demand and the Rod Project in Algeria is also subject to a cap on flow-rate etc. If I was to do a summary I suppose we could say here that we've delivered or are in the process of delivering a number of substantial projects in our Petroleum portfolio. There have been a number of complications in the execution of these projects, both in non operated and operated projects. We've spent some more money on some, but we've also secured additional capacity from a number of them.
On a couple, such as Rod and Minerva, we've had slippage on the timetable for a variety of unrelated reasons, but I think I can say here that overall, these have all been unrelated issues and there's nothing systemic in these issues overall. In light of what's happened with some of these projects - and also I think you're aware of the shortfall we had of production in the first quarter due to extended shutdowns at Liverpool Bay and Bruce, high oil prices which affects our entitlements on projects like Ohanet and also having made the sale of Laminaria - our latest estimate for 2005 is that production would probably be in the range of 125-130 million barrels of oil equivalent. But I can say that in the second half, when these projects are up and running, our annual rate would be more like 135-140 million barrels. I'd make the comment as always, that these are only guidelines, and they're very much subject to what happens to things like entitlements, weather etc., but they'd be our latest guidelines for this year.

At the same time I'd just like to repeat that we are still on track to achieve production in excess of 170 million barrels of oil equivalent in the year after Atlantis comes on stream, and we have a number of growth opportunities in the pipeline which I will shortly outline, which we believe will ensure we continue to grow and add value post-Atlantis coming onstream.

Slide 16 – New Growth opportunities

What I would like to do is now just run through some of those new growth opportunities. During the year we announced appraisal success on Neptune and Shenzi and also at another additional discovery at Puma, and we continued with appraisal activities at Cascade and Chinook. The first appraisal well on the Shenzi discovery was completed during our fiscal year 2004. A second appraisal test has been completed and drilling of the second appraisal well at Shenzi 3 was completed last month. We're extremely pleased with the results so far from the drilling at Shenzi and indications are that we have a commercial field with a multi hundred million barrel hydrocarbon resource. We're actually now moving to drill Shenzi 4 and going on with the appraisal to more fully delineate this reservoir. We've also participated in drilling two successful appraisal wells on Neptune during 2004. These were Neptune 5 and 6. Here in both cases hydrocarbons were encountered and we're now carrying out the feasibility studies for the development of the Neptune resource. We announced the Puma discovery in January 2004. This is also located in the Lower Green Canyon in the Western Atwater Foldbelt and it lies about 13km west of our Mad Dog development. The well encountered approximately 152 metres of net oil pay in Miocene age sandstones. The side track drilling from the initial wells also encountered oil in reservoir intervals of a similar age and obviously we're going to go ahead with appraising that Puma discovery. Cascade and Chinook fields are located in ultra deep waters in the Gulf of Mexico in the Walker Ridge lease protraction area. With our Joint Venture partners we are currently analysing data, including well results and other industry activity in the region, to determine the next steps to appraise these fields, and Steve will cover that a little bit later on.

I made the comment before that about three weeks ago I was in the Gulf of Mexico and actually made a visit to the CR Luigs, the drill ship, which was drilling Shenzi 3. I suppose it made me realise a dream we had some years back about turning the Gulf of Mexico into a core business for BHP Billiton. At the end of 2006 we'll have two fields – Mad Dog and Atlantis producing – with our share of production being around about 125,000 barrels a day. With Neptune and Shenzi, assuming that they do what we hope and we sanction, we could by the end of 2008 have four fields producing in the Gulf of Mexico up to a couple of hundred thousand barrels a day. And with a bit of luck, if Cascade, Puma and Chinook come in, by the end of this decade BHP Billiton could have seven fields producing in the Gulf of Mexico. I truly do believe now we have got this third core emerging business and we are going to see the first production coming out later this month.

Now I'll turn to Australia. In July this year we completed a full well drilling programme in our operated licence block WA-255 in the Exmouth sub basin in waters 65 kilometres from Exmouth in Western Australia. The purpose of this drilling campaign was to appraise the discovery at Stybarrow and the oil shows at Eskdale, and to test the further exploration potential of the block. Our interpretation of preliminary well data has enhanced our previous perception that there is potential volume at the Stybarrow field, indicating Stybarrow is a medium-sized oil accumulation. We're continuing with plans to commercialise this discovery and are currently seeking tenders for an FPSO.

In August of 2004 we also had preliminary results from drilling block WA-12-R in the Exmouth sub basin and this successfully defined a number of oil accumulations. We undertook a six well drilling programme on the permit from May to August and the results of the exploration appraisal programme have been positive, with an increase in the overall volume of oil previously discovered in 2003. We are currently now undertaking engineering studies to select a development option for this project which will be known in the future as the Pyrenees Development.

In January this year we also commenced pre feasibility studies for an LNG project based on developing the Scarborough field and other existing potential gas resources we own in that area. This work is progressing and we have selected a site on the mainland for the proposed gas processing, liquification, storage and export facilities. The initial phase of the project is expected to produce approximately six million tonnes a year of LNG for export either to Asia or the United States. Production from the facility may be used to supply the Cabrillo Port import facility, which is located in southern California. I'll talk more about both Scarborough and Cabrillo Port when I talk about gas at the end of this presentation.

Slide 17 – New Growth Opportunities

A key element in our growth strategy is our ongoing commitment to growing the business through focussed exploration.
You can see that there have been a number of countries in which we are pursuing opportunities and these will be outlined in more detail by Steve in a moment. In 2004 exploration expenditure was US$340 million and our budgeted exploration expenditure for 05 is around $300 million. A substantial proportion of our exploration budget is spent in the Gulf of Mexico, which as I said before, is rapidly emerging as our third core business. We are also continuing to build further business development and exploration opportunities throughout North Africa and the Middle East. The New Exploration and Business Development Team, which is based in London, focuses primarily on the evaluation opportunities in North Africa, particularly in Algeria where we've already created the platform for growth, and in the Middle East where several resource-rich countries are encouraging foreign investment. Opportunities are potentially of significant scale for us to build a material business. Steve will also be going over this in some detail.

So I hope that summary shows you that we have a healthy growth pipeline. We've delivered on a number of projects. We have a number of opportunities at various stages of feasibility and we have a sizeable exploration portfolio.

Well I'd like to stop right now and pass over to Greg Robinson who will give you an update on our production and financial performance.

Financial and Production performance

Greg Robinson
Chief Financial Officer & Chief Development Officer, Energy

Slide 19 – FY 2004 Production by asset

Good morning ladies and gentleman. It's a pleasure to be here this morning. I'm going to briefly walk through, as Phil mentioned, the production; focus a little bit on the revenue, costs, EBIT; talk, walk through a bit of capital, and then we'll talk a little bit about the peer comparison with you know the independents and majors of the industry.

First, let's have a look at production. Production in the last couple of years has been consistently around that 122 million barrel mark and as Phil mentioned, in the first half of this year producing at a similar rate, before we really get the step in of our new projects. Those new projects as mentioned, the full impact we get is Train Four at the North West Shelf, Minerva, Rod, Mad Dog and Angostura. With all of our production coming on in that second half of the financial year, we expect the overall rate to lift to about 135 to 140 million barrels of oil equivalent on a per annum basis. That would blend into full year production of 125 to 130 million barrels of oil equivalent. With the emphasis on a couple of years time, the region we're looking at is around the 170 million barrel mark, so that's consistent with what its been in the past.

It's interesting in the last couple of years we've seen the gas percentage in our portfolio increasing. It's increased from the mid 30% mark to about 45% of production at the moment. We'd expect that to decline as these new projects - well it's not going to decline it's just that the new production is liquid-orientated - so we'll see gas fall to below 40% of production in the years ahead.

Bass Strait and the North West Shelf currently represent about 60% of production and again they maintain their production rates, but with the new projects coming on they'll fall to less than 50% of our production profile going forward. We do continue to manage the portfolio looking at assets and eventual exits, and you've seen some of that activity in the last 18 months as we've exited Bolivia and our recent announcement of the sale of Laminaria. Laminaria is obviously still subject to pre-emption but they're two examples of the way we look at portfolio management.

Slide 20 – WTI vs Average oil price – US$ bbl

Just a quick slide on oil prices. Certainly there's a growing widespread view around the world that energy prices have fundamentally shifted upwards, and it's really driven by very strong China-linked demand, and the potential for supply side disruptions. This slide really illustrates that. We're very closely correlated to the Tapis and WTI benchmarks. You can see us trading at slight discount to WTI and almost on top of the Tapis benchmark. And going forward, with the amount of production coming out of the Gulf of Mexico, we will move away from that a little bit. You'll see more of a discount to WTI as we get the crude being sold into the US. One other point before I move on this slide. We don't hedge anything so there is no price hedging within the organisation on the crude side, and so we're really getting full exposure to the oil price at this point.

Slide 21 – Henry Hub vs Average realised price – US$/Mcf

On gas, sometimes the international analysts have a little bit more difficulty looking at the sensitivity of our gas portfolio. They see the movement of Henry Hub, which is a very volatile commodity. Principally the majority of our gas is linked to two domestic markets in Australia, Bass Strait into the Eastern seaboard and the domestic market in Western Australia. So 75% of our gas production is CPI-linked which gives gradual increases and a much more stable sort of revenue flow going forward. As I've mentioned, the gas portfolio is about 45% today. It represents about 35% of revenue and we expect that the 45% will fall to below 40% as the new liquids come on.

Slide 22 – FY2000 – FY2004 Total costs (producing assets)

On the cost side we've had relatively flat cost performance over the years, which has been a good thing from our perspective. We see the operating costs represent about 26% of our overall cost profile. In our industry remember that most of our operational costs are fairly fixed, so a high proportion of that operating cost is fixed. We would expect our operating costs share would stay relatively flat going forward. Forty eight per cent of that total cost line there is DD&A related, and the important thing to remember about DD&A in oil and gas companies is it's calculated off the P90 reserve piece, and hence the resource/reserve conversion is critical when you're looking at a large slice of the operating cost profile.

We'd expect the DD&A to Boe to go up in the years ahead. With new projects you're certainly not booking the full reserve base, and so the depreciation rates early in the project's life are quite high. Secondary taxes here are dominated by RRT payments in Australia and are linked to price and profitability, so on a total cost basis we'd expect our costs to increase. It's mainly linked to the DD&A increases I've been talking about, but this is very naturally dependent on price and secondary taxes, and also the reserve bookings for the DD&A calculation.

Slide 23 – FY 2004 EBIT (US$m)

Moving into EBIT. EBIT is dominated by our two core businesses in Australia - Bass Strait and the North West Shelf. We continue to see very good EBIT performance from those businesses in the years ahead. The UK assets are still very strong contributors to our business but they are mature assets. As you see that bar representing the European region, as they decline the Algerian assets replace them so we'll still see substantial EBIT performance there. The Gulf of Mexico and Angostura now are going to contribute to production in EBIT, so we'd expect as the Gulf of Mexico emerges as a new core area that it will more than replace the EBIT from some of our more mature areas as they decline.

Exploration spend. You can see on that red bar, which is weighted very heavily towards the Gulf of Mexico, as you'd expect in trying to develop that as a core area. Capitalisation rates for exploration. I haven't put the chart up. The historic rates are in the Petroleum Operational and Financial Review which is available today. But it's been running at a very high rate. We've been running substantially above 30% which is the sort of an internal bench mark we've set ourselves in the past, and it really illustrates the success the exploration group has had, and the amount of effort we've put into the Gulf of Mexico and Western Australia on appraisal drilling, and we would continue to expect that going forward.

Slide 24 – EBIT Sensitivities FY 2005

A quick run through sensitivities. These are pre-tax numbers by the way. Some of the numbers I think Phil mentioned were on a post-tax basis but these are pre-tax. As I mentioned earlier, we don't hedge so there is no direct hedging in the market. You'll see the oil price sensitivity there at $55 million. That will become more sensitive to oil over the next couple of years. You'd expect that number will increase to around the $70 million mark as Atlantis comes on. The gas sensitivity, as mentioned earlier, is less, and I've got there also the exchange rate sensitivities so that if you can see monetary movements around the A$; you know roughly how it's going to impact if it's on an EBIT basis. From an operating cost point of view we have quite a good natural hedge in Australia because we earn our gas in A$ and our operating costs here in A$, we have quite a natural hedge. You know the blessing for us is that we are a very low cost producer and so we remain profitable at very low prices.

Slide 25 – FY 2004 Capex, Exploration & Business Development vs DD&A (US$m)

On capital. This chart illustrates the capital we've spent versus the depreciation and amortisation over the 2004 year. In the last five years, we've reinvested in the business about $4.5 billion. That includes capital and exploration so it's been a substantial investment back in the business. About 50% of that amount is actually invested into the Gulf of Mexico, so it is really a substantial investment into our primary growth area, our new core business around the Gulf of Mexico. Investment in the northern Africa and Middle Eastern area and the UK has been reasonably substantial there on that chart. You'd expect that to come down in the years ahead because that really reflects some of the Rod and Ohanet expenditure that we've been investing in. In Australia investment remains high. We've had a number of projects there – North West Shelf Train Four. We've had projects in Bass Strait. We've had the Minerva Development. We've also had a very small investment in a Coal bed methane project in Queensland at Moranbah. Going forward again, we'll continue to have a high degree of investment in Australia, a number of projects within the North West Shelf, within Bass Strait. As Phil mentioned there are potential new projects with Pyrenees, Stybarrow, Scarborough and so we'd expect Australia still to be getting a large amount of investment dollars. The amount that we've been investing in the last three years on a capital basis, is about a billion dollars a year. We expect to do that again for the next three years, continue to be spending at about that rate. On the exploration side, Phil mentioned the budget this year at about $300 million. We have had some volatility in the amount we've spent on the exploration budget and it's really been around the appraisal and success piece. As we get success we will go back to corporate and ask for money to accelerate those programmes.

Slide 26 – FY 2001 – FY 2004 Total Capital vs % returns

On total capital returns, we continue to be in the top quartile of industry performance on profitability measures and capital returns. The business has done extremely well in the last four years. We are, as I've continually said in this presentation, reinvesting in the business and our capital base is now sitting over $4 billion. The EBIT return on capital has remained very strong at 40% which is a very significant number. It's certainly driven by low cost operations but also by very high oil prices and gas prices, and as you'd expect, some of those capital returns with the capital amount being reinvested there will come down. Stay at very high levels but come down unless prices stay at very high levels.

Slide 27 - Petroleum FY 2000 – FY 2004 Free Cash Flow

Just a quick indication on cash flow. We've over the last five years from 2000 to 2004 really distributed back to Corporate about $5.3 billion. That's excess cash above our capital and our exploration spend. That's pre tax numbers too, so I didn't go past the tax number. But it illustrates just how much cash flow generation is coming out of the business. You know we've consistently been achieving about $750 million on a per annum basis. We'll continue to do that.
When we look at our plan going forward with our own price projections, we see ourselves being substantially cash flow positive for the corporation, even with our amount of reinvestment in the projects already talked about.

Slide 28 – PSC – General principles

Now this is a slide that's a bit busy and I apologise about that, but it's going to be an issue I think for some of the analysts out there trying to get on top of what PSC is and I thought I'd just briefly introduce the subject. I'm happy to talk more later if people want to talk about the PSC's. We have two production sharing contracts with Rod and Trinidad and we have one RSC with Ohanet, so there's basically three projects with these sort of structures - they're going to represent about 12% of our production and earnings when they're all in full production. And just a couple of general points that are raised on the slide - certainly the contractor bears the risk of exploration development and production. The reimbursement of agreed costs is usually over a fixed period. The remaining profit oil is divided at an agreed rate and they're obviously different between different PSC's. Income tax is generally part of those cost barrels, so what we do when we look at this from an accounting point of view is we introduce a tax barrel concept, and tax paid on our behalf by the government we gross back up through the revenue line, and have an offsetting entry as a tax line so it looks a lot more like the normal royalty production scheme that you've seen with our other assets. Tax barrels are reflected in production and as reserves, so this methodology makes it much more comparable with non PSC regimes; it makes it a much easier comparison. As I said I'm happy to talk about that later if people want to get into a bit more detail.

Slide 29 – Petroleum relative to the industry players

On the results of a peer study, you can see that the company's obviously a very big company but our Petroleum division ranks about 24th. So we're in there with the mid level independents although you know we would argue that our asset base is cleaner than many of those groups and certainly dominated by larger core assets.

Slide 30 – Peer Group benchmarking

Our peer performance. This peer group includes 35 countries in the E&P stakes. All the information that's extracted here is through SEC filings and the data represents three year moving averages, and as you can see here. It's just one trend we've watched, and we've watched for a long time, that both finding and finding and development costs for the industry are trending upwards. We've seen that trend for for at least the last four years. BHP Billiton's three year average finding costs as you can see and our finding and development costs remain second quartile. Our reserves replacement as Phil said is in the third quartile. Now this is a notoriously lumpy metric and is really dependent on the pace of our resource to reserve conversion and with very large projects you know it is a lumpy conversion. In the profit area we certainly still perform at the top quartile of the industry and again we'd expect that going forward so profit margin returns on capital you can see right up there at the top; is a very good strong performance.

That's all I've got to say this morning so with that I'll turn over to Steve. Thank you.

Exploration

Steve Bell
President Exploration & Business Development, Petroleum

Slide 32 – Overview

Thank you Greg. Well good morning. I was pre-billed as the exciting piece. I'm only still going to refer to a few viewgraphs so we'll see how it goes. Over the last couple of years my team has been very active in the exploration phase. We've been very heavily focussed on identifying prospects, shooting seismic and drilling wildcat wells. We're still doing that. We're still doing that but we've had a very natural shift in our focus as our portfolio has evolved. In part due to exploration success we're more in an appraisal mode than we have been in the past 18 to 24 months. In fact it was 24 months ago which was when I last addressed this group and I'll be talking to you and giving you an update about our exploration efforts over the past year as well as a look ahead at our expected activities for the next 12 months.

Slide 33 – BHP Billiton Petroleum Exploration Aspirations and Goal

Whenever I speak before a group of prospective investors or shareholders I feel compelled to remind people, how good explorationists bring value to the business, because clearly we can bring tremendous amounts of value when executed well. Our mission is to create value through the discovery and appraisal of hydrocarbon resources with the aim of establishing reserves to support commercially viable development projects. So what does this mean? I'll give you an example in more concrete terms. After I came on board to this company in 2001 I went away with my group and we set some very aggressive resource-based finding costs. They were around top quartile finding metrics. These were resources that would be easily convertible into reserves and I'll talk about this in a little bit. So we set those targets and I would say that we're very much on target, alongside to get towards those targets. And we're doing that by really bringing new ideas to the fore, such as potentially deep water exploration not only in the Gulf of Mexico but elsewhere in Trinidad and elsewhere in the world. New plays offshore Trinidad, new thoughts about deep gas reservoirs in the Gulf of Mexico and elsewhere, and developing those ideas into drillable prospects. So it's the conversion of ideas and the drillable prospects, those prospects and the resources, which is what my group really does. And with these we drill those wells and we verify those discoveries with appraisal and that will then add value to the company. So as I said, two years ago when I went up to address this group I think my final comments were a bit of a teaser. I ended with a statement that said 'I know more than you know right now about our portfolio and watch this space' and at that time there were a lot of things that were occurring that we really couldn't disclose and what this list really shows, is a culmination of many of those things that we were talking about at that time.

Slide 34 – On track to meet 5 year targets (to FY06 based on discoveries made at top quartile resource based finding costs

So here are the things we were talking about. These are representative of over a dozen wildcat discoveries on three continents. Some of these are extremely large and all are very potentially viable projects. Now remember as I pointed out last time, we were not a drilling programme company. We really are focussed on wildcat significant discoveries and so this is quite an outcome.

So let me highlight a few of these. We had a number of successes in the Gulf of Mexico; I'll talk about that; you can see the list through there and Phil's touched upon that. We've followed up on discoveries in offshore Trinidad with new gas finds on acreage next to our Angostura field which is currently under development and will realise first oil as Phil said, in the next few weeks. We've also taken another look at Australia, which we had to take a hard look at early on, but we took another look at Australia and we've made a number of discoveries too, in the area we refer to as the Pyrenees Development in the Exmouth sub basin in off shore Western Australia. By this phase of exploration and appraisal we spent approximately US$870 million. Our estimated P50 risked resource added is about 550 million barrels of oil equivalent net to the company, which brings our resource-based finding costs to around $1.60 per barrel.

Now as I said all these figures are net to BHP Billiton. Now many of you may not be completely comfortable with this metric. This is resourced-based finding costs and on the next slide I want to talk to you about that a little bit. But if you can get a concept around the first number that we target inside the company is resources. This is a number that is before probable and proven reserves. It's the first kind of cut if you will, of what might be coming and so when I give you a number and I give you a metric, you wonder well how do I handle that and how can I incorporate that?

Slide 35 – So how does Resource convert to reserve based FC? A useful guide based on our past 3-5 years performance

So that's what this slide is attempting to do. By tracking our exploration performance within the Gulf of Mexico, Australia and Trinidad and Tobago over the past three to five years we've been able to create this guide to demonstrate how resources convert to reserve-based finding costs. The ranges are based on an aggregate of resource-based finding costs in the Gulf of Mexico, Trinidad and Western Australia. We also now have enough data as we've got into the appraisal phase to understand the real costs of appraisal – the costs of moving from resources into reserves which adds an additional 50¢ per dollar per barrel to the initial discovery costs. During appraisal some features may drop out because they fail to meet our threshold for commerciality. So our conversion rate of discovered and appraised P50 resources to proven reserves will be, and should be, and in every other company is, less than 100%, and this is where a little bit of the black art comes. How much, at what percentage and what cost and what timing do I convert - r do we convert - resources to reserves? In dealing with other colleagues and in talking about this, this is a number that's very difficult to find – there's no metric out there. But when I talk amongst my colleagues in other companies the feel is about 85-90% of the resources in many companies convert ultimately to proven producing reserves. We've taken here a little harsher cut, a little harder cut and saying that we would convert 80% of the resources that we've found. So in that effect, of the resource barrels we find, we'd say four out of five of those should make their way over proven producing reserves and it might be a little bit higher than that. But that's a fair guideline.

So with that our reserve based external finding costs comes in the range of about $2 to $2.50 and as Greg said this is in the upper part of the second quartile and near the first quartile but we're watching this industry-wide starting to move a bit.

Slide 36 – Exploration involves screening of many opportunities but 85% to 90% of funds & effort are allocated to a few select areas

So we take a portfolio management approach to our exploration efforts, which are really focussed on high growth opportunities. These are high marginal outlays that have the potential to add significant value to the company and our focus takes into account all of the opportunities we have world-wide. Fully, 85-90% of our funds and effort are allocated at a few target areas and that's what I'll highlight as we go forward. But in this diagram you can see just how we allocate the money across it. In the pre-capture phase, our New Vventures group screens various opportunities to identify the best prospects for us to pursue and capture. Once captured these are mapped, ranked and the best ones are drilled. Execution of the exploration business is facilitated by quarterly business reviews. These are designed to ensure that our targets are achieved- and if you sat with any one of my team members, they're very metrically focussed and know what they need to do to deliver value. They also know what they can do to destroy value and they're very aware of that. They're also very aware of business milestones that need to be delivered and cycle times are shortened. We constantly upgrade the portfolio. We take a hard cut in every quarter and I would tell you that at the end of every week, me and my direct report sit and go through that portfolio and we look at it with a hard set of metrics, both technical, financial and we use a lot of experience to kind of squint if you will, at the projects we're about to drill and make sure it's what we want to do. We also take out of that to make sure that we aim our capital and our human resources at the best projects. I would actually put forward that this is probably best practice. When I talk amongst my other colleagues, the ability to pull teams together and really get the type of open and honest dialogue that occurs amongst our group and the ability to shift real time is really what gives us the edge to aim our capital and our people well.

Slide 37 – Location of our current exploration screening, testing and executing activities

This map identifies our current exploration activities worldwide. It's a bit busy but you can see through it. The Gulf of Mexico, the North West Shelf and Gippsland basins are our current core exploration areas. We're also focussing exploration efforts in offshore Trinidad and elsewhere in Algeria, Pakistan and in the Exmouth basin of Australia. We're selectively expanding into new areas, including maritime Canada, Brazil, South Africa and Borneo. Where we're screening other opportunities as well - we're just beginning to emerge into the northern coast, the Caribbean coast if you will, of Latin America, sort of offshore Colombia and Venezuela. With my business development team in London we also cast a larger net looking at a wide range of opportunities primarily in North Africa, the Middle East, Russia and the Indian subcontinent. So we do cast a wide net but I would argue that we cast that net quite efficiently and that's really what this next slide is about.

Slide 38 – Exploration and appraisal budget breakdown for FY05 demonstrates focus of expenditure

While overall this year we would probably spend a total of about $300 million in exploration and in the pie chart on the left you note that 85% of our spend is in the existing core areas of Australia, the Gulf of Mexico and Trinidad and Tobago. When I say core areas, to us they are core exploration areas. I'm not pronouncing that Trinidad has emerged immediately as a core area in the terms that are still used, but it's where we can focus. Two thirds of our money is allocated to the Gulf of Mexico alone, reflecting its emergence now as a core business for the company. Over the next two fiscal years we anticipate spending increases for South Africa, in maritime Canada as our exploration activities there advance into the drilling phase. The pie chart on the lower right indicates our budget allocation by category. Exploration including land acquisition, costs and rentals takes up 55%. Appraisal takes up 30% and new ventures and G&A take in the remaining 15%. Two years ago, there would have been very little in the way of an exploration, of an appraisal wedge in this component, so it illustrates that transition as we begin to move our resource barrels into more proven and probable barrels with appraisal. Looking purely at our drilling budget in the list on the lower left-hand side, you can see how we spend our funds by play type. Forty per cent of our money goes to appraisal drilling which reflects that transition I just talked about. Growing the existing phase takes up to 30% of our drilling budget with new field drilling taking 20% and rank wildcat drilling taking 10%.

Slide 39 – GoM: Drilling activity in past 12 months included appraisal wells at Neptune & Shenzi + 2 discoveries. 2 exploration wells currently drilling

So now let's just move forward and take a look at a few of the geographies in detail. And first we'll look at the Gulf of Mexico in the United States and we're currently drilling in the two blue boxes there. We're currently drilling two exploratory tests in the Gulf of Mexico. Makalu will spud in October and is operated by Chevron Texaco. We've a paying interest on that at 30% and a working interest of 40%. We're also participating in a test on the shelf at the Joseph well in which we have about 20% working interest which is operated by Shell. Both of these are targeting potentially large material hydrocarbons in the Gulf of Mexico. Discoveries have been already announced at Puma, which is on the map on the green box, where we found approximately 500 feet of net pay in Miocene age reservoirs. Puma is located in the western Atwater Foldbelt blocks contiguous with our Mad Dog development, and as Phil says in a number of years if one were to go out to this area there is a lot of infrastructure being installed, and you know a great deal of facilities will be seen across the horizon. Closer to shore, discovery was made in July at Starlifter in the red box located in the West Cameron Block 77. The well encountered approximately 125 net feet of gas and this is in an area where there's an awful lot of infrastructure and this gas can be brought on stream very efficiently. On the appraisal side, we are currently drilling at Shenzi field in one of the orange boxes there. We announced results from Shenzi 3 last month and including 330 feet of net oil pay and a sidetrack from the initial well bore is currently underway. We'll be drilling continuously on Shenzi pretty much from this point forward.

Neptune 5 drilled last year and encountered more than 500 feet of pay and a 1200 foot gross hydrocarbon column. Neptune 7 which was drilled earlier this year encountered 114 feet of net pay, so this field is also progressing towards sanction. And you may wonder what happened to Neptune 6? That was, it was just a location that we had some initial shallow drilling problems and so we skid that to the Neptune 7 location, so we're not withholding the Neptune 6 outcome, we just had to skid the rig. You fellows always made the note that we have better luck on the odd wells here than the even wells. Whatever works!

Slide 40 – GoM: Over the next 12 months drilling at least 3 exploration wells along with 3 appraisal wells

So in the year ahead we're looking at drilling at least three deep water exploration wells and three appraisal wells in the Gulf of Mexico. This would include deep tests of the pre-Miocene play at Shenzi and Mad Dog. We've not actually gone into this proven reservoir yet in these two fields so these are fields that are currently only in the Miocene. Cascade was a pre-Miocene discovery that has subsequently been followed on. We recognise these reservoirs also lie below existing fields, so that will happen this year. We're also going to get a test on the Knotty Head structure which is on blocks we acquired in the recent central Gulf of Mexico lease sale held by the Mineral Management Service. We've about a 25% working interest in Knotty Head. Appraisal drilling will continue at Shenzi and we would look to drill the first appraisal wells at Puma which I just spoke about, and at Cascade.

I just want to take a bit of an aside on Cascade. Cascade was the first well to successfully test for hydrocarbons in the pre-Miocene or Eocene strata. It was the first well to punch through those horizons and drill deeper than what had been currently found. Subsequent tests by us and others in the industry have confirmed the potential of this play. It's got a very high success rate now, I think it's well over 60%. At the time we did not make too big of a fuss mostly because it was highly competitive information. We were pretty obscure about what we wanted to disclose. But just really want to make the point here, it was my team that was the first to find hydrocarbons in these rocks and these rocks in the deep water Gulf of Mexico, and it really shows again that it can pay to be a contrarian. Not long ago many in the industry considered the Gulf of Mexico to have been fully exploited. It had a handle, a nick-name, it was referred to as the 'dead sea' and there was nothing left to find by folks who just didn't think it was capable of delivering any new ideas or new discoveries. But this basin has proved time and time again that it continues to be one of the most prolific basins in the western hemisphere and yielding new plays, exciting plays, and I would tell you that we are on the cusp of a number of these that we're involved in. So the message I guess really is that we still have an awful lot of running room here from the deep play on the gas shelf, the pre-Miocene in the central and western Gulf of Mexico, to frontier plays in Walker Ridge and where we've got water depths from eight to 11,000 feet, and in some cases we've got rigs almost 200 miles from the coast. This basin still continues to yield new discoveries.

Slide 41 – Trinidad & Tobago exploration drilling was the focus in last 12 months, with 3 discoveries made

Elsewhere a promising area for petroleum's fourth core business is in the Caribbean and beginning with Trinidad and Tobago. Following on the discovery at Angostura, we're looking at leveraging our proprietary knowledge and experience in the area to capture other plays in this area, other opportunities in this play. In 2002 we acquired Block 3A just to the east, a lease adjacent to Angostura. With our partners we drilled three exploratory wells here late last year and earlier this year. All encountered hydrocarbons with the Delaware well cutting through a promising gas column. We also drilled an exploratory well on acreage we've retained from Block 2C. This was part of a block that is outside the greater Angostura structure in a field that is about to come on, and it had prospects on it that we weren't quite able to test in the initial six year term. So we successfully negotiated a deal with the ministry to access that for an extension. We drilled a gas discovery late last year at Howler, which d tested approximately 22 million cubic feet per day of gas on a half inch choke. And the results thus far have been encouraging. We're sort of looking at more prospectivity for the area. This is very complex geology and we'll be carefully analysing well data with our partners to determine the next steps in the area.

Slide 42 – Trinidad & Tobago; in the next 12 months a significant number of both nearfield and other targets will be drilled

I'm going to cover a few things in the next slide - specifically the blocks, the feature drilling - the blocks in blue. So over the next 12 months we will be drilling three additional exploratory wells on Block 3A, which will at that point fulfil our PSC commitment. Keep in mind that unlike the Gulf of Mexico blocks which are roughly about 5,000 acres in size a piece, these blocks off-shore Trinidad and Tobago are enormous, comprising up to 150,000 acres in a single lease. And we're currently working with partners to determine final locations for the three wells I mentioned. On Block 2C we're looking at new field targets to Kairi, which was the initial oil discovery inside of Angostura field. The initial oil discovery actually turned out to be the very first new oil discovery in Trinidad and Tobago in nearly three decades. Explorers are also studying a deep test of Angostura. Many times the best place to find oil fields is underneath existing oil fields and so we'll be doing that this year as well, drilling deep beneath Angostura to look for further reservoirs. On the acreage front we're currently in negotiations with Trinidad and Tobago's Ministry of Energy and Energy Industries for the deep water blocks that are highlighted there in blue in the north-east corner. And while they were up for award and the government chose not to award them in the current year, but both sides, ourselves and the government, are anxious to initiate an exploration programme here and we are going to be in the hunt to acquire those blocks.

Slide 43 – Bass Strait: The Northern Margin of the basin will be tested with the West Moonfish and other wells

Now moving over half a world away into this hemisphere much closer to home. In the Bass Strait we will be testing the northern margin of the basin with an exploration well to prospect we've named West Moonfish. I just want to make one comment

about the Bass Strait. In this area we're prospecting more for near field opportunities but there is some additional upside for large volume gas in this area.
These are primarily in our categorisation near field opportunities that are tying back to initial infrastructure, and remember that exploration's been underway here since the 1960s and the easier to find large oil fields have already been found, so we'll proceed with West Moonfish this year and after the results of those wells take a look and continue to rebuild the portfolio in this basin.

Slide 44 – W. Australia: An appraisal well will be drilled at Scarborough, Stybarrow & Pyrenees will be progressed towards sanction

Now to move to the other coast. In offshore Western Australia we will be drilling drill an appraisal well at Scarborough. This is potentially a major gas development source for feedstock to our LNG business. This field has become a more attractive business opportunity with the increasing demand for fuel in the United States and elsewhere, and Phil will touch on this in a few moments. Now south-east of Scarborough this past August we announced preliminary results from our drilling campaign in Block WA-12-R located in the Exmouth sub-basin. We started a six well drilling campaign in May, with positive results in both exploration and appraisal programming, and increased the overall volume from previously announced discoveries at Ravensworth 1 in Block WA-155-P and Crosby 1 in WA-12-R. These results combined together with discoveries at Stickle 1, Harrison 1 and appraisal wells at Ravensworth 2 and Crosby 1 on adjacent fault terrains, are relatively close to one another. Combined they equate to a medium sized oil reserve. Engineering studies are currently underway to determine the best development options for this project, which we and our partners refer to as the Pyrenees Development, as well as the Stybarrow field which is also in this region. An important feature to note here regarding our programme is the finding costs can be quite low. Gross drilling costs here typically range from US$2 to US$6 million and wells can reach total depth in some cases in only 14 days. The oil is also within our existing core business with the North West Shelf. We have an extensive knowledge base here. We've been operating here for many years, there's existing infrastructure, and we can realise significant tax relief on the exploration programme that we deploy.

Slide 45 – New Ventures: Strategic study, capture and execute areas

So this one slide covers the rest of the globe. This slide really highlights some of the new venture options that we're looking at and we're pursuing a number of projects along a number of fronts. In a few of these, such as Mexico and the northern portion of South America, the Caribbean coast, and in the Middle East, we already have extensive operating experience. Here we're looking to leverage off that experience that we've built over the years to grow further business. In South Africa and Borneo we're targeting high margin opportunities where we already have a country or commercial expertise. And off-shore Canada is our first entry in the potentially highly prospective new play emerging in this sub-Arctic maritime region. And it is certainly early days for these ventures. I mean these, these are the types of things that you know will yield results in the eight to ten year time frame, but given the technical, commercial and regulatory challenges we face we really have to begin now to begin to fill that pipe line as time goes on.

Slide 46 - Summary

So in summary I'll just wrap up my discussion by reiterating the exploration group and BHP Billiton Petroleum have delivered a consistent stream of sanctioned projects. These contribute to a material cash flow and value, organically building the company's third quartile and the Petroleum CSG within the Gulf of Mexico. And we need to point out our first bullet point - as explorers we tend to be out in front of a lot of people and here we're actually out in front of the statement. We're making a statement but the core's already been built. I'll just emphasize we're in the process of building that core. We are, but we've got all the confidence in the world that we'll emerge. So a lot of core businesses out there and it's one of the fifth core business and a sixth core business. I would tell you that our company has the people, we have the systems, we've got the processes, and importantly I think we've demonstrated certainly over the past few years we've got the discipline, the tenacity to actually deliver results in exploration and so that we can continue to create value for our shareholders. So I thank you for your attention. We'll follow up with questions at the very end and at this point I'll turn it over to Phil Aiken.

Gas Development and Opportunities

Phil Aiken
Group President, Energy

Slide 48 – Gas assets and regional gas strategies

Thanks. Well at this stage I was hoping Rebecca McDonald would be here to talk to you about our gas business but as I said before Rebecca's currently in California where she's been attending the Public Hearings on the Cabrillo Port Project. So what I'll do is I'd like to give you a fairly short version of presentations that she would have given, which really will give you where we think we're going with our gas business overall. Let me start off by saying that we view the world of gas really around four major markets. The four major markets – Europe and North America. East Coast would be known as the Atlantic Basin and the North Asia-Asian market and North American West Coast is very much the Pacific Basin. These have really become almost two separate businesses although the gas world has got a lot of similarities. On top of that also we have a number of smaller local markets which we supply, such as the east coast of Australia and Pakistan etc, and this is where we look at the world of gas opportunities being on these big global markets or regional markets, and then also on the smaller local markets.

Slide 49 – Pacific Basin: Serving markets in Asia and West Coast Americas

Let me start off though by talking about the one that's probably best known to you, which is what's happening in the Pacific Basin. There are really three areas here I'd like to talk about. The first is the North West Shelf. As you know, Train Four of the North West Shelf, the second trunk line and the 11th carrier were all commissioned in the last few months. The expanded North West Shelf capacity now has gone from 7.7 to 12 million tonne per annum, and expansion is committed to the Japanese utilities and also a short term contract into Korea. Another contract which has come out recently - or a tender has come out - for six million tonnes for Kogas. This was released to potential bidders in August. The North West Shelf has been shortlisted for further discussion and we expect to have even more discussions with them when they talk to potential suppliers in January of this year.

At the same time, for the fourth price renegotiations with the Japanese customers was settled in September, and we've now commenced serious discussions to look at extending the existing contracts post their expiry in 2009. With the fourth train coming on stream, now we can start actually also selling into new markets, and so far the North West Shelf has sold six spot cargoes and has another 15 cargoes under consideration. The fourth train has actually come onstream well, and we now see good opportunity for good gas and LNG extra sales in the coming year. All of the North West Shelf participants are very much in favour of train five, another 4.2 million tonne train. The final investment decision for train five will depend on securing sufficient new contracts to underpin this investment, and it's our hope that sufficient marketing steps will be made such that a decision can be made during the first half of calendar year 2005. The North West Shelf remains a very important business for BHP Billiton, and as I said we are very much committed to train five, hopefully being committed during the first half of next year.

Slide 50 – Pacific Basin: Serving markets in Asia and West Coast America

After that we have, as we've told you before, our interest in the Pilbara LNG project. After a very rigorous progress, the site for the Pilbara LNG plant was selected at Onslow. We actively engaged prefeasibility engineering with Kellogg, Brown and Root, and we are moving ahead now quite strongly looking at this project. The find was anticipated to be a six million tonne per annum facility with storage tanks, jetty and loading facilities, and this project would be operated by BHP Billiton. The initial supply will come from the Scarborough Field. The Scarborough Field, at 270km offshore, has a lot of benefits. It's dry gas with very little or no inerts, and therefore although it's a long way offshore, the pipeline actually is very feasible. Three D seismics were completed in May this year and as Steve said an appraisal well would be drilled commencing this month. The project's been granted Major Project status by the Commonwealth Government and there is strong government and local support and we're having consultations with the local communities and these have so far to date been very positive. So we see this as a very viable source of LNG for either North Asia or for the West Coast of the US.

Slide 51 – Pacific Basin: Serving markets in Asia and West Coast Americas

Well the project you'd probably like to hear more about is Cabrillo Port. Cabrillo Port is a unique offshore LNG floating storage and regasification facility. It's similar in size and design to an ocean going ship. It would be moored some 21km off the coast of California. In fact, from the shore it'll just be a speck on the horizon but for the days when there's not fog covering it in. This would be a six million tonne regas facility which would have the capacity to send out up to 1.5 billion cubic feet per day of gas, although it would probably more likely operate at about 800 million cubic feet a day. Just to give you an idea of size, the Californian market is a six billion cubic feet a day market. The total Australian market is about two billion. So 800 million cubic feet a day would supply 10-15% of the Californian market. The gas would serve this Californian market through the existing on-shore system of the Southern Californian Gas Company.

This is a market with strong growth but with diminishing supplies, the government of California is quite committed to the need to develop new sources of natural gas. Per the Deep Water Port Act, BHP Billiton has applied for a licence with the US Coastguard and the Maritime Administration. The draft Enviroment Impact Statement has been released,and four public hearings have taken place – 29th, 30th of November and 1st of December. Two of these meetings were in Oxnard, one was in Santa Clarita and one was in Malibu. As I said, Rebecca McDonald's at those meetings and I spoke to her this morning and we're overall are very pleased with how the meeting went. As expected there was a lot of public debate. One of the meetings at Oxnard had about 300 people, and there were probably 100 people who were very much against the project. But overall the basic reporting has been very balanced, and a lot of people see a great deal of benefit in an LNG project being close to the market but not being built onshore. Where we currently stand is - the public commentary will continue now until December the 20th and we'll expect some time early in the New Year for the final draft report to be published. There are a lot of hurdles ahead yet, but we have come a long way with this project and we remain very committed towards trying to be successful in this offshore terminal. Overall though, this is something which will take some time, but the progress to date is that the draft report is out, the public hearings have taken place and we're now waiting now for the commentary period to end so that the final EIR can be published. So with Cabrillo Port, it's watch this space.

Slide 52 – Atlantic Basin: Serving markets in North American East Coast and Europe

Moving now across to the Atlantic Basin, and it's something which I don't a lot of people realise, that we are now becoming a reasonably, but still a very small supplier, of gas in from the Gulf of Mexico. We currently produce from West Cameron and from Typhoon something like about 50 million cubic feet a day and this will increase when Mad Dog comes on stream by another 25 million cubic feet. Next year we'd hope Starlifter, a small gas discovery we've made, will be able to be brought on-stream and that'll produce another 10-15 million cubic feet a day. And when Atlantis comes on, another 65 million cubic feet a day will go into the market. So you can see, we're still a relatively small supplier of gas from the Gulf of Mexico but there are big opportunities longer term as we have more discoveries to sell the associated gas. We've certainly gained a lot of knowledge and experience of the US pipelines and customers through our marketing, and this stands us in good stead to continue to ramp up Gulf of Mexico volumes and increase our volumes overall. And as Steve commented before there are significant opportunities for our exploration programme in what's known as the Deep Shelf Play. So, to some degree we have got a small position in the Gulf of Mexico but we do see that ramping up over a period of time.

Slide 53 – Atlantic Basin: Serving markets in North American East Coast and Europe

In Trinidad, the Angostura field is a gas field with an oil rim. Our current P50 gas reserves stand at 1.5 TCF, and we continue with the expectation that we'll find more gas. There are a number of opportunities to monetise gas in Trinidad and Tobago. The government of Trinidad and Tobago has indicated to us that a fifth train could be added to the Atlantic LNG with new and additional participants, but they've also indicated they'd like to work with BHP Billiton down stream at the wellhead. The Trinidad and Tobago domestic market is another option, given that they currently have identified additional requirements for some 300 million cubic feet per day, and the history of the domestic market has been one of steady growth. So we've many opportunities for us to actually sell gas in Trinidad, whether it's into the existing Atlantic LNG infrastructure or new trains, and into the domestic market, and therefore having gas available earlier than we possibly might have had if we'd found more oil, actually gives us an advantage.

Slide 54 – Atlantic Basin: Serving markets in North American East Coast and Europe

We will now talk about two other assets which we are involved in the Atlantic Basin. Liverpool Bay as you know is BHP Billiton's largest operated asset and supplies some 250 million cubic feet a day to the Connah's Quay power station. Our North Sea asset also produces about 30 million cubic feet a day. We have a gas and power marketing presence in The Hague whose responsibility it is to market our equity production, and this is also linked to our energy coal CSG, giving us great knowledge about the power industry generally in Europe. Our other gas asset in this part of the world of course is Ohanet, which is our wet gas development. Although we haven't got title to the gas, the Ohanet facility does produce some 700 million cubic feet a day of gas, and we of course get the associated liquids, which are about 56 million barrels a day. In July of this year we won two new blocks – 408A and 409, and we're hoping that these might lead to us having more involvement in the Algerian gas business overall. So although our position in the Atlantic Basin is quite different to the Pacific, domestic supply out of the Gulf of Mexico, potential LNG supply out of Trinidad and Tobago, and our experiences in Algeria, give us an opportunity to use this as a potential core business for us, and we hope to develop our Atlantic business basis more in the next few years.

Slide 55 – Eastern Australia Gas: Discrete domestic markets

Let me finally talk about two smaller markets which we have for gas. The first of these is well known to you – it is the eastern Australian market. As far as the operations and opportunities that we have there, the eastern Australian gas asset, with gas coming from Bass Strait, now supplies not just the Victorian market, where we supply about 90% of the volume, but we also now supply into four other states underpinning from 50 to 90% of the gas needed when pipelines were originally built. BHP Billiton is now the only gas supplier in all five of the states in eastern Australia, and it's expected to have the highest production market share in 2005. In addition to gas growth, we've confirmed our position long-term, as we're placing the largest gas contract due to terminate at the end of the decade, by contracting with TXU and AGL through to 2017. These contracts represent the largest sale of Bass Strait gas since the initial agreements were signed in the late 1960s. On top of Bass Strait we also have projects due to come on-stream in the next few months.

That's the Minerva Gas Plant and also gas from the Moranbah Coal Bed Methane Project in Queensland, and we see opportunities for two large gas field developments at Kipper and Turrum which are likely to be reviewed for investment decisions during the next 12 months. So although it's a market which we've been in for a long time with the supply of Victoria, we see very good opportunities to be a larger player in the east Australian gas market over the next few years.

Slide 56 – Pakistan: Discrete domestic markets

And finally Pakistan. Pakistan for BHP Billiton has been a great success story. Our Zamzama Gas Field is currently supplying some 20% of Pakistan's gas demand. In 2001 we were producing 80 million cubic feet a day; in 2003, with the completion of Phase 1, we're now supplying up to 300 million cubic feet a day; and we expect to go ahead with Phase 2 of Zamzama, which will increase our production to 450 million standard cubic feet per day by 2007. I can say quite honestly we are the preferred operator in Pakistan having delivered our projects early and under budget and we've had an exceptional HSEC performance, the other thing which has been very impressive with the Pakistan government has been our ability to have something like 70% local content. In August of this year we won another block in Pakistan which is on the same trend and the same reservoir as Zamzama, and we anticipate the first well to be drilled there in 2006. Currently we are carrying out the seismic work.

Slide 57 – Gas Developments and opportunities - conclusion

So this is just a quick run through our gas business, but I think really it was just to show the growth and emphasis of all of our gas businesses coming at a good time. World energy demand from 1997 through to 2020 is expected to increase some 60% and a third of this increase is expected to come for natural gas. The LNG market has really metamorphosised in the last few years and continues to change for the good. There's a greater understanding and acceptance of LNG, it's becoming increasingly flexible and enjoying a greater liquidity. The movement of gas from single sources to multiple markets in each basin has dramatically increased, and will only continue to do so. We know there are many players in this market but think that BHP Billiton has the experience and the know-how to be successful, with our proven track record in exploration, project delivery and ability to find markets for our gas. So I'd say to you that in the future you will see us continuing to grow our gas business, but that was just to give you an idea of what we've currently got and what our priorities are about.

Slide 59 - Summary

Well, in conclusion - just before we are opening for questions, a summary. Well, where do we stand and looking at the four issues which I suppose we look at overall. Number one as Greg showed today in terms of efficiency, we're a top quartile performer in our net income per boe and our return on capital. Although we're a second quartile performer in finding, and finding and development costs, I think what you heard from Steve today shows you we have a lot of resources which we hope to turn into reserves and projects and I think we'll continue to see them proven in that area.

In terms of delivery - we've had five projects come on stream between 2003 and 2004 and we've got three new projects starting up before the end of this calendar year. As I said before, we've had some problems with some of the projects but I think this has really been about an enormous workload, and once all these projects are underway you'll start seeing the growth in our production coming through again, and we certainly have several opportunities to continue the growth of business into the future.

Overall, I think our strategy is now well in place. The concept of core businesses has been established, and as we've said we've got the third and we're looking for the fourth and hopefully after that in the fifth and the sixth. And so in conclusion I think the Petroleum business continues to be a very valuable part of BHP Billiton. It is a differentiating factor in BHP Billiton, and I think overall the solid performance, the strong producing assets, the value it creates and the consistent strategic direction will mean good opportunities for us to grow this business and continue to be a significant part of the group into the future.

Well ladies and gentlemen, that's the end of the presentation. We're turning over to questions. If you could put your hand up, identify yourself and I'll either answer it or pass it to one of my colleagues.

Questions and Answers - Sydney

Question:
Promise turning into reality, it's just absolutely fantastic. Just actually along those lines, BHP Billiton if you go back to the Jabiru days, I suppose that was the first very significant onshore, offshore. You've had some very successful collaborations with other companies. Can you just go through the role of operatorship going forward. I note that some of those developments are operated by BHP Billiton, and just the important aspects of what operatorship means and staffing up and getting resources at a time of very difficult time to acquire new resources.

Philip Aiken:
Well no, I think we've always made the comment that when it comes to operator or non-operator, we believe that where it's appropriate we would like to be the operator. There are opportunities sometimes when you wouldn't. I'll give you an example in the Gulf of Mexico. BP is the operator of Mad Dog and Atlantis. But on the way through we've actually operated a lot of the wells and therefore you know we've really learnt and we've worked with capably with BP overall. We will be the operator on Shenzi because it's the first project and that's where we go moving forward. During the construction of Mad Dog and Atlantis we've had BHP Billiton people heavily involved in the integrated project teams with BP. In fact, we've played a leading role in a number of the areas, and I won't go through them but there's been a number of teams where the BHP Billiton secondee has actually been the leader of the project. As an operator in the operator sense, someone once said to me if you can operate Liverpool Bay you can operate anything. Liverpool Bay is one of the most complex facilities. We haven't talked about Liverpool Bay today but Liverpool Bay is an offshore onshore facility. It's just off the coast; it can be seen and therefore it has both offshore and onshore issues. I think we've proven on Liverpool Bay over the last few years that we are a very competent operator, and we've used Liverpool Bay and the Griffin Venture as a training ground for our operators for Trinidad, so we are actually using that quite strongly.

Ohanet, the project in Algeria, has been a really groundbreaking project. Ohanet has come onstream faster than any wet gas project, and there's been four of them, sorry, three of them built and there's one still being built. So we believe overall that over the last few years we've proved our ability to be an operator, and where we've partnered with people we would be able to also learn a lot more. In a lot of cases operatorship is important because a lot of regimes, particularly say in the Gulf of Mexico, the operator really sets the pace. The non-operator's got a role but the operator sets the pace. So I think going forward in areas like that we certainly seek great advantages in being the operator. But, there's other parts of the world where we've been into and people have got experience and have got operation skills, we'd be quite happy to sit back and be the non-operator. So we really don't see it as an issue. We really see it as being operator where appropriate. Currently at the moment we have got under Mike Weill and David Walker an operating readiness agenda. This is something which in fact we're getting a lot of learnings from other parts of BHP Billiton. One of the things which we only talked about recently, was BHP Billiton has got a tremendous track record, whether it's the aluminium smelters in Mozambique or the copper businesses in Chile, or now our own Ohanet project in the desert, the Sahara Desert of Algeria, and therefore again we think there's a lot of leverage we can get from the group overall about operating in remote locations. So it goes to the question, we're very comfortable about being operator but we're not paranoid about it. We'll be operating where we think it's appropriate.

Steve Bell:
On slide 34, all the exploration discoveries we talked about, all but one of those is an operator discovery. All but Puma is operated by BHP Billiton.

Philip Aiken:
Yes certainly from the exploration point of view we believe, and I think there's been some published data about this, our operated drilling performance in the Gulf of Mexico has been first in class. I was thinking more of the production operatorship but certainly on a drilling site we've been very much one of the top performers.

Steve Bell:
In the top quartile.

Question:
Just while we're on the Gulf of Mexico, congratulations on building production at Mad Dog and Atlantis from 80 to 100, 150 to 200 - and I don't know if this is Phil or Steve's question but I'd just like to understand how that came about and if there's potential for that to happen in other projects going forward?

Philip Aiken:
Well on Mad Dog, actually Steve might just make a comment on Mad Dog in a moment. But basically on Mad Dog we believe that the facility which was sized at 80 but when BP started looking through the potential of the wells, it was decided that it was worth going to 100,000 barrels because obviously it created a lot of NPV with the extra barrels you produce in the early years. In the case of Atlantis, when we sanctioned the project we hadn't drilled a well in the northern part of the field, and when we drilled the well and found oil in the northern part of the field it was obvious we could bring it up to plateau quicker, and keep it there for a much further amount of time. And incremental investments like this in topside facilities have very high returns and high NPV's. So in both cases it was really drilling performance, giving more confidence after projects were sanctioned that led to a pretty easy decision made on getting the bigger facilities. But Steve, do you want to talk about the?

Steve Bell:
Oh yeah you covered it pretty well Phil. It's the way we choose our reserve categorisation and our resource categorisation on these features as we bring them forward into sanction is fairly conservative. As Phil pointed out, in both Mad Dog and Atlantis there were undrilled fault blocks that hadn't been brought to fore; reservoirs that had not yet been seen. And so there was still continued upside. So as Phil said, there's nameplate capacity that we expected to be able to expand, but also

with continued drilling, you know more reserves that are starting to get it. And that's, you know I've got to add the exploration piece here, the yet to come here, is as I said, there's still reservoirs that lie below these reservoirs and we've not yet penetrated them. We don't know if they're full of oil or water. They're soon to be tested.

Question: My question is three-fold. The first one is, is the development at Scarborough dependent on the go ahead for Cabrillo Port, and if not, which markets in north Asia are the most prospective? The second one is that as an oil man can you give us your per cent chance of Cabrillo Port going ahead given what you know now? And the third one, is why hasn't your 50% partner, Exxon, in Scarborough, been at all willing to contribute to the feasibility study that you're undertaking? What is it that they're worried about that you're not?

Philip Aiken:
Okay. Firstly I have to make the comment and I think last time I said that every LNG project is in pre-feasibility until it's secured a market. If you've gone to the World Gas Conference in Tokyo last year or the LNG conference this year you would have seen 20 LNG projects which are all going to happen. If we are successful at Cabrillo Port, Scarborough will almost certainly go ahead, so that to me would be your secure a market then you can develop a project. If Cabrillo Port doesn't go ahead, we would still go ahead with the feasibility work on Scarboroug,h but then taking your point, we'd have to start looking for another market. BHP Billiton spends a lot of time in China. There's one terminal being built which is the Guangdong terminal. There's a second terminal proposed. There's up to seven terminals potentially happening there. I think the Chinese see Australian LNG very favourably, a potential market for Scarborough if it didn't go to Cabrillo Port would be into the Chinese market. But obviously getting Cabrillo Port will make Scarborough go faster because it opens up a new market for us.

The chances of Cabrillo Port going ahead, the second question. You know, Steve and I were talking about this, this morning. We can remember the day that we were in Houston and the guys came forward with the concept and we all thought oh okay, and we sort of smiled and said this is worth a go. We probably thought the chances were 10%. I have to say now I'd have to think we're you know 50:50. I mean, I can't put a figure on it but the fact remains is that we have a deemed complete application. We have an environment draft and environmental impact report and we've now gone through two sets of public hearings and we're still going ahead. As you're aware, we've had meetings with everybody from the Governor of California down. We have a team working on this and I think we've got a chance of pulling it off. It's like any investment of this type – it's an option; it's an option we want to develop, and if we're successful it'll be a great opportunity, not just for BHP Billiton but for Australia. It really will be a wonderful project. So you know I really think that we've got a good chance of going ahead.

Your third question is, ExxonMobil have got many LNG facilities around the world and like any company they have to put priorities and to them Scarborough is not a priority. We see Scarborough as a priority for us. We've got a good relationship with Exxon Mobil over it. They don't want to sort of fast-track it. We do want to fast-track it and therefore we're going ahead. Again I think I've made the comment publicly before, if we won Cabrillo Port and Scarborough became more than a dream, you might find a different attitude, because there's no doubt to me as I've said before, there are so many LNG projects on drawing boards. How many of them actually ever happen is always the issue.

Question:
You outlined potentially where the Gulf of Mexico is going and previously you've shown a chart of production going forward that peaked around 170-180 million barrels of oil equivalent by 08. Just wondering what's the real potential is of the Petroleum division say out to 2010? Looking at some of those projects that you haven't even really talked a lot about, you'd have to think it's higher than that sort of number. Another question, more on the exploration front. A lot of companies have located themselves off the African West Coast and I'm just wondering if BHP Billiton's had a look at that and maybe why or why not you're not there? And within Bass Strait more domestically, the Kipper Project, given the amount of gas you already have in Bass Strait, why does that project need to be looked at for sanctioning possibly next year?

Philip Aiken:
Okay I'll handle the first and third one off and flip the second one to Steve. Going forward we, at a presentation here about four years ago we gave a slide which was our prediction of going forward. Unfortunately when you give a prediction that turns into a forecast and really I think going forward we'd rather you guys look at the projects and make your own assessment of that. When I say at the moment 170 million barrels the year after Atlantis comes on stream, you saw today Atlantis our share with the higher oil production and the gas is over 100,000 barrels a day. So we get this big step up in our production when Atlantis comes on. Going forward we haven't, we haven't yet sanctioned Neptune. We haven't yet sanctioned Shenzi. Stybarrow and Pyrenees – we're working on the feasibility for these. You guys can work out the production figures roughly and you can come up with some projections. My only comment would be that as we intend to get to 170 and continue to grow. We don't intend to slip off again and therefore we're very positive about the growth of the business going forwards. But this is all subject to timing and subject to how these things work through. I mean we've said with Shenzi, it's a multi 100 million barrel discovery. We've got three penetrations. We're going to drill four and almost certainly five. And to sit here today and give you a date and a production figure going forward, I don't think really means much. We could give you a range but I think really I'd rather put the projects up, tell you where we're going and let you make your own conclusions there going forward.

So on Kipper, I mean Kipper is subject to a production lease, sorry a retention lease. If we don't develop Kipper in a certain period of time we could lose it and going forward we believe that gas in Bass Strait is very valuable and really Kipper is a project we'd like to sanction and get on with. So Kipper really is a project that we mightn't need the gas today but we will need the gas in the future subject to retention lease and therefore we have to go ahead with the development. But it's a robust development going forward. Steve, West Africa?

Steve Bell:
Yeah on West Africa Craig we have, historically we've spent a few hundreds of millions of dollars in West Africa looking at projects. It's not been successful, but we

were in Angola if you recall a number of years back with, with looking for land. We were as well in Gabon looking for fields. And in many cases what became quite apparent a few years ago was that we probably arrived on the scene in West Africa somewhat late and chose the wrong basins. And you know choosing basins is perhaps one of the most important things we do in our business. And so we withdrew from Angola after drilling a few wells; we withdrew from Gabon. We have looked over the years, and we still continue to look, with new ventures basically from the Moroccan coast right on down through South Africa, so we do look at Mauritania; we look at Western Sahara, some of the emerging places there and we do keep an eye towards that and we will, if an opportunity arises for a robust entry not a single point single well drilling opportunity, but a robust entry, we will enter. Now that said, we have the largest land position off of South Africa and for years the view was south of Namibia there was nothing left to look for, it was all gas prone. We have a very significant position in South Africa on the West African coast of South Africa. We have a lot of that land optioned and there's a very exciting play about to emerge there. We are gearing up for almost ready to be in a position to drill there. So we have been in West Africa, we have looked hard. We didn't quite nail it right the first time. We still keep an opportunistic eye on the coast and again we're positioned in what we think is a fairly exciting wild cat play off the South African coast on the Atlantic.

Question:
I want to go back to two things. One is Scarborough and would it be a possibility that if you did get Cabrillo Port and ExxonMobil who still claimed it was commercially not viable that you would seek to replace ExxonMobil in Scarborough?

Philip Aiken:
Look on Scarborough, at our stage the point at the moment is that we shot the seismic and sole risked it, ExxonMobil agreed to that; we'll probably sole risk the well. That's really a question you could ask ExxonMobil if they eventually wanted to get out of Scarborough I'm certain there's many people who'd take their place. You know we have a constant dialogue with them about the Scarborough facility and we're going to keep on pushing for that project in Cabrillo Port and we'll see what happens in the future.

Question:
On Kipper, what size of development are you thinking of? I must have missed something on the way through because I can't remember the details of Kipper.

Philip Aiken:
We just can't tell you off the top of my head. I just asked Greg Robinson because he's been closer to it. No, the situation with Kipper is the development. Look I can't tell off the top of my head, we'll have to come back to you.

Question:
Now Phil, no doubt you've seen all the speculation surrounding Shell and Woodside and Chinook. If Shell's share of Woodside does come on the market, would you be interested and are you sort of keeping a watching brief on that situation?

Philip Aiken:

I think this is a line that I expected at some stage to be asked this question - but I think we've said right through the previous times when Shell and Woodside have had this situation that it's not BHP Billiton's policy to comment on speculation about M&A and really I can't comment on it at all because I know nothing about it. So at this point in time my view is that we again say that we don't comment on speculation of this type.

Question:
You mentioned with the Kogas LNG tender you expect further discussions in January, is that the sort of the month that you're expecting to hear whether the shelf has been successful there?

Philip Aiken:
Yes and it's a bit of a moveable feast, this one at the moment. I'm not that close to it personally but I understand at the moment we're on the short list and we'd expect in January to have a much better idea about the tender. You're not going to see a tender; you're not going to see an answer in January I believe. It's more about what will be the process of the tender going forward.

Question:
Phil can you make a comment about whether you have increased your long-term oil price and from that can we expect that we'll see a fairly significant change in resource reserves at year end? And the second part is, is ExxonMobil wanting to position itself so there's a joint development at Scarborough and Jansz?

Philip Aiken:
Well the first question is our long-term oil price. We don't comment on what we do with our long-term oil prices, but you know I have to make this point and I'd rather sort of make it as a general comment because we've made it before. When we look at a project we look at our business overall. We look at a whole series of oil prices. We have a long-term oil price which is a long-term trend price, but we also have low tests and high tests. We do probalistic calculations. We do deterministic calculations. And whatever oil price we pick it's going to be wrong, so we don't look at one price and I really do, as a business we sanction projects because they're good reliable projects. We're about top tier assets and we really are about how we actually do look at projects. One to me, one of the biggest tests is our low oil price proven reserves test and if we can get the cost to capital there we know we've got a very robust project. So to answer your question, the answer is no, we haven't changed it; we will always look at it from time to time, but it's not something that we really take that importantly because we really do look at a whole series of prices going forward.

Look, on Jansz and on Scarborough, we haven't had any discussions along that line. Our priority has been really Cabrillo Port. If we're successful at Cabrillo Port we'd like to do something with Scarborough. The two are going ahead together. We're taking a very positive attitude towards both projects. I mean people often ask us about Cabrillo Port, why haven't you got a partner? Quite seriously, trying to do an approval process for the project like Cabrillo Port's a lot easier when you've only got one person to talk to – yourself. And really going forward, if we're successful at Cabrillo Port we'd be looking at Scarborough as the source and I'd suggest that everybody talks about LNG projects. Until they've got markets, they're all in pre-feasibility.

Question:
Just on your reserves bookings. I mean you say they can be quite lumpy but can you just give us a, a bit of colour on what has been booked and what is likely to be booked going forward?

Steve Bell:
Look, we won't comment really on what forward bookings we'll take. I mean that very much is a year end review and it's very much independently looked at. As much as we'd like to at times be able to influence that outcome, it's a very independent process and especially after the past 18 to 24 months of what's been out in the press. I will say that our bookings are conservative as we move through sanction, as we move our projects from appraisal into delineation and into FEED and into sanction. We normally only take 20-30% of what might only be the future bookings of the project. Oftentimes the bulk of bookings do not begin until projects come on stream, and the subsequent years after that to see how performance is occurring. So from that standpoint, I guess to really colour it, not to really give specifics of the answer of the numbers, we're fairly conservative in the way we take it and where you're going to start seeing bookings starting to hit our books will be as we sanction and in the early phases of production. And then subsequent to that you'll see continued bookings over the life of the field as we develop further reservoirs and we see how performance to either water floods or injection behave. Bookings really won't occur in most fields until the end of the field and many of our fields we don't take those last bits of bookings until the 15th or 20th year in that case.

Philip Aiken:
I might just add two comments. The global practice leader who's responsible for the integrity of our reserve booking process actually has a direct line also into Chris Lynch so that it's independent of petroleum. He also has no KPI's or anything linked into what reserves we've booked so we do have a totally independent process within the company overall. And I'd say the second comment I'd pass, is that say like Mad Dog, we've booked less than 25% of the resource we talk about there, but obviously when it starts up and we start getting dynamic data, we start getting analogues we'll start booking reserves and they'll continue throughout the life of the project.

Question:
Just a quick question getting back to the PSC's and RSC's if we can. I'm interested if you can at least give us a rule of thumb because we haven't got a lot of details for some of the projects on the sort of cost recovery specifics we should assume. And then secondly on what the government take or your share of the profit oil may be? It's obviously going to be the key driver of your share of profitability. And when we consider Ohanet, we've obviously got to think about the price of oil and the sort of volumes that you will book at the end of the day. I'm interested in what sort of rate of return on an annualised basis we should assume to determine that number? And then just finally, we've heard you talk about the RSC, PSC's historically. We could talk about portfolio balance and managing risk particularly given your likelihood of developing projects in different regions. What sort of assumptions would, should we

make for those contracts forward and will we see a mix of these things I guess into the future?

Philip Aiken:
A few good questions there. Greg?

Greg Robinson:
Each of these PSC's is different in structure and I think it would take too long to actually go through them in detail. I'm happy to talk about it with you later and talk about how you'd actually sort of specifically model some of them. A lot of the information also is locked up in confidentiality agreements between the government and the company so it is difficult but we can give you rules of thumb just to sort of think that through. Certainly with the RSC there's a different structure to the PSC. It's more an annuity-based return so if you thought about Ohanet, the issue is that as price goes up your production goes down and your reserve bookings go down because you've really got a fixed rate of return against that project. And if you were thinking in the sort of mid return, mid team type returns you're thinking about the sort of right return profile for Ohanet. With the certainly with the Rod and the Trinidad PSC's you've got much better upside and down, well I mean you pick up the downside also with it, but you get much better upside with price increase. Now, it's not the same as running a return against a normal royalty regime, you know where you get a sort of a 1:1 type relationship between profit and price increase, assuming you're keeping your costs flat. With these PSC's, you know some of the higher price environments you start to see the curve of return on profits start to flatten out, and again you'll see very different PSC's around the world. For example if you were looking in Iraq the PSC's, or they're called buy-back contracts, they're very tough financially. If you go into Algeria, not quite as tough for a project like Rod. If you go to Trinidad, different structure again and a bit more upside to the company. So again they're different, they differ by project. I'd point you to the 20F too. We do actually disclose information about these PSC's and the tax regimes within the 20F. As far as sort of thinking about risk around PSC's going forward, there's no doubt that through the Middle East, northern Africa, the west coast of Africa, you know most countries that we go to these days, this is what we're going to be faced with.

You know in Indonesia, areas of Malaysia most of these countries are now dealing in PSC environments, so for the oil and gas industry, probably if you went back 30 years you would have looked at 10% of production under PSC environments. Today that percentage would be substantially higher than that and going forwards you're going to see you know the continual increase of it. So really when you think about risk, it's really about if you're going into a country where you've got a discovered resource there is no technical risk, and really what you're taking is you know production and construction risk, then you know you've got a different profile and those countries can drive fairly difficult or fairly restrictive financial-type environments. We've spent a lot of time looking at this. I mean we've spent a lot of time evaluating the different regions, evaluating the different financial profiles that come out of these PSC's, and clearly if we think the risk reward relationship doesn't work, well then the project doesn't fly internally. So you know, we do spend a lot of time thinking about that. I don't know if that gets to all your questions but you know you've probably have broached a topic that could spend three hours sort of getting into it actually. So as I said I'm happy to talk with you about it later about how you might look.

Question:
Looking through your peer bench marking work and obviously your finding costs and finding and development costs you're now sort of over the three year period towards the drop end and drifting into the next quartile where you don't want to be. Could you talk a little bit firstly, is there a scope for you to reign that back in or is it because it's going into Gulf of Mexico you're going to find deeper, it's going to, you're going to end up drifting further that way? And then just taking it a little bit further, you talked about Mad Dog, Atlantis and I think you sort of went through it quickly and costs are up to capital costs. Can you, do you have any final numbers on Mad Dog? And then Atlantis – costs are up, some of it I think you said were extra development work but also extra costs as well. I mean we're still probably what, a couple of years away from Atlantis completion? I mean how much more pressure could there be? I mean I'm assuming steel prices are up, labour's tight. I mean if I look out over the next few years, you've given us capital guidance but I mean is there a flex in these capital budgets or can I see a lot more pressure coming to bear?

Philip Aiken:
Let me at that one and then I'll put the first question to Steve. Look - on Atlantis, BP with ourselves carried out a major review of the capital. The situation now is that the engineering's virtually complete. Fifty per cent of the money's been spent. All the core contracts have been let. There were a number of areas where there were big uncertainties when the project was sanctioned, and they have now been, those contracts have now been put into place. We agreed another $120 million, $121 million to be exact, our share. That includes contingency for the areas where we haven't got firm prices.

I have a pretty good feeling about the long-term capital being under control. As I've said, when the Atlantis project was sanctioned they didn't have firm contracts for the sub-sea pipelines. The hole now is basically complete. You know, something would have to go pretty wrong now for it to be an issue, because the commitments are made to the major items going forwards,so I think I can give you confidence on that. When it comes to finding costs? Steve?

Steve Bell:
Yeah okay - re's a wide range that I could begin to cut on this but I'll just try and answer it briefly. First of all across the industry, finding cost pressures are up. The cost in the service sector for all sorts of services, one only needs to look at - say the drilling costs - drilling rigs are moving up. So across the industry finding costs are beginning to move up. And finding costs alone by itself is, is when taken out of context without looking at net back and the value on the barrels and the relative profit on each of those barrels, can be a bit of a misleading issue. In Australia we're finding in the North West Shelf we've been finding about 50¢ a barrel right now. Gulf of Mexico is higher than that but in the Gulf of Mexico we have very high value, very high volume, and so we're very much willing to deal with that little bit higher of a finding cost to be able to get those long-term legacy assets. My sense, and this is just my sense, I've got no real hard data behind it, but my sense is that in this environment we're actually going to watch that first quartile band for finding costs expand and my sense is that it is probably going to expand farther than our own finding costs metric. We may actually find when it's done that we actually get clawed in towards, closer

towards that first quartile. That's just a sense I have. We feel we have a pretty good clear view of it for the next number of years, but I do believe that the industry is really starting to expand out in that component.

Question:
Just want to get some sort of an explanation or some clarification of the possible impact of the Longford dispute between you and ExxonMobil. Does this have any impact a) in the long-term relationship between you and Esso over Bass Strait; and b) does it have an impact on PNL for the near future?

Philip Aiken:
As you are aware, we have taken legal action against Esso Australia about the Longford incident. It is restricted to the Longford incident. We remain 50:50 joint venture partners in Bass Strait. We own 50% of Bass Strait.

We will continue to have a longer term relationship with Esso both in Bass Strait and elsewhere. Therefore you know we see it very much as an isolated event and we'd hope that it won't affect our longer term relationship here or elsewhere in the world.

Question:
Just in terms of the operatorship question again and going back to Bass Strait. My understanding is probably three or four years ago you may have had opportunity to take over operatorship as that contract came up, possibly?

Philip Aiken:
No, no, never. No, I think there's never been any discussion about us taking over operatorship of Bass Strait to my knowledge. It might have been a long time ago but not in the last few years, no.

Queston:
Does that ever come up for review in terms of a contract with …?

Philip Aiken:
No, you know Bass Strait dates back to the '60s. It's a very old agreement. The operator is Esso Australia, it's not an issue.

Question:
Put your energy hat on and you brought it up anyway, and talked about the growing demand for energy. What about that one you don't have in your portfolio, uranium, do you have any thoughts on the uranium market?

Philip Aiken:
I was wondering when this one would come. As you know we were heavily involved in the World Energy Congress here recently, and there's no doubt to me that in the world, nuclear power is going to play a role in the future. It plays a big role now. I mean and as a company that is in oil and gas and coal, uranium is something that obviously will always interest us. But BHP Billiton is the world's largest diversified resources company and there are a lot of resources we're not in, and we look at all the resources we're not in from time to time.

Our comment is that at looking at any resource we're not in, have we got the skills to manage it? Can we be competitive? What's the future supply demand dynamic? Does it meet our HSEC practices? As you know we take our HSEC practices very seriously. And therefore uranium is a product that we will keep an eye on, but we have no immediate plans to be in the uranium business.

Okay, well if there are no further questions I'd like to thank you all for joining us today. I hope you found the briefing interesting and we look forward to seeing you again. Thank you.

Questions and Answers – London

Question
Just wondering if you can talk a little bit more about the production increases out of Atlantis and Mad Dog in terms of capacity? I think Mad Dog's gone from 80 up to 100. And Atlantis 150 to 200. What's the key drivers behind that? And also the ability to bring forward any tie-ins into those facilities?

And just secondly, just in terms of exploration, a couple of years back you were looking at Iran and also West Africa. Have those regions now fallen off the radar in terms of future exploration?

Philip Aiken
Let me take the first question. I'll take half of the second question because Steve, the U.S. citizen, can't comment about Iran, but he can talk about West Africa.

First thing when it comes to Atlantis and Mad Dog. Firstly on Mad Dog. Mad Dog originally was an 80,000 barrels a day facility and it really became obvious during the construction that it was easy to ramp it up to 100,000 barrels. Also -- I think that also shows some fairly positive attitudes towards the results we have had from the drilling program. So really Mad Dog, to some degree, was a natural de-bottlenecking, which took place as the project was brought forward.

Atlantis is slightly different. When we actually sanctioned Atlantis, we hadn't drilled any wells on the north side of the structure. They had only drilled on the crest -- on the southern side. And when we sanctioned the project, we drilled the well on the north side and we found very promising results. And therefore we believe now that there will probably be upside on the reserves on Atlantis.

The other issue with Atlantis also is because of this promise on the north side, we can bring it up to peak, and actually keep that peak production for longer. So the conscious decision was made to add another train, another processing train, and go to 200,000 barrels a day. So they were both really about promising results with the drilling programs. The first one was more of a natural creep, where the second one was actually a target going forward.

Referring to exploration. Just a comment about Iran. Iran is an area we have looked at for a long time. As you know, we actually were involved in a project there as a technical advisor on Foroozan. Basically, we didn't go ahead with that project because we didn't really believe that the development process was one that really met our requirements. The operator there is a company called Petro Iran. And they were looking at what was a much smaller project than what we were looking at, at the time. So we really withdrew from that project, because the project didn't meet our criteria of a project going forward.

We never really talked about exploration in Iran. Iran is really about buy-back contracts where the exploration risk is quite low. And it really wasn't about exploration, it's really about business development. As I said before, we will continue to look in North Africa and the Middle East, and I wouldn't rule out that part of the world. But at the moment, our priorities are probably more towards where we have these core businesses.

West Africa Steve? You can comment on that.

Steve Bell
Just a few comments. In the past -- over the past decade we've actually been quite heavily involved in West Africa. We were in Angola until only a few years ago with two blocks, and we were in Gabon with two blocks as well. We drilled, I believe, two wells in each country. And we just didn't choose the right basins. There was a large land grab, if you recall, in the past decade, and the basins that we were in, we just had dry holes out of our discoveries -- out of our explorations.

So we withdrew from West Africa. We were not able to build additional high quality land, so we withdrew from the classic Angola, Gabon area. We have looked elsewhere up along the coast, we have looked from basically Morocco, straight down south into South Africa. Not really finding much that we really wanted to put in our crosshairs at this point.

That said though, we do have large land position off South Africa, on the Atlantic coast and options on land around there. As we mentioned, we will be drilling a well in offshore South Africa, most likely in the coming year. So we have not completely withdrawn from the coast, we're just on the southern margin. Okay?

Philip Aiken
Thanks Steve. Second question?

Question
Three key numbers I'd just like to focus on. Firstly, expected production going forward. You had a number last year of 180 million boes in five year's time. I know at the time you were a little uncomfortable with that. You thought it might be stretched. Did I detect that there was 170 in there today?

The F&D costs, you were at 525 last year, you're now at 843. That's a fairly substantial step up, even accounting for the fact, or even more so when you're accounting for the fact, that it's a rolling number.

And capital intensity, you were a couple of years ago, you had about $20 of capital per boe produced back in 2000. You're now at 33, and on our numbers it's going to go up even higher than that when you get the Gulf of Mexico coming in.

The questions are: if you want to replace the 180 million barrels of oil at those sorts of finding costs, you're committing to about $1.5 billion per annum to find and develop. And on our numbers, that's about 40% of cash flow back at $30 a barrel. Are you comfortable with that level of commitment? How does it fare compared to industry? The finding cost of 525 going up – last year you mentioned 650 was about industry average. I think you mentioned here that the whole industry is going up. How do you compare?

And also the final one is -- when you're on the $33 a barrel, the asset turn looks very attractive at today's price, but you're going to slip below some of the mineral businesses if you go back to a relatively more acceptable oil price. So it's just comments about those numbers. Are you comfortable where it all fits?

Philip Aiken
Let me try and cover them. Greg's probably still with us but I might try and cover them from here and if I miss anything I will ask Greg Robinson to make a comment.

Firstly on production. About four years ago - not last year, about four years ago, we showed 180 million barrels five years out. At the time we said it was not a forecast, it was a trend. And we were looking actually at what might happen five years out. Since that time, projects like Iran haven't happened. And I think it's really in the last year or so we have said that the year after Atlantis comes into production, we will be operating at a rate of about 170 million barrels a year.

Atlantis is a huge project. As I showed on the slide before, our share of production is about 100,000 barrels a day, and you will see our production move up, and when Atlantis comes on stream, we will go to that figure round about 170.

We've always put a range, because downtime, cyclones, all sorts of issues can change production. So the 180 is really an old figure, it really goes back some years. The range is in that 170 million area in the year after Atlantis comes on stream. And that's the difference between those two, the 180 is a figure that was quoted about three or four years ago, and it was not a forecast. It was more a range of figures that could have applied. That's the answer to that question.

On the finding and development costs, there is two parts of that. There's a denominator and a numerator. It's a three-year figure, and the figure's blown out this year because we only booked 39 million of reserves last year. And that's one of the reasons it blew out.

The other reason it probably came out also was the Ohanet project, and we talked about the Ohanet project before. It's a $1 billion project, but you've got to remember that we don't get title to the gas, and therefore when we're doing our F&D cost, we are actually looking at the total cost of that project against a lot less barrels.

If you look at our deepwater projects going forward, we're still getting our metric which we've talked about in the past. As I've said before, looking at one-year figures can be a little bit misleading. And I think on F&D costs we've got the effect of the lower reserves bookings during the year and how that's affected the business overall.

On the third question about capital, I think we've said quite obviously over the last few years that BHP Billiton probably underinvested in the oil and gas business some years back, and hence we've got a really high return on capital and we've had very low capital intensity. Going forward, we have to make sure that the capital intensity is in accordance with the industry. At the moment we are towards the second tier, or second quartile. But I think as these projects come on stream over the next few years and we start booking more reserves, you will probably find our capital intensity metrics in terms of F&D costs improving.

But the fact remains that our return on capital will go down. When you say it might go as low as some of the minerals businesses, I don't think you can really count that in some degree, I really believe that the petroleum business will always be at the higher end of the return on capital. And it's just the nature of the business, it's a capital intensive business for sure. But obviously going forward our cost base will change. You will probably see our secondary taxes come down, our lifting costs go up marginally, you'll see DD&A increasing. But I think in common with the past is that overall, our margins will probably remain fairly similar where they are today, but you will see a decline in the return on capital.

Let's try to answer the questions there as they are. Going forward, it's something we look at. We are not about growth for growth's sake, we are about efficient growth and about adding value. And the questions you have raised are things that we are obviously looking at all the way through.

Greg, is there anything you would like to add from Melbourne about those?

Greg Robinson
I think, Phil, you've answered the question -- a lot of questions actually in the question that was asked. But, certainly the statistics put forward are a representation of the portfolio -- a general representation of the portfolio.

There is a difference in a lot of companies, and depending on whether you're actually developing gas or developing in the deep water. So again, it goes to the margin of the product you're actually producing. Clearly we are developing in expensive areas like the deep water, but we are producing very high margin barrels of oil in a very good tax regime in the U.S., so on a margin basis we should be able to maintain very high margins around that area.

So Phil, I think the rest of it was what I would answer.

Philip Aiken
Okay. Thanks Greg. Actually I'd forgotten you were there. Right, so question over here?

Question

Phil, you've given us a lot of good news in terms of production expansions. Can you outline on some of the more mature assets, what sort of rate of production decline we should be expecting over the next few years?

Philip Aiken
Yes, on Bass Strait I think we have said quite openly that Bass Strait black oil production is probably declining 15% per annum. In Bass Strait now a lot of it's about how much gas we sell, the gas in Bass Strait is basically wet, therefore the more gas we sell the more condensate we make.

What's happened in Bass Strait is, I think Rebecca talked about it before, [there's been] the pipeline to Sydney, which started up in 2000, the pipeline out of Tasmania has given us more gas markets, and therefore we hope, to some degree, we'll stabilise production in Bass Strait in terms of barrels of oil equivalent, we'll stabilise it to some degree. But there will be a decline in the black oil.

North West Shelf, Train 4 and hopefully Train 5 will be barrels of oil equivalent, but things like Cossack Pioneer are obviously in decline. And that's an area which will continue to see decline over the next few years, although there are some opportunities there to actually stabilize production, but that's not really significant in our total mix.

Liverpool Bay -- we're probably now seeing decline in Liverpool Bay in our oil production of about 10% per annum. Liverpool Bay remains the major source of liquids for us, and probably overall over the next three to four years you'll start to see that drop off. I'm a little bit nervous to say too much about Liverpool Bay from the point of view that we are still doing infill programs there, and we would hope to mitigate some of the decline. That's something maybe we could look at a bit more in the future. We certainly have had some success there with the infill programs and with liberating some of the rich gas fields in that area.

Laminaria, as you know, we've sold. I think that probably takes up most of the core assets.

North Sea -- David Walker's in South Africa. I might spin this one to him. I honestly don't know. David, North Sea? Is he there?

David Walker
Yes I'm here Phil, thank you.

Actually the decline rate in the North Sea on the oil side for Norsat is round about the standard 15% that you described. On the gas side though, again, it will continue fairly good gas rates for quite some time.

And you mentioned Liverpool Bay impact. Again, the Liverpool Bay gas rates will actually carry out for quite a long time to past 2010 at the current rate, because of the contract there. So hopefully it becomes more of a gas asset over the next few years. And Norsat pretty much along the same lines, it becomes more of a gas asset for us.

Philip Aiken
David, I said oil production in Liverpool Bay about 10% decline. Is that a bit low?

David Walker
It's actually a bit on the low side, it's actually probably closer to the 15 or 20%.

Philip Aiken
Alright. Okay. Next question? I think we had a question --

Question
I just wanted to go back to that question about replenishment of reserves. Because it seems to me, I think Greg mentioned $300 million per annum on exploration spend, you have production at 180 million barrels. May I turn the question around and say are you not telling us something? Watch this space was mentioned before?

Do you expect to see -- or can you answer -- do you expect to see a big lift in reserves because you're going to be converting resources across quite cheaply? And in fact, this part of the story we're missing here, in that we're going to see perhaps higher production levels going forward?

Philip Aiken
Let me try and give you a general answer then I'll ask if there's any comments from my colleagues. Our base exploration budget is about $300 million a year. Last year we spent more because we always try to make sure if we have success we can fund the appraisal programs. So the base figure's about $300 million, and that will probably increase if we have appraisal opportunities.

At the moment, if you were to do a rule of thumb, I think Steve gave a figure of, say, let's use a $2 figure. $2 at 150 million barrels, that's $300 million. In the next few years, we are going to have to lift our exploration spend. As our business grows, as we grow up to 170 million barrels, say, after Atlantis, if you are going to replace 110% of that, you are going to see our exploration budget in dollar terms grow over the next few years. The nature is, as the company grows, you're going to spend more money on exploration, but that's going to come over a period of time.

Your actual question about converting reserves -- at the moment, the Gulf of Mexico projects, what we've actually got as proven reserves is quite a low figure, it's quite a low figure overall of the figures we quote. For example, on Atlantis, we say 635 million barrels proven probable reserves -- well, 635 million. We'll probably book less than 25% of those, and really we won't convert that to reserves until we get the dynamic data and we have the ability to meet the SEC guidelines for booking reserves in deep water. So yes, you will see them, but they won't come in one big step. They will come over a period of time as we actually develop the field.

Steve, do you want to add any comments?

Steve Bell
I think you handled it quite well. I think the only final point is just in the resource to reserve conversion, one needs to recognize that we don't take a large bulk volume up front early. So -- at a sanction point, when that field comes on, we may only have booked about 25 to 30%. That's over the life, especially the early life of the field, where we begin to convert the rest of that into reserves.

So we're carrying, and it's really why we're trying to indicate, we're carrying a large volume right now of resources. We're trying to indicate how that might convert. But that will convert, as Phil said, in a somewhat lumpy way as projects come on, as the fields perform and so on. So we're pretty comfortable that we get the delivery pipeline.

It's just not hidden (ph), on a finding cost basis back to the F&D costs. Four quarters conversion in the deep water of the Gulf of Mexico is a very short and narrow window to measure projects that actually unfold over a four to six year period. And so that's the piece to look for. We feel pretty comfortable that a 3-year rolling average is the right way to look at it.

Philip Aiken
I might go to South Africa now and see if we have any questions from South Africa.

Michael Campbell
Thanks Phil. I ask do we have any questions here from South Africa? It doesn't look like it. We do.

Question
I understand that Libya is opening up somewhat next year in terms of some of the opportunities there. Can you just discuss how well connected BHP Billiton is politically to benefit from any expansion opportunities in Libya? And what are the chances of BHP Billiton becoming a significant player in that market?

Philip Aiken
Well, a very quick question about the political situation -- political connections. Libya is opening up and is very competitive, there's lots of companies looking at Libya. We believe, both with our Australian and U.K. connections that we have political connections and also encouragement to look at Libya.

Really that's not the main issue. The main issue for us is can we get good exploration blocks, can we get good value and can we make money for our shareholders. And I might ask Steve to comment briefly on what he thinks of the Libyan bid rounds and what we're looking at in Libya.

Steve Bell
Yes, as you mentioned, EPSA 4 is coming up in the early part of the new year. We are poised to bid and we've got partners set up to do so.

From our standpoint, we're quite keen about the emergence of Libya now back into the western oil world. And we do plan to bid on those blocks. And beyond the contacts, as you imply, everything we're reading into the commentaries is very much a very open process around which only a few bidding parameters are going to be quite clear about who wins and who loses. So we think the winners in Libya will be those that have good data and can bid aggressively. And that's what we're positioning ourselves to be able to do.

Philip Aiken

Michael, any more questions?

Michael Campbell
No more questions from us. Back to London. Thank you.

Philip Aiken
Well we'll just see if there's any questions on the phone.

Operator
There are no questions at this time sir.

Philip Aiken
Okay. We'll come back to London. There were a few people here.

Question
Just a couple of questions on the gas side. First in terms of Train 5 North West Shelf. What percentage of your capacity do you intend to have underwritten ahead of an approval on that?

And in terms of Scarborough, just quite a good set there. I know that Gorgon, the Gorgon field is inside it in terms of the location to the coast there. Where would you see Scarborough being developed relative to Gorgon in terms of timeframe? And I guess with Exxon there as partner, are you happy then with them with 50%, given they're operator in your own backyard?

Philip Aiken
I might take the first question and I'll give the second question to Rebecca.

On Train 5, it really is a difficult question to answer because there are six partners and they've all got to be happy, and as you know, in the North West Shelf, this is a unanimous decision. From our point of view, we would want enough volume to at least know we have returned the cost of capital. And we would want that committed going forward. That was basically how we committed into Train 4 and I think that was pretty well publicly said.

LNG's going through an interesting phase, as Rebecca said, at the moment. And if I'd been talking about Train 5 three years ago, I would have been very positive it was going to happen next week. Last year I would have been pretty negative about it happening. But I think at the moment, with the contracts in Japan secured through until 2009, the new contracts coming on, the short-term contract in Korea and now recontracting in Japan and the Korean contracts, I think there's a very robust number of opportunities for Train 5 to happen. But a rule of thumb for me would be looking at least having enough volume to get the cost of capital.

Rebecca?

Rebecca McDonald
You mentioned about Gorgon, and you mentioned that it was inside and, I assume by that you meant it's physically closer to the [indiscernible]. Gorgon is physically a bit closer, however, gas from Gorgon is very high in CO^2 in particular, and so they're

talking about handling the gases on Barrow Island. You might have noticed Barrow Island there.

I'm not going to comment on somebody else's project in any great detail. There are issues around Barrow Island from an environmental standpoint, because that's where the CO^2 would be removed. And so therefore there are probably some obstacles associated with that gas that did not exist for Scarborough, fortunately for us.

And again, while Asia is a market for us, so is the west coast of the Americas, so we've really given ourselves, I think, some options around that. From my perspective, Scarborough gas could very easily get to the market before another LNG project in Western Australia.

Philip Aiken
Okay. Any more questions?

Question
I was wondering if you could just make a few comments about thermal coal prices, the kind of increase you might see for next year for annual contract prices. And briefly the --

Philip Aiken
I'd rather not. This is a petroleum briefing today. And really I think commenting on thermal coal prices here today is not part of the agenda today.

Questioner
Okay. I thought I'd ask anyway.

Philip Aiken
Any more questions?

Question
I think Rebecca mentioned a few numbers on Starlifter, I think 30 million cubic feet a day and production potentially starting up as early as the second quarter, which would imply presumably sanctioning in the very near term. Can you maybe give a bit more flavor, first of all on Starlifter itself and then on other shallow water deep gas potential prospects that you may have in the Gulf?

Philip Aiken
I'll make a quick comment and then maybe Steve and Rebecca can comment. Starlifter, very simply – it's close to infrastructure, a couple of well completions tied back into existing infrastructure, not a big project, not a lot of capital. If everything goes right it could be on stream in the first -- second quarter of next year. But it's not a major project. It's quite small, couple of wells and tied back to existing infrastructure. It's relatively small but it's very high margin, would be the comment I'd make on it.

When it comes to the deep shelf, Steve? Rebecca?

Steve Bell

We've got a number of prospects that look somewhat similar to Starlifter and we have built a fairly significant land position. In fact, we're the largest stake bridgeholder on the shelf for deep gas. And we will be drilling. As I mentioned, we've got one well drilling there right now with Joseph, and we'll be drilling a few more in the coming years.

But Starlifter itself, as Phil said, it's a fairly straightforward, easy tie back, 10 million net gas, and 10 million cubic feet per day net gas. And it's a pretty standard, straightforward piece of business in this part of the world.

Philip Aiken
I think the point here is that obviously in the Gulf of Mexico, our major priority is about Mad Dog, Atlantis, Shenzi etc. If we get an opportunity like a Starlifter, we will also be looking at other nearfield opportunities around Typhoon, for example we were very successful with Boris. We have had a disappointment with another one we drilled there just over a year ago - Tiger, which didn't turn out. But there are other nearfield opportunities. And these are not big projects that you are going to hear a lot about. They're just normal projects we do and the normal way we do out business.

And these are the opportunities, these are usually high margin, they are projects where you're looking at existing infrastructure, whether it's platform or pipelines. And we just continue to look at those opportunities as they come along.

Now there was another question. Maybe one? No? No more questions. Just before we finish, are there any more questions in South Africa? Doesn't look like it. Anybody left in South Africa?

Michael Campbell
One further question in Johannesburg

Question
I think somebody mentioned a structural shift in energy pricing. Have you changed you long-term oil price assumption to your number crunching?

Philip Aiken
No. As you know, we don't actually say what our long-term oil prices are. But I think we've often commented, we look at a long-term trend price. But when we do our projects going forward, I often make this comment, whatever oil price we put in the project, we know it will be wrong. And therefore we don't justify projects on one oil price.

When we do a project, we look at a low price, we look at a mid price, we look at a high price. We do deterministic calculations, probabilistic calculations, and really we look at a whole range of prices overall. So having one price really is not applicable for us.

The other comment I'd make is we're always looking at what happens on the low side because we have as a Group, overall, low cost, first tier assets and we'd continue to have that sort of attitude going forward, which would mean that all our projects would be very robust, even at low oil prices going forward.

Michael Campbell
No more from Jo'burg. Thanks.

Philip Aiken
Thanks Michael.

Well, unless there are any further questions here, which I can't see, I would just like to conclude by thanking everybody for joining us today.

I would like to thank those here in London, also in Johannesburg, and those who've been on the phone. I would like to thank my colleagues, Greg Robinson in Australia, David Walker in South Africa, and Steve Bell and Rebecca McDonald here in London. So thank you for joining us and we hope you found today interesting. Thank you.