# BP Presentation to the Financial Community

John Browne, Group Chief Executive

Good afternoon.

We are delighted that we are meeting with you face to face and as ever, there is much of interest to discuss. The format of the day is, however, pretty conventional:

Firstly, Byron will take us through the 4Q and full year results which were disclosed earlier today.

Then, we would like to talk about our strategy and our view of the external environment.

The leadership team will then speak on the sub-strategies and operations of each of the businesses. Specifically, Tony Hayward and Andy Inglis will discuss E&P, Vivienne Cox will cover Gas and John Manzoni, Refining and Marketing.

The purpose of these presentations is to demonstrate to you that we have the assets, markets and capabilities to deliver our strategy.

I'll then pull it all together in terms of progress to date and guidance for the forthcoming year and beyond, especially as it relates to our ability to continue to generate free cash and distribute it to shareholders.

I know many of you listened to the technology webcast hosted by Iain Conn in December so we won't repeat that, but we'll be happy to take questions on it when we come to the third part of the event – when the entire team will be ready to answer your questions.

So first to the results. In 2005:

- we delivered a record level of underlying net income of $21.1bn, up 32% vs. 2004 on a per share basis;
- we delivered a record level of free cash flow of $25bn;
- we strengthened our balance sheet by reducing the gearing level to below 17%;
- we completed the sale of Innovene, yielding cash proceeds of $8.3bn;
- we replaced 100% of our production with new proved reserves and had another strong year of exploration success. This is the thirteenth year in a row when we have replaced 100% or more of our production;
- we started up seven new upstream projects – Rhum, Clair, Kizomba B, Central Azeri, West Azeri, Mad Dog and Atlantic LNG Train 4;
- we launched the BP Alternative Energy business;
- we distributed about $19bn of cash to shareholders;
- and finally, we announced a dividend to be paid this quarter of 9.375 cents per share, an increase by 10% year on year.

This is the first year in which we are presenting our results under IFRS. As expected, this method of accounting creates significant volatility in profit measures, although of course not in cash flow. This volatility results from the requirement to mark to market embedded and financial derivatives and the effective inability to account for economically matched transactions as hedges, this last effect resulting in asymmetric treatment of different parts of the same economic event.

Some would argue that IFRS neither produces a record of the accountability of management nor a measure of the changes in the economic value of assets and liabilities. I would agree with them. What IFRS actually does is to make our results more difficult to understand. I hope that Byron in his review of '05 will be able to help you better understand the underlying performance of the Group.

But this issue should not distract us from either the true quality of these results or the strength of the outlook for the company.

2005 was a very good year not just because of the year's performance, but also because we were able to confirm the foundation for even better years to come.

Our reserve replacement is the product of the strategy we put in place more than a decade and a half ago. The resources we now have provide the base from which we expect to grow production by 4% per year through to 2010 and strongly thereafter.

We expect to maintain a steady and disciplined pattern of investment and protect the efficiency of that investment by controlling cost increases below the level of inflation.

We continue to high-grade the portfolio and we expect divestments to be at an ongoing rate of around $3bn a year.

And as a result of all that, we expect to continue to distribute substantial amounts of cash to shareholders through buybacks and dividends. If the average oil price is the same as it has been over the last three years – that is with Brent at around $41/bbl – the planned distributions over the next three years should total around $50bn.

At current prices – that is with Brent at $60/bbl – the distributions would be around $65bn.

So a good year, but not the end of the story. As I may have said before – the best is yet to come.

Now let me hand over to Byron who will take you through the details of 2005.

**Byron Grote, Chief Financial Officer**

Good afternoon. As John indicated, I'll focus on our fourth quarter and full year results. This will set the stage for my colleagues to elaborate on our longer term strategy and operating plans.

Looking first at market conditions, prices and margins in both the fourth quarter and full year were up significantly compared with 2004. Oil prices and refining margins peaked in 3Q, while gas prices grew strongly in 4Q.

Our average oil realisation approached $54 per barrel in the fourth quarter, and exceeded $50 per barrel for the year. This reflects tight global production capacity, as well as the hurricane-related interruptions during the second half.

Our average gas realisation increased to over $6 per thousand cubic feet in the fourth quarter, as prices in all markets rose substantially.

Our 4Q refining indicator margin remained high by historic standards, although it was lower than the record level reached in the third quarter.

Overall marketing margins in 4Q recovered from low 3Q levels, partially offsetting the decline in refining margins.

Turning to the financials, our fourth quarter result was adversely impacted by a number of factors related to International Financial Reporting Standards, as John mentioned. We have treated some of these as Non-Operating Items in line with earlier quarters, but have retained others within the normal operating results of the segments.

Accounting under IFRS has made our reported earnings more volatile, as we saw in 4Q. It is not possible to accurately estimate all the impacts in advance of the quarter close. Although they are unlikely to be material in the context of the Group over the year, they can dramatically affect the results of an individual segment in a given quarter. I want to stress that they represent asymmetric accounting treatment of the two sides of risk management positions for which there is no economic exposure, and that they would be expected to net out over time. I will come back to this point again when I discuss the impacted segments.

Now moving to the slide, our fourth quarter replacement cost profit of $4.4 billion was 26% higher than in the fourth quarter of 2004. On a per-share basis, the increase was 31%. This reflects the benefit of share buybacks over the past year.

Our profit including inventory gains and losses was $3.7 billion, up 22% in absolute terms or 28% per share.

These figures include non-operating items, which I will describe in a moment. Excluding these, our underlying replacement cost profit was $5 billion, up 5% in absolute terms, or 9% per share, compared with 4Q'04.

Operating cash flow in the fourth quarter declined compared with a year ago to $4.2 billion. The year on year difference mainly reflects seasonal inventory builds at prices that were significantly higher than in 2004, as well as tax phasing impacts.

The 9.375 cent per share dividend announced today, which will be paid in March, is up 5% on the prior quarter and 10% higher than a year ago. The Sterling dividend is up 17% year-on-year, reflecting the strengthening of the dollar.

Our full-year results at the bottom of the slide are records for the company. These include: replacement cost profit of $19 billion, up 25%; profit including inventory gains and losses of $22 billion, up 31%; and operating cash flow of $27 billion, up 14%.

Our fourth quarter earnings included a post-tax charge of over $550 million for non-operating items. The pre-tax charge was $1.2 billon. The main element was a $1.4 billion net IFRS mark-to-market charge on embedded derivatives. This was mainly related to long-term UK gas agreements, where the contractual pricing terms did not keep pace with the increase in the gas forward price.

This chart shows the main elements driving the 25% improvement in our full-year replacement cost profit, from $15.4 billion in 2004 to 2005's record $19.3 billion.

Charges for non-operating items were around $700 million greater in 2005.

Higher oil and gas prices added around $7 billion year-on-year.

Acquisition and divestment activity was neutral overall. The 4Q gain on disposals in TNK-BP offset the impact of prior sales of non-strategic assets.

Higher depreciation, depletion and amortisation charges impacted our result by around $100 million year-on-year.

Operating incidents at our Texas City refinery and extreme weather events impacted our results by around $3 billion pre-tax, or $2 billion post-tax as shown here, compared with 2004. This includes foregone production at prevailing prices and margins, as well as directly related response and repair costs. It does not include the charge taken in the second quarter for Texas City third party liability claims, or Gulf of Mexico Shelf impairment charges related to hurricane damage, which we reported as non-operating items.

We also took incremental charges in our Refining and Marketing segment, concentrated in the fourth quarter, for planned restructuring actions intended to improve our efficiency and competitive position.

Other factors netted out. Underlying operating improvements and strong supply optimisation performance during the year offset the impact of cost pressures and a higher tax rate, both resulting from the strong price and margin environment.

I'll now summarise the 4Q results for each segment, starting with Exploration and Production.

As shown in the chart, our E&P result increased 38%, to a record $6.6 billion, driven by higher oil and gas realisations. The increase excluding non-operating items, primarily an $800 million charge related to embedded derivatives, was 52%.

Our fourth quarter results also included around $130 million of repair costs related to storm damage in the Gulf of Mexico and Thunder Horse, on top of the $100 million reported in 3Q.

TNK-BP contributed over $700 million to our 4Q result, 73% more than a year earlier. This reflects higher prices and higher volumes. Our 4Q result also included the $300 million adverse impact of the lagged calculation of reference prices for export duties as Urals prices peaked in 3Q and then declined. This was largely offset by a $270 million gain on disposals. All of these figures are post-tax, consistent with IFRS reporting for equity accounted entities such as TNK-BP. We also received dividends of more than $500 million from TNK-BP in 4Q, which brought the full year dividends to nearly $2 billion.

Although our full-year production growth was constrained by the impact of extreme weather events, we achieved total production of over 4 million barrels per day. This reflects higher production in our New Profit Centres and TNK-BP.

On a UK reporting basis, this is the 13th consecutive year that we have replaced 100% or more of our production. This chart summarises our total reserves replacement for subsidiaries and our proportionate share of equity accounted entities in past two years under both UK and US reporting bases. The results shown include reserves added, through discoveries, extensions, revisions and improved recovery, excluding A&D activity.

Based on the UK's Statement of Recommended Practice, or SORP, our total combined reserves replacement was 100% in 2005. This is based on our long-term planning price assumption. The 2005 result reflects a change in this assumption from $20 to $25 per barrel. Absent the change, we estimate our 2005 UK SORP reserves replacement would have been similar to 2004, which was 110%.

US reporting practices require the use of year-end prices to calculate reserves, so the result is influenced by the impact of price changes on our share of volumes held under production sharing contracts. On this basis, our reserves replacement was 95% in 2005.

Turning to Refining & Marketing, we reported a pre-tax loss of $160 million for the fourth quarter of 2005, compared with a $1.3 billion profit a year earlier. Refining and marketing margins strengthened between these periods, but this was more than offset by three major items that impacted our fourth quarter result.

Firstly, our Texas City refinery was shut down in the third quarter as Hurricane Rita approached, and is yet to restart as we complete its refurbishment. The absence of this refinery, along with storm related impacts in other businesses, reduced our fourth quarter result by $1 billion. This includes profits foregone in the prevailing margin environment as well as direct response and repair costs.

Secondly, we recognised restructuring charges of nearly $500 million in the fourth quarter, primarily related to planned actions to improve our operating efficiency in Europe.

Thirdly, our 4Q results include around $500 million of adverse impacts, largely related to asymmetric accounting treatment of portions of our normal operational activities under IFRS fair-value accounting.

Much of the volatility we saw in our 4Q result was driven by the forward trajectory of market prices at year-end, combined with the fact that we entered the quarter with very low levels of refined product inventory following the hurricanes, and exited the year with relatively high levels as we built stocks in line with normal seasonal patterns.

Our 4Q result in Gas, Power and Renewables was around $100 million. This includes more than $300 million of charges for non-operating items, mainly related to IFRS accounting for embedded derivatives. Excluding these non-operating items, the result was around $400 million, around the same level as in 4Q’04.

This reflects lower gas trading and marketing margins relative to the very strong contribution in 4Q'04.

The IFRS accounting effects, which reduced the R&M result as I just described, by contrast increased our GP&R result by nearly $300 million in the fourth quarter.

In other Businesses and Corporate, or OB&C, we reported a charge of around $400 million. This was $150 million greater than last year. Excluding non-operating items, the year-on-year difference was $100 million.

Fourth quarter results in the past two years reflect phasing of costs for corporate activities over the course of the year. This phasing impact was slightly greater in 2005 than in 2004.

Following the announced agreement to sell Innovene, we now report our Olefins and Derivatives results in two places.

Innovene, which we have now sold, is reported as a discontinued operation. We completed the sale of Innovene to INEOS on 16th December, realising cash proceeds of $8.3 billion in 4Q.

Operations that were not sold as part of Innovene, mainly our joint ventures in China and Malaysia, are reported in Other Businesses and Corporate for 2005. For 2006 reporting, we intend to report these operations as part of our Refining and Marketing segment. We will restate historical results accordingly, and provide further information in this regard prior to issuing our first quarter results.

I'd like to close my discussion of Segment results with updated guidance on various Group Items for 2006.

Following transfer of the retained Olefins and Derivatives businesses, we expect this year's result for Other Businesses and Corporate to be within the previously indicated range – a net charge of $900 million, plus or minus $200 million. This does not include the impact of our annual review of environmental and other provisions, which occurs in the third quarter, and which resulted in charges averaging around $450 million in the past two years.

We use primarily floating rate debt to finance the group, so our finance interest will continue to vary in proportion with our debt level and prevailing interest rates. We expect our other financing costs to improve from a net charge of around $100 million in 2005 to a net credit of around $100 million in 2006. This is largely due to growth in our in pension assets during 2005.

Excluding these financing impacts, we expect both our charges and cash funding levels for pension and benefit plans in 2006 to be comparable to those in 2005.

Turning now to income tax, our actual tax rate depends on prices and margins during the year. This guidance is based on the assumption of similar market conditions as in 2005.

Holding market conditions constant, we would expect to report an effective tax rate on earnings of about 39% in 2006, compared with a reported rate of 32% in 2005. There are two main factors driving this increase. First, the 2005 rate included a one-time net benefit of around 3 points from provision releases. Secondly, the announced tax increases for the UK North Sea are expected to increase our underlying effective tax rate by around 2 points, and to also require a one-time deferred tax adjustment resulting in a further 2 point increase in our reported rate for 2006. Beyond 2006, the new underlying rate of about 37% would apply, other factors being equal.

The UK tax changes also increase our marginal tax rate to around 42%, compared with the 40% rate I previously indicated.

The cash tax rate in 2005 was 31%. Tax payments tend to lag earnings, so some of the taxes on last year's record results will be paid in 2006. The UK tax changes and prevailing prices and margins will also impact the cash tax rate. Putting all this together, and assuming similar market conditions as in 2005, we expect the cash tax rate to peak at around 40% in 2006 and then fall back toward 35% in subsequent years.

Just as changes in our portfolio and the level of prices impact our tax rate, they will also impact the rules of thumb some of you use to model our results. These are shown here. As in the past, they should be considered simply as broad directional indicators, which are more useful on an annual basis than for quarter-on-quarter comparisons, and for price moves within a much narrower range than we have seen in the past few years.

Returning to overall Group results, and turning from earnings to cash, this slide compares our sources and uses of cash for 2004 and 2005.

Cash inflows in 2005 approached $38 billion. Operating cash flow increased to $27 billion, and disposals added more than $11 billion.

Uses of cash remained consistent with our strategic intent. Organic capital expenditures were around the same level as in 2004 and distribution of cash back to shareholders increased by 40%.

Our net debt ratio ended the year at 17%. The reduction in 4Q reflects the stronger cash flows, both from underlying operations and the sale of Innovene, net of normal year-end working capital and tax phasing outflows, most of which will reverse this quarter.

We continue to believe that a 20-30% gearing range provides an efficient capital structure and the appropriate level of financial flexibility. Our aim is to return gearing to the lower half of the band.

During 2005 we returned around $19 billion to investors via a 26% increase in our per-share dividend and a higher level of share buybacks. Share buybacks totalled $11.6 billion for the year, reducing shares in issue by 4%, and we accelerated the pace of buybacks during the second half.

We remain committed to distributing 100% of all excess free cash flow to investors, other factors being appropriate. Since the start of the year, $1 billion of shares have been purchased under our closed period buyback programme. With our year-end gearing and strong cash generation, we are well positioned for further substantial share buybacks during 2006.

That concludes my presentation of the results. Now back to John.

## Section 2 – Strategy and Prices

**John Browne**

Thank you, Byron.

As Byron said, the results we delivered in 2005 were magnified into a record by the strong external environment. But these results could not have been delivered without the position established in the past era of low oil prices, the subsequent level of investments and ongoing performance improvements. These have allowed us to capture the margins available.

In '05, the world economy grew around 3%, somewhat slower than in '04. This supported oil demand growth of over 1% despite the strength in oil prices. For '06 we expect economic and oil demand growth to be relatively similar – the US economy continues to expand and there is robust growth in the emerging economies.

In '05, the year-on-year growth in non-OPEC volumes was lower than average. But this reflects the substantial impact of the Gulf of Mexico storms. Overall, we think there was a relatively modest growth of around 0.5 million b/d, with new production mainly from Angola, Brazil, China and Russia, offset by declines in the North Sea and onshore North America.

And with the modest capacity additions that were made in OPEC, global production was running close to capacity, as in '04.

This resulted in very strong prices – the Brent oil price averaged over $54/bbl, up 42% from the '04 level.

The global market worked and supplies were forthcoming. Fundamentals have already eased as the production lost from the hurricanes – which peaked at 1.5 million b/d – has now largely come back on stream and new production is starting up inside and outside of OPEC. But world demand growth remains robust, and OPEC spare capacity is likely only to rebuild towards its 3 million b/d historic average level over the next few years. OPEC's market share is expected to remain largely intact as will its ability to deliver its price objectives. The vulnerability to a significant supply disruption is also expected to remain high.

This backdrop is why we believe there is good medium term support for prices to average above the $40/bbl level, as we indicated a year ago. This, of course, presumes no sustained major downturn in demand which could result from a deep and long global slowdown.

Over the longer term, the range of possible price outcomes is much wider. Quite how, and indeed when, the transition takes place between the 'medium term' and the 'long term' is, in my view, incapable of prediction.

Higher oil prices lead to conservation and substitution and also tend to alter the mix of energy sources used in the world. There is likely to be increased supply of conventional crude oil and non conventional liquids – some biologically derived, and some from conversion of other hydrocarbons, as well as from bitumen. Concerns about security of supply could promote the development of localised energy sources and concerns about climate change could promote low carbon energy sources. Both require technology advances but over time, these responses could lead to a reduction in expected oil demand and prices well below $40/bbl. BP has a strategy that is designed to be robust to a very broad range of outcomes, and this is why we test our projects down to $25/bbl.

At the same time, there are potential drivers that work to sustain high prices. These include stronger growth in demand, particularly in emerging economies, slower than expected advances in the development of alternative energy sources and the risk of non-OPEC growth falling below present expectations.

Turning now to gas prices.

Gas markets have been particularly strong, building on the trend seen over the last few years. Prices reached record highs during '05 in the two largest liberalised markets of the US and the UK. The annual average gas price in the US increased by 52%. This is because prices are set by competition at the margin with oil. But the price was also bolstered by the severe hurricane related disruption to domestic supply – about 17% of US domestic gas production was lost at the peak.

Since 2000, US gas consumption has continued to fall by about 1% per year on average. And despite the additions of new import capacity, the US market is likely to remain supply-constrained for several years, given the continuing decline in domestic production, as well as the current limited availability of international LNG supplies. US gas prices are likely to remain strong for the medium term, frequently well above fuel oil parity levels in the spot market.

The UK became a net importer of gas for the first time in '04. There is significant new import infrastructure planned over the next few years. The Isle of Grain LNG terminal is scheduled to be joined, in a few years time, by two more terminals in Milford Haven, and two new pipelines providing access to offshore supplies. These are expected to change pricing. UK spot prices should become more closely linked to the largely oil price driven European and Henry Hub influenced Atlantic LNG gas markets.

Whilst underlying gas demand should be strong in both the US and Europe, driven largely by power generation requirements, the impact of high gas prices on future demand growth is a key uncertainty. So while gas prices may be at or above distillate parity during cold snaps this winter, further out we should expect them to move within the fuel oil to distillate range.

Next, a word on global refining margins. BP's Global Indicator Refining Margin averaged about $8.60/bbl in '05, up by 36% from '04. Over the past two years, the surge in global demand for oil products has reduced the level of spare refining capacity which had existed for so long.

Hurricanes Katrina and Rita had a major impact in the second half of the year, playing as they did into an already tight market. Refining margins peaked at nearly $30/bbl in this period and yet by December were back to $5/bbl as markets rebalanced, supported by the IEA led release of strategic stocks.

In addition, the marginal crude oil barrel became increasingly heavy and sour. This has resulted in a widening differential between light, sweet and heavy, sour crude oil streams. Complex upgrading refineries, such as ours in the US and Germany, are well positioned to take advantage of these differentials. More stringent product specifications have put additional demands on refining hardware and infrastructure, effectively reducing supply capacity.

Looking out across the next few years the environment continues to look robust, particularly for upgraded refineries. Demand growth is likely to be greater than capacity additions.

This is why for the next few years we expect global indicator margins to remain above $5/bbl.

Further out there are more uncertainties. Confirmed and unconfirmed refinery projects would increase refining capacity by nearly double market growth by '08. Many of these projects will not come to fruition, but clearly some will, especially in light of strong margins. This means that we should continue to expect cycles in margins. A long term successful strategy relies on having quality assets in the right locations.

In the end, the environment cannot be forecast with precision. We believe that clear strategies, implemented with strategic discipline and operational responsiveness are the key to competitive performance and are factors within our control. So I'd now like to turn to our business segments and their operational implementation.

## Section 3 – Implementation

We will start with E&P where our strategy is unchanged and it is to grow production with steadily improving returns by:

- focusing on finding the largest fields, concentrating our involvement in a limited number of the world's most prolific hydrocarbon basins;
- building leadership positions in these areas; and
- managing the decline of existing producing assets and divesting assets when they can no longer compete in our portfolio.

We carry forward significant momentum, including the planned start-up of more than 20 new projects over the next three years, underpinning our production growth of over 4% at an oil price of $40/bbl through 2010.

Over the next few years, this new production is expected to result in overall higher unit cash margins.

We have a large and high quality set of opportunities. We have 18 billion boe of proved reserves and some 41 billion boe of additional resources. We expect to move around 11 billion boe of these resources into reserves by 2010. On the top of that, based on our proven exploration track record, we should add over time a further 10 billion boe of resources from our existing exploration portfolio. Successful access to new positions would allow us to continue to build further on this position. It is the quality and the magnitude of this resource position that underpins our expectation of continued strong production growth beyond 2010. Put another way, we don't need to acquire anything to continue our strong growth.

The success of our Russian investment is reflected in its production growing faster than that of competitors, reserve replacement well ahead of production, and very attractive dividend flows. We expect this to continue.

We expect to continue a disciplined approach to capital expenditure of around $11bn in '06 and maintain an intense focus on cost control. We expect to maintain the strength of the overall portfolio, sustained by the nature of the additions and an ongoing programme of "tail" divestment.

Now I'll hand you over to Tony and Andy.

**Tony Hayward, Chief Executive, Exploration and Production**

Thanks John – good afternoon ladies and gentlemen. Andy and I are going to do a double act on E&P today – I'll start with a brief review of the E&P strategy and progress with our exploration programme; Andy will review progress on the major projects, the development of our new profit centres, and how things are progressing in our existing profit centres. I'll then pick up with Russia and how the segment overall is shaping up through to 2010 and conclude with a view of how our resource position is developing for the longer term.

Let me begin with strategy, which as John has already stated has remained unchanged since 1989. The consistent application of these fundamentals has guided everything we have done despite the oil price ranging between $10 and $65 per barrel over that time period.

We focus on a limited number of the world's most prolific hydrocarbon basins – where the opportunities can be material to BP.

Our focus is on finding the largest fields – because big fields matter for two reasons.

One, the larger the field being developed the greater the number of barrels over which to spread a fixed cost base thereby lowering the unit costs.

Two, big fields attract continuing investment to increase the recovery factor. In fact, in the history of the industry no field greater than 1 billion barrels has ever been abandoned.

We have been a first mover in many of the most promising new areas of opportunity – from the deep waters of the Gulf of Mexico and Angola, enabled by new technology, to Azerbaijan and Russia enabled by political change – and have been successful in creating the number one or two position in each of these areas.

We manage the decline of our existing producing assets, and exit when the opportunities for future investment are no longer competitive within our portfolio.

Throughout we exercise rigorous quality through choice, not choosing to drill every exploration prospect; not choosing to develop every discovery; and not choosing to invest into every mature asset. Over the last 3 years, we have divested an average of $2.5 billion per annum. We expect to be able to divest around $2 billion per annum going forward.

All of this is designed to build production with steadily improving returns.

Our strategy begins with a focussed exploration programme.

As this external analysis by Wood MacKenzie demonstrates, we have been the industry leading explorer over the last decade – finding more oil and gas at lower cost and creating more value than any of our principal competitors.

This success has created enormous value which allows us to high grade our investment opportunities, supporting both higher returns in the projects we choose to develop, and a higher level of disposal proceeds for those that do not meet our investment criteria.

Over the last decade we have on average discovered in excess of 1 billion barrels of oil equivalent a year at an average finding cost of less than $2 per barrel.

In 2005 we continued our strong track record despite delays to the programme because of the storms in the Gulf of Mexico. We made a total of 12 discoveries from a focussed exploration programme of 19 wells. Major successes included: a number of new discoveries in the deepwater Gulf of Mexico; a group of new discoveries in the South East of block 31 in Angola, where we now have 9 discoveries from 11 wells; and a second important discovery in Sakhalin, which is beginning to emerge as a potential new profit centre for BP.

Our core exploration programme is now focussed around:

First - the deepwater Gulf of Mexico where we continue to see significant potential within our existing portfolio;

Second - Angola, where over the next few years our focus will shift from the eastern area of block 31 to the western sub salt area;

Third - Trinidad, where we will begin this year to test deeper plays, in a prolific gas province;

Fourth - the deepwater of the Nile delta, where our Raven discovery at the Miocene level in 2004 opened up a new play system. On the basis of the prospect inventory we hold today, we expect the Nile delta in Egypt to emerge as an important new profit centre for BP in the early part of the next decade;

Fifth - Algeria, where we were successful in accessing three very large tracts of exploration acreage in a licence round last year, two of which are adjacent to our In Amenas project area;

And finally - Sakhalin, which as I've already mentioned, whilst it's still early in the exploration of the province, we see significant future potential.

In 2006 we expect to increase investment in core exploration to around $700 million from around $500 million in 2005; this is a reflection of the depth of our opportunity set. In total on a risked basis, we have an exploration prospect inventory of more than 10 billion barrels oil equivalent.

Let me now turn to reserve replacement and finding & development costs.

As Byron has already highlighted, on a UK reporting basis, this is the 13th consecutive year that we have replaced 100% or more of our production. Our reserve replacement ratio for subsidiaries and associates, using our long term planning assumption of $25 per barrel, was more than 100%; at $20 per barrel it would have been around 110%. Over the last five years we have replaced 134% of our reserves. On an SEC basis using year end 2005 prices reserves replacement in 2005 was 95%.

Turning to finding and development costs.

Industry finding and development costs have risen significantly over the last few years, driven by a rise in capital expenditure as new provinces such as Azerbaijan, Angola, Kazakhstan and Deepwater Gulf of Mexico have been opened up, and by sector-specific cost escalation which I'll discuss later.

BP's 5 year rolling average finding & development cost at the end of 2005 for subsidiaries and associates was around $5.10 per barrel of oil equivalent – a very competitive performance versus the industry. Let me now pass to Andy.

**Andy Inglis, Deputy Chief Executive, Exploration and Production**

Thanks Tony, and good afternoon. I'd like to start with an update on the progress of our major projects.

As this chart shows, over the last 3 years we have brought on stream 20 major projects, which have together developed 2 billion barrels of reserves and which we expect to add 500 thousand barrels a day of production in 2006. With the exceptions of Thunder Horse and BTC, all have essentially started up on schedule.

Specifically in 2005;

In the Gulf of Mexico we started up Mad Dog and completed 3 out of 5 pipelines of the Mardi Gras transportation system.

In Azerbaijan, Central Azeri came on stream in February, and West Azeri started up as the year closed, some 4 months ahead of schedule. We inaugurated the BTC pipeline in May; oil is now in Turkey; and we expect to have the first crude at Ceyhan in the second quarter of 2006.

In Angola, Kizomba B started up in July, some 4 months ahead of schedule.

In the North Sea we started up Clair and Rhum. And in Trinidad, we commenced liquefaction in LNG Train 4 during December and lifted the first cargo in early January, with ramp-up following Cannonball start-up this quarter.

Over the next three years, we expect to start up a further 24 major projects which are planned to develop around 3.7 billion barrels and add 850 thousand barrels a day to production in 2009.  As you can see, the majority of these are already in development.

In 2006 in the Gulf of Mexico, we are planning to start up the Thunder Horse project in the second half of the year followed by Atlantis around the end of the year.  We will also start up: Shah Deniz in Azerbaijan; the Temsah re-development project in Egypt; In Amenas, which is our second gas project in Algeria; and Dalia, the second hub in Block 17, in Angola.

Looking to 2009, and beyond, we already have a deep slate of major projects under appraisal.  The level of technical challenge in these projects is increasing as we head into deeper water and operate in harsher environments.

Our response to this has been the development and application of leading technology and project management skills. As a result:

- we are supporting the right level of targeted technology spend and focussing that spend on areas of technical leadership, including advanced geophysical imaging, reservoir access and reservoir management.  We discussed these in detail in our recent technology webcast; and

- we are investing in project management capability through our Projects Academy - an innovative partnership with MIT, now in its third year of operation.

Higher prices have increased the challenge of getting sufficient high-quality inputs to develop our business. The most important input is people, both within BP and within the contractors who provide us with many critical services. Our ability to mitigate these risks is based on:

- first: focusing on material projects, so that scarce resources are not diverted to lower value activity; combined with

- appropriate pacing of projects to manage demand; and

- application of supply chain management skills.

With the strength of these projects, the New Profit Centres are expected to grow strongly through the remainder of this decade and bring increasing volumes of higher margin barrels into the overall segment mix.

This should have a material impact on the segment's overall cash generating capacity over the next few years as many of the new projects have higher margin barrels than those of the segment as a whole.

Let me give you a few examples at $40/bbl.

In the Gulf of Mexico, our new projects are characterised by low lifting and transportation costs and, as a result, EBITDA margins are expected to be around $30 per barrel. Over the next two years, we expect to add over 200 thousand barrels a day to our Gulf of Mexico production.

Azerbaijan and Angola show similar characteristics, where over the next 3 years we expect to add 200 thousand barrels a day, and 140 thousand barrels a day of new production respectively.

Now let me turn to our existing profit centres which, to remind you, are Alaska, the North Sea, North America Gas, Latin America, the Middle East and Egypt.

In 2005, year on year decline was higher than we had forecast mainly due to the impact of abnormal events: Hurricanes in the Gulf of Mexico, storms West of Shetland, equipment failures, and the largest turnaround season for several years in the North Sea.

Despite these events, underlying operating efficiency has remained stable in all of our existing profit centres, with the exception of the North Sea, where we are taking actions to address the operational issues that arose. The 2005 reported production number was also impacted by higher prices.

Looking forward we have not changed our view on the decline rate in our existing profit centres, which we expect to be around 3%. Some areas, like the North Sea, will decline more quickly, while others, like Egypt and Latin America, are expected to grow over the period. Our projection of production in 2006 from our existing profit centres is essentially unchanged, relative to July of last year.

This view is underpinned by 4 things:

First, the scale and quality of the underlying resource base – over 23 billion barrels of oil equivalent of proved and non-proved resource in the existing profit centres – and the technology levers we have to unlock this prize. More on this later from Tony.

Second, best practice in reservoir management. The large developed reservoirs in the North Sea, Alaska and North America Gas continue to perform in line with expectations.

Third, operating efficiency, which as I said, remains broadly stable or improving.

And, finally, new project start-ups. In 2005 we started-up Clair, Rhum and Farragon in the North Sea and we announced the expansion of our Wamsutter gas field in Wyoming.

Tony, back to you.

**Tony Hayward**

Thanks Andy – let me pick up the story with a brief update on TNK-BP.

TNK-BP continues to perform very well. Organic liquids production growth remains strong and ahead of our Russian competitors. Liquids production in 2005 averaged 1.82 million barrels of oil per day, up just under 10% over 2004. Total production including gas exceeded 2 million boed for the first time in the third quarter of 2005. Since BP's involvement in 2003, the total production growth, including Slavneft has averaged 12.5% annually compared with our projection at the time of about 6%. Going forward we expect total TNK-BP production growth to moderate to between 2% and 3% over the period 2005 to 2010 as optimisation opportunities decline and we invest to make the transition from brown-field-led growth to new green field projects.

The longer term potential continues to be demonstrated by the reserve replacement and the success in our exploration programme focussed in the Uvat area of west Siberia. Over the last two years the organic reserve replacement ratio, on a UK SORP basis for BP's share of TNK-BP reserves, has exceeded 100%.

TNK-BP continues to be self funding. Capital expenditure grew from around $1 billion in 2003 to $1.3 billion in 2004 to $1.8 billion in 2005. This year TNK-BP intends to invest around $2.5 billion. Upstream investments are expected to include further extension drilling in the Ust Vakh area of the Samotlor field and in the Kammenoye field, as well as the greenfield Demiansky project in the Uvat area. Going forward over the medium term, we expect capital investment to be between $2.5 and $3.0 billion per year.

In the downstream, 2005 saw further substantial performance improvements in netbacks via channel optimisation, increased refining throughputs and the start-up of the Vacuum Gasoil unit at the Ryazan refinery.

We now feel we have a thorough understanding of the asset base and have begun the process of portfolio high grading. At the end of last year the first step in this process was completed with the disposal of non core producing assets in the

Saratov region along with the Orsk refinery. We anticipate further disposals in the course of this year.

TNK-BP's internal capability continues to grow. The programme of investment into HSE and integrity management is delivering improved safety and integrity performance. Control and management information systems continue to improve. TNK-BP is investing into new technology, including new and upgraded drilling rigs and in the training and development of staff.

In December the first phase of the corporate restructuring project was completed. This project, one of the most complex to date in Russia, provides minority shareholders the opportunity to share on an equitable basis in the profits of TNK-BP.

Dividend payout from TNK-BP continued to strengthen in 2005; total dividends received by BP including those related to the sale of non core assets amounted to around $2 billion.

Let me now discuss the overall level of investment in the E&P Segment. This chart shows our level of capital investment over the last 3 years and a forward projection through 2008.

2005 capital investment was $10.1 billion. As we discussed in the middle of last year we have seen large increases in prices for our mix of goods and services. For example, we have seen the cost of equipment rise significantly – with rates for some of the more sophisticated drilling rigs rising three-fold in two years to over $400,000 per day.

For Exploration & Production overall we have seen price increases of 9% in 2004 and a further 12% in 2005, a trend we expect to continue into 2006. In 2005 we were able to offset 4% of the increase through demand management, technology and supply chain management. The overall impact on our 2005 capital spend level was about $800 million.

We expect 2006 capital expenditure to be around $11 billion. The exact level will depend on the dollar exchange rate, and our continuing ability to offset around 3-4% of the sector specific cost escalation.

Also shown on this chart is BP's share of TNK-BP's and Pan American Energy's capital investments. Neither is reported as consolidated BP capital, but both are clearly important components of our overall economic investment. Of course, both Pan American Energy and TNK-BP are able to fund their investments from their own cash flow. On this basis, total E&P investment in 2005 was $11.4 billion.

For the medium term, a level of $11 to $11.5 billion excluding associates is a reasonable expectation. In the face of tightness in the service sector, with the challenges of cost pressure and service quality, we are determined to continue to take a disciplined approach to our capital investment programme. This is about focus; exercising rigorous quality through choice, progressing only the most material opportunities, and ensuring we do not pursue options where there is not the capability to execute efficiently. We will continue to test each major investment opportunity at $25 per barrel to ensure that it provides appropriate returns in lower price environments.

Let me now turn to costs.

Portfolio is the biggest driver of costs. As we have consistently emphasised, our objectives are to invest in large fields where the economies of scale result in low unit costs, and to actively manage our portfolio as fields mature. Over the last three years, we have divested more than 240 thousand barrels of oil equivalent a day of production with average lifting costs of around $5 per barrel. By contrast, over the next three years, as Andy has highlighted, we plan to bring onto production 24 new projects with an anticipated plateau production rate of around 850 thousand barrels of oil equivalent a day and lifting costs of around $2 barrel.

Like others in our industry, we are seeing the effects of the current high oil price environment impact the costs of people, supplies and services. From 2004 to 2005 we believe we experienced annual cost escalation of 7% of which we were able to mitigate around 1.5% through technology, demand and supply chain management. We expect that we will see continued sector specific cost escalation of at least this level over the medium term.

A focus on supply chain management is a key element of our programme to mitigate market cost escalation. Let me give you some examples:

In 2006, the market rate for offshore rigs is expected to rise on average by around 50%; because nearly half of our fleet is on long term contracts, we expect to mitigate this rise to an average of around 30%.

Similarly, we have secured 70% of our US onshore rigs on long-term contracts with a limited number of suppliers.

Across the business, we are generating significant savings by aggregating demand and making longer term commitments to suppliers.

In the face of rising costs our approach is to continue to focus our activity set on the most material opportunities and exercise rigorous discipline in the choices we make.

The desire for a greater share of the higher rent available in this environment is not only restricted to suppliers of goods and services. Governments have already moved to raise taxes. The UK is a prime example, but over the last 18 months, tax take has also increased in Russia, Trinidad, Venezuela, Argentina and Alaska.

Most of our future production growth is in areas in which production sharing agreements are in place. These have mechanisms that automatically adjust the level of Government take to energy price – for example, this applies to our operations in Angola and Azerbaijan.

This chart shows our projection of production through the end of the decade based on $40 per barrel, assuming our 1st January 2006 portfolio.

Cumulative production growth 2005 to 2010 is projected to be around 4% compound annual growth rate at $40 per barrel - consistent with our prior guidance of around 5% compound annual growth rate at $20 per barrel.

Relative to our last projection in July of last year, the shape of the profile has been impacted by four things;

- Firstly, the hurricanes in deepwater Gulf of Mexico, and the follow on impacts of the Thunder Horse incident have shifted the major ramp up of production growth in the deepwater Gulf of Mexico from 2006 to 2007;

- Secondly, moving the oil price from $20 per barrel to $40 per barrel – impacts 2006 by around 20 thousand barrels of oil equivalent a day and 2010 by around 250 thousand barrels of oil equivalent a day;

- Thirdly, divestments of around 45 thousand barrels of oil equivalent a day – around 25 in Trinidad and around 20 in Russia. We would expect this level of portfolio high grading to continue over the medium term; and

- Fourthly, as I said earlier, an updated view of TNK-BP's anticipated production growth rate of 2-3% over the next five years.

In 2006 we expect production for the Segment to be between 4.1 and 4.2 million barrels oil equivalent a day at $40 per barrel.

Let me now turn to the long-term sustainability of our resource business.

This is the most important chart I will show you today - it explains why we have such great confidence about the longer term. So I'll take a few minutes to explain it to you

In 2001 our resource base on the bottom left of the chart was 41 billion barrels of oil equivalent, a resource-to-production ratio of 33. At year end 2005, our resource base on the bottom right has grown to 59 billion barrels of oil equivalent, a resource-to-production ratio of 40 - an increase of 18 billion barrels of oil equivalent, or 44% over 5 years.

The chart describes the movements in our resource base over the five year period. Over that time we produced 6.7 billion barrels of oil equivalent and moved 9.1 billion barrels of oil equivalent into proved reserves primarily driven by the sanction of major projects.

We added around 8.0 billion barrels of oil equivalent through our exploration programme and 7.8 billion barrels of oil equivalent through appraisal and reservoir evaluation activity, a direct consequence of a focussed technology programme designed to unlock our resource base.

Finally our active portfolio management resulted in a net purchase of 0.8 billion barrels of oil equivalent of proved reserves and 8 billion barrels of oil equivalent of non proved resources.

So to summarise, over the last 5 years, excluding acquisitions, we have added 15.8 billion barrels of oil equivalent to our non-proved resource base and 9.1 billion barrels of oil equivalent to proved reserves - a track record we believe is unequalled in the industry. That is why we are so confident about the longer-term.

This chart shows how we expect to progress our resource base into reserves and production going forward.

Today's proved reserves which are either on production or under development amount to 18 billion barrels of oil equivalent of which 43% is gas.

Between now and the end of 2010 we expect to move into development a further 11 billion barrels of oil equivalent of reserves.

Beyond this we estimate that we have around 30 billion barrels of oil equivalent of additional resources. Around two thirds of this can be developed with existing technology; the remainder will require new technology development. As we highlighted in our technology presentation at the end of last year, we are working on a focussed set of recovery technologies that have the potential to unlock many of these resources; these include viscous oil in Alaska, tight gas in North America and low salinity water-flooding which is being piloted in Alaska and has widespread applicability across much of our portfolio.

To these estimates should be added a further contribution from our continued track record of exploration success, as I mentioned earlier on a risked basis we estimate more than 10 billion barrels of oil equivalent will be added from our existing exploration portfolio.

It is the scale and quality of our resource base, a consequence of the very strong incumbent positions that we hold in many of the worlds' great hydrocarbon provinces, coupled with our focussed investment in capability building and technology – that means we expect to continue our track record of strong production growth beyond 2010.

Let me now summarize the E&P segment.

We continued to build on our exploration track record with 13 years of reserve replacement of 100% or more.

Cumulative production growth from 2005 to 2010 is expected to be around 4% - underpinned by

- One, a broad slate of major projects which remain on track,
- Two, detailed plans to hold decline in our existing profit centres to 3% and
- Three, continued strong operating performance from TNK-BP.

We have a strong and growing resource base, in our major incumbent positions.

And finally, in the face of a challenging environment for the sector, we will continue to take a disciplined and focussed approach to investment, ensuring rigorous quality through choice, progressing only the most material opportunities and ensuring we do not pursue options where there is not the ability to execute efficiently.

Ladies and gentlemen thank you very much. Let me now hand back to John.

**John Browne**

Thanks, Tony & Andy.

Turning now to Gas.

BP is currently the second largest gas producer amongst the International Oil Companies.

Our business has a strong and growing marketing presence in North America, the world's largest gas market, whilst building a base in the markets of the future, particularly in Asia.

We operate a fully integrated business from the upstream resources to the customer, capturing value along the entire gas chain and reflecting the upstream value in the E&P segment.

We have ownership or access to the key infrastructure that allows us to sell our equity gas into high value markets and generate margins from the provision of a broad set of gas related services to customers.

And finally, LNG is rapidly growing in significance in our portfolio, an area in which we are the second largest IOC player.

Vivienne.

**Vivienne Cox, Chief Executive Gas, Power and Renewables**

Today I want to talk to you first about our gas business and then briefly mention Alternative Energy which we launched late last year.

So let's start by talking about gas.

Gas is growing its share and now it is almost a quarter of the world's energy markets. But it is also important because it provides a bridge to a lower carbon future.

We are already one of the world's largest non state gas companies, and this part of the business is a material, and highly profitable part of the Group. We operate our gas business as an integrated portfolio, from upstream production, through midstream assets to the markets, and we have great opportunities all along the value chain. Our strategy is to build on the growth we have achieved in the last 5 years by continuing to increase gas production, growing our midstream LNG and gas pipeline business whilst at the same time growing our downstream marketing presence. We aim to maximise the value of our equity production, as well as capturing additional value from the transportation and marketing of 3rd party gas.

Turning first to the Upstream part of our gas business.

Today we are the second largest gas producer amongst the International Oil Companies, with daily output of 8.4 billion cubic feet in 2005: that's bigger than the national output of either Norway or Algeria. And we are the largest supplier of gas to North America. The gas comes from our domestic US production, from Canada and as LNG from Trinidad and Tobago.

Our Upstream gas production is projected to grow by an average of 4% per annum through to 2010. That would give us over 10 billion cubic feet per day as a resource base for our midstream and downstream activities, providing a really firm foundation for our future growth.

Gas now represents 36% of our hydrocarbon production and 43% of our proved hydrocarbon reserves. Today's production is backed by 46 trillion cubic feet of proved gas reserves, the 2nd largest reserves position amongst the non state producers. This gives us a reserves-to-production ratio of almost 15 years. But we also have very significant non-proved resources, and over time these will be pulled through into proved reserves to underpin our future production growth.

I'll move now to our midstream activities. Here we have transformed our portfolio over the past five years. We have invested all through the chain in LNG – liquefaction plants, ships and re-gasification facilities. We have also invested in regional pipeline gas. For example, we have recently made a long term pipeline commitment to connect BP equity production in the Rockies to premium Eastern US gas markets. We are also investing in the South Caucasus pipeline to transport our production from Shah Deniz in Azerbaijan into the domestic market as well as to Turkey and Georgia. By integrating our gas assets and our access to markets we are maximising the value of our equity production.

80% of our current gas production is domestic and regional pipeline gas – that's around 7bcf/d - and the other 20%, about 1.7 bcf/d, is monetised in the form of LNG.

LNG's share of our overall gas production has doubled since 2001 and is projected to grow further to 30% of our gas production by 2010. If we look at equity gas into plant, we are currently the second largest non-state company in LNG, and we expect to retain that position through to the end of the decade as we continue to grow.

For the future, we are constructing the Tangguh project in Indonesia, which is expected to start production in late 2008. This is planned to provide gas to customers in North Asia, and - for the first time – LNG exports from Asia to the West Coast of North America. We are also a partner in the construction of the fifth LNG train at Australia's North West Shelf project. This is expected to start operating in 2008, and the gas is planned to go to North Asia. These projects provide a strong foundation for our growing gas business in the Asia Pacific region. With operational control of liquefaction capacity we can build further opportunities to capture income in the midstream of the gas chain, and we have secured three LNG ships under operating leases and have a further four under construction to give us additional flexibility.

As well as the monetisation of our own equity we are steadily growing our merchant LNG business by acquiring third party LNG under short term and long term contracts.

Another key part of our midstream gas business is our access to over 1 billion cubic feet per day of LNG re-gasification capacity. About two thirds of this capacity is in the US and the UK, to provide access to premium markets for BP-branded LNG sales. Much of that gas will come from our equity in Trinidad & Tobago, where the fourth liquefaction train is up and running.

We have made other terminal investments in Bilbao in Spain and in China. The import terminal in Guangdong province, which is scheduled for start up in the middle of this year will be China's first LNG import facility. We are also seeking approval for a 1.2 billion cubic feet per day LNG terminal at Crown Landing in New Jersey.

So, we are making choices with the gas we produce, moving it either by pipeline, or as liquefied natural gas to customers in Asia, Europe and the US. We are developing new markets for our gas by developing technologies to convert gas to liquids, and we continue to monetise gas through growing our power generation business. With the power industry consuming approximately 35% of the world's gas we see this sector becoming increasingly important to BP.

Turning now to the downstream, we make most of our sales in North America, where we have established a market leading position.

Our success has been based on holding a portfolio of transport and storage assets. This allows us to optimise gas flows from supply basins, and means that we can deliver a comprehensive and flexible level of service to our customers. We have been very successful in growing our customer portfolio and see further opportunity for growth.

So, that's our integrated gas business. Now I want to remind you about BP Alternative Energy, the business was launched in November of last year.

We are moving forward with our plans, investing approximately $350m in 2006 in all four of our focus areas - gas-fired power stations, Solar, Wind and Hydrogen. We anticipate that this investment will grow to approximately $8bn over the next 10 years. In Solar, we are doubling capacity by 2007 and trebling our sales in those three years. In Wind we plan to add over 400MW of additional production, to become a top-tier wind power operator by 2015. As for hydrogen power, our plans are moving ahead for converting the Peterhead power station to hydrogen, and we are well advanced in progressing other opportunities. Producing low carbon power is only part of the story. We can use our power trading and marketing expertise to provide low carbon power to our wholesale customers.

So, we are one of the world's largest gas companies, the second largest gas producer amongst the International Oil Companies, with a strong portfolio of reserves to underpin our growth over the next few years. With our strong midstream and downstream positions we have exciting opportunities to add value throughout the entire gas chain. We are also moving forward with new opportunities in low carbon power where gas-fired power development will form an important element of this new business.

**John Browne**

Thanks Vivienne.

Now let us turn to the Refining & Marketing segment and John Manzoni.

We are refurbishing the Texas City refinery and plan to restart production 1Q onwards.

We are increasing investment in our advantaged refining base and plan to invest around $1.5bn a year over the next three years to enhance flexibility, margins and reliability. This compares to an investment rate of around half that level in the past three years.

We are securing low cost feedstocks from the supply envelopes around these refineries by having access to the right infrastructure and application of our supply and trading skills.

We are improving margins in marketing through superior focused customer offers and implementing cost efficiency programmes reducing unit cash costs by 10% by 2008.

And finally, we are continuing to apply our advantaged technology, building new acetic acid and PTA capacity in Asia and thereby aiming to maintain a global competitive position.

John

**John Manzoni, Chief Executive Refining and Marketing**

Thank you John. Good afternoon.

I want to begin by reminding you of the shape of R&M, and its core businesses, which changed somewhat during 2005 as we absorbed Aromatics & Acetyls.

This slide shows the distribution of operating capital employed. You can see that Aromatics & Acetyls now comprises 12% – around $5bn, with about a third of this being in the rapidly growing Asian markets. So Refining and Marketing now consists of around 60% manufacturing businesses, including Aromatics & Acetyls, and 40% customer-facing businesses.

Our goal is to have leadership positions in all of our businesses. We focus on the relevant performance metrics for each business separately, allowing us to be clear on the optimal investment patterns and positioning.

But we also consider the integrated nature of the businesses along the hydrocarbon value chain. Increasingly, we are leveraging the supply optimisation skills in our supply and trading organisation to derive additional value along that supply chain.

Today, I will focus on three of the businesses and talk about our future plans. I'll cover Refining, Aromatics & Acetyls, and Retail.

So to begin with Refining. Our strategy starts with having the right assets configured in the right way, located in the right places. Then, we focus on the operations of those refineries – and we also optimise the commercial outcome by having a flexible feedstock and product slate.

Fundamental to this is to have all the parts of the portfolio operating safely, and carry out a comprehensive action plan to underpin our confidence in the integrity of all of our operations.

Byron has described the impact on the segment's 4Q result of the explosion at Texas City on 23rd March last year, and the subsequent shut down brought about by

Hurricane Rita. The incident in March, and the work involved in bringing the plant back on line has been, and continues to be, a huge focus for our organisation across many dimensions.

Before we had completed the repairs from the March explosion, the refinery was shut down completely as a result of Hurricane Rita on the 21st of September. Since then – the plant has remained down. We are taking the opportunity to refurbish the refinery and bring about a substantially improved standard of operation when it returns to service. Bringing it back on line safely is our top priority – and we are being uncompromising in our standards of rigour as we prepare the plant for start up.

We have undertaken a rigorous inspection programme, to ensure that every critical piece of equipment is subject to a full engineering evaluation prior to start up. Repairs and modifications have been completed in order to minimise the risks, and improve the safety of the operations going forward.

Our supervisory and operating staff are being retrained in general operations, and in unit start up procedures prior to bringing each unit online. And we have clarified the management accountabilities and processes throughout the refinery.

We now are about ready to begin re-starting the plant. Based on our current estimates, we are anticipating it will begin operation shortly and gradually ramp to around 200 thousand barrels per day. Our current projections have the refinery running at almost 400 thousand barrels per day by around mid-year.

This rigour, of course, comes at a cost. Byron described earlier the impact on the segment's 4Q result from having Texas City down, and we estimate the impact in 1Q will be between $600 and $800m, depending upon the actual start-up date and prevailing margins.

We are ensuring that the lessons from the Texas City accident are applied much more broadly. Our capital expenditure programme includes around $500 million of incremental spend to further improve plant integrity everywhere.

As we implement the programmes which we have underway today, I am confident that all our refinery operations will be safer, better maintained and even more efficient than before.

And we have a system which we believe is well positioned for the future.

Let's start with geography. John has described our overall global outlook for refining margins, which look to be reasonably robust over the medium term. But despite this being a globally interconnected system, the dynamics of the three major regions are quite different. We continue to believe the US margin structure will remain advantaged. It will be difficult to add significant capacity in this market, so that margins will be based on import parity. More than 50% of our overall capacity is located in the US.

The chart shows two other ways in which our portfolio is advantaged.

First, we have the advantage of scale – the average capacity of our refineries is more than 200,000 barrels a day, which is significantly greater than any of our integrated competitors.

And second, we've invested into the upgrading and conversion capacity of our refineries. This slide uses the latest Oil and Gas Journal survey data for 2005, and represents conversion capacity using the Nelson Complexity Index. You can see that we have a greater complexity index than any of our peers. This should allow us to take advantage of the changing crude slate going forwards, which is likely to include increased volumes of extra heavy sour grades.

So we have complex refineries benefiting from the advantage of scale, located in the geographies likely to deliver the highest margins.

Our intention is to build on this advantage by a targeted increase in our investment programme. We can see specific opportunities both in the US and Europe for additional upgrading capacity in our existing refining base.

This slide gives a perspective of those additional opportunities in the existing base. Over the next three years, we have opportunities to almost double the investment to around $1.5bn p.a., with the incremental investment going mainly into additional upgrading capacity and integrity investments.

Over this period, upgrading investment is expected to represent approximately 40% of the total, up from around 20% in the '03-'05 period. A significant option is to upgrade our Northern tier refineries in the United States, with the potential for a substantial increase in coking capacity in these refineries. These investments will allow us to take much heavier crudes into those refineries and benefit from the wider spreads which are likely to be available. We also plan to invest in a substantial energy efficiency project at Cherry Point.

In Europe we plan to begin upgrading projects in Castellon, Nerefco and Bayernoil. In addition, we can see opportunities to the tune of about $300 million a year for very rapid payback projects.

All these investments are robust at lower margins, and we believe therefore are good for all seasons. Over the next five years while our refining crude capacity will remain largely unchanged from these investments, we plan to increase heavy / sour crude runs from 55% to around 70%. At the same time, we expect to increase our light product yield by about 3%.

Of course it's not only the location and investment patterns which determine the quality of the refining portfolio – it's also how we run them. This slide shows two indicators of how we operate our refineries. The bars represent the benefit we gain from applying our supply optimisation capabilities.

In 2005 the margin earned through commercial optimisation, based on internal estimates, was three times higher than that in 2003. We have consistently improved the commercial optimisation in our refineries since that time, both by supplying them with more economic crudes, and also by adjusting the plant to produce the most valuable product slate. The outcome in any year is partially dependent upon the volatility of crude and product markets, but subject to that volatility, we are confident we can build further on this track record.

The yellow line on the chart shows the energy intensity index, which is a measure of energy efficiency within the refineries. Since energy represents around 20% of the total running costs of our refineries – this is an important metric to manage down. Our track record is clear, and some of the investments that I have described will further reduce that index.

So to recap on Refining. Our first goal is to bring Texas City back into operation safely, and ensure that the lessons are widely and rigorously applied. Overall we have a high quality refining base located in the right places to take advantage of the market conditions which exist today, and which we believe will continue in the medium term. We have plans to increase investment to upgrade further our existing refinery portfolio and to continue to improve their operations.

I now want to describe the Aromatics & Acetyls business for you.

This is a world scale business, which makes paraxylene, PTA & acetic acid. PTA is used in plastic bottles and in polyester fibres. At every stage of this chain we have world beating technology and a leading market position.

Our strategy has two main thrusts:

- to invest to maintain our competitive position in the market place, and in particular to invest in China, where the main growth in PTA demand is taking place

- to continuously renew our technology leadership position which yields both operating cost and build cost advantages.

Over the past 5 years we have grown the production capacity by 35% – ¾ of which has been in Asia. In 2005 we commissioned new acetic acid plants in Taiwan and China, and we announced further investments in China. We expanded our paraxylene businesses in Europe and in the United States. And finally, we also sanctioned a second PTA plant at Zhuhai in China – which is designed not only to be the world's biggest single train unit at 900,000 tonnes per annum, but to employ the world's best technology, deliver the lowest build costs, and to attain the lowest operating costs. Zhuhai is planned to come on-stream in late 2007.

Our technology leadership has resulted in improving cost efficiency as you can see from this chart, and we fully expect this trend to continue as we introduce the next generation of technology into both the PX business and the PTA business.

So this is a very exciting business, one which is growing extremely fast (particularly in Asia), and in which we have, and plan to retain, a leadership position.

Let me now turn to our Retail strategy, which has three main components:

- firstly, to differentiate our offers to continue to attract more customers and grow gross margins;

- second, it is to focus our investment and capital employed into only those areas where we can be either number 1 or number 2 in the market place;

- and third, it is to control costs so we remain competitive and deliver attractive cash returns.

Looking first at the differentiated offers. This chart shows two components of differentiation in the Retail business. Our Ultimate gasoline and diesel brand continues to move from strength to strength. In 2005, we launched Ultimate in 5 new markets. The left hand chart shows the continued growth in margin, year on year, including 60% growth in 2005. The yellow line shows the share of Ultimate in our total fuels mix, in markets where it has been launched – as you can see it has doubled over the last 2 years.

Gross margin from our convenience stores also continues to improve as you can see from the right hand chart – in 2005 it was around 20% greater than in 2003. And it's not only the absolute gross margin from our sales: the yellow line shows that we are getting more efficient – sales per square metre continue to improve as we increase sales in our stores.

Last year, in our Retail business, around a half of our gross margin was generated from activities other than standard grade fuel, up from around one third two years ago.

Not shown on these charts, but across our network as we focus our footprint into fewer larger, higher quality sites – the average throughput per site has grown from 3.6 million litres per annum in 2000 to 4.1 million litres per annum in 2005.

The second element of our strategy is to focus our portfolio on those areas in which we can achieve leadership positions.

This slide shows the pattern of investments and fixed assets. We have reduced capital expenditure to around $800 million in 2005, and plan to continue at this level over the next few years, focused on upgrading the quality of our assets.

At the same time, in 2005 we started to accelerate divestments, and we plan to continue to divest at about the same level each year for the next few years, as we focus the asset base for capital and cost efficiency.

Over the course of the next 2 years, we expect our net investment into this business to be approximately zero. By the end of 2007, we plan to have reduced our company owned sites by more than a third, while retaining a number 1 or number 2 position in 85% of the markets in which we operate, and increasing the quality and efficiency of our assets.

The third dimension of our strategy is around efficiency. We have to deliver our offers to the customer more and more efficiently.

This applies across all of our marketing businesses. During the course of 2005, we have defined significant efficiency programmes across almost all of our businesses. You saw the first impact of that in the nearly $0.5bn restructuring provision in the segment's 4Q results.

These programmes are designed to address both operating and overhead costs in the delivery of our customer offers.

The first phase of these programmes should be complete by the end of 2007, and we expect them to deliver cost benefits of around half a billion dollars in 2008. This programme is targeted to deliver a 10% reduction in unit costs across our Marketing businesses.

We are currently defining the next stages, which are aimed at streamlining our transactional systems, further improving productivity and costs, as well as improving our customer service.

I have described several aspects of strategy for three of our businesses. And before concluding, I want to describe the investment patterns for the segment as a whole.

This slide shows both history and our plans for all the businesses in the segment. Disposals have averaged around $1bn p.a. for the last 3 years – and I expect them to remain broadly at this level going forward. High-grading our Retail portfolio represents a significant part of this.

Capital expenditure is expected to increase over the next few years as we increase investment into plant integrity, and implement a number of Refining upgrading projects. And we will also build new capacity in Aromatics and Acetyls. Relative to the recent past, we plan to spend a higher proportion of the total investment in the manufacturing businesses.

And so to conclude, I have talked about four things which underpin the focus of our activity, and give us confidence in growing cash flow delivery over the course of the next few years.

In Refining it is firstly to bring Texas City back into operation as a better, safer and more efficient refinery than before the accident and shutdown, and to ensure the lessons are embedded in all of our operations across the Group.

We plan to increase investment into our manufacturing assets - mainly to improve our upgrading capability in Refining, and increase Aromatics & Acetyls capacity in China.

We will implement efficiency programmes across our Marketing businesses to deliver improvements in productivity and returns.

The first phase of this is underway – and more will follow. The fourth quarter provides additional momentum to these programmes.

Finally, in Marketing, we intend to continue to improve our customer offers, to build loyalty and capture more gross margin.

Overall, the investment patterns and strategy for the segment have been set so that, at standardised conditions, our operating capital employed should remain essentially flat, gross margins should increase by virtue of our offers and our investment in the portfolio, and costs should be held broadly flat through the efficiency programmes I have described. The objective is to increase cash flow, and improve returns out to 2008.

Back to you John.

## Section 4 – Financial Framework and Outcomes

**John Browne**

Thanks John.

I now want to turn to the prospects for the Group as a whole and look at these in the context of how we've been performing competitively.

Since 2000, we have grown oil and gas production at more than double the rate of world production growth. We intend to continue growing. We are directly involved in oil fields which are expected to contribute almost half of the growth in non-OPEC production over the medium term.

BP has consistently been the fastest growing super-major with production growth averaging 4.4% p.a. against a range of 3.6% to minus 1.7% for our peers.

We replaced more of our production with reserves than any of the other super-majors. Part of this industry-leading track record was based on the performance of the successful TNK-BP transaction which more than offset our continuing disposal of mature and less efficient production.

Our growth has contributed to improving returns. As you know, we have communicated with you over the past couple of years in terms of cash based measures of returns which we think are more appropriate. However, we recognise that these measures have not been widely adopted as they do not lend themselves to competitive comparison. So let me today focus on another useful measure: return on average capital employed (ROACE).

We have been very successful in significantly improving our returns based on this measure.

You have heard me say many times that the effective measurement of ROACE, particularly on a like-for-like basis against peers in other accounting jurisdictions, is neither simple nor standardised.

That said, whether we measure underlying ROACE against reported capital employed or adjust for purchase price accounting by excluding goodwill for BP and our peers, BP has improved ROACE consistently and at a significantly faster pace than our peers since 2001.

Our underlying replacement cost ROACE excluding goodwill has improved from 13% in 2001 to 24% in 2005, a rate of improvement averaging some twice the average rate of our peers.

Whilst the environment has clearly contributed significantly, our differential improvement has been driven by underlying operational and capital efficiency improvements. We expect the underlying trend to continue as we grow production and bring more capital into service, achieve higher gross margin capture in R&M, benefit from the disposal of the Innovene business and continue to reduce costs.

We have continued to grow the absolute level of capex over the last five years so as to deliver our strategy.

We have been investing proportionally at a higher level than our peer group. From '03-'05, our reinvestment rate was 65% of operating cash flow, compared to 55%, on average, for our peer group.

As my colleagues have demonstrated, we have a deep portfolio of high quality projects available. We plan to manage the pace and timing of our investment to maintain our track record of growth, improving capital efficiency and returns while ensuring that the organisational capacity and capability of the Group are matched to our capital investment plans.

Over the period '03-'05 our total capital expenditure, organic and for acquisitions, averaged about $15bn p.a. We expect to maintain this level in '06, substituting acquisitions by organic activity. In addition, we expect our share of the capex for our associated companies to be about $2bn in '06. If you add these back to get a feel for the investments made for the Group as a whole, you will get a level of around $17bn for '06.

Beyond '06, we expect our capital expenditure to increase by about $0.5bn a year, through '08.

Over the last five years, our divestment level has averaged more than $6bn a year. Opportunities will continue to exist to high grade our portfolio and we expect disposals to contribute around $3bn a year on an ongoing basis.

The exact level of capital expenditure will of course depend on a number of things including:

- sector-specific cost escalation above the 12% p.a. we have seen so far; this could stem from very tight capacity in the supply sector;

- time critical and material one off investment opportunities which further our strategy; and

- any inorganic opportunities that may arise.

At present, we don't expect any of these things to affect our capital expenditure.

Our core objective is to grow sustainable free cash flow and to distribute it so as to grow shareholder returns.

Free cash flow in ’05 was $25bn as a result of the strong environment and proceeds from the sale of Innovene. This has been reflected in the increased level of share buybacks, while growing dividends and strengthening the balance sheet. Over the period ’03-’05, the average oil price was $41/bbl and our actual free cash flow averaged about $15bn a year.

That period was characterised by a particularly high and probably unsustainable level of divestments. In addition, oil prices rose which meant that the value of our inventories increased by more than their volume. This created a build up of working capital. The net effect of adjusting the free cash flow to a sustainable divestment level of $3bn with no acquisitions and correcting for the price effect of the working capital build would have meant that our free cash flow from ’03 to ’05 would have been around $13bn a year.

Looking forward to ‘08 it is our aim is to grow this level of sustainable free cash flow through the comprehensive set of activities which we have already described.

In order to underpin delivery, we have a five point business plan.

Firstly, we expect to grow production by about 4% a year to 2010 in a $40/bbl price environment. We have already discussed the projects, programmes and their improving margins that underpin this growth. Given the quality and magnitude of the resource base that Tony has shown you, we expect to continue our track record of strong production growth beyond 2010.

We will keep a sharp eye on cost control, aiming for cash costs growing at less than general inflation. Some cost efficiency programmes are already underway such as the one started in 4Q by R&M in Europe. These programmes are expected to reduce costs on a sustainable basis by $0.5bn in ‘08. Our overall approach is to limit the increases in cash costs from ’05 to ’08 to well below the level of general inflation of around 3% a year, excluding changes in fuel costs and exchange rate. We are planning more programmes, many to do with overhead costs.

Building on our track record, we expect to deliver further improvements in the Return on Average Capital Employed relative to our peer group.

We plan to maintain the total capital spend to around $15bn in '06 and grow it at about $0.5bn a year to '08.

And finally, we expect to continue to high grade our portfolio, and expect divestments to be at an ongoing rate of around $3bn a year, half our historic level. We don't expect these divestments to have a material impact on ongoing free cash delivery.

Let me now turn to the financial framework. As you know, it has three components:

- the dividend;
- the level of gearing; and
- the use of free cash flow.

Our dividend policy remains unchanged. It is to grow the dividend per share progressively. In pursuing this policy and in setting the levels of dividends, the Board is guided by several considerations, including:

- the prevailing circumstances of the Group;
- the future investment patterns and sustainability of the Group; and
- the trading environment.

We talked earlier about our view that oil prices might have a support level of at least $40/bbl in the medium term. However, we continue to use our planning assumption of $25/bbl as a good yardstick for testing the downside in the balance between investment and total distributions to shareholders.

Dividend per share growth depends on both the level chosen for total cash flows used to grow the dividend and the number of shares outstanding. That in turn depends on level of share buybacks, which will depend on the environment that prevails at any point in time. During the period 2000 to '05 dividends per share grew rapidly as share buybacks began to make a difference.

We have paid out a total of $29.1bn dollars of dividends over the last 5 years. During this period, the dividends per share in dollar terms have grown about 13% p.a. – about 2% ahead of the growth of total cash flows distributed as dividends. For the last twenty years, on average, our rate of growth of dividends per share has been 3-4% above the rate of inflation.

Our approach to the level of gearing is unchanged. We believe that a gearing band of 20 to 30% is the right level to maintain an efficiently leveraged balance sheet while ensuring protection against lower energy price worlds. In practice we entered '06 below this level as a result of the Innovene proceeds.

As a reminder, we have three targets. These remain unchanged.

The first is to underpin growth by a focus on performance, particularly on returns, investing at a rate appropriate for long term growth. This is covered in our five point business plan.

The second is to increase the dividend per share in light of our policy.

And the third is to return to shareholders all free cash flows in excess of investment and dividend needs, all other things being appropriate.

This chart shows the potential amounts of cash which could be distributed by way of share buybacks and dividends. These numbers are of course somewhat by and large in nature. It is much the same chart as we showed last year, now updated for '05 delivery and a wider range of oil prices and refining margins. We've compared what we distributed in '03 to '05, and other things being appropriate, what could be distributed over the '06 to '08 period.

These estimates are based, of course, on assumptions on oil prices, refining margins and so on. Under the same set of conditions as we actually experienced between '03 and '05, with the Brent price at about $41/bbl, the amount of expected future cash distribution would be around $50bn in total. At $60/bbl, we estimate this could rise to around $65bn.

Now for '06 specifically, we expect:

- production to be in the range of 4.1 to 4.2 mmboed at $40/bbl;
- capex of around $15bn; and
- divestments of around $3bn.

To summarise:

The near term operating environment for the Group looks very favourable. We have considerable momentum going forward and our strong incumbent resource and asset base underpins our distinctive growth prospects.

Our focus is on translating this strong environment and growth into cash delivery which we intend to return to shareholders. We remain focused on executing our established strategy, maintaining capital and cost discipline, strengthening operational excellence and continuing to high-grade our portfolio.

Thank you very much ladies and gentlemen and now we will be happy to answer your questions.

# Cautionary Notes:

## Forward-looking Statements

This presentation and the associated slides and discussion contain forward looking statements, particularly those regarding BP's asset portfolio and changes to it, acquisitions, capital expenditure, cash flow and cash generation, competitive position, costs and cost inflation, cost reduction plans, demand for oil and gas, divestments, dividends, finance cost and interest, free cash flow levels, future performance, gearing, growth, impact of inflation, margins, pension and benefit plan funding, prices, production capacity, production decline rates, productivity, resource additions, returns, share buybacks and other distributions to shareholders, tax rates and the effect of tax increases, and the progress and timing of projects. By their nature, forward-looking statements involve risks and uncertainties because they relate to events and depend on circumstances that will or may occur in the future. Actual results may differ from those expressed in such statements, depending on a variety of factors, including the timing of bringing new fields on stream; future levels of industry product supply; demand and pricing; operational problems; general economic conditions; political stability and economic growth in relevant areas of the world; changes in laws and governmental regulations; exchange rate fluctuations; development and use of new technology; changes in public expectations and other changes in business conditions; the actions of competitors; natural disasters and adverse weather conditions; wars and acts of terrorism or sabotage; and other factors discussed elsewhere in this presentation.

## Reconciliations to GAAP

This presentation also contains financial information which is not presented in accordance with generally accepted accounting principles (GAAP). A quantitative reconciliation of this information to the most directly comparable financial measure calculated and presented in accordance with GAAP can be found on our website at www.bp.com

## Cautionary Note to US Investors

The United States Securities and Exchange Commission permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or formation tests to be economically and legally producible under existing economic and operating conditions. We use certain terms in this presentation, such as "resources" and "reserves", that the SEC's guidelines strictly prohibit us from including in our filings with the SEC. We also include certain operating measures which are calculated using proved reserves attributed to equity accounted entities as well as consolidated entities and which exclude acquisitions and divestitures. SEC Staff guidance states that such measures should not include both proved reserve additions attributable to consolidated entities and equity accounted entities and should be based on beginning and ending proved reserve quantities as disclosed in the Form 20-F. U.S. investors are urged to consider closely the disclosures in our Form 20-F, SEC File No. 1-6262, available from us at 1 St. James's Square, London SW1Y 4PD. You can also obtain this form from the SEC by calling 1-800-SEC-0330.

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