



Cairn Energy PLC

Half Yearly Results 2016

Tuesday, 16th August 2016

Simon Thomson, Chief Executive Officer

Good morning everybody. Welcome to Cairn's Half-Yearly Results presentation. I'm Simon Thomson, Chief Executive. With me are James Smith, CFO; Richard Heaton, Exploration Director; and Paul Mayland, COO. As in the usual way, we've got a presentation to run through with you this morning, and we'd be very happy to take questions at the end. It is being webcast, so although it's quite a small room and we can all hear each other, there will be microphones to ask a question, and please do state your name before asking a question.

Cairn's strategy is to deliver value for shareholders from a balanced E&P portfolio. To do that, we seek to create significant growth opportunities within a portfolio that is both sustainable and self-funding. Within that portfolio we've got exposure to material discoveries and prospectivity principally in Africa and North West Europe, and those interests are held at appropriate equity levels for the size and scale of company that we are.

Our UK developments are progressing on track and under budget, and will deliver significant production for us from 2017 onwards. And as you will have seen from today's announcement, we have established a substantial and growing resource base. It's worth noting that our net combined 2C and 2P resources now total in excess of 0.25 billion barrels of oil equivalent.

As a company we'll continue to focus on value creation monetisation, but that's linked with a successful track record of HSSE and corporate responsibility. And that latter point is very important for us in respect of a calling card with both host governments and partners alike as we assess additional new venture opportunities to add into the portfolio. We have commitment to continued delivery of value from discovery and development, including potential further returns to shareholders, and that's in line with a consistent strategy of creating, adding and ultimately realising value for shareholders through monetisation.

So, a few words on Senegal where a safe and successful appraisal drilling campaign has confirmed the world class nature of the SNE field. Paul and Richard will come on and talk about the detail, but in summary we're delighted with what we have proven up thus far, and also with the additional potential that we see, not only in SNE but also in the surrounding acreage position.

The resource base continues to increase, and today we've announced a significant upgrade in our contingent resource estimates. The SNE 2C STOIP is in excess of 2.7 billion barrels, and that's with current gross recoverable resources now standing and revised to at the 1C level 274 million barrels, at the 2C 473, and at the 3C in excess of 900 million barrels. For the sake of comparison at the 2C, as you know the previous guidance was 385 million barrels, so a significant increase. In addition, we still see in excess of 0.5 billion barrels of risked resource upside, and right now we're working on the exploration prospectivity to finalise prospects for consideration in the next phase of drilling. Richard will talk about a couple of those exploration prospects in his section of the presentation.

As Paul will outline, development planning is underway. We believe we're well placed to benefit from cost deflation and also project optimisation, and that in turn has a very positive knock-on effect to our economics, as James will outline. The third phase of E&A drilling is scheduled to commence at the turn of the year, and again we are benefitting significantly from reduced costs both in respect of rig and also associated services.

So in summary, we see continued delivery of value from Senegal. The combination of reduced costs, increased resources, and also near-term activity that will access in our eyes significant potential upside. So there's a lot still to go in Senegal.

James.

James Smith, Chief Financial Officer

Thank you, Simon. Good morning everyone. So in the next few slides I'll go through the cash flows for the first half, the current funding position, and an update on our future capital investment plans. As you'll see, the focus remains very much on capital discipline to continue to ensure that we retain the flexibility to direct investment to the assets where they'll deliver the best returns.

For us today, that's really about two key areas. The first is completion of the Catcher and Kraken projects to deliver sustainable cash flow from next year, and those barrels are with an all-in average production cost of US\$17 a barrel at plateau. The second, which we'll spend most of our time today talking about, is further de-risking of Senegal, and that's really an asset that's delivering on our principle strategic goal as a company which is about material, low cost resource bases within large acreage positions. Beyond that, investment plans are really about earlier stage exploration activity across the rest of the portfolio, and continuing to assess the opportunities to enter into low cost new business development opportunities.

So this slide just takes you through the first half cash flows. As you can see, US\$603m was the opening cash position. Principal expenditure during the period was on the full well Senegal appraisal and exploration programme, and on the Kraken development project. During the first half, and actually as of today, we continue to be fully carried with respect of the Catcher project, so that's why there are no cash outflows there. So all of that together with relatively low activity across the rest of the portfolio, or low capital investment across the rest of the portfolio I should say, and a continuing low G&A expenditure, with debt remaining undrawn, that took us to a cash position at 30 June of US\$414m.

So taking that forward, the next slide sets out the current sources of capital available to the Group over this year and the next year on the left hand side; and on the right side the expected or committed and planned uses of that capital again over the period between now and the end of 2017, which will deliver us into free cash flow in the North Sea.

So starting on the left; US\$414m opening cash position. That, together with a Norwegian tax receivable, effectively takes us to cash resources for the Group of roughly US\$460m. In addition to that, we expect to be able to draw up to US\$260m between now and the end of next year on the reserve based lending facility that we put in place to fund the North Sea development project.

Clearly next year we'll also be moving into operating cash flow phase in the North Sea, first of all in Kraken, and towards the end of the year we expect on Catcher. There's some guidance there in the box of what we'd expect operating cash flow to be from Kraken, ramping up in the second quarter of next year towards peak. Even at US\$45 oil representing the forward curve, that would be round about US\$100m of operating cash flow next year.

So all of that together is about US\$800m or so of existing funding available to the Group between now and the end of next year. If we look at beyond that in terms of the operating cash flow, as I said oil and production costs for Catcher and Kraken of US\$17 a barrel, significant tax shelter, means that even at today's oil price in the mid-40s we'll be generating around about US\$250m of operating cash flow at plateau production, or at US\$65 in oil Brent for illustration, about US\$400m of operating cash flow.

On the right hand side you can see, starting with the committed uses of capex, and moving into what we plan further in Senegal. US\$45m of working capital, effectively activity undertaken in the first half where cash flow out has been post-30 June. US\$315m represents the total development capex for Catcher and Kraken net of the carries in favour of Cairn between now and the end of 2017, and you can see there the split between the two assets and the phasing between this year and next.

Committed as of today exploration and appraisal activity, US\$55m, which represents ongoing activity in Senegal, plus relatively low commitments across the rest of the portfolio. And in the next two blocks there represent what we see as being still under currently planning phase, but the expected minimum activity in Senegal in 2017. So that's two appraisal wells with one or both of them having a relatively full testing programme, and pre-development study work ongoing on the assets, so that totalling around about US\$80m.

As Paul and Richard will come on to say, 2017 is going to be a key year for Senegal in terms of moving it towards a development concept decision and submission of a development plan in 2018 and 2019. So clearly there is the potential for that programme in Senegal to expand well beyond those two wells that we're envisaging as being the firm programme.

Last point on funding. None of these plans includes a resolution of the ongoing dispute in India with regard to the retrospective tax application to our internal reorganisation in 2006. That was a US\$1bn asset that was taken away from us in 2014 for which we're seeking full compensation through the international arbitration process. That process is now well underway. We submitted our full statement of claim to the Arbitration Panel earlier this year, and the Arbitration Panel has asked India to respond in full before the end of this year. So on that basis we'd expect to move to hearings in the first half of 2017, and a ruling thereafter. So as I said, none of that included here, but clearly we are expecting a positive outcome on that.

Next two slides provide an update on the two UK development projects, and really it's a similar story in some ways across both of them, development drilling running ahead of schedule, subsea installation in the North Sea completed on Kraken, and expected to complete by year end on Catcher. For both of them the critical path item to getting to first oil is really around FPSO construction, and you can see here the Kraken vessel in Singapore with all of the modules now lifted on and sail away expected in Q4 of this year.

On Catcher, you will recall we guided the market that there had been a bottleneck in the hull construction in the yard in Japan. The mitigation plan which the partnership has put in place to address that has now been affected, and you can see here the complete hull/vessel joined together in Singapore awaiting the modules to be lifted on top, and that keeps us on track for expected first oil in 2017.

The story across both of those development projects, as well as across the rest of the portfolio, has been one of benefitting from the flipside of the lower oil price environment which is an improved cost and contracting environment. You can see here we've been very active in managing our capital programme and our project costs over the last 12 months. Starting on the left hand side, the first two points together, we have deferred about US\$80m of previous

exploration commitments where they didn't make sense as investments in the current oil price environment.

Where we have been exploring here in the UK and Norway, that activity has come in around US\$40m below the original budget. There isn't a block on this chart here for it, but it's also worth remembering that in the first half of this year we undertook a four well appraisal programme in Senegal for the same cost as has originally been budgeted for three wells. Then here, you can see the most significant blocks on this chart in terms of capex savings were across the two development projects. So together across Catcher and Kraken net to Cairn savings between now and the end of 2017 are about US\$160m, and we continue to work on initiatives with the operators of those projects so expect more to come. So all of that net of having taken on more equity in the Kraken project, means that we have deferred or reduced US\$226m of capex to the end of 2017 over the last 12 months.

Onto the asset where we're expecting to have the optionality to deliver the most value from the current cost environment, and that's in Senegal. This slide provides an update on the development scenario and associated costs for an SNE 2C development. It's a chart in the same format that you'll find back in our Capital Markets Day in May 2015, but with some important revisions to that. We'd previously guided for full development capex per barrel of around about US\$20 based on analogue fields and similar water depths for FPSO developments. But based on the improved contracting environment today, but also importantly our experience of drilling five wells into the reservoir so far, we're updating today that guidance with reductions of 25-30%, so we see sub-US\$15 a barrel all-in development capex for a field of the 2C size that we've guided to.

This assumes a leased FPSO development, so you can see the bulk of the capex there is really in development drilling and subsea installation. So the good thing about that is that it means that most of that capex is back ended towards first oil, which clearly enhances the economics and the financing plan for a development of that type.

Operating costs associated with that development scenario, US\$8-10 a barrel, and that includes an FPSO leased cost assumption in there. And again on timing, the guidance remains the same. So with the development recommendation in 2018 and FID in 2019, we'd expect first oil to be in the window 2021-2023.

Next slide here sets out of the economic outputs of that development scenario if you like, with NPVs per barrel at the various oil prices, and unlevered project IRRs at those same oil prices. You can see there with the dotted yellow lines, which represent the guidance we gave back in May 2015, that that results in a pretty significant upgrade both in terms of value and project returns from the previous guidance. And as you can see, pretty healthy returns even at today's oil prices and we think reaching a threshold 10% return in the low 30s Brent. Clearly these are economics for the 2C standalone development of an SNE field scenario, but as Richard will come on to talk about, the significant resource upside potential in the block, so exploration success near to that field could clearly be developed at relatively low cost as a tieback to the central development.

Finally on SNE economics, this slide here sets out the results of that development plan in the context of breakeven oil prices for other projects globally, it's taken from the Goldman Sachs study of international upstream projects which we've screened for development phase projects, and you can see SNE ranks extremely highly on that list in terms of its ability to attract industry capital. And as Paul will come on to outline in a bit more detail, whilst SNE is normally a deep water development, the operating environment, the geological characteristics and the fiscal terms altogether combine to mean that it actually ranks above many shallow water or

shallower water development projects and even some onshore ones in terms of its economic attractiveness.

So in summary, before I hand over to Richard to talk in some more detail, the focus has been very much on capital discipline to make sure that we have an investment strategy that's very, very focused on assets to deliver returns in a lower oil price environment and as a result of that we're very well positioned to deliver the business into cash flow phase next year and to support from the current balance sheet our continued investment in the Senegal asset, whilst in the background continuing to build the portfolio opportunity set in the background.

And on that note I'll hand over to Richard.

Richard Heaton, Director of Exploration

Thanks, James, and good morning everyone. First of all, just a brief reminder of Senegal. Two years ago we still hadn't made our discoveries in Senegal so we've made a tremendous amount of progress since then; six wells now drilled. And you'll see that essentially the first two wells both were discoveries, they were both the first wells ever drilled in the deep water offshore Senegal and the first two oil discoveries of any size in Senegal as well.

We've focused our attention since nearly wholly on the SNE area, it's shallower water, the reservoirs are better quality there, and that is really where the bulk of our effort has been to date. What's new today is that we're announcing an upgrade in the resources that we see in that field and also giving the detailed figures out on very large in-place oil that there is in the field. We have a very large area in the licence and I'll be talking about the exploration potential there as well.

So the next slide really talks about the results of those wells that we've now drilled. We've had a very successful and safe campaign to appraise the SNE field, we now have five penetrations across that field, roughly sort of nine kilometres in a north south line and about five kilometres from east to west, right in the central portion of the field. The field during that time, as we've proven with these wells now, has increased in size and at the very top seal the area of the field is over 350 square kilometres. We have across that area now, so far as we can see there's a very consistent 100 metre gross oil column there with a gas cap above it in the centre of the field.

We can see that everywhere we drill those five wells we have good quality reservoirs and better than perhaps one would normally predict in these age of rocks and type of rocks, but it's very consistent, and shown on here, just one of the reservoir layers in the upper levels of the reservoir. Right across the field we always find sands, we always find them of good quality, we can actually tie them very accurately on the seismic data, we have new seismic data and we process seismic data now that ties very well across the field, and we can use the amplitudes from the seismic data as shown on that little map to almost differentiate between where there's gas, where there's oil and water, and some of the internal features of the rocks there.

We've recovered a huge amount of core data, every bit of core that we try to capture we recover back to the surface, we have 600 meters of rock in the laboratories in Aberdeen and elsewhere being analysed, it allows us to really characterise the reservoirs of the field very, very accurately. Now that work takes a long time to complete, it's a huge amount of data, we integrate that with all the log data that we've got from these wells as well. It's a fabulous database to work with and we're still working through it.

What that means is we are able to confirm a great deal more certainty now about the field, we've got great information that allows us to understand how it's put together, and essentially as we said and saw in SNE-1 the reservoirs are best at the bottom and then we have lower reservoirs above that, the finer grained and slightly thinner reservoirs above that. We've got good test results out of both though, the lower reservoirs, 8,000 barrels a day out of one test and in the upper reservoirs 5,000 barrels a day. Those are great test results for anywhere, some of the better ones that you'll see along the West African margin.

In the test that flowed 5,000 barrels a day from the upper reservoirs, some slight pressure depletion which shows that the connectivity there is not quite as good as in the lower reservoirs, and that will be a feature of trying to understand that uncertainty when we come to the next phase of appraisal.

So the resource base is hugely improving as we go through, for the first time here giving the figures on where we were at March with the associated in-place oil, the STOIP, and today's estimates are independent estimates given by ERC-Equipose, demonstrating if you like the consistency between our own and an independent auditor's view.

And we've now got over 2.7 billion barrels in place at the 2C level and a recoverable resource out of that of 473. And you can see it's a wide range, these are probabilistic estimates, this is trying to take into account still the very large variation there is in the field, because we're still really at the relatively early stages, only 18 months after discovery, of trying to piece together what is now a very large field. But it's a great story, what we will be doing with the next wells is trying to understand better the connectivity and make a yet more informed decision about how best to develop the field and what sort of field development plans put in place, and Paul will go on to explain some more of that.

Not only is there obviously a good field but we went into this area because if you did find hydrocarbons there's a great upside story here, there's lots of different plays to go for, there is an exploration potential around it which we can tie back to a main project, and working that data now, integrating the new well data with the new seismic data and coming up with more detailed exploration prospectivity which we will incorporate into the next drilling plans.

Paul will give more detail on the actual drilling plans a little bit but essentially I'll just give some details on two of the prospects, one in the shelf area and one in the deeper water area now. Altogether we estimate there's probably another 500 million barrels of mean risk resource in those prospects to go, so you add that together with almost 500 million barrels in the SNE field and the block potential, still a billion barrels which is the guidance that we've continued to give.

So the Sirius Prospect we've talked about before, this is on the shelf, it's just to the north of SNE, it's at the same reservoir levels, we can separate it out at some of the upper reservoirs here within SNE, we see this as relatively low risk, it's a stacked field as we now know from SNE is the case, probably around 80 million barrels, just over 80 million barrels when you consolidate those in the prospect, but a very high chance of success based on what we see in SNE, so a 67% chance of success. This could be a very attractive tie-in prospect.

And if we go to the basin you can see the FAN well in there to the north, that FAN, a very large column of oil, over 500 metres altogether of oil soaked rock, but the reservoir quality in there, it's quite deeply buried, not so good. Further to the south, there's a prospect here that we're looking at which is much shallower, we can see the feeder sandstones coming in from the shelf, from the field, SNE field, we do hope that the reservoir quality here might be better. In just one layer in this prospect we have about 150 million barrels mean prospect resource in here with about a 15% chance of success. It is a stratigraphic prospect, stratigraphic trap, that does work at FAN, it could well work here, again it would make a very attractive tie-in.

Now all this work is still very much ongoing, integrating all the new data from SNE and the new seismic, we haven't made decisions firmly yet on which wells we'll be drilling as part of an exploration programme, that is still yet to come. And at this point I'll pass on to Paul to take us through the next stages of the operations.

Paul Mayland, Chief Operating Officer

Thanks, Richard. Good morning ladies and gentlemen. As already mentioned, we intend to move to a third phase of drilling offshore Senegal, commencing towards the end of this year, and we aim to build and indeed improve upon the good HSSE performance that we achieved during 2015 and 2016.

The proposed programme is anchored around two firm wells, plus multiple one well options and both semisubmersibles and drill ships are under evaluation for what has already proven to be a very sought after contract.

There are a number of objectives to be addressed in this programme, including testing certain reservoirs that otherwise have not yet been tested and interference testing between wells, and this was always part of the joint venture's appraisal strategy reflected by the fact that we've installed pressure monitoring gauges in two of the existing four appraisal wells. And as Richard has also alluded to, exploration opportunities are also likely to form part of the programme.

In parallel with the earlier appraisal drilling we've remained conscious of the expected journey through appraisal and development planning and the requirements ultimately for a final investment decision to deliver oil production offshore Senegal. We've completed a highly successful second phase of drilling, primarily focused on the SNE appraisal, and that as Richard has outlined has provided us with an excellent data set.

Further appraisal activity is focused on improving the definition of the project, in particular related to water flood planning of the upper reservoirs which ultimately influences the number of drill centres and their location and the number, location, offset and orientation of production and injection wells to be drilled on the field.

The concept that we've previously outlined, a floating production, storage and offloading vessel with subsea wells remains valid and the 2C resources presented today guides us now to a plateau rate of between 100,000 and 120,000 barrels of oil per day.

I think everyone is familiar from the capital markets day of last year with the timeline shown at the bottom of the page, I think that illustrates the remarkable progress the joint venture has made in only 18 months since discovery and the considerable effort that we will undertake together over the next 18 to 24 months to allow us to submit an exploitation plan in the first half of 2018.

On this slide you can see a diagram which outlines a range of offshore projects versus water depth taking us all the way out on the right hand side to the current technology limit for deep water of around 3,000 metres. SNE obviously sits very comfortably within this window and is classified as a deep water discovery being located in approximately 1,000 to 1,200 metres of water. Indeed, it is worth noting that the SNE reservoir depths are actually less than the water depth alone in other global ultra-deep water discoveries in the Gulf of Mexico and indeed, close by in Africa.

Also shown on the diagram on the left are our two non-operated UK projects, Catcher and Kraken, and these have given us excellent insight into the service contractors, their performance on the projects and their differentiating characteristics. They've also allowed us

to sharpen our views on contract strategy and models for execution particularly at this interesting time in the industry, which we will inevitably along with our other joint venture partners clearly discuss and seek to apply in Senegal.

So moving onto the next slide in terms of development conceptual engineering we've initiated pre-engineering studies with an established engineering house and we've outlined the initial preliminary reservoir and wells basis of design. We've also installed a MetOcean buoy this summer offshore Senegal to gather further data in respect of optimising facility design.

And overall we believe this project is very well placed being at the concept select stage to now benefit from project optimisation, cost deflation and further standardisation, because although there's some CO₂ in the gas stream the reservoir conditions and fluid conditions are otherwise relatively benign and this will allow us to utilise existing standard oilfield equipment, and because of the scope and phasing of the project it is expected that this will be very much on the radar of the usual service providers.

Onto the next slide in terms of conceptual development well planning. In addition to preparing for the next phase of drilling, as illustrated in the photo of our new pipe yard in Dakar, the wells team have been working together with the joint venture completing initial studies in respect of conceptual development wells.

We believe that around 15 to 20 wells will be drilled prior to first oil as part of a multi-year ongoing development drilling campaign which will comprise oil producers, water injectors and gas injectors. Approximately two thirds or so will target the upper reservoirs with the remainder targeting the lower reservoirs.

A variety of well types are being investigated but most are ultimately of a near horizontal or high angle type with lateral sections of around 1500 metres in the reservoir and may or may not include some form of intelligent completion.

On average we believe that the well costs have reduced by around 25% from our previous estimates and this has been carried forward in the economics presented by James earlier.

So in summary we're making good progress in terms of commencing another exciting phase of exploration and appraisal drilling anchored around the SNE discovery and we expect to start that campaign and operations before the end of the year.

We believe that this particular project is well-placed to benefit from further optimisation, cost deflation and standardisation, and we remain on track to submit an exploitation plan during 2018.

I will now hand back to Richard who will describe our exploration initiatives elsewhere in our portfolio and our ongoing new venture activity.

Richard Heaton

Thank you, Paul. As Simon pointed out in his introduction we have a balanced portfolio and as well as the Senegal story we have an interesting and building portfolio in the UK and Norway. Of course we've talked about the two development projects but our exploration plans in the UK tend to be centred around those fields; and if we go to Norway where we have the Skarfjell discovery in 2012, we have a focused exploration portfolio around that area too where our expertise can be honed. And we also have a building position in some of the less well

explored parts of the Norwegian Sea and Barents Sea where we share the NPD's view that with just 100 wells drilled today there's a considerable yet to find potential in that basin.

We've taken operatorship in Norway over the past year and we now have some operated licences: that gives us greater control. And we're making sure that this portfolio on its own is a balanced portfolio with a good deal of activity in the coming years.

Beyond that of course we have to continue to look at new ventures. The current market state means that it's probably a good time for an acreage reload and refresh the portfolio but we're looking for those options where we can get in at relatively low cost. We see those, there are quite a number of them at the moment, and we're very focused on making sure that we access the best of them, focusing first of all along the Atlantic margin where we do have some technical expertise and knowledge. But it's a great time to be trying to do this and we hope to bring some new news over the coming years on this.

At that point I shall pass back to Simon to summarise.

Simon Thomson

Thanks, Richard. So in summary we continue to offer significant growth opportunities within a balanced portfolio. We've got a material and growing resource base in Senegal as you've seen and we've got further near term drilling activity to access upside resource and are benefiting from a lower cost environment.

We've got balance sheet strength and we've got substantial cash flow from near term production from Kraken and Catcher in 2017. And the company continues to focus on value creation and monetisation of success as you see from a familiar diagram on the right, that continues the long-term strategy of creating, adding and ultimately realising value for shareholders.

With that I'd like to hand over for questions.

Q&A session

Question 1

I've got two questions, both on Senegal. Firstly thanks for the oil in place figure that's helpful. Is it possible to give an indication of the split of recovery factors between the lower reservoirs and the upper ones; taken in aggregate at the moment it looks like quite an undemanding 18% or so but I suspect there's quite a wide variance there?

And then, secondly, just on the timeframe you laid out for development in Senegal is that something that the government is comfortable with in terms of time to first oil? And, secondly, is there any indication on introduction to local content requirements?

Simon Thomson

Yes let me answer the second part of your question first. The government's absolutely on board with that timeframe and indeed when we submitted the appraisal plan with the joint venture last year tied to the three year extension on the licence all those timeframes were agreed with the government.

And local content I think is included in the production-sharing contract from the point of view of what we can do but I don't know if there's any further details on that.

James Smith

There are no particularly onerous provisions in the PSC as you may have seen in some other jurisdictions but clearly we already are working to include as much local content and local training as possible.

Richard Heaton

Obviously the lower reservoirs do have higher recovery factors in fact the upper reservoirs there are many layers in those. Some of those we expect to be able to water flood, others may ultimately simply be depletion production on some layers.

In fact that's obviously where the upside lies within the range of volumes that we have and that is essentially what the focus of much of the appraisal in the next phase is going to be. So for us to be able to find out answers for those is really the aim there.

So it's a little bit early to give out specifics but essentially the lower ones as you point out will have better recovery factors.

Question 2

I wonder if you could clear up a couple of things first off? So Woodside's obviously taken or looks to be completing the deal with Conoco can you clear up if there is any pre-emption and if you're interested in that? And also with the change in participant does it put more emphasis on you to operate the project when it moves into the development phase?

And then, secondly, on the drilling plan, so you've got two firm wells which sound like they're going to be appraisal wells and the pace of exploration in the wider portfolio is the Senegal government happy with that and is it more likely than not that you do two to four wells this year?

And maybe the last one if I can, just a slightly different point here, you talk about the breakeven of the project given that the oil price is US\$45 today would you FID this project at this oil price?

Simon Thomson

Yes but I'll let James come back to the detail on that. But on your Woodside question we've confirmed to Conoco that we are supportive of Woodside coming into the joint venture. From our perspective we think that they should be a value adding partner for us. If you look at their exposure to equity interest Nova Scotia, Ireland, North West Africa, there's actually quite a lot of alignment with the way that we look at the world as well. So we're very supportive of them coming in actually and we're very supportive of the original principle; they have a lot of offshore, deep water-operated experience. And therefore we see no reason why the original intention for us to provide an option for somebody to take on that operatorship at the time of development still stands. So that would still be the case as it has been with Conoco.

I think the thing I just want to clarify on the drilling, so you've got two firm wells which sounds like they're going to be appraisal wells but you're also to explore your portfolio to keep the government happy with the pace of progress so I wonder if you could be realistic about what you could drill next year?

Simon Thomson

As we say we've given guidance to the firm two and then multiple options. So I think the good thing about the changed environment from the point of view of contracting is that we can and will have a number of individual well options, a large number of individual well options. And obviously it is our intention to drill more than two wells but that is yet to be finally firmed up with the joint venture and work is ongoing right now actually, as I mentioned from the point of view of the exploration prospects and Richard has touched on a couple of them but there are others and it's a case that will continue to be work in progress.

So I think from our perspective actually having that contractual flexibility is exactly what we need. So that will probably be a rolling update from us to the market.

Question 3

Firstly, on the Conoco sale I think overall the valuation was pretty disappointing to what the market was expecting. I know you can't specifically comment obviously on Conoco but I think what was more surprising was that industry interest was low in that despite the low price there wasn't actually other players that were prepared to pay up and get into the licence, given certainly the outline of the developing economics that you suggest. So in that context could you maybe talk a bit about what Cairn plans from a farm out perspective and a monetisation perspective, clearly you've got what some 300 or so million dollars of capitalised costs in Senegal, at what point do you look to try and sell down and bring in other partners to help fund the full development?

And then just a quick follow-up on the development planning how many wells does that development plan assume, I guess trying to get an understanding of the expected recovery per well that you assume in your guidance?

Simon Thomson

Let me cover the first part of that question and maybe Paul can come on to the second part. Don't assume that there isn't a lot of industry interest in this field. There aren't very many half billion barrel fields out there at the minute in terms of new plays with more upside potential around it. And there were particular circumstances as you know in respect of Conoco effectively exiting a number of deep water positions. So arguably in the current oil price environment that doesn't give you the best environment for achieving the best price.

But I think from our perspective it doesn't diminish industry enthusiasm and I think our job, as we've said before, is to continue to ensure that we have sufficient financial flexibility and indeed as we talked about the rig contract, rig flexibility to ensure that we can continue for as long as we think's appropriate before we think it's the right time to divest equity. And certainly at the minute we're under no pressure to do that. It remains an option. As I say there is industry interest.

And of course if you're staying in an asset and if things like carries and deferred payments become involved you can quite often get to a very different structure in terms of absolute consideration. So we're comfortable with that at the minute.

Paul Mayland

I think obviously you can back out from James' number what the total development capex is and as you said a lot of it is back-ended, we'll drill quite a number of wells through production,

and you've guided between 15 and 20 on initial field start-up which you compare for example with Jubilee, Jubilee started up with about 17 wells. So, it will be a multi-year programme, and ultimately the number of wells that are drilled are ultimately going to be really what is the resource space you are exploiting. But I expect it to be done in phases in a similar way to Jubilee.

Question 4

I'd just like to check on some of the resource upgrades. It looks like at the low end at the 1C the upgrade has come from the STOIP increasing 44% to 1.8bn. At the upper end the increases come from increased recovery rather than a STOIP increase, slide 18. I was just wondering if there was a possibility or scenario in your appraisal results where you would see the 22% recovery factor moving down to be applicable to the lower end STOIP i.e. improved recovery for lower in place numbers. Is that a scenario you could see from appraisal?

Richard Heaton

We're at an early stage, which is why there is such a range. Pretty much any scenario could happen through appraisal; that's why we need to drill the wells to find out.

The biggest prize is going to be confirming really how much we can recover from the upper reservoirs, because that is the bigger part of the gross volume there. But there are still quite significant shifts that could happen in the lower reservoirs too; and that is, as Paul I think pointed out in some of the possibilities of drilling plans, that is still something that we have to consider as well. So, both are possible.

If I may have one follow up. There's a very large gas resource that hasn't really been talked about; how much of the development scenario you show here takes that into account?

Richard Heaton

Essentially we'll be reinjecting the gas to help with the recoveries in the early part of the field life. But clearly ultimately we will have to look at the gas resource, but at the moment that is something for later in the plan.

Question 5

Back on the resources: I was trying to understand the contribution of the lower sand and the higher sand within the resource range. Is the 1C, for instance, mostly the lower sands, and the variation therefore as we go up to the 2C and 3C there are more and more I guess a percent?

Second question is around how your 2C assumptions compares with the view of the partner? Is it a question of the recovery factor? Is it something else? Which sum is the higher figure for the 2C?

Lastly, more on an RBL question and headroom. As we get closer to Kraken first oil and more cost is being sunk the value of the reserve goes up, so should we expect the potential size of the RBL to go up as we reach first oil?

James Smith

The guide that \$260m availability guidance between now and the end of 2017 takes into account what you've said. So, effectively the availability under the facility is driven by two things: one is a NPV calculation of the underlying fields and the other is the progress of capex effectively; that capital investment is co-funded by our equity and bank debt. So as investment continues in the field the net capacity effectively increases, and then again when it's on stream.

So that \$260m takes us through to Kraken being on stream and completed.

Richard Heaton

In terms of split between the lower reservoirs and upper reservoirs, I think the 1C, 2C levels then the change at the lower reservoirs is relatively modest. But there is still quite a significant upside that could be realised from those through potential of further appraisal drilling, which would then allow us to remap those lower reservoirs.

But the biggest changes are really: what is going to be the recovery from the upper reservoirs? That is the focus of what we need to find out from the interference testing and further appraisal. And we assume that that is where most the variation can come between different assessments; it's where the most uncertainty lies. And in fact if you just apply a very small percentage change in average recovery to that very large STOIP figure you can see how it's easy to come up with slightly different figures.

At this stage in the evaluation we're very comfortable with where we are; but you can see it's well within the range to put quite different figures into that.

And does the IC include much of the upper sands?

Richard Heaton

It includes some as well, yes.

And in terms of the comparison with the partners for the 2C?

Richard Heaton

As I say, different partners could take different average recovery factors over this sort of figure, and you could easily get different results.

It's recovery factor?

Richard Heaton

Yes.

Question 6

Can you share some details on the FPSO plans for Senegal – it may be a little early – but in terms of estimated conversion timing and costs etc?

Paul Mayland

Obviously we've got quite good experience because we're in two projects just now, one being obviously a new build hull and the other being a conversion.

It's probably too early to say. What we're really focused on is sort of locking down the concept and obviously the scale of the development, and that's really what we'll be focused on in the next 18 months or so, both through and in parallel with ongoing appraisal drilling, and then I think we'll have a better assessment of it. But I don't think it will materially change from the timelines that we've had on our existing projects.

Question 7

At the moment this feels like a one-hub development. I'm just wondering if that's how you see it given the exploration potential you've got a look at, and what could change your view on that?

Paul Mayland

That's why we're keen to go back to do further appraisal because obviously, you're right, it is a hub, there's a large resource here; clearly we want to move it forward and start production. But what is the scale of a facility that we should ultimately build, bearing in mind there's further exploration potential; and particularly because that exploration potential sits within a relatively easy tieback range for an FPSO solution for example.

I don't have any further answers other than that, but it's very much part of our plans.

Question 8

Can I come back to the Woodside deal metrics? I take your point about other interests and potentially being a willing seller. Is it fair to say though that those deal metrics now put a cap or a ceiling on pricing for the near future? And what milestones do you need to achieve in order to see a step-up in pricing?

Then just to change the focus onto Kraken. It looks like you've got a willing seller in one of your partners there; would you be interested in increasing your stake on Kraken?

Simon Thomson

I think on the first part of the question, there were specific circumstances for that transaction the way it was structured, so I can't comment any more than that.

Does it cap upside? Well, that's linked to interest in the project, oil price, cost and all the rest of it. I think that's a moving picture. So we haven't seen any diminution in the kind of incoming interest in this project. Our job is to ensure, as I said earlier, that if we do want to transact it's at the right time and obviously at a price that we consider attractive. So we want to keep that flexibility open.

In terms of Kraken, as you know, we took our proportionate share of partner interest earlier in the year with the First Oil interest. I think we're comfortable with the level of exposure that we have. We do continue to look from a new venture perspective, both on the E&A side of the portfolio and also on the production side of the portfolio. So I think for us it's a balance of risk exposure to particular projects, and it may well be that we might bring in cash flow from

elsewhere if we saw the right kind of deal. But we're comfortable with the level of equity we have.

Question 9

A couple of different questions for you this time. Firstly on Vedanta: how do you view the proposed merger between Vedanta and Cairn India?

Secondly, on the cost base. Now, I can see you've done a lot of work on the capex to bring it down to \$12 to \$15 a barrel. If I can split that into drilling, completion and subsea what kind of scope do you see for further reductions there? And the opex number was fairly nailed on at under \$10 a barrel; do I not understand that there should be significant scope going forward to bring the yard cost down for FPSOs and could you not actually make savings there? Or do you not expect to see the yards bring down their cost estimates?

Simon Thomson

On the first part of the question, as you know, we haven't made any public comment on the proposed Vedanta transaction. There's a shareholder vote on 12th September and we'll vote accordingly.

James Smith

On the capex and opex estimates for Senegal we're in the middle of contracting a rig at the moment and we're in the middle of seeing what the contractual relationship is like with the two FPSO constructors at the moment. I'd say in the guidance we gave today we probably haven't taken the most aggressive end of the range that you see in today's environment, because we've tried to predict what it's going to be like over five years or more, getting us through to first oil. And the capex numbers there, the economic outlooks there include a 20% contingency. Of course if the oil price stays where it is today or goes lower then there is the potential to see some of the possibly more aggressive contracting strategies that are existing literally as of today, but we've tried to predict something that is perhaps more sustainable.

And then on opex, again I think it compares reasonably well with analogues. Jubilee opex is probably \$8 a barrel, something like that. It is of course linked to your oil price outlook.

Jubilee, they own their own concern?

James Smith

They've gone through the purchase option now, yes.

And that's \$8 per barrel. So, your \$10 a barrel includes leasing costs or...?

James Smith

It includes leasing costs, yes. Sub term is roughly half and half. So, if you worked that out, as you saw on the chart there, 100,000 barrels a day, roughly 100,000 to 120,000 a day peak production rate you can back out from that what we're assuming to be the day rate on the FPSO.

Question 10

A few different questions. The first one on India; could you just give a bit more detail around the process? The way I understood it is that you're going to have the hearing in the first half of next year so should we have a definitive resolution at some point next year?

Second question was on potential hedging strategy with the new fields coming on stream, what's the kind of thinking around that?

Then the final question on Skarfjell; I'm just wondering, you've got concept selection coming up at the end of this year, is there any capex allocated to Skarfjell for 2017 and is that an asset you want to continue in?

Simon Thomson

Yes, is the very final bit of the question. James, I'll let you continue.

James Smith

Yes, just to continue on the last one first, on Skarfjell. In terms of projections there is continued pre-development type spend and studies included in our capex projections for Skarfjell. But clearly we won't be giving a detailed development capex scenario until it reaches FID post-concept select.

On the other two points, you're right, that is the timetable for the arbitration process that's been set out. Clearly we don't include, in terms of our funding plans, a firm resolution of \$1bn inflow in terms of the compensation we're seeking from the arbitration panel in 2017. We take a cautious view on that but actually we've been encouraged by the approach the panel members have taken so far trying to keep this on a tight timetable.

Our strategy on hedging is not to do it for its own right in terms of protecting against oil price volatility, but to do it to protect debt capacity and capex programmes. And we'll continue to look opportunistically to do that. As of today it probably isn't the best time to try and tie in a floor but between now and first oil we'll continue to look at that.

Question 11

You mentioned in your results that the amount of capital available under the debt facility is \$260m, and I assume you derived that from the outcome of the redetermination talks you had in March with the banks involved in the RBL. Can you say what sort of oil price at forward curve they were assuming when you calculated the \$260m as capital available under that facility? And coming into September I assume there's another redetermination process, and whether you think that'll be more favourable in terms of increasing the capital availability under the facility or whether it could limit it and reduce that figure of \$260m?

James Smith

That's right, the \$260m guidance is based on the redetermination process and the model that was agreed back in March. That's phased availability obviously as the investment in the two fields continues between now and the end of 2017.

In terms of whether that guidance remains current or not, the redetermination process back in March was the next three years, say, roughly around where the forward curve is today, stepping up towards a long-term oil price view in the high \$50s.

The oil price has continued to be relatively volatile and different banks take different views. We've actually seen a slight improvement if anything in terms of bank price decks. So, if we're running the model today with the updated price decks that guidance might be a bit higher. But clearly we won't update it formally until the September redetermination. But I'd say it remains pretty current.

Question 12

Just one follow up question. With regards the opex and the question of leased versus new-build FPSO it seems pretty much the mantra that people go for leased FPSOs these days and it reduces your cost to first oil. But given the large in place volumes, and therefore arguably a very long life of this field if you can work out how to recover it all, is there a scenario in the concepts left, and given the way costs are going as well for new builds, for an owned FPSO development concept?

Paul Mayland

It's fair to say it will be under consideration, there's no doubt about it.

James Smith

Yes, and obviously what would be standard is also the option for a purchase after, and then you can negotiate the number of years. And today we'd be in a reasonably strong negotiating position. Clearly that needs to tie in with financing plans for a development scenario, how much therefore of an equity cheque you're having to put in upfront and how that ties in with the cost recovery profile and so on. But clearly it's a question of running the economics.