Cairn Energy PLC

Capital Markets Day

Monday, 11th May 2015

Simon Thomson, Chief Executive Officer

Good morning everybody and welcome to Cairn's Capital Markets presentation on Senegal. I'm Simon Thomson, Chief Executive, and together with the team we'll be running you through a detailed presentation on Senegal.

It will take approximately one and half hours we think. There will be then a short five-minute break. For those of you have indulged in the Scottish Senegalese breakfast of dates, mango juice and shortbread that might be very welcome at that stage. And then we'll resume again for questions and answers. It is being webcast today so when we get to questions there will be microphones, and if you could just state your name before you ask a question that would be helpful.

So following the discoveries in Senegal in the autumn of last year we indicated that the next milestone event for the joint venture would be the submission of the evaluation report to the authorities in Senegal. I'm pleased to say that evaluation report was submitted on schedule last week. And the report details all of our technical understanding to date on the acreage, and also our forward plans in respect of the further appraisal and further exploration on the acreage. And this presentation today will provide you with a summary of that understanding and those forward plans.

And I hope what you will see from this presentation is the significant value that we believe we have already created in Senegal, and the significant additional value that we see yet to come.

A few words on strategy. The Senegal discoveries have been made within Cairn's business model, and that's a model that seeks to add sustainable value growth for shareholders from a balanced E&P portfolio. We've built an attractive mature basin position in the North Sea. And the future cash flow generation from that position, married to our current balance sheet strength, means that we are well funded to be counter cyclical in the current oil price downturn, and commit to an extensive drilling and data acquisition programme in Senegal.

And why all the focus on Senegal? Well, we believe that this is indeed a world class basin play. As you can see, we're saying today that we see full block potential of gross mean risked resources of in excess of a billion barrels. We have selected a seventh generation dual activity drillship to carry out a programme of up to six wells. And that programme is going to commence in Q4 of this year and will include a rapid appraisal of the shelf discovery.

And the approach to Senegal is absolutely consistent with Cairn's strategic delivery over the last many years. We are a highly experienced operator with a focus on health and safety, and also a focus on providing benefit back to the communities in which we operate. We take large acreage positions with follow-on potential in the event of success, and we form strong partnerships with industry and government alike.

And we're always focused on routes to monetisation, and as you know, over the last ten years we've returned in excess of $4.5bn to shareholders as a result of asset realisations stemming from Cairn operated exploration successes.

Turning to the agenda, we're going to cover every aspect of the Senegal asset today, from the discoveries through to the appraisal and development plans, and on to the significant exploration upside that we see on the acreage. I hope that you will come away with a sense of the size and scale of the opportunity and the value proposition, but also the strength and depth of the team who are managing the various workflows associated with this project.

A number of the team are going to be presenting today, they'll briefly introduce themselves, and there are full biographies available at the back of the presentation pack. In addition there are a number of members of the Cairn team in the audience who aren't presenting today, Tom Morris, Senegal Asset Manager, we've got John Clayburn, Head of Geoscience, Ian Bully, Principal Geologist – so a number of the Cairn team. And please feel free after the Q&A session to ask any questions to those individuals.

So with that introduction I'd now like to hand over to Richard to commence the exploration story.

Richard Heaton, Exploration Director

Thank you, Simon, and good morning everybody. My name is Richard Heaton. I'm a geologist, some hints of which might come through some of this presentation shortly. I've been with Cairn quite a long time, and I think Senegal is one of the two or three major successes which Cairn has had on the exploration front, and I'm very proud to be part of the team that's been involved in it.

I think, as Simon said, the strategy that Cairn has had over the years has actually not changed significantly in many ways, and that is we're creating the value growth through exploration, so it's through the drill bit. The important thing in everywhere we go is that we try to find places that we like technically, we've got to like the rocks in the first place because that's where it all relates back to. And we try to take out significant positions so that the acreage, if we have success – because exploration is quite a risky business, as you know – where we have success we've got that follow-on potential. But it's not just the rocks, it's no good if the commercial terms don't match those risks. So we've also got to have appropriate commercial terms.

Where we have differed I think in the past few years is that we have built up what we believe is a very, very attractive balanced portfolio. And what we mean by that is that it's not just one or two things, it's actually making sure that we're looking to the longer term, that we're taking in those good technical areas and good commercial areas the right levels of equity, we're getting the right number of opportunities to be able to play the risks out. And that's what we've built up. I'll take you through that over the next few slides and introduce you getting, if you like, step by step closer and closer to Senegal before we dive into the real detail.

We have built up a portfolio that includes emerging basins. We're starting to look at some of those. You could argue very much now that having discovered oil in Senegal that's no longer strictly as frontier as it was. It's very early days, it must be said. We've just drilled two wells, but they're both successes and it's great to have that success. The Barents Sea, we're starting to look to that, it plays to many of our strengths. We've also got mature exploration going on in the North Sea, we've had successes there, obviously mostly building around the two fields. And those fields, Kraken and Catcher, they will provide us with the cash flow to keep going at this process, to make sure that we know that we're right sized for the exploration task that is going to create the value.

We've also got to look for the next thing too, so we keep our eye out, whether it be around our existing acreage, whether it be looking at new basins that match the sort of technical expertise that we have. Even now we're needing to try and make sure the next thing, the next growth spike that we can try and find in a few years' time, by looking at low cost, the long lead, getting in now whilst you've not got massive commitments to make to it, whilst you build up that exploration background.

So that's the background story to exploration at Cairn.

We start to zoom in on what we have therefore as part of that portfolio. Really there's an Atlantic margin theme to a lot of it at the moment. There's a reason for that; we've got a team of about 40, 45 geologists and geophysicists who are staff, there's obviously a lot of people helping us. But we plot where their expertise lies. And a great deal of it does lie in what we call rift basins and passive margins. And those are the edges of continents that have drifted apart.

What this diagram here shows is the continents a long time in the geologic past were all together. And as those of you who will have heard of continental drift, they've split apart. It's happened a number of times in the Earth's history, but the one that we're talking about is a super continent here that was called Pangaea. It drifted apart in the geologic past at the end of the Triassic, to start with, around about before the dinosaurs. And effectively that created a very narrow set of basins. They start off as cracks in the Earth's crust, and they drift into narrow oceans and then increasing oceans. It's during those early phases of ocean creation that you often get the right sequence of things happening to create hydrocarbons. And it's in those areas that most of our team have had the majority of their expertise, their experience of finding oil and gas.

So we've concentrated along the Atlantic margin. And there are lots of themes here that allow you to take learnings from one area – and no two things are exactly the same – but you can take some learnings and move them from one to the other. So in Senegal – which we'll come to in much more detail today of course – we've taken out an area there. It's in one licence, it's in three blocks. It's quite a large piece of acreage. Just to the north in Mauritania we also have a large licence there. We're not the operator, that's Chariot, but it's still part of the same theme. You go further up we've a number of pieces of acreage in Morocco, in different basins there, through to offshore Ireland, even the North Sea, up to the Barents, and indeed even off Greenland. The themes of some of the geology remains the same.

So obviously most recently in the past year we've been very busy off this particular section here with an operated programme last year of four wells. The first two in Morocco didn't find oil and gas in commercial quantities, but the second two in Senegal certainly did. And it's that which will be driving us through the next very active phase of exploration.

We've also of course been very busy elsewhere shooting seismic, drilling non-operated wells, and there will be a programme over the coming years in those areas.

So zooming in yet again, a little bit closer, trying to look at the coast of this part of Africa. This is a sort of geological map of the seabed, and really it demarcates where the edge of what we call the continent, the continental crust here in this dash line, so this is Africa, separated from the ocean crust created as the basins formed. And there are cracks through here which usually are the result of differences in onshore geology, and as the basins form it creates slight differences between sections, so it becomes segmented. Our strategy really has been to say look, we're not exactly sure as explorationists which of these is going to work – it could be all of them work, although that's not usually the case, some will and some may not work so well. So we've made sure that we've taken some acreage out in a number of places along here. And there's been a common theme, there's a common theme about source rocks that generate that oil and that gas. The age of the rocks actually is quite similar, so you start to develop an expertise in the sorts of rocks that you're going to get. The rivers that run off here drain different sorts of terrain here. So some rivers make good sediment for the reservoir rocks and others make poorer sediment for reservoir rocks. You can start to learn from what you're seeing in the wells what might make a good area.

And at the moment Senegal is looking absolutely great. What makes this good is that we appear to have rivers that are feeding good sands off there, we have found good quality source rocks that are mature. People knew that they were there, but how good are they? And it was important that one of our wells went through those in order to be able to prove a petroleum system.

Everything that's guided us in the acreage we've taken out is in the fact that in the 1960s and 1970s when people started to explore offshore – because until then they really didn't have that capability, it was mostly onshore – but the first offshore drilling started, if you like, transporting some of the technology at the time over from the States, where they were drilling off the Gulf coast, a lot of the companies went to the African coasts and started exploring. They found oil, they found gas as they went along this coast. But in this particular part, although they found a number of shows nothing commercial. Of course it was a different story in Nigeria, in Gabon, in Congo, in Angola. And everybody knows that that's where all the energy then went, it was much easier. They didn't have the capability to move into the deep offshore. So it's only since the development really of deep-water drilling rigs that you can actually understand and get into drilling what is in the deeper water.

And 3D seismic of course has come along since then, and that makes a huge difference to what you can see and the detail of the models that you can build. And both of those have been critical for us in taking our exploration forward.

We zoom in yet again, right into Senegal now just to demonstrate this point. The country of Senegal here, our acreage in the middle. There were several wells, four of them drilled here along the structure known as the Rufisque Dome by Esso end of 60s to 70s. As well as these wells here right offshore, well, well away from the coast, there were research wells drilled in the deep sea drilling project. This was the time that geologists and geophysicists were starting to understand that continental drift really did happen. Before that people hadn't a clue really what was going on. There was lots of argument. But it was to prove continental drift that a lot of this deep sea drilling went on. And what they found not only was the evidence that there were these volcanic rocks that create the oceans, but on top of them, in the very far parts of these basins, they found thin source rocks, source rocks of Cretaceous age mostly, that actually as you go further back onshore become buried, become thicker, become mature for oil and gas and it's critical. So even off Senegal there were some of these, but there are a series of them all along the African coast.

You can see that to the south there are one or two oil shows as well. No major fields, but some oil found here. And as we go further to north, into Mauritania, oil and gas and even condensate, and as many of you may have observed just last week I think, Kosmos announced a find of gas, quite deep water here, just at the southern end of Mauritania. So things are working, but it looks like in this coast, despite the different transfer elements that are coming off, breaking it into some basins that are good and some are not, some are salty, some are not, there are systems that are working. And they do vary a little bit along here. But it looks like as though where we are in this part that the whole system is working quite well.

A lot of folk, a lot of companies looked at this area for many years and didn't have their models of how it was going to work. They told them that it was going to be very risky. Our view was that this looked very well. And we were followed in that belief by FAR, who held the acreage that we farmed into, and also of course our partners, ConocoPhillips, who also believed in that model. It's easy to say now in hindsight that it works, it's not so easy to take that step when you're exploring before you've drilled the wells. But it's going to work. And I think that's what we'll spend a lot of the rest of today talking about.

This is just a finalisation slide before I pass onto a lot of the detail. I'm not sure how well this is showing up on these projections but this is an image of our 3D seismic with the seismic panel here, but this is a very complicated extract of very detailed information that you can get out of 3D seismic. It's taken at one of the number of reservoir levels in our discovery at SNE-1, and it points to where we see this reservoir coming good. And you can see a culmination with the reservoir on it here, and at the same level you can see another one here, another one here, another one here. Once you start to find things working then the beauty of it is it should work elsewhere too.

So what we have done last week and myself and Rob and a number of others, and Martin were in Senegal last week we were putting together this plan, handing that over to the government, a lot of work has gone into that. It is a plan where we will be appraising the SNE find, evaluating that, and also the FAN find which was in slightly deeper water. There'll be coring and testing of the SNE field – testing to make sure we understand how the wells might flow oil out of the reservoirs there. And coring to get really detailed information to make sure that we can make our plans for development correctly.

And the beauty is that we've already found oil here, our mean P50 or 2C estimate here around about 330 million barrels, so we've got a wide range – it could be from about 150 all the way up to 670 million barrels. So it's early days but I think one is behove with such an interesting large find like that, possibly one of the bigger finds last year, perhaps the biggest. Not only do we have that but clearly we do have prospects and leads around it. So at the moment Cairn estimates around about 380 million barrels gross risked mean in prospect and a similar figure actually in a series of leads. And not everywhere in our licence area do we have really brilliant quality seismic like this. We need to get some more and that's one of the things I'll come on to.

So it's a very exciting place to be. I hope that's given you a good geological introduction to what it might be, and so at this point I shall hand over to Rob who will take you through a lot about Senegal, the country, and the partnerships that we're in.

Rob Jones, Regional Director, Africa

My thanks to Richard and good morning to everybody. Richard I hope has explained why Senegal is such a good place to explore. I'm going to take the story on now by explaining why it's also a very good place in which to do business. After all in the end that is what this project is all about.

Senegal is a stable country. It has a new President, elected in 2012. This picture was taken at an event in November last year, three or four days after we'd submitted our notices of discovery at the request of the President.

President Macky Sall is a geoscientist which, if you're a geoscientist that's pretty good because he's part of the club. But his history in Senegal goes back to having been the director general at PETROSEN; but when we have conversations like this he has an immediate understanding of what we're doing, and therefore an expectation of the sort of timeframes that we would be able to achieve what we need to do. So from that perspective the President is a very good ally to this project and has therefore taken quite an interest in what we're doing.

Senegal is located, well you all know where it is, on the corner of West Africa. It's an important regional hub, it services a very large hinterland and that provides Senegal with a firm economic base, but the economy is only as big as it without access to energy, no economy grows without access to energy. So our project is going to be a very important project in the way in which Senegal, as declared by the President, shall transform. And he has a vision for 2035 and in that vision it is economic growth but it's also stability of government and stability of legal and other regulatory systems. That I think is very good and will help us as we take our project forward.

Moving on, Dakar is a pleasure to visit. It's compact. It doesn't take more than about 30 minutes to get from our office, which is pretty much in the centre, to key stakeholders such as PETROSEN. I'll mention a couple of others here, Hassmar who control offshore maritime security. They get involved in our operations ensuring everything's done properly; DEEC who have responsibility for the environment – that of course apropos what Simon said earlier, is really fundamental to a successful operation. The port is nearby, the Customs House is a vital part of the infrastructure. And then looking with half an eye to the future, IFC and the World Bank are well represented in Senegal too, as are the US; this is the US's largest embassy in West Africa. And then there's a smaller British embassy downtown as well. So it's a great infrastructure, easy to get around and therefore easy to do business.

So what is the business? The business is all about delivering value. To do that we have got a very strong partnership, it comprises ourselves, as operator, and we've been the operator since the early part of 2013. Soon after farming in we brought ConocoPhillips into the partnership. That has significantly enhanced and broadened our technical capability, and in due course they may get more involved. But ConocoPhillips being a major international company has got plenty of expertise in the development arena that we can draw on and, as we mentioned before, Simon mentioned they're getting even more involved by virtue of the rig which will be operating here in the autumn.

We have continuity through FAR's presence which is now heading towards a decade. And I think everybody benefits from Cairn, as the operator, because we are very focused, we have that edge; we move quickly, so we have brought a pace, and will continue to bring pace to this investment and operation. So in the short time that we have been in Senegal, since early 2013, we brought in a rig, we drilled the wells, as Richard described, we included a farm down, which improved our risk profile and equity profile. Within a few months we commenced drilling. August was the first actual discovery, last year; November the second discovery, or the notices of discovery and now, six months later, as we've just described, we submitted a very ambitious plan to the government of Senegal. So we are making things move.

My section is about doing business in Senegal so here are some of the key people; the person on the left is, that's me, but photographed with Simon, Matt Fox, who is senior EVP at ConocoPhillips and I think actually of all the people here the most important is the gentleman second on the left, which is the director general of PETROSEN. Now PETROSEN is a vital partner to us, and they really are a partner. They are the regulator. They also work as an advocate, if you like, to the Ministry, and in due course they will be very much a partner in the project. Their equity position changes on commencement of development.

Business is many things, one of which is having comfort around the legal system and I won't go into a huge amount of detail on the legal system per se, but just would like to explain that the production sharing contract which we signed, or we have become a successor to its signatory, is the contract by which we operate with the government. That has above it a petroleum code which works in concert with the production sharing contract. It provides the framework and foundation for the production sharing contract and the two work actually very well together.

That is important. I had a list of people in the first slide, so I'm going to mention other people who are important to us. The DG reports to the Minister of Energy and Renewables, who, of course is part of the cabinet, and on up through Prime Minister and up to President. We know all of those people – I've had several meetings on many occasions.

What the government is obviously very focused on is not what we have done, of course we're pleased with what we have done, but they're very focused on what we're going to do. And so last week, together with most of the team that are down there, we submitted our programme to the government. That was due six months after notices of discovery and it was indeed submitted a week ago tomorrow.

In this six month period, between the discoveries and that event, and that six months was laid down in the PSC, we have built up a work programme which was approved by all of our joint venture in April this year. And that work programme is the start of the three year programme which we've presented to the government.

I just want to clarify something there which is that the work programmes in the PSC are annualised in order that we can reflect as we go. So each year in September we submit an annual work programme to the government, we're of course at liberty to amend that as and when. So this year the amendment occurred in April and the 2016 work programme will be presented to the government in September, once agreed by our partnership.

But the programme this year is three wells, two of which will be appraisal wells on the Shelf Edge discovery and one of which will be an exploration well. In addition to that we have the intention, and we will do this in Q3, to acquire, in the blue shaded area here, an additional 3D survey. That has, I think, great significance. One is that it will enable us to close a certain amount of prospectivity which runs down the east side of the Sangomar Deep block, but extend the play trend in its detail up into Rufisque. And as you'll see from Chris Burnside later Rufisque has particular relevance because the paleo shelf break is what Richard described there is a present day shelf break and by the time we get up in here the water depths have reduced to 100 metres or so. So in terms of planning for future infrastructure Rufisque has a very important potential role to play in the project.

The symbols on here – green is the firm, the orange are what we have planned. I think Richard also referred to the rig and because of the annualisation of the work programme, the rig contract or rig selection is based on the three firm wells for this year but we have options to extend that programme, and plan to extend it, subject to that presentation to the government in September into 2016. So there will be continuous drilling, continuous results from round about the 1st October through to well into Q2 next year. And those results will keep everybody in this team over here very busy but I hope everybody else very keen and interested in what is going on.

So what is going on? Well we've had this acreage, or this acreage has been licenced since about 2004. We farmed in, in 2013 and I would give praise to the people who have been involved in this since we did farm in. It was obviously a great choice but in the short time, it seems like a short time – two years – we took over the operatorship. Behind the scenes that's a lot of financial, commercial, legal, and other work to be done. That was done in parallel to preparing the rig, deciding on the prospects, all of the detail associated with that; announcing last year the discoveries; putting in this ambitious and robust programme last week; but importantly Richard gave some flavour about this, Martin will give more, and I think Richard will come back and re-emphasise that the data points that we have acquired in the Shelf Edge discovery and the FAN discovery have enabled us to refine and redefine the prospect inventory and that play trend right through this acreage, the 7.5 square kilometres by the way, so it's a substantial body of acreage, right the way through into those shallow waters.

We're not afraid of a bit of hard work and the middle box here outlines what we're going to be doing, and this slide was presented last week in Senegal, so we're right on track to commence appraisal of the Shelf Edge and FAN commencing later this year. We do anticipate new discoveries. We've substantially derisked and because of our data points and our new understanding of the sites that we have, plus the end product of a reprocessing project we will have considerably more detail. There will be further exploration drilling, not just in this programme but I can envisage in future programmes, but critically important from that we want to, at the earliest sensible, technically justifiable time, achieve commerciality. And our focus is very much on achieving commerciality.

That's an iterative process, as everybody is aware, but will involve during this three year period, working out the development plans and Chris Burnside, who's going to talk this morning, will talk to you about how we think those are beginning to shape up. And importantly from that we then produce the justification to the government to define those areas which we will retain for exploitation. And to put this into some perspective the exploration period is generally six to eight years, this evaluation period is three plus, we hope, a bit, but three years is what we've recommended. This period of exploitation is at least 35 years.

Highly significant timelines because of the vision in Senegal to build its own economy and you can see very quickly I think that what we do through these timelines synchronises extremely well with the government's plans. So we anticipate full support from them in that regard.

What you will see in terms of exploitation will be ideas about integrated developments. That is because already we see the potential for multi-field development, there's already two discoveries but there will be more. We need to be clear about how we develop so that we exploit synergies and efficiency wherever possible. There will be inter-field synergies, wherever possible. There will be inter-field synergies – there's probably some inter-field dependency which we can already see, but importantly for the project, and via the PSC and its cost recovery mechanisms, we have a very clear focus on achieving early oil production and we will come to talk about that shortly. Of course from the government's point of view and from ours we want to be able to identify the maximum areas possible through that whole process.

The PSC is a very good robust document – James is going to talk about some of the more fiscal elements but the PSC defines those things which we must do on behalf of the government. We're a contractor, it's a production sharing contract, we are the contractor and the PSC defines this list. Simple words but I'm sure you can all imagine that behind each of these bullets is a plethora of work which we need to do and of course we will do it. The guys presenting this morning are going to take you through these elements of gathering the necessary geological and petrophysical data, that's important. They'll take you through how we intend to estimate size and delineate these fields, but also the new ones to come.

Importantly, we mentioned testing and coring in an earlier part of the presentation, that is very much front and centre of defining reservoir productivity, so a well test from which we recover hydrocarbons will give us an enormous amount of information. Chris is going to talk to that. That in turn feeds into, and I'll just draw your attention for example to well count. In other words the better the reservoir, the less the wells, the better the economics. At the moment all indications are from the Shelf Edge discovery that the reservoir conditions are very good, and that should help the economics. You'll see some estimates of that in due course. We need to do all of this within the next three years, and for that it's important that we have, which we do, and we retain, which we will, the support of our partners and the Government of Senegal.

This slide is a short and I hope sweet summary. Nine months ago if we'd coloured this map it would have been dotted blobs around the two well locations. So in a relatively short time we have made those fields, defined them. You're going to see more granularity this morning in respect of a rapidly evolving and building prospect inventory, so that gives us plenty of opportunity, plenty of choice. And you'll then see from Chris his focus or our focus on getting, within the next couple of years, to a really good understanding of how we can take Shelf Edge field into exploitation. Actually, our vision goes well beyond that, as you'll see in a later presentation. So from six months ago/nine months ago through prospect inventory and into exploitation.

That gives me the right opportunity to pass the bat onto our Exploration Manager for Senegal, Mr Martin Dashwood. Thank you all very much.

Martin Dashwood, Exploration Manager, Senegal

Thanks to Richard and Rob, they've set the scene for the next section, which is discovery and appraisal. The first slide, I think, captures the essence of the opportunity and the achievement to date that we've made. It's already been mentioned that we have an active petroleum system here, we've demonstrated that with the first two wells. And this is crucial, you don't have world class producing basins without world class source rocks. And we've demonstrated world class source rocks with our FAN-1 well. In addition, we found these world class source rocks over a number of intervals, so this is really quite a breakthrough to have it at such an early time in the evaluation.

Secondly, we had back-to-back discoveries. We didn't have time between the discoveries to make changes between the two wells, these were independent discoveries, and we're very pleased about the results of those. The initial assessment that we made prior to drilling was that we'd identified something like seven to eight different play types, and by drilling two of these they were the largest prospects that we identified. We tested some four plays with those two wells. But as you might expect, to test four plays not each of those were drilled optimally, and you'll see a little bit about what that meant for our FAN well later on. The FAN-1 well itself, the source rocks were predicted to be present in the well but these were thicker and better than expected, and we hope to establish seismic evidence to support reservoir improvement away from that location.

The other thing is, you can see from the upper image we had a fairly extensive lead and prospect inventory mapped prior to drilling. You can see the location of the two wells. Basically to the right of the centre of the diagram there that's the Shelfal area, and off to the left to the west is what we call the Basinal area. Following the discoveries you can see again that we've gone into a lot more detail in identifying and finessing some of those prospects and leads; the two discoveries again noted there, and you can see that we have trends both along the shelf and within the basin for follow-up opportunities.

So with these multiple prospects and leads on trend, these lead to a very encouraging series of follow-up wells which we'll detail shortly. The other thing we're planning is for 3D acquisition. That was approved by the partners this year. 3D seismic has been crucial to the discoveries we've made to date. You can see the outline of the seismic polygon here, and we're extending the seismic up to the north-east into Rufisque Block which I think will be crucial for that area.

I think, as I've already mentioned, the two wells targeted multiple plays. These were both structural and stratigraphic. The FAN play, which you see on this portion of the cross-section here, multiple stacked reservoirs targeted. We also see the interval that had the significant source rocks, a very thick interval of potential source rocks there. Also, you see the migration path that we interpret from the basin up, up onto the Shelfal area, and this is where we had our SNE discovery. So we had thick oil column down here at FAN-1, and then gas on oil at SNE-1.

As you can see from the lower image, this is the Shelfal area focused to the north and the Basinal area down to here, and you can see that we have a domal feature, domal closure, which is reflected on the cross-section also. That's where we had the SNE-1 discovery. You can also see that we have a number of other leads and prospects along that same trend. I think one other important thing is on this cross-section we have this erosional top to the trapping here, and we have sealing shales there which provide trapping geometries for a number of these leads and prospects on the shelf.

We believe that this discovery was potentially the largest made in the offshore in 2014. You can see the water depth, and you've already heard we have a significant oil bearing column of over 100 metres; the net oil bearing section of around 30 metres with some gas above that. You'll see from the cross-section here that we have some of our thicker sand, so this is the gas oil contact, this is the oil water contact as penetrated in the well. As you can see, we have some of our thicker sands within the oil column; but also we'll have some of these thicker water sands as well as some of the gas sands within the oil leg over the domal structure.

In terms of resources, I think it's already been mentioned the values that we carry; 2C case of 330 million barrels and then a range between 150 and 670 million barrels. We've also established that we have a high quality crude, it's a medium to light crude of 32 API oil. This was a video sent from a rig shortly after we had recovered oil in downhole chambers, and we particularly like that image. It was at this point that we realised that we had the potential for a producible oil at this location.

So SNE-1, this slide captures the reservoir statistics for the discovery. As you can see, we have good porosities and very good oil saturation, and that's throughout the reservoir intervals. Porosities in the range of 25/24 per cent throughout the hydrocarbon bearing section, but also good porosities in the water leg, which is encouraging, because quite often the chemistry will cause deterioration of the porosity in the water leg. And high oil saturations. The other thing you see here is almost a textbook example of a gas leg on an oil leg on a water leg, and this was from a large number of process samples we took with downhole MDT sampling, and Chris Burnside will talk a little bit more about that in his development section.

So in terms of the forward programme, following the discovery which was made in November 2014 this rapid appraisal programme is planned. The plan, as you've already heard, is to drill at least two appraisal wells with coring and flow testing. Some of the main objectives of this programme will be to demonstrate connectivity and continuity of the reservoir, also productivity. As we've mentioned we have this broad domal feature and some 70 square kilometres, and connectivity and continuity of the reservoir will be important to establish. Of course the other thing we want to establish very early on is commerciality as soon as possible. In addition, the additional well data will help us populate both static and dynamic models, and this will assist in our development planning. The other thing we want to do is reduce the uncertainty on the ranges. We want to increase our 1P numbers, we want to confirm and possibly increase our 2P numbers, and we also want to evaluate the upside on the field. Also, we want to continue with exploration on the shelf to increase the overall resource base.

In terms of choice of appraisal locations, this Boston Square style analysis shows the discipline that we've brought to the upcoming decisions on the appraisal wells. We're looking at a number of different possibilities. Characteristics in the bottom left, these are important but they're not critical and they're not particularly well specific. Some of the points in the top right corner, these are areas that we can address before drilling, so for example the uncertainty on depth conversion, this is something we're addressing through pre-stack depth migration. This is depth imaging. And also we believe that with carefully chosen appraisal wells we can evaluate the variation in reservoir quality. Reservoir quality is always an uncertainty, but we believe that there is as much upside as there is downside on the reservoir quality.

The next slide shows potential appraisal locations, and this is really just for illustrative purposes, these are not locations that have been defined or chosen at this stage, but they show some of the choices that we have. So a central location could help confirm our depth model, and it could intersect all zones and it could allow for coring and flow testing. The northern location could evaluate the upper zone, and it would also test the reservoir presence and connectivity some distance from the SNE-1. As I mentioned before, this field spreads over a large area and connectivity will be something we want to test early on. The northern well is also a well that we would consider coring and testing. The eastern location, this could provide valuable data again for our depth model. The southern location, once again confirming reservoir connectivity, possibly showing a field extension to the south, or if not certainly de-risking a contiguous prospect which we see just to the south of the field. So there's significant potential in the south.

Moving onto FAN-1, again you can see this well was drilled in slightly deeper water. It had a thick oil bearing column of over 500 metres in these multiple stack deepwater fan sands. The net pay was 29 metres. The focus now is to develop geological models supported by seismic evidence for improved reservoir thickness and quality away from this well, and that could be within the north FAN prospect itself, or it could be in one of the other fans which we map along trend. The FAN-1 well has discovered a significant oil in place but with a wide range, and as you can see our low case is 250 million barrels in place, mid case 950, and the high side could be as much as 2.5 billion barrels in place. Once again, the oil gravity here is medium to light oil, and this was tested at multiple intervals in the well.

Forward programme for FAN-1. This has already been mentioned, we've started on seismic reprocessing and modelling of the reservoir here, and we hope this will determine reservoir characterisation. We're also doing a number of studies on rock physics and on rock fluid, samples as well as integrating all the logged data. As described, we believe that all the above will help with our predictive models. Employing state of the art seismic techniques to resolve lithology and better resolve porosity will be possible in this area. We hope that these results will allow us to make a better estimate of the accumulation. The FAN field was included in the evaluation or appraisal programme submitted to the Ministry of Energy last week; and if our work is successful we believe that there are potential for multiple additional wells. That's all I have, so I'll hand over to Chris Burnside to talk about the development.

Chris Burnside, Exploitation Manager, Senegal

Thank you, Martin. Good morning. My name is Chris Burnside, I'm the Exploitation Manager. I've worked for Cairn for two years, having previously worked for Chevron internationally for about 20 years, mostly in new field development.

I would now like to focus on how we plan to convert these discoveries to resources and production. The evaluation programme is designed to confirm the critical parameters - the connected volume, the reservoir connectivity and the well deliverability - in order to make the correct choice on the development scheme for the field. Although we need to confirm a number of these parameters, we currently envisage that the first development of SNE will be a FPSO development with subsea tie-backs.

We envisage a capacity of about 100,000 barrels of oil per day, as I said, with spare capacity to add in further satellites. This would lead to a minimum economic threshold of about 200 million barrels for the first development. Obviously satellite development could be brought on at a much lower threshold if the satellites overlie the SNE field, as in the Bellatrix prospect, which we'll hear a little bit more later, and then you'll probably won't even need a new drilling centre. Other more distant satellites may require more subsea architecture, possibly including subsea pumping to increase production rates.

Within West Africa, there are a number of subsea deep-water oil tie-backs of up to 40 kilometres. So the tieback distance we're looking at is well within current technology capabilities.

At the bottom of the slide, you can see the project timeline. We expect to submit the evaluation plan in about three years' time, as outlined earlier. We would then move to first oil three to four years later, following a standard industry development process.

If we take another look at this log that Martin showed earlier; we can see a number of key aspects that are important from a development perspective. MDT logging provided high quality fluid samples for analysis, and also indicated a benign environment of approximately 4,000 psi and 70^{o}C. It also indicated this constant pressure profile throughout the reservoir with gas overlying oil and with underlying water, but all in pressure communication; which is an encouraging sign for the development phase.

Due to the nature of this reservoir, we would expect to use horizontal or high-angle wells to develop the field. This will obviously reduce water coning and gas coning and help us connect up the different sands you can see in this log.

Although we only have one well in the SNE field at this point in time, it gives us a good idea of the development challenges that we face. For example, we are currently looking at interference testing to understand the communication between different appraisal well locations, as this directly impacts the recovery per well and obviously the final well count in the development phase.

Here you can see an artist's impression of one possible development concept for the SNE field. You can clearly see the variations in the water depth and, as we said, there's about 100 metres in the shallow area, going down to about 1,100 metres at the base of the shelf.

The red lines show the outline of our blocks. As I mentioned earlier, it's likely that we'll utilise a floating production storage and offloading vessel with subsea wells in the first phase. Due to the relatively shallow depth of the reservoir below the mud line and the large areal extent, - it could be 60 or 100 square kilometres - we'll need a fair bit of subsea architecture to connect up the drill centres. This will include manifolds, subsea pipelines, control umbilicals and risers.

In our preliminary evaluation we've cautiously assumed up to 30 development wells for production, plus water and gas injection for maintaining pressure and also for increasing recovery.

As you'll have heard, there's plenty of scope for further discoveries, for adding resource, and with continued success, we can expect many phases of development. Satellite tiebacks proximal to SNE will be best developed as tiebacks to the hub FPSO, which will help maintain plateau production of that facility. However, more sizeable discoveries in the deep water may be best developed within an additional FPSO due to ullage constraints.

In contrast, if we make discoveries on the Continental Shelf within the Rufisque or Sangomar Offshore Blocks, which is shallow water, these will probably be more economically developed using fixed leg platforms.

Due to the relative proximity of the shallow and deep water development, it's likely that there's going to be some synergies or sharing of infrastructure between these different facilities, which should further increase economic value and extend production lives.

We have already commenced a number of front-end loading studies to help us drive and focus the appraisal programme on the significant project issues. As mentioned earlier, the production well count will have a critical impact on commerciality, so our studies are currently focused on understanding reservoir connectivity and well design to produce efficiently both the thin and thick sands, you saw in the log earlier.

To maintain the project pace, we are currently performing reservoir modelling, technical studies and development feasibility work in parallel with appraisal drilling. This work will position the JV to make an appropriate decision on the development concepts for the first phase at the end of the evaluation programme, which we anticipate in about three years' time.

This will require high levels of activity, both in terms of appraisal drilling and technical studies, but we feel that this is achievable and appropriate to deliver a project that will be robust and deliver on expectations.

I'd now like to hand over to Paul Mayland, who will discuss the operational aspects of the project.

Paul Mayland, COO

Thank you Chris. Good morning ladies and gentlemen, my name's Paul Mayland and I'm the Chief Operating Officer. I'm on my second call of duty with Cairn, and for the younger members in the audience, that should not be confused with the Xbox game!

I'd like to explain our near term plans for the execution of the forthcoming phase of drilling in Senegal. I'd like to touch on our capabilities as operator, and also that of the Joint Venture, as we look beyond what we believe will be a successful second phase of exploration and appraisal drilling. And finally, I would like to provide some context for development and cost analogues prior to James, later in the presentation, summarising the economics.

In terms of the forthcoming drilling, the operational objectives are relatively straightforward. We aim to drill the second phase of wells in Senegal safely, more efficiently and at lower costs than the first phase, and to ensure that the technical requirements are achieved and the appropriate data is gathered.

We want to build on the lessons learnt from 2014, including logistics, approvals and clearances and the overall drilling performance. We also want to improve and build on the excellent onshore HSE record and extend that into the offshore environment, working closely with the drilling contractor and the service companies.

The soft end oil field services market, due to the dramatic fall in the oil price later in 2014, should allow us to not only improve the pricing, which had become somewhat overheated over the last few years, but also to improve the quality of service provided back to us by these companies as there is less strain on their own human resources and equipment.

And most significantly, we are working well with Conoco and we'll incorporate a joint drilling contracting and logistics team in 2015 and 2016, drawing on the capabilities that we have collectively in Edinburgh, in Dakar and in Houston.

In terms of the rig selection, the plans are well advanced. After a three month period of negotiation, evaluation and assessment with numerous rig contractors and operators, we have selected, in our view, the lowest cost technically acceptable rig through a competitive process. A strong preference was to utilise a rig that is already operating with a good track record to be able to work in water depths of up to 15,000 metres and to commence operations in the fourth quarter of 2015. And the rig selected is the ocean rig Athena, which is currently contracted to Conoco in Angola and has completed two very deep wells with rig-related MPT of less than 10%. So the operational performance is good, the HSE performance is good, and we'll aim for that to continue whilst the rig is operating in Senegalese waters. The majority of the remaining drilling services will be tendered to secure current market pricing and this process is underway.

I've mentioned the Joint Venture and it's worth noting that we believe the current Joint Venture brings many benefits and capabilities that can be applied to the existing planned exploration and appraisal, but also to future potential developments.

Firstly, there is a common and universal commitment to HSSE and sustainable development within the Joint Venture. Cairn, of course, is very familiar with operating at this stage of an emerging hydrocarbon province where there is a national desire to move steadily forward, with the general overall aim to produce first hydrocarbons from the basin. We have experience of this, in particular, in Asia. As Rob has alluded to, PETROSEN, to date, have offered invaluable guidance in Senegal, have been a constructive technically focused partner and have deep regional knowledge.

Conoco, as you know, is a US independent E&P company, headquartered in Houston and has operations in the US, Canada, Australia, Malaysia, UK, Norway and, of course, elsewhere in the globe. Many of their existing projects, although not necessarily all in deep water, are of a scale and potential complexity that one could imagine and envisage an event of continued success in Senegal. We have engaged the deep water drilling team for 2015 and 2016 to support us and hope that the respective skills and expertise of both Cairn and Conoco staff can contribute positively to the overall success of the project in the next phase and in the longer term. And FAR, as most people are aware, is an ASX listed explorer and have provided continuity and knowledge within this licence for almost a decade.

If we now move on to the typical project timelines that guide us as we look forward. This slide outlines a number of mainly deep water projects operated predominantly by majors in West Africa, and principally in the petroleum provinces of Angola and Nigeria. It should be stated that every project is ultimately unique and has its own characteristics in terms of the operator, the partnership, including the national oil company, the field size and its complexity, the oil type and, indeed, the reservoir management plan. The plot show for each field the licence award date, the period to discovery, which, of course, can be many years, and the subsequent timeline from discovery, which is the red shaded bar, extending through to first production, which is shaded in green. These examples show the wide variation due to the unique field characteristics, but with the average discovery to first oil timeline of seven to ten years, which guides our forward planning and the overall direction that we've provided to date to the government of Senegal.

We move on to development and cost analogues. It's often difficult to pick out analogues at an early stage of evaluation. However, I'll take the liberty to illustrate two global examples which have some similar, but I must emphasise not all, characteristics, to our SNE-1 discovery in Senegal. The Gumusut Field in Malaysia is an example of a relatively large 400 million barrel light oil field developed using a leased floating production system; and the Baobab Field in Cote d'Ivoire is a medium-sized field around 200 million barrels, developed with an FPSO, but has heavier crude than SNE-1. You can read the details on the two respective slides, but I'll try to bring out some of the common features to SNE-1 discovery in Senegal.

The water depths in both these examples range from 1000 to 1,500 metres, the reservoir depths of 28,000 to 32,000 metres, oil initially in place of approximately a billion barrels. Floating production systems employed with subsea wells and a reservoir management plan focused on optimising initial oil production through water flood and gas-free injection.

Many fields can have challenges, but these can be mitigated and the overall risks reduced. The extensive data and subsequent studies planned by Martin and Chris' teams in particular, following the forthcoming programme, will ensure these risks can be identified and reduced to as low as possible. We will work closely with the Joint Venture to draw on our own and their depth of experience in relation to production technology, subsea systems, floating production and oil field chemistry. The analogues at this stage simply provide us with a benchmark for our economic screening, which will be outlined later by James.

So I hope that these slides have illustrated that we are well underway with our operational plans for 2015 and 2016; we are developing our thinking for the longer-term through exploration and appraisal and potentially into development, and that all of this can be achieved with proven technology available today.

At this point, I will hand you back to Richard, who will outline the further potential of the block. Thank you.

Richard Heaton

Thank you, Paul. For my second section I'm going to focus on really the exploration potential and adding further value.

It's not very often that you are fortunate to find a new basin. It's what every explorer dreams of, essentially, because it gives you a lot of running room, and that goes right back to the first slide I talked about, making sure that when you have a find you've got some running room. And it looks like we have it here. And as many of the talkers before, Martin, Chris and Rob, have alluded to, there is a good deal of running room in here. It is quite a large acreage position, and before we drilled these licences, Martin showed a diagram of the prospects and leads pre-drill, we've just managed to now do a couple of very, very important things, significantly de-risk those, but also now, with the very high quality seismic data that we do have, we are also able to refine them. And knowing that there is oil and gas there is a massive step forward. You can then, once you know it's there, you can look for lots of other things. Where else could that oil and gas be?

The source rocks that were found in the FAN-1 discovery were, as Martin said, kind of better than we had hoped, really. They were in the range of possibilities, but it was a good find and they are mature and we believe that they are pumping large volumes of oil upwards and into this Shelfal area, as well as it staying within the basin as well. And our job really is to find out just how much more. And it's quite difficult to imagine that with two wells in a big basin, both of which have found oil and gas, that they're the only two that are going to happen. And you know from the shows that were in these wells here, drilled by Esso back in the 60s and 70s, that indeed there will be some more. Onshore there are smaller gas fields, but to date, no oil that we're aware of.

So we've been very busy, if you like, trying to assess what it is that we have maybe in our acreage, and I think a couple of years ago, when we were presenting this area for the first time, we made an assumption or an estimate, a 'yet to find' estimate, as we call it, which is quite an arm wave, but it's a statistical approach to what might be in an area. If the models worked, we said about 1.5 billion barrels on risk in all. I think that what we've been saying today is with the field that we've found and the prospects and leads that we see risk we're perhaps looking at something just over one billion. I'll take you through some of that detail now.

We currently have five things that we call prospects. In other words we've got good enough seismic data, we've got good ties to it, we've finished our work on these, we think we understand all of those. We have many more leads, 18 at the moment but effectively work continues day by day as we mature our understanding in the area.

Now a lot of the maturity there to do with leads that need to be confirmed is to do with seismic data, and we do have seismic 3D of very good quality here. It's better than we would normally have. But even then we're reprocessing it, and we're seeing the first results of that reprocessing coming out just now. That should be finished in June some time. And we're also using it to invert, as we call the data, to try and link the rocks and the reservoir quality to the seismic attributes. And it does allow us to do a huge amount of quite detailed work.

Over the rest of the licence through we're quite thinly, by relative standards, spread in terms of seismic data. It's mostly 2D data there. You can see the green lines are the 2D data – it's how people used to explore some time ago. It gives you pretty good section approach; for the sort of detail we can now extract in 3D it's not in the same league. So we have agreed with the partners to acquire a new 3D over this part of the licence where you can see there are a lot of those leads. And that should allow us to convert some of those to prospects. Not all, we'll probably convert that – that's the nature of leads they're pretty uncertain at the moment – but some will, and we take account of that in our, if you like, risking of them, as I'll show you shortly. This is a large survey. We aim to do that this summer it's out to tender at the moment essentially. And we look forward very much to seeing the results of that later this year. It will be a key foundation for our understanding of the whole area.

Again, even before we started the drilling, as Martin mentioned, seven or eight plays were seen in the licence. We still see those. We've really targeted so far in the two wells about four of those plays. We've had success at SNE in one of these sorts of plays. A subtle variation on that is this sort of play where this wiggly line goes in, sealing non-conformity, goes in three or four directions. We have tested this play. It didn't work at the location in SNE-1 because it was lying beneath this area. It didn't work in SNE-1 it's not to say it couldn't work elsewhere, so we're looking elsewhere for that. We do see places where there are fault closures, there are canyons with fill in. We haven't attempted drilling any of these so far. This was the basin floor fans that we were looking at in the FAN-1 well. These definitely work; and we know these work many places around the West African coast. Often the question here is getting enough quality reservoir. And that seems to be one of the challenges for us to find out where the good reservoir there is in the basin. There are in parts of the licence south potential plays adjacent to salt related features. And also we know we have the edge of a carbonate bank, and sometimes around the world you get effects that create traps at the edge of these banks. So all these are seen.

Rather than go through all the prospects, because there's quite a large number, and leads, I'm just going to take you through a couple. I think Chris has already mentioned the Bellatrix prospect. I think in previous incarnations this has been called Buried Hill. It's one of these features where erosion in the sea has created a feature that traps like this. This is a map made in depth around one of those features. So indeed it looks just like it would if you were on an ordnance survey map. It's a structural feature, as is SNE-1, but in this case very steep dips basically on three sides. This is a line running across it here, seismic line. So it's this kind of feature here.

Interesting thing: this is SNE-1 one here, and you can see that parts of this feature overlie the northern end of the SNE field. And as Chris has mentioned, that's important, it de-risks it; but it also means that potentially you can drill an appraisal well in SNE and capture the edge of this prospect – one of the things that we're contemplating.

We've given a resource range here. This is a prospective resource, so there are no proven hydrocarbons here. But this is one of the larger prospects, so a mean figure here of about 160 million barrels recoverable.

Just to the north of SNE, another feature that is quite similar in trapping style to SNE. So this unconformity trap here you see is a flatter feature, but you see is essentially sealed on this unconformity edge here. Here's a seismic line across it, a similar age to the SNE-1 . And again, quite a substantial mean resource figure here. So, this is a prospective resource again. Before we were drilling the Shelf Edge fields and the FANS we would say probably one in six, one in seven sort of risk for geological chance of success. Of course the key, having found the oil and gas and found the reservoirs, is that those risks are now significantly reduced.

So those are two of the several prospects and leads that we have at the moment. We're continuing to work those. No firm decision has yet been made about which of these we're going to use or drill as our exploration well. That is something that the partnership will be coming to shortly.

If you take in mind the risks and sizes, this is a plot, it's a bubble plot – not quite the same axes as we have normally shown before. This is to try and eke out, if you like, more information on the prospects themselves. So you can see the geological success factor here – not commercial success but geological success – is on one axis; the gross risk resources on another. And you'll see the darker greens are our prospects where we are rather more certain of what the risks are. The leads, and many of them are actually uncovered in this cluster in here, much higher risk on the whole but quite a wide range of resource numbers in here. And it's the 2D data that is really trying to move these from leads into prospects and increase that. Hopefully they will migrate in the right direction.

The lowest risk here, Bellatrix, which overlies the SNE field to the north, or partially overlies it, a very high chance of success. You know you're on the migration path, you know you have a pretty robust structure. And there are geophysical attributes that you can use in the 3D data that give you a very good feel that some oil and gas will be found in that location.

So all together this is where we get our billion barrels from. We're not plotting SNE on here, because that's not a prospect. But if you take the P50 or 2C number there of 330 million barrels, if you sum the means of these prospects, that's about 380; if you sum the means of these much riskier leads that's about 350 million barrels – that takes you to our number. And that gives you a feeling, if you like, of the certainty involved. Certain we've got SNE-1; we've got a well for it. It is only one well though, but it's certain as a range of volumes, as we've explained.

The prospects we're pretty clear what size they are; we've got good 3D data over those. We've de-risked them significantly. So in the basin they've perhaps moved to one in fives; here they're one in three, one in two. Even better than that at Bellatrix. The leads remain pretty much where we were before because of the risk on traps there. But that's where we get the numbers from.

So I'll just finish up now just trying to summarise what all that means in terms of what value we think we can add. I think James will explain in his next presentation just the commercial side of this. But it's an attractive area to be. It's very rare that in one well, in SNE-1, that you get as much information back, as much certainty back from that well as we did in that well. The reservoirs are good. The contacts that we've identified from the pressure data are extremely clear. It ties the seismic data quite well. It tells you that there is some variability in the seismic depth conversion, which is the source of a lot of the variation that we have in potential volume. But that is very easily, if you like, dealt with by appraisal, as Martin set out in his logic behind how we're trying to choose locations there.

But what you can see is that if a number of these things come to be that we've got a good means to develop those within a relatively sensible area of development radius, 30kms. And that's the background to the slides really that Chris was showing. So that's a great place to be. It's a pretty exciting programme that we've got coming up. And there are not many places in the world that I've seen that you can, if you like, work such an area, brand new area of a basin with such good data, with a clear path to success, with clear follow-on potential. And it's a great project to be involved with.

It's early days. We're also very busy, as Paul mentioned, getting ready for the next phase. It's pretty good that we're in a counter cyclical point in the industry as well, because it is relatively straightforward drilling at SNE-1, we actually managed to drill that well on time and on budget last time as an exploration well. And now we know what we're dealing with we should be able to get those drilled very safely and quite quickly.

So I think I'll finish at that point and hand over to James, who will give an overview of the economics and funding in this project.

James Smith, Chief Financial Officer

Thanks, Richard, and good morning everyone. So in these last few slides before I hand back to Simon to sum up, I just wanted to set out some of the economic analysis that we're using as we look forwards towards the commercialisation of the resource base we've discovered in Senegal. Clearly we're at a relatively early stage in considering the detail of development concepts, and there are a number of significant variables as a result of that. But as we look across that range of different scenarios and assumption sets we do see robust commercialisation potential for what we have in Senegal.

As you've heard, we have a well-defined discovery at SNE-1, and as a result this economic analysis presented here focuses on the P50 case for a standalone development of that SNE-1 discovery. But clearly there is a significant resource potential beyond that.

Looking at minimum commerciality thresholds, we use a number of different metrics, but all of those triangulate around about a 200 million barrel threshold for a standalone development. Clearly there are a number of prospects quite close by to SNE-1, and the threshold for the development of those as tiebacks would be significantly lower than that 200 million barrel number.

So with what we have, which is a P50 estimate of 330 million barrels, and a P90 to P10 range of 150 to 670, you can see that we already have a relatively high confidence in the commerciality of the discovery.

As we've mentioned, we've submitted an initial evaluation programme to the government, which is up to six appraisal and exploration wells: three firm and three contingent. And we are agreeing a rig contract which reflects that process. So the beginning of that programme will focus on defining and proving out the SNE-1 discovery and the commerciality of that, and then we'll look to expand the resource base. And I'll come on to the funding plan for that programme in a few slides' time.

So on this slide we turn to the shape of our scoping economics for the SNE-1 P50 case. And this slide sets out the key assumptions and inputs for that analysis. You can see capex in the region of $20 a barrel; opex in the region of $10 a barrel, although it could be significantly lower than that. And those fit well within the analogue ranges that we have: so 17 to 26 for development, and you see five to 15 for opex. Those are all deep water FPSO projects that we use as analogues across West Africa, Brazil, Gulf of Mexico as you would expect. In terms of first oil, it's three to five years, as already been mentioned, from FID to first production.

To touch on the fiscal terms for the moment. We've got a relatively familiar structure, production sharing contract. It's a cost recovery mechanism, then a profit or sharing based on production tranches. And there's corporation tax set within the PSE and stabilised within that contract. The terms themselves are appropriate to the frontier basin nature of the licence. And the PSE structure provides fiscal stability, and the cost recovery mechanism, as many of you will be familiar with, clearly allows for the JV to recoup its investment from the front-ended cash flow.

If you look at the profile on the right-hand side of the page here, using all of those assumptions, you can see that's a roughly $3 billion development capital spend prior to first oil. And at that point we're ramping up fairly quickly here to a notional 100,000 barrels a day FPSO capacity from the discovery and potential tiebacks to it.

This slide sets out the economic results of that development model. And for that we've used three different price and cost scenarios. So in each of the two charts on the left-hand side you can see our base planning case, which is $90 oil. And that we tie to a cost environment that existed in the first half of 2014. Then as we set out the downside scenarios to that, $70, which approximates roughly to the forward curve, and $50 in a lower oil price environment than we have at current, we've done what we think are relatively modest cost reductions from 2014 levels of 10% and 20% respectively. As you know, the service sector has fallen more significantly than that since the first half of 2014 so it's quite possible to imagine scenarios that are more positive than these that we've represented.

The charts themselves show on the left-hand side an NPV per barrel at the point of project sanctions and on the right-hand side the project IRRs, life of project IRRs that is, again at the point of sanction. So as you can see for projects of this type, P50 case, you can see an extremely compelling case for sanctions certainly on our planning case, but also where the forward curve is, and even in a much lower oil price environment than we have. In fact when we look at breakeven analysis, so an IRR ten threshold for a project of this type, somewhere in the mid-30s to $40 a barrel. And clearly if costs had fallen more significantly than we've assumed then it could be lower than that.

I know many of you in the room, analysts in particular, will hear lots of breakeven analysis from oil companies, and that tends to be using different methodologies and different assumption sets. So we thought it would be useful to put that in context a little bit by showing our analysis alongside an independent piece of research. Here you see the breakeven oil price from Goldman Sachs top 400 global projects study, which many of you will be familiar with. And we've modelled SNE using exactly the same assumptions that they use and using the same return thresholds that they use to set it alongside those projects. And as you can see, it stacks up pretty competitively on that basis.

Moving back up to a Group level and thinking about the balance sheet and the funding position, this chart sets out the sources of capital and then the capex programme out to the end of 2017. And that's an important timeframe for us for two reasons: firstly it's when we're delivering production from the North Sea, so from 2017, we'll be delivering cash flow to sustain the business going forward from Catcher and Kraken. Secondly, it takes us through the evaluation phase in Senegal to the point where we're going to be thinking about sanctioning development phase for the projects we have there.

So as you can see we're well funded through to the end of 2017 to deliver both the committed development capital programme and the committed E&A programme, and indeed to follow on with six wells or more wells in Senegal to take advantage of the success that we have there.

The numbers here should be relatively familiar to some of you, at least the ones towards the left-hand side from the year-end presentation: there's a cash and debt facilities in blue there; the committed development capex for Catcher and Kraken through to the end of 2017, total $590 million. This committed E&A programme here is the programme we have in the North Sea, the end of the West African programme running into this year, and the 3D seismic programme that we've talked about in Senegal. We've shown there notionally the cost of a further three wells, so that's wells four to six that we submitted to the government, stepping down. And as you can see, as we move into 2017 obviously we're delivering operating cash flow from Catcher and Kraken which creates more headroom to follow on from success.

So just to reiterate again some of the key messages we delivered at the end of the year-end results presentation, which remain very much true: Senegal is the key focus for Cairn going forward because of the value potential there being so great. Nevertheless, we're doing that within a balanced portfolio and with a strong funding position to make sure that we continue to have the financial flexibility to deliver the programme and to deliver the strategy. Importantly we always have an open mind about actively managing the portfolio to keep the right balance and in monetising assets at the appropriate point to deliver the greatest returns to shareholders, and we'll continue to do that. But for the time being the focus is naturally on proving on what we've discovered in Senegal, expanding the resource base there; and moving it towards commercialisation.

At that point I'll hand back to Simon to sum up.

Simon Thomson

Thanks, James. So as you've seen I hope throughout this presentation we are absolutely focused on maximising value in Senegal as we lay the foundations for a multi-field, multi-phase exploitation plan. We're focused, very focused on achieving commerciality. To do that we're moving into a phase of extensive activity and investment. We'll by the second half of 2016 have completed up to six additional wells; we'll have acquired more 3D seismic and we'll be planning already for additional wells prior to the end of 2017, which we anticipate to be the exploitation phase. And the work streams and studies that we're undertaking ensure that our level of understanding will match our pace of process.

We will continue to focus on safe and effective operations. And we're already in the formative stages of an orderly handover of development operations to our partners, Conoco. We'll continue to focus on the value because we believe there is significant additional value to discover in Senegal. And we look forward to updating you with our progress on that.

And finally it's worth remembering that that focus is set against a backdrop of a balanced, well-funded company with a continued focus on allocation of capital and resources. In short, we are well placed to take advantage of this exciting opportunity.

So that concludes the presentation – a few minutes over one and a half hours. We are going to take a short break now and we'll resume for questions and answers in around five minutes. Thank you.

Q&A session

Simon Thomson

I think in view of no doubt everybody's got busy schedules, we'll kick off the Q&A. Just to remind everybody as this is being webcast if you could wait for a microphone and just say your name before you ask the question, that would be helpful. If there are any questions? Nathan.

Question 1

Nathan Piper, RBC

I've got loads of questions actually. I'll restrict myself. In particular on the relinquishment schedule on the block, you're obviously working very hard to keep as much of the acreage as you can, but you've got a huge acreage position and finite time and money. I know Rob alluded to it, but how should we think about how your acreage position could alter over time, whether or not you draw them, just the mechanisms of how the blocks work.

Rob Jones

The conversations that we've had with the Government have been along the following lines, which is that on the provision that we submit a meaningful, robust evaluation programme, we will retain the acreage as required. The presentation last week I think was very useful in that regard, though there is a common understanding between ourselves, joint venture and the government with respect to what needs to be done, and a clear recognition that the value for everybody is on making sure that whatever we develop is developed in a unified way. At the moment there are no particular issues, we don't anticipate having to relinquish large scale amounts of acreage until the end of the evaluation programme.

Nathan Piper

That's clear. And just a second question on the geology as you go into the shallow water. Obviously the water depth reduces but does the geology change, i.e., are you still targeting things that are 2,000 metres deep? And would you expect the geological characteristics to change, would the reservoir thin into the shallower water, or the unconformity change, i.e., have you got any risks around seal?

Richard Heaton

Essentially obviously we've only got two wells at the moment, one in the basin and one on the shelf. We've got the old wells from the Esso days, but they're on a particular structural feature. We are able with the seismic to map pretty continuously between them. We can use the seismic attributes in the 3D where we have it to see that there are places that look better and places that look less good than where we've already drilled. But that's a theory based on, if you like, looking at the seismic data in the one location we have. The next two or three wells we drill will be very important to actually give us some confirmation around that predictability. But we do believe we should be able to use it to that effect to say yes we can see that in the seismic. We don't know yet whether it thickens or thins so much, we haven't got 3D data going all the way back into the shelf. It will clearly vary a bit, but it's on a relatively stable shelf area so that carbonate bank that existed there did give it a reasonable platform. There will be input points for rivers, we don't know how many there are, that may have some variability as well. That's the sort of thing we'll find out through this drilling programme.

<u>Question 2</u>

Rafal Gutaj, Bank of America Merrill Lynch

Just turning back to slide 30 where you look at your appraisal targets and potentially where you might be drilling: you set out the objectives of each of these wells, but could you just talk about the risk profile? Also, if you've got any idea of preference at this point of where you'd be initially kicking off the appraisal programme?

Then secondly, you might not be in a position to discuss rig rates obviously explicitly, but it would be very helpful if you could give some colour on how things have changed versus your Cajun Express rig rates that you had over the summer last year.

Simon Thomson

For the better. I'll let Martin answer the first part; but on the second part you're right, we can't, the rig rate is confidential at this stage. But it does as we've indicated reflect current market rates, so yes, obviously a significant difference to the rates that we encountered with the rig last year.

Martin Dashwood

If I can take those two points in reverse order. In terms of preference, we're right in the middle of having those joint venture meetings and discussions. In fact, we've got a fairly major series of meetings later this month. I think what we would say is that we need to look at this as a group of wells, so I think we wouldn't have I feel like a first choice, we'd probably have a first pairing, and we'd look to have that pairing give us the optimal information to establish that minimum economic reserve size. So those discussions are ongoing.

In terms of risks, I think as we've said before one of the things we want to establish is reservoir continuity and connectivity. We've got a relatively simple broad domal closure, so I think it will be the architecture of the reservoir within that closure that will be something we need to establish. I think as we also mentioned, if you go back to our Boston Square, the other issue is depth conversion. We don't see that as a major risk but it's certainly an uncertainty, so we want to optimise the location of development wells, hence we'll look to appraise the areas where we feel there is some uncertainty. I think the other thing is, right now with the depth conversion again there's probably as much an opportunity for certain areas of the field to be taller than we currently see.

<u>Question 3</u>

Brendan Moynihan, BMO Capital Markets

Just a couple of questions. The first one to talk about funding to end 2017. Just flexibility and if you could give us any scenarios. Obviously if we see Catcher and Kraken late, what sort of impact are we going to see to your operational cash flows? And just see if I can get a better understanding of what expansion do you have on your RBL potentially; and do you see any funding pinch points to end 2017, and I guess the flexibility you have around your equity level in any projects going forward?

Then I guess just back on that same question in terms of appraisals of SNE-1, the discovery, how many appraisal wells are we talking about? I was surprised to hear it's going to be 30 development wells.

Can you make a comment, going back to your slide 29 on your matrix, if you can touch on reservoir compartmentalisation as well and what you know now from seismic and any work you've done, and how many appraisal wells will you need to do before you will have a better understanding of that concept?

James Smith

On page 59, as you were referring to, what are the risks around this? Well, clearly the key risk in here is schedule risk around the development project. We have a huge amount of focus on monitoring those projects and they remain on track and indeed on budget. As you can see from the chart on page 59, we're fully funded to deliver the programme through to six wells and potentially beyond that in Senegal without any of those cash flows from Catcher and Kraken. So that's not necessarily a pinch point on our ability to fund ourselves, although it's obviously a key focus of the business strategically and in order to maintain the debt facility. Does that answer your question?

Brendan Moynihan

Just what further flexibility do you see or will you use as a lever? Do you see any pinch points over the next couple of years in terms of equity in current projects, and that if you see obviously delay on any of your current projects obviously you might be heading towards a pinch point come end of 2017?

James Smith

We keep an open mind about having the right equity interest across the portfolio, and we'll continue to do that, but we'll do that for value reasons. I don't think looking at the funding schedule we need to do that for funding reasons even in the event of delay.

Chris Burnside

In terms of development well count, we've deliberately assumed quite a high number of wells at this point in time. As I said, it's a large area and in worldwide terms a relatively thin oil column, so you have to spread out the wells. That's going to be driven by reservoir connectivity, which we don't know too much about right now, it depends on the depositional environment. There's no obvious faulting so it could be very well connected. As you saw from the MDT pressure profile, certainly there's communication vertically within the reservoir and that may indicate that you've got good connectivity overall. If this was the case, then you'd be spacing your wells out a lot further and you'd have a much reduced development well count; but really the number of appraisal wells will be dictated once we've drilled the initial few. We'll have a much better idea of what we see and that's one reason for trying interference testing very early on. We may be able to test over several kilometres. And if we prove up connectivity, that will give us the confidence to go forward with a lower well count.

<u>Question 4</u>

Caren Crowley, Davy Research

Just a couple of quick questions the upcoming appraisal programme on the SNE discovery will that include a horizontal or high angle well?

Could you also guide what your expectations are in terms of flow testing that discovery?

And finally you mention a P50 figure of 330 million barrels owing to SNE; can you say what recovery factor you use in concluding that number? Thank you.

Chris Burnside

In terms of the initial appraisal wells, we're planning vertical wells at this point in time. We may look at horizontal or high angle wells later in the programme, but we think we can get the majority of the geological information more efficiently from vertical wells. As I said earlier, it's a relatively shallow depth below mud line,so we can drill these wells relatively quickly and relatively cheaply.

In terms of production testing, we're looking at the details of that right now but we'd probably look at testing both the thinner sands and more thicker, blocky sands within that test to understand the range in deliverability of the wells.

In terms of recovery factor, we have a wide range at this point of time and as I say that also depends on the nature of the sands. We expect very high recovery factor in the blocky sands, with a favourable mobility ratio with the light oil and water you'd expect good recovery. In the thinner sands we might get less efficient recovery and so we've deliberately discounted our overall recovery for that until we collect some more information in the appraisal programme.

<u>Question 5</u>

Elaine Reynolds, Edison

You keep talking about these thin and blocky sands can you give a range of the sand thicknesses that you're seeing?

And also were you able to establish any sort of permeability figure from your MDTs?

And on the FAN well can you say a bit about what's driving that wide range in your STOIIP please?

Martin Dashwood

The thickness of the sands or the variability of the thickness of sands with thin sands we're talking in terms of a few metres, to tens of metres. And the thicker, blocky sands we're looking at tens of metres sorts of ranges.

What was the next point?

Elaine Reynolds

Permeability from MDT?

Chris Burnside

Yes we ran MDT over the entire interval and got mobility data in addition to pressure data, which actually showed that we have very good permeability. In the thinner sands on top of the oil column, for example, we still see very high quality & permeability. So that's reflected in the porosities of mid 20s percentage.

In terms of the FAN, I'll let you talk about that.

Martin Dashwood

The high range of uncertainty or the high spread if you like on the STOIIP of the FAN is reflective of a few things. Firstly we've got a single well into really quite a large complex reservoir interval. We had no oil/water contacts measured in the well so that each sand is oil down to shale. And it's potentially a very, very large area without the contacts; just by its very nature the volumetric on certainty is quite large. But I think the range 250 million barrels to 2.5 billion is a very fair range and we'd certainly hope to reduce that uncertainty with the next well.

<u>Question 6</u>

Stephane Foucaud, FirstEnergy Capital

I will have two questions. The first is around the PSC and I wonder whether you could, I think you touched base on the fact that the working interest may change as you move to development phase, perhaps some colour on that would be great? And maybe if there is any ring-fencing on the PSC, on the cost oil taking place following an important initial discovery?

And my second question is more on geology, on the Rufisque block, I think you showed new prospects, one is just north and the other one is just south of the previous Exxon wells and I was wondering what are your thoughts of what Exxon missed at the time and what may be different in what you see?

Rob Jones

In respect of changes in equity, the only potential change in equity would be in respect of PETROSEN who could increase their equity during exploitation from the current 10% to 18%, but they will be a paying partner from that point onwards. And we factored that into our forward projections.

Rob Jones

Yes that's our conservative assumption. You asked a second question, which was in respect of ring-fencing within the PSC. We don’t assume any ring-fencing within the PSC on our model.

Richard Heaton

And on the geology the leads they’re not prospects around there so they really are at the moment just seen on single seismic lines. What we know is that the data that Exxon had available to them when they were initially acquiring the data and drilling these wells is very poor and they were drilling very much I guess what they thought were the highest points. Obviously we have a much more complete understanding now of what we think’s going on. We hope some of those leads mature into prospects but the fact that they’re down at the one in ten to one in seven level tells you that some will and some won't. So it’s early days yet.

<u>Question 7</u>

James Midgley, Mirabaud Securities

I think it’s one for Richard. You talk about potential multi-field, multi-phase developments, does gas form part of your plans going forwards?

And can you talk about how you expect the phase to change across your acreage position, maybe with reference to Bellatrix and the old Esso wells as well please?

Richard Heaton

And Chris can chip in I think if he has any further information. Essentially the gas is going to be used for reinjection in order to optimise the recovery of the oil. I think obviously at some point well into the future it may come that we have to consider what to do further with the gas but that's not at the moment in any of our evaluation plans, in the immediate future.

James Midgley

And with Bellatrix is there a gas risk there would you say?

Richard Heaton

I think that we have taken into account in our volumetrics that there are obviously a range of possibilities for what the gas versus oil split is going to be, so there's an assumption in there that there is likely to be some. But as in SNE we don’t see that as being particularly large in the most likely case.

Question 8

David Mirzai, Société Générale

A few questions for you: first, just on Senegal and resource nationalism I've obviously seen a few of the African governments in countries I cover operating and bringing in new rules and then backdating them, is there any way to mitigate this? And does Senegal have a history of this in other regions of its primary development?

Simon Thomson

Well I think the first point to answer is that there's never any way in essence for a company to mitigate against a government action other than doing what the company said it will do. And I think from our perspective we've gone in, as you've understood today, at a very short timescale, invested relatively large sums of money, and proved up what we believe is a major resource for Senegal. I think there's a level of understanding at the governmental level of experience, because there is some existing onshore gas production, albeit fairly limited, in Senegal, of the way the system works from the point of view of PCS management. You can never predict the future, but I think right now they're a country who recognises there is a potentially very substantial resource which could be for a significant benefit for Senegal, so I think they're very focused on allowing us to move forward under the current terms and get to proving a commercial discovery, so I don't see that.

David Mirzai

Secondly, just on the geology, I've seen a number of initial discoveries in the Atlantic margin region fail to impress with the follow-up appraisal wells. Now a lot of that has been down to those have less structural elements, you yourselves say there's lesser risk of faulting and that you can see an SNE. In that case, what are your key risks around volumetrics on SNE?

Richard Heaton

Essentially, what we've well defined in SNE is a gas oil contact and an oil water contact and we've got that very, very crisply. That's one of the things that we have in depth and we know exactly where that is, and we can intercept all the reservoir units in depth because we have the log. But if you can imagine, you've got one 8.5" wide hole, you've got 60-100 square kilometres of area, and the reason there's that wide range of area is that the depth conversion, which we've talked about two or three times, the overlying geology is quite complicated with a series of river systems that have come in and cut channels and canyons and then refilled them.

What it means is that in moving from the timed domain, because seismic is just how long does it take the noise to bounce back from the different rock layers, you've got to convert that time it takes to depth. And if it goes through lots of different sorts of complicated sort of rock, then you get quite a varied answer over the field. We've just go the answer at one point at the moment, which is in that well, you know it for sure there. What we have is a range of possible answers around about it. So if we look at the different variables in the input, that is really a gross rock volume variation, much of which is driven by the way that you do the depth conversion. So you can honour all the data and you can still come up with this variability.

However, what we also have is we have seismic attributes in the 3D data that give us a pretty good idea of where the reservoirs are, and, we believe, according to the well, where the actual different fluids are. So we're able to put some markers on that but it's still quite a range at this point. The next two or three wells will be very key, and that's the whole point of them, is to narrow that range.

David Mirzai

Thanks. And just lastly, on the oil provenance, as I remember, the original FAN-1 well intercepts a number of different source rocks, which created a number of different sources of hydrocarbons, whereas the SNE well was predominantly one hydrocarbon type. Have you done any studies regarding how you've arrived at just one oil type at SNE when the migration route probably would have allowed all of the oil types that way?

Richard Heaton

Yeah, obviously we have done a very large amount of work there. To a large extent, it's quite informative for us to know all that detail, but probably not a good idea to tell everybody else all that detail! So we've kept much of that to ourselves for the moment, but it does help enormously in our confidence in being able to understand how the basin is plumbed, so it is an important point, yes.

<u>Question 9</u>

Alessandro Pozzi, GMP Securities

I have a follow-up question on SNE in regards to the two appraisal wells and I was wondering if you can give us maybe more colour on how the two appraisal wells will be able to de-risk the 3C contingent resources and whether they are going to be trialled in the P10 area of SNE?

Chris Burnside

I think that comes back to the depth conversation, primarily.So we will select the locations for different drivers, as was illustrated in the talk, but there are some areas where you could prove up the high side. It's a big structure, as we said 60–100 kilometres and that's the relief of the structure. This is the depth conversation issue that Richard was just talking about. So if we step out a little bit, they'll tell us more about the GRV (the Gross Rock Volume), and the size of the accumulation, which is the biggest upside.

Alessandro Pozzi

So if the essential well comes in, it will still help you de-risk in the 3C, or you're relying more on the flank wells?

Chris Burnside

I'd say the big thing about that is it gives you a second control point on your velocity models for your depth conversion, so that makes a huge difference. A combination of wells really helps you decide which is the best depth conversion and therefore what size of structure you have. Two or three points triangulated really helps largely reduce that uncertainty.

Alessandro Pozzi

And the last thing on well cost, would you expect the cost of the three wells to be compared to the previous one that you drilled in the area?

James Smith

I mean we won't give out well-by-well guidance, but the estimate we've given for the total programme, which is the three wells, assuming that two of those are cored or tested in a success case, and the 3-D Seismic Programme, so that's the committed programme, if you like, that we've submitted to the government, the firm programme of US$95 million. Sorry, that's net again.

<u>Question 10</u>

Tom Robinson, Deutsche Bank

A couple of questions from me. The first on follow-on potential. Can you talk about what insights the two discoveries have provided elsewhere in your Atlantic Margin portfolio? Or, indeed, the acreage that sits outside of your portfolio that you may start to think looks interesting now.

And then secondly, just to come back on the previous comments on gas and development, could you talk about the government's expectations for gas and if some of the additional prospects were to be more gas related rather than oil, does there become an expectation for some of that to be used domestically?

Richard Heaton

On the first one, clearly it wouldn't be sensible to give too many details away about exactly how far we think the lessons learnt from here can be applied. I think many folk have worked this margin for a long time, many people looked at this acreage before we did and decided that we made it work, or took the plunge and have now made that work. I think there are undoubtedly lessons that you can take from here and we and others will go back and say, are there any of the things that can actually apply elsewhere? There are similar sorts of discoveries of different sizes along the African Margin to this. I don't think that, without considerable study, going back and poring over lots of old data from right around the margin, it will be possible to say and a light suddenly goes on and say, ah, we need to be drilling there. It will take a little bit of time to pull that together, but that is indeed the question we are asking ourselves at the moment, but obviously to give away what we think of that at the moment would not be a sensible thing.

James Smith

I think on your second point, a perfectly reasonable question. I think right now, our focus, and that's what's in our evaluation submission to the government, is to use the gas for reinjection, to optimise oil recovery. I think anything in the future is an issue for the future, and right now, the government's absolutely aligned with our approach.

<u>Question 11</u>

Michael Alsford, Citigroup

Just a couple of questions from me as well please. I just wondered if you have done any work on what the commerciality threshold would be for development in the basins. So, for example, the FAN prospect, what would be the threshold there for that structure?

And then just secondly on Cairn India, I have to ask, but could you maybe update on the process, have you had any formal or informal discussions with the government and the authorities there please? Thanks.

Simon Thomson

Yes, on the second one, we've had lots of discussions with the government, formal and informal. Where we are on India at the minute is that we are in a period where we have submitted our notice of arbitration, we're in discussion with the government regarding that notice. We've appointed an arbitrator and we're waiting for their response. The dialogue continues, and you no doubt will have seen there's been a lot of press recently about the focus amongst the Indian authorities of seeking to resolve legacy issues quickly. So we're waiting for a response on that.

On your second point I'll let James answer.

James Smith

It's early days in terms of the information we have to give an accurate answer to that. Clearly it's a PSC with a cost recovery mechanism. Increased investment levels come back quite quickly from cash flows. Clearly it will be more expensive to drill in the deeper water; but in terms of well density and so on I think we're at a pretty early stage of working that out. Indicatively it might be 300 rather than 200.

<u>Question 12</u>

Kate Sloan, Macquarie

A couple of questions from me please. Firstly, partner Conoco, obviously very big company; could you just talk a bit about their commitment not only to the near-term programme but to progressing a development with the pace you've talked about with the early stage stuff?

And just secondly on the funding side of things: the blue bar on page 59 suggests that the RBL size has come down quite significantly. Could you just confirm the number we're looking at now versus the 575 that we had last year?

Paul Mayland

Just on Conoco I think it's obviously for them to provide guidance on what they think of the project, but certainly at the joint venture level and operational level they've been very supportive. I think at their earnings call on 30th April certainly Senegal got a mention in terms of their exploration. So I do think it carries quite a high profile in the company.

And in terms of the people that they've got working on the project generally pretty supportive. I think the joint team brings together the two skills of the respective parties, Cairn and Conoco. And certainly through the evaluation programme I think they'll move forward at the pace which has been set and agreed and presented to the government. So we're pretty hopeful that they're very aligned with us.

James Smith

On the debt availability the bar on page 59 is intended to represent roughly what we think will be the drawdowns ultimately for Catcher and Kraken funding. The size of the facility itself as you know is $575 million. As we said in the inception, around about 150 million or so of that we use for letters of credit, guarantees and other operational performance guarantees. And therefore at inception we anticipated that around $400 million would be the cash drawdown to fund Catcher and Kraken.

Now since that point we've farmed down a third of our interest in Catcher, and the bank's price decks have come down a little bit from low 70s to high 60s. So, those two factors combined probably reduce that from 400 to more in the 300 region.

Question 13

Sanjeev Bahl, Numis Securities

Firstly, with regards to the development is there pressure from PETROSEN and also from ConocoPhillips to potentially oversize the first developments rather than focus on an EPS that could accelerate cash flow? Just maybe if you could comment on that?

Secondly, when we look at overall capex, first of all I presume that includes a purchased FPSO? There seems to be quite a wide uncertainty range on per well EUR, with drill ex being quite a large part of capex. I'm just wondering whether you could comment on how much a completed horizontal well would cost and that uncertainty range.

Rob Jones

I think it's fair to say that in all of the discussions we've had in respect of everything we've shown today there is very full alignment. We needed to have that in order to submit the programme to the government last week. In respect of how granular we got in terms of plans, most of what we've shown today is conceptual. And clearly the purpose of the evaluation programme is to gather all that relevant data so that we can be more definitive about the way things progress after that. But we are completely aligned with ConocoPhillips, and we have full support from PETROSEN in that regard as well.

Chris Burnside

In terms of the FPSO, our current assumption is that it would be leased.

In terms of oversizing, it doesn't actually cost that much extra to get a slightly higher oil capacity, so we would want to have adequate fluid handling capacity on the FPSO -so I don't think that would be a big bone of contention. A little bit of extra capacity is probably not a bad thing, particularly when you have a portfolio of potential satellites to tie back to it at a later date. But obviously none of that work has been done yet.

In terms of horizontal wells it really depends on the complexity for the cost. You're starting probably at one and a half times the cost of a vertical well. But a lot of that will depend on things like sanding issues and the complexity on how you target the individual sands. As I said earlier, we have a combination of thicker sand and thinner sand, and maximising recovery from the entire oil column is going to be key. So there might be some added complexity to those wells that actually would add to the cost. But that would always be done on a value basis. That's probably all we can say right now.

Simon Thomson

One more? And please, if we haven't covered all your questions we'll be hanging around afterwards; feel free to ask.

<u>Question 14</u>

Unnamed Analyst

The question I had is you hadn't shown it in this presentation but you had previously shown amplitude responses conforming to structure associated with this particular discovery. My question is: was that predominantly a gas effect or an oil effect or was it some combination of both? The slide that you did show on here was a spectral decomposition as a seismic attribute. I was curious if there was a particular frequency domain that was more predictive than other frequencies; i.e. was it a low frequency domain or a high frequency domain that gave you the better response because it stood out quite noticeably on SNE-1?

My final question was just on the appraisal well; it's not really an appraisal question. On the eastern flank appraisal well it does appear that you could intersect a Cenomanian target that you showed as an exploration target. But you hadn't mentioned that when you were talking about the actual appraisal programme. So my question is: how significant would the choice of the eastern flank well be to test the Cenomanian potential exploration target?

Martin Dashwood

The specific attributes I think we really feel that that was work in progress. And it's also something I think we're keen to keep in house at the moment. It's something which we're still reviewing with joint venture partners. And getting into specifics of high and low frequency I think is something we'd rather not do in open forum.

Simon Thomson

The flank appraisal well?

Chris Burnside

I think that's something we're looking at. It's just in terms of Bellatrix is quite close, and that could be combined with an appraisal location. But the details are still being worked with joint venture, so whilst that's a nice synergy,we wouldn't like to bank it just yet until we've had further discussions with the joint venture.

Simon Thomson

I'm conscious that maybe a couple of other people want to ask questions, please feel free we'll be hanging around. But I'll draw things to a close now and thanks very much indeed for your attention. Thank you.