



Cairn Energy

Preliminary Results 2017

Tuesday 13th March 2018

Simon Thomson, Chief Executive Officer

Morning everybody and welcome to Cairn's results presentation. I'm Simon Thomson, Chief Executive. With me are James Smith, CFO; Paul Mayland, COO; and Eric Hathon, Exploration Director.

So in the usual way we've got a presentation to run through with you this morning and we'll be very happy to take questions at the end. It is being webcast so there will be microphones available if you do have a question.

Turning to the first slide. Cairn's strategy is to create, add and realise value for shareholders. These last few years have seen the company rebuilt, we now offer a fully funded, full cycle sustainable portfolio with an active development pipeline and a multi-year material exploration drilling programme.

For that exploration we continue to focus on gaining large acreage positions with follow-on potential in attractive fiscal environments and an appropriate level of equity risk. So we're always looking at that balance of cost, equity and reward.

If you look at the bottom left of the slide, in terms of our portfolio and running through the various steps, first of all in terms of identification, we're constantly seeking to identify new opportunities to bring into the portfolio. So the two blocks in Mexico last year were an example of that and also Suriname which we announced today. We have a very active team and I expect that we will be bringing other opportunities into the portfolio during the course of this year.

They lead to that next step: exploration. As you know we've got an active programme in the UK and Norway over the next couple of years, targeting over a billion barrels gross of unrisks resources. In fact we're currently operating two of those wells. And in Mexico next year a lot of activity is ongoing now to plan for four wells over 2019 and 2020, again, that's targeting over a billion barrels gross across those two blocks in terms of unrisks resource potential.

Where we do have success in exploration we quickly move to appraisal. So last year saw the successful and safe completion of the third phase of Senegal drilling, so that field is now fully appraised.

That leads us to development. Obviously we have two developments moving forward to FID: one is Nova, formerly Skarfjell, and the other is the SNE development in Senegal. As you will

know, both of those have been generated from exploration discoveries within the Cairn portfolio.

We will talk today about Kraken and Catcher production. 25,000 barrels a day net to Cairn at the mid-year on plateau. As I say the developments within the pipeline will sustain and enhance that plateau. That production provides us the cash flow in terms of the ability, the final step there, to be able to not only reinvest in the portfolio in both sides, in the ongoing exploration activity and maintenance of that production profile, but also potentially at the time of our choosing to monetise and potentially enact further returns to shareholders.

Now, all of that is carried out against the backdrop of continued capital discipline and prudent balance sheet management.

James Smith, Director of Finance

Thank you, Simon, and good morning everyone. So on the next few slides I'll take you through an update on the current financial position as well as guidance for 2018. Then we'll take a financial overview of the two development projects mentioned, Nova and SNE, which Paul will then go on to expand on. And then finally we'll take a look at the longer-term cash flow shape of the business.

On slide five, you can see with regards to the funding position at year end the cash on the balance sheet \$86m, a Norwegian tax receivable in respect of 2017 exploration activity in Norway of \$38m, and the debt facilities, the RBL facility for the North Sea remained undrawn with availability at year end of around about \$200m.

Looking forward to the capital programme and cash flows for 2018, you can see the RBL development expenditure expected of \$140m across Catcher and Kraken, and I'll come onto some more detail on that in a moment. Currently committed exploration appraisal spend of \$95m, and that facility undrawn at year end, we expect the capacity under that to increase during the year as Catcher and Kraken go through the final stages of commissioning and to peak at around \$400m later in the year.

Production guidance for the year net to Cairn, as we've already guided, 17,000 to 20,000 barrels a day, with opex of \$18 a barrel on average across the two fields net to Cairn.

Around about 30% of that expected production for the year is hedged with a floor price of \$58.40, effectively to enhance debt capacity and underpin the committed forward capital programme.

As ever the business plan is fully funded without the value, or in the absence of the value of our investments in India. Our \$1bn of investments there are frozen by the tax department, and that dispute continues. Indeed the tax department has been pursuing enforcement action in 2017 against income due to us. But ultimately the resolution of that dispute is going to be via the Sovereign Treaty arbitration process, which as you know is now well advanced. Final submissions are due shortly and the hearings will be in the second half of August, with an award thereafter, probably in Q4 of this year.

As a reminder, our claim under that treaty process is for \$1.3bn, effectively the value taken from us in 2014 when the shares were frozen and other income that's been seized since, on the basis that that has breached the protections available to us under the investment treaty between the UK and India.

So looking back now at the cash flows in 2017. The opening cash position \$335m. Financing cash flows in during the year, principally the completion of the Flow Stream royalty financing on the additional equity we acquired in Kraken in the prior year, \$75m. You can see the first capital item across UK and Norway, \$60m spend, that was the Tethys well which is ongoing, planning for this year's multi-well programme in Norway and UK, and seismic processing. That \$60m should be considered net of the \$29m drawing on the exploration financing facility; so effectively net of tax rebate that's \$31m spend in the UK and Norway.

In Senegal \$103m, that delivered the five-well appraisal and exploration programme for the original budget intended for four wells, so we expanded that programme and delivered it well under budget, as we previously announced.

In the international region, \$67m. That's principally the Druid Drombeg well in Ireland and Mexico entry costs and seismic purchase costs associated with entry into Mexico, and other seismic costs across the portfolio. And then finally the development spend during the year, \$146m, that was split \$98m on Kraken and \$48m on Catcher.

So if we take that with the admin charge for the year and the operating cash flow, which is disclosed in today's preliminary results announcement, the first cargo sale on Kraken, the settlement of our Mongolian royalty income, net of opex for the year, with the tax rebate due from 2016 activity in Norway of \$30m takes you to our year end cash closing position of \$86m.

Looking forward now to the capital programme for 2018. You can see here the split out of that expected \$140m on Catcher and Kraken remaining development spend. Catcher that is for the ongoing development drilling during the year as well as the first oil payment to the FPSO owner when first oil was reached, paid in January.

On Kraken that \$70m will be for the ongoing DC4 drilling and subsea installation, and also includes a \$15m carry over from 2017 activity, cash outflow in respect of 2017 activity.

And those development costs don't yet include what we expect to be the beginning of Nova expenditure, sanction for that in the coming months.

The remaining items: Senegal predevelopment spend, \$35m across the international portfolio, including predrill exploration costs in Mexico and the close-out costs for the relinquishment of our acreage in Western Sahara.

And then finally \$35m net of tax rebate, that guidance is provided for the Norwegian and UK drilling programme, expected four wells this year, and some associated seismic costs. That's a total capital expenditure for this year currently committed of \$235m.

Looking now at a financial update of the SNE project. As we've previously said, we're targeting approval by the government of an exploitation plan covering the full half a billion barrel resource base in SNE this year. Phase one of that development plan will be targeting principally the deeper S500 reservoir sands, 240 million barrels with target peak production of 100,000 barrels a day.

We're reiterating today our capex guidance for the project across all phases of \$12 a barrel. Phase one will obviously be slightly more weighted towards subsea and production facilities, and subsequent phases more weighted towards drilling expenditure. But in aggregate around about 60% of that total development cost will be well related.

That translates into capex prior to first oil net to Cairn of about \$800m, with first oil expected in the period 2021 to 2023, and we've already begun work on the project financing of that capital spend.

As you know, it's going to be an FPSO development. We assume for these economics that it will be a leased FPSO and as we've announced it's relatively likely that that may be a redeployment of an existing FPSO vessel.

So that leads to all-in opex, including the FPSO leased in the range of \$10 to \$14 a barrel, with that range predominantly depending on the vessel candidate used for the development.

So if we take all of those inputs together with the attractive PSC structure, if you recall it's a 75% cap on cost recovery and then the government participation directly in the project between 10% and 18% through Petrosen, and then profit oil through the PSC terms at around 20% expected for the production levels that we have, all of that gives very robust economics, even at \$50, as you can see, and we calculate that the IRR ten breakeven of the project at FID was in the mid-\$30s Brent.

So moving to look at Nova, formerly called Skarfjell, which is up for sanction by the joint venture in the coming months. This is an 80-million barrel oil equivalent field in which we participate 20%, discovered in 2012 following our acquisition of assets in Norway. It's going to be developed as a subsea tie-back to the nearby Gjøa field, and as such development costs of around about \$15 a barrel over the life of the development, which translates into net capex to Cairn of approximately \$200m.

As a tie-back it's a relatively low opex production, \$7 per barrel at peak production. And so all of that again delivers robust economics. You can see there project IRRs unlevered at \$50, \$60 and \$70 Brent. It also is a project that fits very well into the cash flow profile of Cairn.

Looking out now over the slightly longer term through to SNE coming on-stream. You can see production growth from this year into next as we have Catcher and Kraken coming fully on-stream for a full year in 2019, and thereafter Nova coming on-stream in 2021, which sustains that North Sea production base. As I mentioned, development costs net to Cairn prior to that Nova production coming on-stream of about \$200m. And we expect to be able to draw substantially on the existing RBL facility in order to support that development expenditure.

That gives us a position from the North Sea where we're generating at \$60 Brent sustainably about \$350m of operating cash flow through to the period when SNE comes on-stream. And that's a very solid funding base in order to deliver those developments.

We have SNE coming on-stream there; clearly a very transformational event for the portfolio. Whether that's from the production uplift with us continuing at the current participating interest or whether it's the opportunity to monetise part of that interest during the development process, but working on existing participating interest, that's net capex to Cairn of about \$800m. We've already begun work with the JV and the government on project financing for that. So on the basis that we will be able to leverage about 50% of that expenditure for debt funding, that capex is clearly something that can be easily sustained out of the North Sea cash flows.

That said, of course we always actively consider portfolio management across the asset base in order to optimise our capital allocation. But the important thing is that we have the funding flexibility to be able to make the choice to do that at the optimal point for the portfolio.

I'll hand over to Paul to talk about the projects in more operational detail.

Paul Mayland, Chief Operating Officer

Good morning ladies and gentlemen. 2017 was a very successful year for Cairn in terms of delivering a number of operational, development and production milestones. Our operated drilling projects were successfully executed without lost time injuries, and included the wells in deepwater offshore Senegal. We also actively participated as a partner in the deepest water exploration well ever drilled, in Atlantic Ireland. Wintershall as operator completed frontend engineering and design studies on the Nova field, and both of our UK North Sea projects came on-stream just over three years following final investment decisions.

2018 also contains a number of significant planned milestones for the company. In Senegal we plan to prepare and submit the Evaluation Report formally documenting the end of appraisal in the first half of this year. Then the Exploitation Plan shortly thereafter, which is a full life of field development plan targeting a plateau oil rate of 100,000 barrels of oil a day.

We aim to commence and in progress through front end engineering and design with key contractors for SNE Phase 1 and Senegal. The plan for development and operation (PDO) for the Nova field will be submitted to the authorities in the first half of this year, and a final investment decision on that project taken by the partners thereafter. And on both fields in the UK North Sea, we're anticipating continuing to optimise the production performance. The operator, EnQuest on Kraken, is already producing steadily between 40-50,000 barrels a day. And on Catcher, Premier plan to complete FPSO commissioning to raise from our current levels of up to 30,000 barrels a day, to the targeted plateau of 60,000 barrels a day.

The SNE project in Senegal remains on track with the schedule we first outlined to the government and investors following the discoveries in late 2014. Three years later, we have successfully concluded appraisal and completed the concept select stage, and this was established following integration of the final appraisal well data and the met-ocean environmental and geotechnical data gathered in the last year. The Environmental and Social Impact Assessment associated with the project, which outlines the benefits the project may bring and how the project risks will be successfully managed, is targeted for submission before the summer. The Exploitation or Field Development Plan, as I've already said will follow in the autumn.

This plan will see SNE developed in several stages, allowing for oil and potentially gas sales. An initial phase focused on the lower better quality reservoirs, but including an important component of the more extensive upper reservoirs which contains approximately two-thirds of the overall 2C resource. A further phase which extends the subsea production system and adds further development of the upper reservoirs. And a third phase seeking to maximise economic recovery of oil and gas from the field. This overall plan will be very typical of West African developments. We're targeting approval by the end of 2018, at which time we expect to have progressed FEED with the preferred contractors.

The diagram illustrates the preferred concept of two initial subsea production flow loops, one North and one South of an existing submarine canyon feature, connecting subsea wells via a turret moored FPSO on the eastern part of the field in approximately 800 metres of water.

Tenders for the FPSO and for the subsea production system and the subsea umbilicals, flow lines and risers, have been issued to the contract community. We expect a lot of interest in this project, and Woodside have already completed, on the JV's behalf, a very comprehensive engagement process such that the project is very well understood, and we believe will be competitively bid for, recognising it will be the first offshore oil project in Senegal.

This project like any other has some unique features, but overall it benchmarks well with other West African oil projects. Following extensive reservoir modelling in 2017, recoveries per well, as shown in the diagram, are consistent with the typical range for relatively shallow reservoirs developed under water flood with low viscosity oil. The light sweet nature of the crude positions it well for local African and international markets, and should attract strong pricing.

If we move on to Norway. Operator Wintershall has optimised the Nova project, and incorporated their experience from the similar Maria project, which was also a subsea tieback. The PDO is prepared and is anticipated to be submitted in the second quarter this year to the NPD for a project that will deliver 50,000 barrels of oil a day on plateau, and develop gross reserves of 80 million barrels of oil equivalent. The Nova fluids will be processed on the Gjøa host platform, which will involve a single module installed on an existing slot. Development drilling will commence in 2020, and first oil is expected in the second half of '21.

On Kraken we have much improved production uptime, and are now consistently producing between 40-50,000 barrels a day when all 11 existing producers and 10 injectors are online through the process trains. Uptime for both production and injection systems in January and February was particularly good, and it was only the extreme recent weather that we saw right across the UK that disrupted this performance and resulted in a shutdown. The JV has now taken the opportunity during this shutdown to bring forward as much as possible of the operator's previously announced process improvement work, which was previously scheduled for April and May.

The objective for 2018 is to continue this good performance, and to optimise production and injection across the field allowing for these process improvements. Then in the second half of 2018, to complete the subsea scope for drill centre 4 and drill and complete the remaining four planned development wells, two producers and two injectors in a central core part of the field.

The full cycle capex is down 25% from the Final Investment Decision, and with regular liftings now established strong interest has been shown in the crude from European, US and Asian buyers.

And last but by no means least, all of the JV was delighted to achieve first oil from Catcher just before Christmas last year. The plan in 2018 will be to complete the commissioning of the FPSO and to ramp up to the production target levels of 60,000 barrels a day before the summer. Full cycle capex is down 30% from the final investment decision, and 14 of the planned initial 18 development wells are now complete.

Reserves have been upgraded slightly, and strong interest has been shown in this medium API crude, with it currently trading at a small premium to Brent. And looking out further on Catcher, the JV is evaluating possible development of satellite discoveries in the vicinity of the FPSO.

So, in summary, a successful 2017, and we're already making strong progress against our planned operational milestones in 2018, including our first operated well in UK continental shelf where we are close to finalising a rig slot for this summer.

I'll hand you over to Eric to talk through our exploration growth plans.

Eric Hathon, Exploration Director

Good morning everyone. I'm very pleased to be here. This is my second results presentation since joining Cairn. We've had another very active year in exploration in 2017, and we're going to continue that trend in 2018 and beyond.

As you've heard from Simon, from James, from Paul, Cairn is now a full cycle E&P company. We have production at Kraken, Catcher, anticipating FID at Nova this year. But exploration is still a key to our continuing to create value, a robust portfolio of prospects which leads to a number of material drilling targets is critical to that success. Our goal, is to have consistent results on a three year rolling average.

As we enter 2018, our exploration focus is moving from Senegal to a very active UK & Norway programme, and we continue to add acreage to our portfolio, including the blocks in Mexico and the new block in Suriname.

So first we're going to recap our efforts in Senegal where we had a successful third exploration and appraisal programme, and we're now moving into the development phase. We've talked through these wells in detail previously so I'll summarise by saying we drilled five wells, all five encountered hydrocarbons, both oil and gas. We're integrating the results of the programme into our view of both the SNE field as well as the FAN and FAN SOUTH complex, and assessing additional opportunities.

As you've heard most interestingly, the SNE NORTH well found hydrocarbons in the S500 Series below the field oil water contact at SNE, which demonstrates that it is a separate accumulation. This has very positive implications both there and farther north here in the Spica prospect, where data suggests that in the S400 Series an oil accumulation could extend well north into it. Our work programme for both Spica and some of these other areas have been submitted and approved by the government, and we are now looking forward to developing potential additional opportunities.

If we go to UK/Norway, we have entered into an exciting phase where we have matured our portfolio and have entered into drilling. The Tethys well spud, and the Raudåsen well has also spud.

All of this, as we've talked about before, is consistent with our strategy: we build a portfolio; we refine it; we mature it; we drill out best opportunities; and we realise value. Of course the additional benefits in the UK and Norway is you have an abundance of infrastructure, so both standalone and tied back developments are possible in a relatively short period of time. In addition, the tax environment in Norway makes exploration very cost effective. As we've said several times, our plans are to drill up to 10 wells by the end of 2019, and we are targeting over 1 billion barrels of gross unrisked resource at a very modest cost, in a prolific hydrocarbon basin.

We've recently had the round table on our Norway programme in January. I won't go into more detail other than to say as we heard the initial Tethys exploration well, the initial vertical well has TD'd, and we're now drilling a side track to that. The Raudåsen well spud last month and is currently drilling ahead, and we'll have results on both of those wells shortly.

Finally, I'll say Cairn will be operating our first operated well in the UK this year, and our first operated well in Norway next year, so another milestone as far as operatorship.

Now moving on to Ireland, where we completed the frontier Druid/Drombeg dual target well in September. While both the targets were water wet we did find excellent reservoir in both

intervals, and we took and gained significant knowledge from this well, the southernmost well drilled in the Porcupine Basin. We're applying those learnings to our 16/18 and 16/19 blocks where we have a brand new 3D survey.

This is what we like to do, we core up in an area, we get multiple opportunities, and then the well results, whether success or dry hole, we can then apply those results to other acreage in the area. And that's how we build and generate synergies.

From this new 3D is an example from this data, here's the seismic line, here's the surface, and these sort of yellow and orange events coming through, those are turbidite channels and turbidite fans that are ponding on our block, which demonstrates clearly the presence of reservoir on the block. Now that's not the only element we need, but that's a big one, and it's really exciting to see that and it demonstrates what you can derive from state of the art technology.

So given this encouragement and the high working interest we have on both of these blocks we will be looking for partners this year. It's early days here with brand new seismic, but that data's showing significant promise.

In Mexico we are planning to continue to mature the prospects we identified in the bid round last year, and we are to drill at least two wells in 2019. At least one operated by Cairn and the other operated by our partner, ENI, in Block 7. Now we're submitting the exploration plan for our operated Block 9 to the government this month, and their approval of that plan starts the four year exploration phase. So we're at the very beginning, although we have done quite a bit of work already.

ENI, the operator in Block 7, will also be submitting the exploration plan for that block this month. And we continue to work the additional offshore bid rounds, including round 3.1 which is the acreage you can see on the map marked out in green. So we continue to look for additional opportunities.

Finally, and something I'm really excited about, is we're introducing our entry into Suriname, and this basin of course has received a lot of attention, primarily from ExxonMobile's activity in Guyana to the West. I'm sure you're all familiar with that. Now, Suriname, as you can see on the map, is the conjugate to Senegal, you can see our Senegal block, and this is a paleogeographic map from the middle Cretaceous, about a hundred million years ago, and before the Atlantic Ocean had completely opened these were adjacent areas. What we've done is we've taken proprietary knowledge we've gained from our activities in Senegal to speculate on prospectivity in Suriname.

Today this is an immature frontier licence and we need new seismic data, we'll shoot 2D, potentially 3D data, and we'll have to do lots of work before we know if we have drillable prospects. But what's really exciting is we took proprietary knowledge, we applied it in an innovative way, and it's allowed us to enter a frontier area early, and that's often where we realise the most value.

In summary, what I want to leave you with is we have a robust portfolio of exploration opportunities at various levels of maturity, including drill ready prospects in UK and Norway where we have already started drilling. And Mexico which is maturing into 2019 activity and 2020 and now we've added more acreage. So you can see that progression as we move through 2018, 2019, 2020 and beyond. And I expect that before the year end my hope and expectation is we'll announce additional acquisitions.

In summary, I'm really pleased with the progress we've made and I look forward to reporting to you on it the next time we meet. I'll turn it back over to Simon Thomson.

Simon Thomson

As you can see the company offers a very active programme across our balanced business. The production that we have from Kraken and Catcher provides sufficient capability to invest in a very material programme on a multi-year basis of ongoing exploration drilling, but also to ensure sustainability of that cash flow generation through investment and further development activity in Nova and in Senegal.

In terms of the exploration drilling, as you've just heard, we're going to be very active in UK and Norway over the coming two years. Mexico will be added in next year and then there are various different opportunities that can be added in to ensure that we have a continuous programme year-on-year of exploration drilling across a number of different plays and basin types.

In conclusion, I thought it was worth looking back at what we said this time five years ago at the results presentation in 2013. We said then that we wanted to re-gear the capital base to exploration success. We said that we wanted to access future cash flow generation to fund our exploration activity and that we wanted to have appropriate equity interests in operated frontier exploration. And if you track forward to today you'll see that we've achieved those goals within the current business offering.

So we have a full cycle E&P business, we have production, we have that cash flow generation from Kraken and Catcher, we have line of sight on two developments within our portfolio which will ensure sustainability of that cash flow generation, and indeed potential enhancement of it and we have exploration exposure. Obviously we made that frontier discovery in Senegal, we're very active UK, Norway, we have Mexico, we have other frontier areas that we will be adding into the portfolio.

And we retain the funding flexibility I think most importantly, not only to add those further opportunities into the portfolio but also at a time of our choosing, to monetise and potentially effect further returns to shareholders. And with that, I'll hand over for questions. Thank you.

Q&A session

Question 1

Nathan Piper, RBC

You talk about a lot of expenditure across the whole portfolio, and historically you talked about shareholder returns. Isn't that the risk that even on that arbitration success and the potential selling down in Senegal that the Cairn business will require quite a lot of those proceeds?

Simon Thomson

From our perspective, because we are confident in the successful outcome of that, obviously we'll look at the business in front of us on that day, but there's an opportunity to effect a relatively significant cash return to shareholders. And similarly in Senegal, there may be some redeployment but we perceive that there may be the opportunity for further returns as well.

Nathan Piper

And just one question on Nova. The operator of the host platform has got a slightly different view about whether or not Nova's going to go ahead, or how it's going to go ahead. Have you any comments on what has been talked about by Neptune on that?

Paul Mayland

Yes, I think obviously we're in a process of negotiation in respect of Nova but I think if we stand back a little bit it's to everyone's benefit to see Nova developed going forward and we are pretty confident that that will all be resolved amicably.

Question 2

David Mirzai, Deutsche Bank

The first question on Suriname. I'm mindful of comments by some of the explorers of the transition zone offshore West Africa who have come to the decision that whilst we drilled there too quickly and with too high a risk following initial success several years ago, obviously we've seen success from Exxon, we've also seen a few dry wells over the last 12 months. What can you do really to mitigate that kind of process? Is it involved in bringing in specific partners who have experience in that area?

Eric Hathon

Well, we certainly, if we mature this to the point where we wish to move forward towards a well we'll bring in partners, but Cairn's fully capable and knowledgeable on both sides of the margin, being as I said, the conjugate.

And as far as mitigation, I mean we'll have a full programme of 2D seismic, potentially 3D seismic and a fair bit of work before we get to a well decision. And in the meantime we'll continue to see well activity there which will also inform our decision.

David Mirzai

Secondly on the UK portfolio you have, by all accounts, a good decent constructive portfolio which gives you good cash flow, but what are the opportunities within the UK and the Norwegian areas to improve on the fund and the finance and the scalability of that business? Does an acquisition make sense? Does a merger make sense? Or do you quite like the way the portfolio pans out at the moment?

Simon Thomson

I think we're comfortable with the way the portfolio's looking because it's more or less as per design now, in terms of offering that combination of production, development activity and a very active exploration portfolio with a fairly concentrated acreage holding around wells that we're drilling.

I think we are constantly looking at whether there are opportunities to bring into the portfolio in UK, Norway that could enhance that value. It's a pretty competitive environment, we're not wanting to overpay for anything. We'll continue to review if there is something that we think is value accretive then we'll look very hard at that, but I think we don't have to do anything.

Question 3

James Hosie, Barclays

Just a question on the SNE project. You've narrowed the guidance in a number of elements, whether it's the plateau production and talking about redeployment of the FPSO what are you going to have to do to narrow the guidance on first oil and what makes this a three year rather than a five year project?

Paul Mayland

We've gone out to tender to the FPSO contractors and the subsea community and we've got a pretty good handle on the opportunity set that we expect to be brought forward. There are some modifications potentially required to those vessels, so that scope will have an influence over the timing, and then there's the overall approval process; but we think at this stage recognise there's obviously both opportunities and risks, but that window that we've set out previously is still valid. Going forward, once we're through and into FEED we may well change it.

James Hosie

Another question, on finance. You talk about having \$200m available in the RBL at the moment but I'm seeing here it's \$350m, \$400m, what needs to happen to get up to that level? Is it Nova being sanctioned? Is it SNE being sanctioned, or is it about the maturity of the UK portfolio now you're through development?

Simon Thomson

It's not related to SNE, where we're contemplating almost certainly a separate debt funding solution. So the increase in the RBL facility in the North Sea will be driven by a number of factors. One of them will be the inclusion of Nova once it's sanctioned and the other two are around the completion of the commissioning phases of Catcher and Kraken. So under any project financing facility you typically have completion tests for assets once they've been

producing for a certain period of time, once a certain number of wells are on-stream and so on. So it's those tests which have either been entirely met or are very close to having been met in the next month or so.

James Hosie

So we should assume that you get to \$350m, \$400m this year?

Simon Thomson

Yes, its six monthly redetermination so there's one at the end of March and there's another one at the end in September.

Question 4

James Carmichael, Peel Hunt

Just on Senegal and the exploration side, I think previously you indicated that there might be some exploration drilling in 2018, obviously that's not in the programme at the moment, so I'm just wondering when you're thinking that you might come back and test any additional prospect there? Is it now likely to be alongside any development drilling?

Also on Tethys, there's also some mixed messages maybe from the NPD website suggesting that the first well was completed as a dry hole and now the second well's being appraised. Is there any colour you can provide around what's happening there?

Simon Thomson

Well, I'll hand over to Eric on that, other than to say we can't comment until the NPD comment in terms of the outcome of the well, we're restricted in doing so.

Eric Hathon

Tethys, the first well we drilled to near the top of the reservoir and had mechanical difficulties. Then for safety reasons we abandoned that first well which was the totally appropriate thing to do. We moved over, redrilled that well, so that's the number 14 well reported by the NPD jargon and we drilled that successfully to TD and all I can say is on the back of that well we're now sidetracking.

Relative to Senegal that's correct it is highly likely that further activity exploration/appraisal in association with predevelopment and development activities.

Question 5

Sasikanth Chilikuru, Morgan Stanley

One question on your 2018 guidance if you can provide what your cash flow guidance was for 2018 including your hedging and the sensitivity around it?

James Smith

We haven't given specific cash flow guidance for the year, what we've said is that with the North Sea fields on plateau will be generating about \$350m of operating cash flow at \$60

Brent. For this year, the inputs are there to form a view. Production guidance in the range 17,000 – 20,000 barrels a day on average over the year. Opex related to that is \$18 a barrel. We're still benefiting from full tax shield on that production, so it's effectively the production multiplied by your oil price assumption, less \$18 a barrel. So at \$60 Brent that's in the range of \$250m - \$300m of operating cash flow.

Question 6

Michael Alsford, Citi

Firstly on Cairn India, we're close to knowing the outcome of the arbitration process but could you maybe say what you can see is the risk that the Indian government could frustrate this process and delay further the arbitration in August from a legal perspective?

Secondly on the capex and SNE, clearly development drilling is a big chunk of the capex, 60% I think you said, so could you talk about what you're assuming in terms of rig rate for that number because clearly rig rates today are \$200/250,000, what are you assuming for that in the project capex?

James Smith

On India you're right it does feel relatively close, it's been a two year process to get here under the arbitration. The hearings will be in August, we'll then be waiting for the arbitration panel to issue its award. That will be a process that will take a number of months so we're expecting that to be a Q4 event.

India have not been successful in their most significant efforts to frustrate the process. They made an application to have a stay. They made an application to have the case split up into jurisdictional arguments and merits arguments. All of that might have delayed it by many years but, that hasn't happened. We've successfully defended that.

They were successful in a six month extension around document production and submission of defence arguments, so the original hearing date was in January, that's now been moved to August. In granting that extension the arbitration panel were clear that in asking India to proactively confirm that that would address any timetable concerns that they had and India did that and therefore the tribunal responded to say that they would grant that extension but they would not be sympathetic to any further requests for extension. And indeed there is quite a bit of redundancy built into that timetable through to August. Effectively there's not very much happening between March and August in terms of the procedure.

The other thing that the tribunal said in granting that extension was that they would seek to issue the award as expeditiously as possible, in their language, after the hearings.

So I think in terms of the timetable for the hearings in August, India has been given a very firm message that that should now be a solid timetable.

The treaty is designed to be the last recourse to justice so a treaty award is not appealable, it's final and the enforcement provisions around a treaty award are very strong. So an award in our favour will be enforceable internationally, it's not as if we have to go to the India courts to get our shares back or to get the compensation for the loss of the shares. So again the treaty is created with a very robust enforcement basis.

Paul Mayland

On the Senegal capital guidance, we acknowledge we're in a low in the market and utilisation and not just on drilling units or drilling services but indeed subsea and installation. So it's going to be, in our view, a very competitively fought for number of tenders, and certainly that's what we're hoping but I don't want to make any promises about how much cost reduction we could see. But on the drilling side I think we sometimes get a little bit fixated on the rig cost and there's no doubt that's come down significantly compared to say the 2013/14 cycle and there's also obviously been big opportunity to secure improved costs in other areas and EnQuest and Premier have done a very good job in that regard in respect of Catcher and Kracken. We've seen prices tendered below budget on Nova which is encouraging and therefore we look forward to the next three to four months in terms of hopefully securing and attracting prices and structures for SNE in Senegal.

Question 7

James Thompson, JP Morgan

Following on on Senegal the plan is to hand over operatorship to Woodside later this year, could you update us on the process and timing of that around the relevant document submissions?

It's the first time for Senegal to approve a development project, what gives you the confidence that it's going to be done in a timely fashion?

Finally in terms of the development plan you outlined what is the plan for gas in the first couple of phases of development?

Simon Thomson

In terms of the confidence, we've been very closely aligned with the Senegalese with the whole of the joint venture in framing the documentation submission and request and timings for approval to align with them to ensure that they have sufficient time to approve ahead of elections which are coming early next year. There's obviously this project and there's the BP Kosmos project, both of which require a number of different approvals. We are relatively confident in the sense of the alignment and the continual conversations that go on with government, at various different levels, to ensure that everybody is fully aware of what needs to happen and when.

But you're right that's a big area of focus for us to ensure that the permissions and approvals are all achieved within the necessary timeframe. I think if we weren't aligned in the way that we are with Petrosen, with the government, we might have more of a concern but I think the knowledge sharing is pretty good.

Paul Mayland

Every oil and gas project needs to consult with the people of the country so we have started that journey. The public consultation plan has already commenced in terms of describing what an offshore oil project is, what does it look like and what does it mean for Senegal. As Simon's already stated, the President and the various ministries are very supportive of the project.

And in respect of Woodside we've worked very collaboratively with them. I made three trips to Australia last year. We've had people seconded both ways into the organisations and we have

a pre-development delegation agreement. We're trying to build to a position where the transition is very smooth. Obviously it goes through the normal operating committee resolutions but the natural plan is to transition through the summer such that the evaluation report is really an end of Cairn's journey as operator and the exploitation plan is the start of Woodside's journey as operator and hopefully in 2021 to 2023 they'll be looking back favourably on a project that they've executed well as set out in the original exploitation plan.

So we've got good confidence that we're working as well as we can within the overall partnership.

In terms of gas, a similar sort of position there so there's a general recognition that there'll be an initial phase of gas-free injection. But there has been an identification in terms of market capacity and conversion, particularly for power but that's likely to come in what we call the second phase, which is likely to be a few years after first oil.

Question 8

Mark Wilson, Jeffries

If you could just clarify the capex first oil at Senegal that doesn't it include the FPSO because that's a least scenario?

On FPSO, you say refurbished FPSO is that project-specific or really just a change in the market, I'm thinking obviously of Catcher being a new-build a few years ago?

Lastly, are you participating in the upcoming Mexico shallow water round?

James Smith

The answer to the first part's very simple no it assumes that effectively all of the FPSO costs are built into the lease.

Paul Mayland

Yes the redeployment is a change in the market and probably a little bit of a change in oil companies overall philosophy in terms of standardisation of approach. We're also fortunate in the cycle that we've managed to identify a number of vessels that are available that fit quite well with the capacities that we're looking for and the type of fluids that we have in SNE in respect of both the oil and the gas.

Eric Hathon

With respect to Mexico you can all tune in live on March 27th to the Mexican Government's bid round and at that point you'll determine whether we've bid in the bid round.

Question 9

Thomas Martin, Numis

I've got three questions. On the RBL and the project financing RBL you've spoken about how SNE won't be feeding into your existing RBL and you've also spoken about how the market's very competitive from the contractor side so could you elaborate a little on what sort of options you are looking at? Is it vendor financing as the primary route? Are there other things you're

looking at? Would you consider issuing bonds or are you talking about some sort of separate bank facility just tied to that project?

Secondly, can you remind me on the SNE exploration side of it, I think that you have to ring fence the development areas, is it your aim that you're going to be able to ring fence all of the area or have I got it completely wrong and you don't need to ring fence it? Also do you think you're going to be able to hold on to the Fan area?

And the third one was just are you able to quantify the Kraken realisations that you're getting in terms of price versus Brent?

James Smith

Well I can deal with the first and the third part and then hand over to Eric to talk about the question around acreage around SNE.

It's still relatively early days in defining exactly what the funding solution for SNE is, it's likely to be a standalone. The base plan is that there'll be a standalone project financing solution for the SNE project in which all of the joint venture participants will be able to participate. So the sources of capital for that financing will be commercial banks, but could also include export credit agencies for example, multilateral agencies, the World Bank has been very active in Senegal. So there are various pools of capital that we are warming up to participate in what is likely to be a project financing facility specifically for SNE for all partners. So that's the base plan, clearly there are alternatives around that, on our own balance sheet and the other part that we'll look at. But that's very much the base plan.

In terms of Kraken, we sold our first cargo in the year we just reported on, so I think you can calculate from what we've disclosed that the realised price there was about \$52 per barrel and look at what the prevailing price was at the time. Our marketing agreements are based on a discount over a certain period of time around when the lifting occurs. The cargos that we've sold this year have tightened that discount rate and indeed I think the operator has talked about selling at around about a \$5.50 discount on one of its liftings as well.

So the broad guidance we've given is that we expect the discount to be around about 10% to Brent. And the pattern has been moving towards that as we've sold the early cargos.

Eric Hathon

Yes our intent clearly is to capture, as you said ring fence, all the area that we see as potential going forward, particularly as it relates to a potential tie back to SNE, but that's work in progress.

Question 10

Job Langbroek, Davys Research

A quick question on the full cycle E&P business could you just tease out briefly how you think about capital allocation to the various units, whether that depends on the cycle or whether it depends on the strategy at that particular point in time?

Simon Thomson

Basically the design has consistently been when we get to this point you can allocate half of the operating cash flow to reinvestment on the sustainability of that cash flow and the other half into ongoing exploration activity. So on a rough basis let's assume \$150m plus or minus per annum on exploration activity wherever that happens to be. This year, it's a focus on UK, Norway, planning work on Mexico and so on. Next year will be UK, Norway and Mexico but potentially others.

So that is not affected by cycles. The design of the company, the design of the breakevens and so on is that we can consistently aim to provide that year-on-year exposure to exploration activity. I mean it's lumpy of course so some years might be higher; some years might be slightly lower but to have that exposure to a combination of frontier, emerging basin and mature basin exploration year on year.