Company: Woodside Petroleum Ltd

Title: Half-Year 2018 Results Briefing

Date: 15 August 2018

Time: 9:30am AEST

This document should be read in conjunction with Woodside's Half-Year Report 2018 and the Half-Year 2018 Results and Briefing Pack which are available on the company's website, www.woodside.com.au.

Start of Transcript

Peter Coleman: Look, good morning everybody, and thanks for joining us for our 2018 half-year results. As you would have seen this morning, we released our half-year report and the results briefing pack to the ASX. Joining me on the call is our Chief Financial Officer, Sherry Duhe. As we've done in previous years, we'll make some introductory remarks before opening up the call to a question and answer session.

If I can take you to the slide pack, you'll see the standard disclaimer on slide 2, and a quick reminder that this presentation does include some forward-looking statements and that our reported numbers are all in US dollars.

Since our announcements at the full-year results, we've been very busy, I must say. We've had a productive first half, and we're delivering on our growth plan. So, let's run through some of the key financial and business achievements.

As you can see in the financial headlines on slide 3, our net profit after tax was $541 million, and our interim dividend for the half was US$0.53 per share. Operating cash flow was 25% higher than the 2017 first half, at over $1.5 billion. We generated free cash flow of $363 million while investing in growth and completing the Scarborough acquisition. Our financial position is robust, with low gearing and strong liquidity. Our balance sheet is in good shape for the upcoming growth phase.

On slide 4, we've spoken before about our clear plan across three time horizons. In the first half, we made good progress on Horizon I, and are preparing for Horizon II and beyond. We have a clear roadmap for growth and it's underpinned by our outstanding base business.

Slide 5 further details that outstanding base business, where you can see our facilities continue to perform strongly. We delivered production at 44.3 million barrels of oil equivalent, which was 5% higher than the first half of 2017. At Pluto LNG we exceeded 99% reliability.

We've maintained a low unit production cost of $3.60 per barrel of oil equivalent at Pluto LNG and the North West Shelf project. We now have Wheatstone on stream with both Trains 1 and 2 exceeding nameplate capacity. Based on the performance of Pluto, Wheatstone and our oil assets, we've increased our 2018 production guidance from 85 to 90 million barrels of oil equivalent, up to 87 to 91 million barrels of oil equivalent.

We're delivering the committed growth that will underpin the targeted production of approximately 100 million barrels of oil equivalent in 2020. As you can see on slide 6, Wheatstone is expected to contribute in excess of 13 million barrels of oil equivalent by then. Next year, we'll be producing from both Greater Western Flank 2 and Greater Enfield projects.

Greater Western Flank 2 is almost complete, and the final forecast cost is around 30% under FID budget, which of course, is very pleasing to all of us.

On slide 7, we've had lots of activity in the first half across our priority developments: Scarborough, Browse and Senegal. There's been significant progress since we announced the acquisition of an additional 50% in Scarborough in February of this year, and subsequently assumed operatorship. We've awarded contracts for the concept definition phase at Scarborough, and initiated contractor engagement for the front-end engineering and design phase. The geophysical survey has been completed for the proposed export pipeline route.

The North West Shelf project has reached alignment on key terms and pricing for tolling of third-party gas, and you can see that we expect the toll to be less than $2 per million btu for Browse gas. As I discussed in the Investor Briefing Day in May, cost reductions have been achieved on the subsea, well and pipeline scopes for Browse.

The Senegal team has also been busy evaluating tender responses, and we've seen capital cost reductions at present approaching 10%.

So, we've progressed well in the first half. Sherry will now talk in some more details about our financials, and I'll come back at the end and run through some of our expectations for the rest of the year. So, over to you, Sherry.

Sherry Duhe: Thank you Peter, and good morning everyone. I'll start on slide 9, where you see that our strong base business delivered a 25% increase in net cash from operations, compared to the first half of 2017. Sales revenue increased due to higher pricing and higher sales volume. An 18% increase in the average realised price resulted in $279 million of additional revenue. New production following the start-up of Wheatstone Train 1 in the second half of 2017, and Train 2 in June 2018, as well as strong Pluto performance, further increased sales revenue by $204 million.

Moving onto slide 10, our net profit after tax increased to $541 million. Our strong sales revenue was impacted by the timing of exploration activities, depreciation and financing costs.

A significant exploration drilling program was completed in the first half of this year. With this now behind us, we are expecting reduced exploration spend in the second half of the year

Depreciation increased due to Wheatstone start-up, year-end 2017 Pluto reserve provisions, and higher production from Pluto. Net finance costs were impacted by one-off events, associated with the early bond redemption in May, foreign exchange hedging costs related to the equity raising, and the start-up of Wheatstone which reduced capitalised borrowing costs.

On slide 11, the Directors have declared an increased fully-franked interim dividend of US$0.53 per share. The interim dividend has been determined having regard to the half-one 2018 underlying NPAT of $566 million, and our strong operating cash flow in the half. The total value for the interim dividend is $496 million, which is up 20% on the same period as last year.

The strength and performance of our base business is reinforced in slide 12, which outlines the strong growth margins achieved by our operating assets, accompanied by sustained competitive production costs. Our unit production costs for the North West Shelf project and Pluto LNG were maintained at a globally competitive $3.60 per barrel of oil equivalent.

Then on slide 13, you can see that our shareholders are receiving the value of improving market conditions. As average realised price has increased, production and other cash costs associated with production have remained steady.

Slide 14 further demonstrates our capital and operating discipline, with the free cash flow breakeven price per barrel remaining stable as the average Brent price increases. This once again speaks to the strength of our underlying business, and our ability to pass the benefit of rising prices onto our shareholders.

Turning now to slide 15, Woodside is in an excellent position as we continue to execute our strategy. You can see that we have minimal near-term debt maturities, and our debt maturity from 2025 complements the significant cash flow generation targeted from our key developments. We are well positioned to fund growth.

In order to prudently manage Woodside's near-term debt, a 10-year $600 million unsecured bond was repaid, and two five-year bilateral facilities totalling $200 million were cancelled during the period. Bilateral facilities were reduced by a further $500 million after 30 June 2018.

On slide 16 we see that expected increase in our realised LNG price as a result of the improvement in lagged JCC and spot prices. Our second quarter realised prices were impacted by the proportion of spot sales, the delivery basis of our cargo and customer mix. As you know, LNG contracts typically have at least a three-month lag, so the impact of rising Brent on sales revenue is slightly delayed.

Finally, on slide 17, our guidance on 2018 investment expenditure remains unchanged from February. Exploration expenditure is expected to reduce as we prioritise capital allocation to the development of the high-quality resources within our portfolio.

As Peter also highlighted, a significant milestone was achieved subsequent to the period, with alignment between the North West Shelf project participants on key commercial terms and pricing, for processing Browse and other resource owners' gas through the North West Shelf LNG facility. We are executing our strategy with proposed developments that utilise our existing LNG infrastructure to develop new, globally cost competitive natural gas resources.

I'll now hand you back to Peter to outline our key priorities for the second half of the year.

Peter Coleman: Okay, thanks Sherry. So look, to summarise, I want to talk you through what you can expect on our major projects between now and the end of the year.

Referring to slide 19, we can expect concept select for Scarborough and Pluto Train 2. We then move into concept definition phase, and what we call FEED readiness. Really, by the end of the year we're finalising the preparatory information to allow us to advance into FEED in Q1 of next year.

For Browse, as we've foreshadowed, a significant milestone will be reaching the preliminary tolling agreement between Browse Joint Venture and the North West Shelf project in Q3. As we progress to concept definition entry, we'll also commence key contracting activities to address the technical development of the project.

In Senegal, for the SNE development, the team will be submitting key regulatory documents for primary approvals, in anticipation of FEED entry in Q4, to support FID in 2019.

Then, finally moving to slide 20, our outstanding base business continues to be the engine room. It's enabled us to increase our production guidance range. Pleasingly, we've maintained low operating cost, and our key financial metrics are very strong.

Moving to the next pillar, we're on budget and schedule for our near-term projects, and it's great to see Wheatstone performing so well. Together these outputs will contribute to targeted production of around 100 million barrels by 2020. This is really a significant year for our material growth opportunities. The progress we make will position us to capture the current cost market, and the expected LNG supply gap in the early 2020s.

Importantly we're delivering value for our shareholders. We've increased cash flow and accordingly we've increased our distributions to shareholders. With those introductory remarks, I'll now hand over and welcome your questions.

Operator: Thank you ladies and gentlemen, we'll now begin the question and answer session. If you wish to ask a telephone question, please press star-one on your telephone and wait for your name to be announced. If you wish to cancel your question please press the pound or hash key. Once again ladies and gentlemen it is star-one.

Our first question is from James Byrne from Citi. Please ask your question, James.

James Byrne (Citigroup, Analyst): Morning guys. Firstly, just on the preliminary toll for Browse on the North West Shelf which you've described as being less than $2 MMBtu. Can you perhaps give us an idea of how much downstream late life Capex the Browse Joint Venture is paying out of the total?

Peter Coleman: Yeah James that's a good question. The toll is an expected toll over the life of the facility. It's actually broken into three components. One is an operating component. So that component basically shares the operating costs with the North West Shelf on a pro-rated capacity basis. So, for example, if Browse takes half the capacity of North West Shelf, then it actually reduces the cost to the North West Shelf participants of their operating expense by 50%. Then Browse will pick up that 50%. There's a profit element in there as well that gives the North West Shelf a return on the value of the current assets there.

The third element, then, is the future capital requirements. Now that future capital requirement will be on an amortised basis. So, we've amortised it within the toll based on a - both a rolling number that will be approved by the Browse Joint Venture for the North West Shelf to spend. So, for example, we'll have a 5-year forward-looking program for capital expenditure to keep the plant in good order. That will be approved by the Browse participants. The North West Shelf will then go and spend that money. There will be a small profit fee on that, and then that amount will be amortised into the toll on a yearly basis. It will be a rolling amount.

So the number I'm talking about - $2 - is not a fixed amount. It will be a - if it's less than that, but it will be an average over the period of the life of the facility.

James Byrne (Citigroup, Analyst): Okay, that's really helpful. Just on the foundation contracts for Pluto, I was wondering if you might be able to comment about how negotiations are going with repricing those contracts. Are you still comfortable that there won't be a material difference in realised price?

Peter Coleman: Yeah, I think you may recall James, we tried to address this at Investor Briefing Day when we looked at the difference between renegotiating existing contracts through price reviews. So, recall the existing contract is still in place. This is simply reviewing the pricing in that contract. Then new contracts - brand new, greenfield contracts, so to speak - in this instance of course, those pricing review outcomes are somewhat bound by average landed prices in Japan, which is substantially higher than what you would get on the spot market or in the short-term market at the moment.

We've not commenced discussions yet with the two parties, Tokyo Gas and Kansai Electric. But I don't expect there to be any change in our view. In fact, looking at the JKM number this morning at $10.40 and what we're seeing with China demand, and so forth, I'm probably even firming my view that those negotiations will be satisfactory for us.

James Byrne (Citigroup, Analyst): Got it, okay. For Pluto, I mean in the context of Scarborough coming into that facility and obviously the expansion as well, I'm wondering if you can perhaps comment on how we should think about late life Capex being deferred at Pluto with Scarborough coming in, acknowledging that there's still a range about how much that upstream contributes from Scarborough.

Peter Coleman: Yeah, I think that's a difficult question to answer. The reason is the late life Capex will be around until we develop WA-404-P, or do we preferentially develop Jupiter and Thebe, which is just roughly 2Tcf, but which we hold 50%, and bring that through to the Scarborough platform? So, we've got optionality there.

We're also just beginning preliminary discussions with the owners of the Outer Exmouth assets around what their preferences would be. They've clearly indicated they would like to come through that Scarborough facility at some point when capacity is available in the future. So, I would say that's a story that's yet to unfold for us. We just haven't worked that optionality, to be quite frank with you, James.

James Byrne (Citigroup, Analyst): Okay, that's all from me this morning. Thanks Peter.

Peter Coleman: Thank you.

Operator: The next question is from James Redfern from Merrill Lynch. Please ask your question James.

James Redfern (Merrill Lynch, Analyst): Good morning Peter. The first one is on Wheatstone. So, I understand that Wheatstone Train 1 operated around 10% above nameplate capacity in the June quarter. I just want to understand in terms of Train 2, how long will Train 2 be shut down for in August to replace the strainers? Then, what is the effective capacity of Train 2? As I recall it's higher than Train 1 due to compressor upgrades. I've got one other question after that please. Thank you.

Peter Coleman: Okay. Look just quickly on Train 2, we think it will be a couple of weeks. We've actually just started that process. So, for those of you who watch LNG cargo movements and so forth - I know you do - out of the ports, that work has just commenced. So, we expect it to be a couple of weeks. And you know this - we've mentioned in the notes - in fact that train has been performing better than Train 1. We would expect that because we learned a lot of things as we went through Train 1.

With respect to the increased capacity, you're correct. We indicated previously that we spent some capital monies on increasing the capacity in the compression train and the liquefaction train. So basically, the drivers for the liquefaction, we couldn't do that in Train 1 because it was too late in the construction process. But we were able to do it for Train 2. I'm a little leery in giving you a forecast at the moment on where that is, but it's certainly north of the 10% that you've indicated.

James Redfern (Merrill Lynch, Analyst): Yeah, thanks Peter, so look, just high level, sounds like Wheatstone could well run at 10% - 15% above nameplate capacity, which is a great outcome.

Just in terms of the tolling fee for processing third party gas, should we assume that the tolling fee at Pluto Train 2 to process gas from Scarborough is also going to be below $2 per MMBtu? Then, I just want to understand, processing third party gas at North West Shelf, aside from Browse, will also be a different price, based on those criteria you were talking about before in terms of covering operating costs, and so forth? Thank you.

Peter Coleman: Yeah, look we haven't set a toll yet at Train 2 for Pluto. I would expect it would be higher than the $2, just based on the fact that it would be a brand new train. So, you've got to look at the entire system and getting - being able to get it to market. So, for those who choose to toll through that particular facility, the basis will be very similar. But that - I think that second element which was the profit element, on the invested capital, will be higher. Then the third element being the Capex, will obviously be lower.

But, to be honest James, the team is actually running through that now. But it's certainly north of the $2 number. I wouldn't expect it to be the same to give us an adequate return, because we've got to invest in that and our shareholders expect a double-digit return on those sorts of assets.

With respect to North West Shelf, the North West Shelf - it's an interesting question, and that's why it's so important that Browse, in fact, is the anchor tenant. Because Browse is able to put so much volume then into North West Shelf, it

actually brings down the average cost for any other participant coming in. Their prices based on some of the scenarios we've run will be around - it might be a bit higher - just simply because the percentage of Opex and so forth that they'll be sharing, will be a little bit higher, just simply because of the volume.

If Browse doesn't come in first, then the costs for other participants will be significantly higher. So, there's a huge incentive for all parties to get Browse in there first, so that they can underpin the North West Shelf for some period to come. It's a formula. It's not always intuitive. You would think the next incremental one would be lower, but the reality is it relies on Browse to come in there to keep it low because the North West Shelf goes into decline.

James Redfern (Merrill Lynch, Analyst): Okay that's great. Thanks Peter. That was a great result too. Well done.

Peter Coleman: Thank you.

Operator: Once again ladies and gentlemen it's star one to ask a question. But our next question is from Mark Samter from MST Marquee. Please ask your question Mark.

Mark Samter (MST Marquee, Analyst): Yeah, morning guys. I've got three questions, actually, if I can. Just the first one - this is probably more a question for the investor day, but I was in my garden - I think you said at investor day that you were willing to sanction Scarborough with less than 50% of contracted volume.

I guess implicitly above that figure you can't finance a project like that. By definition, certainly debt markets see that as a riskier proposition. Can you just tell us how do Woodside conceptualise that risk? Should we think about it that you put a higher hurdle rate on a project where there's more volume's uncontracted? How do you think about the balance sheet? Do you have to keep lower gearing through that investment cycle as well?

Peter Coleman: Yeah, that's a good question Mark, and welcome back from the garden. This really relates, interestingly, to our view on the liquidity of the market and the depth of the current LNG market. You can almost say the super majors, the big players, are doing it now because they do it under the veil of portfolio. Really, what they're saying when they put volumes into portfolio, they're willing to take on market risk, because they're going to then on-sell it out of their portfolio.

We can do that, and we're developing that portfolio, but we prefer on balance to have a line of sight as to where it's going to. So, my comments at IBD were really aimed at the long-term contracts, those 15- and 20-year contracts that we've talked about, that the reality today says if you could get 50% of it away on long-term contracts you would be doing fairly well. Then the mix of it will be short- and medium-term contracts. So, it's just our view of where we think that the market is heading and the liquidity and depth of the market.

From a risk point of view, no, we don't change anything on the balance sheet, or the way that we risk the project. We do run different scenarios though, to be quite frank with you. So, as we start - we look at our forward cash requirements, particularly cash out of the business and the commitments of cash. We do stress test the balance sheet by putting into it 2 or 3 years of pricing numbers that you've just seen recently, to make sure that we don't get the Company into trouble during that period of time. So, it doesn't come down to the project itself, but we look at it on a total Company basis.

Mark Samter (MST Marquee, Analyst): Thanks. Just a quick question on the dividend. It looks like the payout ratio this time was up closer to 90%. Should we see that as a one-off anomaly, or do we think whilst you're going through this period before the investment cycle starts again we should think about the payout ratio could be sustainably that bit higher?

Peter Coleman: Look it's a good question. I'm sure everybody is trying to work that map out and then trying to work out whether this is also a projection of what we think the profit will be for the year. No, it's really reflecting a couple of things.

One is, we had stronger cash flows in the first half than we expected. So, you may recall our Investor Briefing Day pack was based on cash flow projections at $65 per barrel oil flat. Average pricing during first half has been above that. So, we've actually had more cash.

Revenue was up 25% on the corresponding period year on year. So, we looked at all of that. We then looked at our activity levels. The Directors exercised discretion and judgment, and decided that a $0.53 dividend was appropriate. So, it was those sorts of things. I would say it was not formulaic at all. But it was taking into regard the strength of the cash flows, the amount of money that we had currently sitting in the bank, our requirements, and our view of what the next six to 12 months was going to look like - and Sherry indicated that when she mentioned that we've got a three-month lag in our pricing - so you can almost say our pricing for the next three months is already locked in.

So, all of those things gave us confidence to increase the dividend as a payout ratio. So, it was all in that, and I think then you look at it in that total bucket of distributions because that's per share, as you know. If you looked at the diluted effect of the equity raising, you can see that the total distributions were up about 20%. So, they match up with that revenue increase that I think shareholders would expect to benefit from that.

Mark Samter (MST Marquee, Analyst): Great. Then the third one is - this is more out of curiosity to be honest - you've spoken about scaling back exploration and being a lot more focused on your core projects, and then in the annexure there's a slide saying that you've gone into Bulgaria. I mean, hopefully that field doesn't extend across the maritime border into Turkey at the moment, I suspect. Can we just put that move into Bulgaria in context of being more focused?

Peter Coleman: Yes, it's a really good question. It's an oil play that we're looking at, and I must say we had some eyeball to eyeball moments with the exploration team as to do you really, really like this, and they kept coming back and said, this was the one. If they only had one area that they were going to go into, this was it.

So, to be honest, Mark it was on the back of the strength of what we think the prospectivity is of that particular block and the fact that we've got an excellent operator there with Shell, so we felt comfortable in being able to go into that block, but it gives us some more focus as well.

Mark Samter (MST Marquee, Analyst): That's brilliant, thank you.

Peter Coleman: Thanks.

Operator: Once again ladies and gentlemen, it is star-one to ask a telephone question. Our next question is from Andrew Hodge from Macquarie. Please ask.

Andrew Hodge (Macquarie, Analyst): Thanks guys. I've just got three, hopefully short, questions. The first one is just about PRRT. The guidance that was given in the quarterly was for a lower PRRT credit than I think most people have been forecasting. I just wanted to get an idea about relative PRRT balances and when you expect to pay PRRT.

The second one is about AASB 16. We've already seen companies report boosts to EBITDA from this as an artificial shifting down of costs, and I wanted to get an idea about that.

The third thing was just about – Rio has talked about pretty substantial cost increases happening through WA. Just wanted to see what impact you've seen, if any, from your operations as well as from tendering for contracts.

Peter Coleman: Okay, Andrew. I'll get Sherry to address the first two and then I'll come in and talk about the costs.

Andrew Hodge (Macquarie, Analyst): Okay.

Sherry Duhe: Okay. So, Andrew on the first one - and I think we've probably answered this one before - on the PRRT, as you mentioned, the biggest asset that we have is related to the Pluto asset, but we really don't make a prediction around when and how that asset might come off of the balance sheet or reduce in time. It's really dependent on a lot of factors, most importantly being the oil price around that.

So, indeed, when you look at increasing revenue that happened in the period, that's the biggest factor that decreased our credit this time around. But as you know, PRRT is quite a complex calculation around that, so we'll probably leave it at that in terms of projections.

To go onto your AASB question, I think the important thing to consider for Woodside is that this is non-material adjustment for us over the period. It truly is a timing issue and we took a call when looking across at what our peers were doing and what our auditors were telling us, and have moved from the entitlement to the sales method and you can see that impact that comes through in the notes of the financial statements in terms of what we adjusted around that.

Andrew Hodge (Macquarie, Analyst): Not AASB 15 Sherry, it's 16, the one that…

Sherry Duhe: So sorry.

Andrew Hodge (Macquarie, Analyst): …you have said is material.

Sherry Duhe: Okay, so sorry, on the leases - 15 versus 16, thank you.

Andrew Hodge (Macquarie, Analyst): Yes, yes.

Sherry Duhe: On the leases, that will be material. We're still in the process of working through that in the second half of the year, and we aren't in a position yet where we're giving a projection on that. We'll come back with that in the second half of the year.

Peter Coleman: Yes. Andrew I'll break ranks. It will affect gearing of course for us, and it will be noticeable on the gearing number, but we'll still end up within our gearing range and targets, and it certainly will not affect our investment rating.

What we need to do then is consider as a Board, once we see that finalised, whether we want to provide different guidance as to what our target gearing range will be, because it doesn't actually affect the cash flows of the Company, as you know.

Andrew Hodge (Macquarie, Analyst): Yes.

Peter Coleman: It's simply where the liabilities reside. So, you will get a different number and it will be a few percentage points different on the higher side, and we've just got to look then to see, as we go forward, whether we actually break our guidance or not, and so forth. Otherwise it doesn't affect the way we work at all.

Andrew Hodge (Macquarie, Analyst): Just on that, I mean we've seen people moving operating leases, so things which would currently be in Opex. I was trying to work out what you guys would have under that at the moment. Would that be on the shipping side or would there be anything else that would be under a lease?

Peter Coleman: The majority will be in our ships, so that's the LNG carriers, is where the majority of that is. Equally though, as we start to look at things like Senegal and so forth, when you're looking at long-term FPSO leases, that's also something that could come on as well.

So, they're things that we're going to have to look at, the industry is going to have to look at, because the AIPN standard JOA at the moment - joint operating agreements - basically will push all of these liabilities onto the balance sheet of the operator. So, some of those joint ventures are going to have to look at those structures, because it's simply not fair for operators to take on all of those liabilities, simply because they happen to operate. So, the industry is got some changes it's going to have to make as well.

Andrew Hodge (Macquarie, Analyst): Yes. Yes, I recognise obviously it's across the entire industry. Then the last point on costs, yes.

Peter Coleman: Yes, just costs - look we're not seeing any significant costs. We've just completed a couple of wage deals here. EBAs have been completed by our major maintenance contractors, and they're, I would say, CPI-plus type increases, so in the 2 to 3 percentage points on those increases. So, nothing large at the moment.

We've probably seen more pressure in offshore drilling, and particularly longer term, as we start to look at programs post-2021. We're starting to see that the offshore drillers are starting to increase their costs forecast there as we're trying to lock in some of those contracts, which just points to the fact that we said we need to get into the market now and go after these things.

We are also seeing yards start to fill overseas, so we are watching closely the yards in China, for example, which have been empty for the last two years, but now starting to get filled up, believe it or not, by chemicals projects out of the US. So, as costs have actually gone up on the Gulf Coast in the US, some of those chemical expansions for those major plants there are actually going offshore, and being modularised in Chinese yards. So, we're watching some of that pretty closely as well.

Andrew Hodge (Macquarie, Analyst): Just on the Capex, Exxon has made a comment about costs being slightly higher than the rates that they've received from some of the projects. I'm just curious from your perspective about the rates you guys have been receiving at an early stage for Scarborough.

Peter Coleman: Pretty good. We've got some - we've actually got a couple of unsolicited proposals in, so it tells us we're within the ballpark. Certainly, the numbers that are coming in, they still haven't got to where we think they need to, so we've got some arm-twisting and negotiating to do, but it's pleasing because the trend is in the right direction at this point.

Andrew Hodge (Macquarie, Analyst): Okay, thanks very much guys.

Peter Coleman: Thanks.

Operator: The next telephone question is from Mark [Busuttil] from JP Morgan. Please ask your question.

Mark Busuttil (JP Morgan, Analyst): Morning everybody. Just a couple of slightly dull questions if I may. There's an $87 million exploration write-down that you've included in underlying earnings in the half. Just wondering if you can explain where that came from, and how likely it is to be recurring? Obviously, that's up a lot from where it was last year.

Then the second one - just in terms of Wheatstone depreciation, would that be reflective of both Trains, and therefore a similar sort of level going forwards?

Sherry Duhe: Okay, yes, Mark I can take both of those questions. So, on the first one in terms of the exploration write-off, that is related back to the comments that we shared as we went through the call. We had six wells that we drilled

during the period, and several of those were written off due to the results of those wells, and we would not expect that to happen going forward.

I think Peter has mentioned it as well. We've got one appraisal well in Myanmar to complete in second half, and also the well in Peru, so indeed, that was an unusual concentration of that activity in the first half of the year.

In terms of the Wheatstone depreciation, I don't think that we would expect that to be a recurring amount that's going forward, in terms of just a one-time start-up around that, but indeed you do see the flow through of that activity increasing from 2017 where we didn't have Train 1 onstream or Train 2 as well.

Mark Busuttil (JP Morgan, Analyst): Okay, great, thank you.

Peter Coleman: You know what, on that one, Mark, of course it's the straight-line depreciation that will change as Train 2 comes on; whereas of course the UOP doesn't change because of the offshore.

Sherry Duhe: That's right, and we did provide for your guidance to reflect that as well, to help you with looking forward in terms of the annualised amount.

Mark Busuttil (JP Morgan, Analyst): Okay, excellent, thank you very much.

Operator: The next question is from Ben Wilson from the Royal Bank of Canada. Please ask your question Ben.

Ben Wilson (Royal Bank of Canada, Analyst): G'day Peter and Sherry. I just had a quick question on your Senegal activities. Firstly, on the resource size that you're thinking. If I recall back to the acquisition, I think you implied a gross resource of about 560 million barrels.

Firstly, whether there's any thoughts post-appraisal drilling on that initial resource estimate in your mind? And secondly, the operator at the time, Cairn, about a year ago, gave some pretty detailed figures, or outlook, about development scope, plans and costs, and whether you've got any thoughts on how those may have changed?

Lastly, whether you foresee any requirement for any further appraisal drilling before sanctioning a development there? Thanks very much.

Peter Coleman: Okay. Look on total resource size, our view hasn't changed. What we have recognised though, is that the upper 400 series of sands is quite complex. We knew that going in, but of course, you never know the true degree of complexity until you start drilling wells.

The lower sands, the S500 series, is a nice blocky sand. So, we said look, we've got a couple of things that we need to do. To fully appraise the upper sands would take some time, and capital that we just said can be better deployed elsewhere. We wanted to make sure we locked in these low costs in the market, and also of course, we do have some requirements under the PSC to ensure that we have a development plan in by early next year.

So, with all of those factors, we said we could spend a lot of time trying to understand the upper sands and probably never be satisfied. So, the best thing is put a low-cost development in, get it moving and then at the same time dedicate a number of wells to the upper sands, and produce and learn as you go. So, it's really trying to de-risk the forward capital for us.

I think we've talked about that initial development will be just over 200 million barrels, or thereabouts, of that 560. That's well underway, and the cost that I mentioned in the pack is basically around the FPSO drilling packages, subsurface and so forth, for that particular development.

There'll be then a phase 2 of development that will be some time later, after we've – basically, after we've had long-term production tests, and so forth, on these upper sands to work out the best way to produce them. So, that's how we're thinking about it. Cairn's very aligned on that. We just had the resource independently certified and of course Woodside's numbers are starting to move closer to the operator's numbers. We started off in a more conservative position, and we're starting now to move more towards where Cairn has been projecting their numbers. So, our differences are changing there.

What's changed, or do we need to drill any other wells? The answer is no. We believe the field is fully appraised for this first phase of development, so we don't expect to drill any further wells. We do have in plans a view that we need to drill an appraisal well on FAN, and the FAN discovery. You may recall we made the discovery and then we drilled a well quite some distance south of FAN. That well was unsuccessful, but it did not delineate or appraise the FAN discovery itself. So, we're working with the Government of Senegal and the regulator there to secure rights to be able to go and drill that appraisal well. That, then, would be a tie in into the base development for Senegal.

Ben Wilson (Royal Bank of Canada, Analyst): Okay, that's great. Thanks very much, Peter.

Operator: Last question from Glyn Lawcock from UBS. Please ask your question.

Glyn Lawcock (UBS, Analyst): Hi Peter, it's Glyn. Just a couple of questions. One, I know it's very early days in the China/US trade dispute, but just wondering how that's impacting customers' thoughts, and discussions you may be having in the marketplace at the moment, and any thoughts you might have looking forward?

Then just secondly on exploration, I note the spend drop going out over the next couple of years you talk about, is that focus-driven, opportunity-driven, and how should I think about that in terms of your comment earlier regarding rig rates lifting? I think you made some comments about you're trying to lock them in now, is there risk on the exploration spend as well, looking out? Thanks.

Peter Coleman: Look firstly, on the trade dispute, we haven't seen anything come through yet that's material, between the US and China. Now, of course, as you know, there were some US companies sign MOUs with China earlier this year, for offtake, we haven't seen - our view is, of course, they're going to be made more difficult to finalise those SPAs. There was an announcement earlier this week of an SPA with CPC in Taiwan being finalised. They're obviously not part of that trade dispute.

So, in general, I would say this works in Woodside's favour, with respect to the confidence of the Chinese buyers, and actually what price will they pay. At least they know, if they do a deal with us, the price that they will pay. At the moment they've probably got to assume that any price they pay for gas coming out of the US will have a tariff on it. Whether that tariff remains at 25%, or whether it's something different, I don't know. We'll see how that brinkmanship plays out over the next few months, and whether that tariff even stays in place. So, it's just too early for us to tell, but directionally I think it favours gas coming out of Australia. There's no doubt about that.

With respect to where the US gas will go, the forecast now is that Europe is going to start to take more and more gas, and I think that LNG, not just pipeline gas, I think that's a positive, and you're seeing that because Groningen and other fields, the UK North Sea, are all going into fairly significant decline, so that was naturally going to occur anyway. So that'll go over there. It may affect shipping rates because the transit of shipping will be a little less. You'll have less cargos coming out of the US into Asia, at least into the China market for growth. But that China market wasn't a big part of the market anyway, some of it's going to Japan.

So, we haven't seen that play out at the moment, but it will. There's no doubt it will in my mind, but give us another year or so to see that play out.

On exploration, I would say the change here is to be focused. We went broad, we took an opportunity as prices crashed to get into some acreage areas that we coveted. We couldn't do that before when price was at $100 per barrel. We've gone after it, we made a number of discoveries, unfortunately some of them were non-commercial, so we found oil, but not enough. We've opted to exit a couple of those areas just simply because, and by the way the operator has stayed, based on the view that we just don't want to put more money into something that we're just not sure what the outcome will be.

It's focused and we just naturally had to do it, because as we look at the opportunities in front of us, pulling $100 million a year out of exploration for five years, it's not small money, it's half a billion dollars over five years, and I think our shareholders would want us to spend that on our known growth projects, at the moment. So, that's how we're looking at it. Refocus the exploration, exit those areas where we can see commerciality is not going to play out, and give us the returns we want.

Then the exposure longer term on exploration rates, we're starting to see a little firming, more in the seismic market than anything else, they will firm over time because the super majors have not been exploring, and at some point they'll have to move away from acquisitions and get back into exploration. So, all of those things will start to put a little bit of pressure on the exploration budget over time.

But I can't tell you what that will be, we may keep the cap on the budget, just means we drill less wells, or we may increase it, depending on the opportunity. But that's next years' conversation. What we want to do is give you guidance now as to where we think this is going to play out over the next three or four, five years.

Glyn Lawcock (UBS, Analyst): Wonderful. Thanks very much.

Peter Coleman: Thanks, Glyn.

Operator: Thank you. There are no further questions. Sorry, please continue.

Peter Coleman: Yes, okay well look, thanks, everybody, for joining us this morning, and thanks for the quality of the questions. We'll be around talking to investors next week, and obviously providing some more insights to where we think things are going and so forth. So, we appreciate the time you've spent with us this morning. We appreciate your support and the effort that you put into understanding Woodside's story.

We are moving things forward, I'm not going to say I'm excited, because I'm working too hard to be excited at the moment, but as you can see, we've made some significant progress on things that most people thought were probably immovable objects. We've started the momentum and what we've got to do is just keep the shoulder to the grindstone and just keep these things moving, moving, moving. So, our heads are down at the moment, and working very hard, but the opportunities are in front of us and you can see we're starting to move them through the decision gates, which is very, very important.

So again, thanks for your time this morning, and we look forward to catching up over the next few days and weeks.

End of Transcript