# Event Transcript

**Company:** Woodside Petroleum Ltd
**Title:** Investor Briefing Day 2019 - Q&A
**Date:** 19 November 2019
**Time:**

**Start of Transcript**

**Peter Coleman:** I'm now going to move to a Q&A period. We've got 45 minutes for this; I'll take questions from the room and also I believe we may get some questions from the webcast as well. The guys will run around with microphones, if you could just put your hands up and identify yourself please.

**James Byrne:** (Citigroup, Analyst) Morning Peter, James Byrne from Citigroup. Now in your opening remarks you mentioned the LNG price fairy. I'm very glad that you did because I wanted to clear up something with you. It sounds like the language has kind of changed a bit here, whereas say at the site trip earlier this year, you said you're positive on the commodity, you want your price reopeners in your contract clauses, to be able to capture higher prices in the future. But this morning you've said that you'll look at the economics of these projects based on current market prices. So when I was up in Asia recently, market prices today slopes low 11s. Are you saying that you can get a return above your hurdle rate, call it 11% slope, for example? I presume you're not going to give us your break-even price, but I'm just trying to understand the resilience of these projects, to outcomes that could see low prices. Thank you.

**Peter Coleman:** It's a good question. So my comments this morning were around, exactly right, the resilience of the projects themselves, which differs to my view on where I actually think the commodity price is going to get to. So when you start to talk about the price fairy helping you out, of course there's a general rule in any business, when prices are low, you always think they're going to get higher and when prices are high, you never believe they're going to get low. So we're at a low point in the cycle for sure, when you look at it on historical benchmarks; we're definitely at a low point in the cycle, although we have been here before as an industry, so we need to be careful of that.

Equally, that low point in the cycle delivers low cost for us and so the last time the industry was really able to get excellent returns was back in the early 2000s where we also had low prices and low cost for a long period of time. What we're trying to do here is lock in the low cost, not lock in the low price. Our view is that prices will improve, clearly, with the market through the mid-2020s, but equally I'll also test it at today's pricing because I need to make sure that we don’t fall into the trap of moving forward projects that has price growth built into it that's actually not reflected in the marketplace today. There is a difference between having a forecast and the reality of your marketplace today, so thanks for asking that question for clarification. I hope that helps.

James Byrne: (Citigroup, Analyst) Just clearing up on the capex, so just to be crystal clear, last year was $11 billion real, for Scarborough Pluto train and it's now $10.1 billion real.

Peter Coleman: Last year it was $11 billion real for 100%, this year it's $11.4 billion real *[Correction: nominal]* for 100%. The 10.1 is a different number. I'm not sure what number you're referring to with the 10.1, the equity share? Yes, sorry, the equity share is 75% of the offshore, 100% of the onshore, equals the 10.1.

**James Byrne:** (Citigroup, Analyst) Thank you.

**James Redfern:** (Bank of America, Analyst) James Redfern from Bank of America, two questions please on the train 2, the capex intensity appears to $1200 a tonne, I think that’s higher than what was flagged a couple of years ago on the presentation. I think from memory, you were targeting less than $800 a tonne, so just want a bit of commentary on that please and I've got one more around the economics of Pluto train 2, thanks.

**Peter Coleman:** The capex intensity on a like-for-like basis, as you measure it against US projects, for example and I've got Daniel Kalms in the room who is leading the project, it's under $900 per tonne at the moment. We haven't finalised that yet because we're still arm wrestling with the contractor, but it's under $900 per tonne.

**James Redfern:** (Bank of America, Analyst) Okay, thanks, yes, because I was looking at $6.1 billion divided by five million tonnes, you get 1200.

**Peter Coleman:** Yes, well like I said, on a like-for-like basis, so you've got to look at those US projects don't put in your cost of capital, your interest payments and so forth, so what we do is we strip down so we just get the base cost to build the project so that when people look at those numbers, they can see a number that compares like for like.

**James Redfern:** (Bank of America, Analyst) Thank you, just another one, I want to confirm, on a standalone basis, does Pluto train 2 have an internal rate of return above 12% and a positive NPV, is it really simple, or are those returns looked at on integrated basis with Scarborough?

**Peter Coleman:** So we'll look at the project on an integrated basis and that integrated basis, Woodside has the value of being able to leverage the common infrastructure that's already established, of course train 1, the building of train 2 and then the offshore. The train 2 standalone return at the moment is below 12%. It's still a very solid return, it's well above our cost of capital, but it's a lower return than 12%. But then of course that then flows into the upstream part of it, which we own 75% of and remember, we're targeting to sell down train 2 to 50%. So we look at it and say it's just moving where the value is and we hold 75% of the upstream. It also then allows us to unlock significant value in train 1 and the common use facility, because those facilities are already sitting there built, so there is very nominal investment that we require in train 1 and the common use facilities to extract value out of them.

We've got to look at each part of the puzzle. It's an enabler, but what it does, it clearly makes its cost of capital return and as Meg showed you, it will be a fully wrapped lump sum contract, so from a risk point of view, we see that as appropriate for the risk that we'll be taking on the contract, for a site that's already prepared. I know you've been up and see the site, the site's already there, the hardstand area is already there, the environmental approvals are already there. The greater risk is in the upstream, where we still have to drill the wells, we still have to produce them and so forth and it has commodity risk associated with that, whereas the plant does not have commodity risk, so it was appropriate to apportion the risk differently between each segment. But overall, what it does is it allows us to unlock a huge amount of value that's sitting there latent in the existing facilities.

**James Redfern:** (Bank of America, Analyst) Thank you.

**Saul Kavonic:** (Credit Suisse, Analyst) Thanks Peter, I'm just going to put all my questions in one go. On the first one, just on the reserves increase, I mean you and Meg, Exxon, Exxon's not a stupid company, what's the rationale for Exxon not having done these relatively easy piece of analysis and upgrading before selling it to you at such a cheap price? Secondly…

**Peter Coleman:** Let's just ask one question at a time, Saul. I'll let you ask multiple questions, we'll just ask one. I wish you didn't ask me that question and you should have asked Meg, because we've scratched our heads on this one as well and I must say, challenged the organisation very hard. They had a 63-page presentation to me to convince me we had got it right and the others had not looked at it for a while. I think as you saw in Kimberly Walpot's video, there as basically the use of new information, so we had new technology available to us, which is full waveform inversion. The flag went up when we first went into the data room when we acquired equity from BHP and there was some information that just wasn't there that we expected would be there at the time. When we went into the Exxon data room subsequently, we were looking for that same information and it wasn't there and so we immediately formed a team to go and have a look at that.

Now the explanation is straightforward, but you think it shouldn't be. I think there's two parts to it. Firstly, the data, this was the first time the data had been brought together. You may recall Exxon originally drilled the wells in the field and then BHP decided to sole risk a number of wells. That data at the time was not available to Exxon because BHP held that, because they sole risked those wells and in fact, Exxon had to take, in my understanding, take legal proceedings to get access to some of that data, so it was never properly integrated.

When we came in, of course, we were a cleanskin, so we were able to get access to all of that data and we saw that there were disconnects within the data. You add that to the technology, you add that to the fact that the operator probably had this on care and maintenance for a number of years because it was under retention lease and remember, one of the reasons that Woodside was able to get hold of this asset is because we held the onshore assets, which were the key to unlocking the offshore resources. Standalone offshore resource with a new LNG plant just wasn't going to be economic, but an offshore resource that came to an existing facility, leveraging existing infrastructure was able to do that. So I don't think there's any criticism at all, we're not drawing any criticism, but we certainly asked ourselves the same question, is why are we so smart when some very, very smart people before us haven't picked up on this?

Now to test that, of course we also went out to our - and this is unusual for us, we wouldn't normally do this when we're still at a 2C basis, but we went out to Gaffney Cline who are our external verifying agency for our reserves and Gaffney Cline has given us a letter of comfort with respect to that resource number, they've come in very close. We haven't got the final letter off them yet, but we expect that before the end of the year, but we've been in contact. Hopefully that explains some of that.

**Saul Kavonic:** (Credit Suisse, Analyst) Good thank you. On the interconnector, just in general, is there any update on what you've seen in the North West Shelf prior to Browse, particularly if Browse ends up being a little bit late? What is the limit on the amount of volumes you can send across prior to 2027.

**Peter Coleman:** It depends on the gas that's going across, but roughly, if it's Pluto gas, it gets limited by the ability of North West Shelf to treat the nitrogen, take the nitrogen out of the system. We've got Daniel Kalms and Niall Myles in the room, they're the experts on this, but they tell me it's somewhere between one to 1.5 million tonnes that we can get across of Pluto gas. Now typically they guys do a little better than that. When they start optimising it, running it through the plant, so from a planning basis at this point, that's about where it is.

**Saul Kavonic:** (Credit Suisse, Analyst) Lastly, slightly different subject, what's your latest thinking in terms of how long you want to still be CEO of Woodside to see out these projects? Are there any updates beyond your press announcements of sticking out another five years last year?

**Peter Coleman:** Yes, we don't make announcements on when the CEO's leaving because I think history would tell you from recent announcements you can't believe it. It's kind of like a bank, a bank never tells you they're going to go close their doors until the day they close their doors. I know there's a few banks in the room. We'll have an orderly CEO progression, that's what I can assure you. You've seen some of the leadership team this morning as we've been rebuilding that leadership team. You can be assured I'll be here through the FID of these projects and to get these projects moving. I think once that's up and we're all comfortable with where it is, then we'll have conversations with the Board about when the right time is. Certainly it's not imminent at all, I can tell you that truthfully, unless there's something going on I'm not aware of, but certainly in my discussions, or you don't like what you saw this morning, I don't know, but seriously, it's not imminent at all, Saul and you can be assured that I'll see these out as far as it makes sense.

**Saul Kavonic:** (Credit Suisse, Analyst) Thank you.

**Mark Samter:** (MST, Analyst) I'm Mark Samter from MST I guess given I haven't been invited to the sell-side dinner tonight, I have to ask all of my questions now, so there could be a couple, I apologise. First one, James alluded to the fact that downstream capex has gone up, I mean your guidance has been incredibly hard because you gave us separate but real first and you gave us an integrated number and now you've gone back to separate. But certainly looks like downstream is up, which means upstream is lower. I'm just interested, two questions, if you contextualise, you're saying $5.3 billion for the upstream, if you gross out BHP's guidance from last week, they're saying it about $5.5 billion to $7.5 billion. Can you explain the difference there and can you categorically confirm for us there's been no scope changes, no change in the number of well drilled to RFSU?

**Peter Coleman:** No not really, Mark, there's not really been any scope change at all. The upstream has been locked in for some period of time. My guess is BHP numbers probably also reflected what they thought direct range of equity positions may be and also they may be carrying a different contingency than us at this point in the project. I haven't sat down and compared the two numbers…

**Mark Samter:** (MST, Analyst) It wasn't equity differential and that's what you want.

**Peter Coleman:** Yes, so I didn't sit down with Geraldine and go through her numbers to see what was being presented. All I can say is these numbers have held solid and these are the numbers that the operator has been giving BHP through the project. The scope hasn't changed, so the number of wells hasn't changed, the size of the offshore facility hasn't changed markedly. We've been looking at the pipeline diameter and trying to make it as large as we can to reduce back pressure around those things, but they're kind of minor changes in the overall scheme of things.

In the plant, there's been an increase, a couple of hundred million dollars increase in the plant or thereabouts, to be able to treat heavies in the gas. We actually, again, went back to the fundamental gas analysis and whilst this gas has been purported to be very dry, there were traces of heavies in the gas and we said just being conservative, we'll put some upstream treatment facilities there to strip those heavies out. We don't want that to be a surprise on day one. So again, a lot of the data is old and what we're trying to do is make sure that we're covered for it, so there has been an extra investment in upstream, sorry, plant, to cover that.

**Mark Samter:** (MST, Analyst) With the tolling number on slide 41, the more than $1 billion, can you confirm what – did you charge yourself a toll on Pluto? What tolling volume does that assume on Pluto?

**Peter Coleman:** Well, that number is the current equity range. Now, what this is, is a gross toll number. Remember, as part of the toll, there will be a capital recovery portion of it and then there will be an expense, or OpEx, portion of it. That's just the gross recovery. If you look at the numbers going out, then this is what we'll get back in. If you want to net that out and take out the expense and say, well, you're just moving it from one hand to the other, then the net toll effect will be roughly about $650 million, or thereabouts, in there. That's how the money will move. But if you just look at it at a top line number, without taking some of those things out, it's $1 billion. You take them all out and then it's on both the profit element and a return on capital element, it's going to be about $650 million.

**Mark Samter:** (MST, Analyst) Then just one the Scarborough reserve upgrade.

**Peter Coleman:** Yes.

**Mark Samter:** (MST, Analyst) I guess there's a lot of fields, offshore WA, that use the same technology as the people who got it so wrong before you got - I mean, those that have actually drilled wells, we've not see any meaningful reserve upgrades from any of those that - correct me if I'm wrong, but over the last 15, 20 years, some of them have had reserve downgrades? Why have they not seen what you've seen, in reality, when they've actually started producing? Wouldn't you have rathered drill some wells before the - coming up with this number?

**Peter Coleman:** Look, I think you've got to look at it on a field by field basis. The general rule of thumb, as you know, the big get bigger - the larger fields get bigger. As Meg showed, you don't have to have much of a change in assumptions to really fundamentally change what the recoverable resource target is. Technology changes over time. I would look back at the north-west shelf, for example. The north-west shelf, from recollection, started off with around 14 Tcf to 16 Tcf. That's now north of 24 Tcf. You do have upgrades over time, as technology improves, as to - drilling techniques improve and so forth. It's not unusual. It was a pleasant surprise for us. But equally, I would say it wasn't one that we weren't looking for. We didn't stumble over it. We were actually looking for it when we went into the data room and we saw that there was some gaps in the data.

As I said, I can explain it, it doesn't always sound logical in that regard. But equally, this is a field that has been sitting there since 1979 and people haven't been getting their mindset around development, except when BHP sole risked.

**Mark Samter:** (MST, Analyst) I'm just - okay then, one more. With - Scarborough gas is being equity marketed, obviously.

**Peter Coleman:** Yes.

**Mark Samter:** (MST, Analyst) I mean, BHP only gave them the tolling agreement yesterday. They're not the world's largest LNG seller in the world. What gives you confidence that they're there to market this gas to your first half FID?

**Peter Coleman:** Well, again, that's BHP's problem. We've - problem and opportunity. We've talked to BHP, over time, as to whether they wanted to jointly market with us, or equity market. They've decided that they wish to equity market their gas and we're fine with that. At the end of the day, if they have to sell gas to us, then that's fine and we'll sell it into the market place. But at the moment, they've got a capability to equity market. They are small, but they currently equity market their North West Shelf gas, as you know. I think - my guess is they're trying to build that capability.

**Damien Gare:** Peter, we've got a webcast question as well, from Peter Arden from Bell Potter Securities. He says, Woodside traditionally holds the majority interest in all of its long-term projects. If Sangomar is to be a long-term project, why doesn't Woodside hold more like 50% to 60%? Or is this indicating that Woodside doesn't regard Sangomar as a long-term project?

**Peter Coleman:** I would say, typically, what we try and do in our projects is, when we operate, we target an equity level of anywhere between 40% to 60%. The reason for that is when you're operator, you take on certain liabilities and obligations. To make that worthwhile, you generally want to hold a larger equity in there. It also means that some of the voting requirements and so forth means you can kind of get it across the line, because you've got a larger percentage. Then that gives you surety on development and so forth. Simply, in Sangomar, in answer to the question, all that was available at the time was 35% and so, we purchased the 35% that was available. With respect to other equity coming into the market, if it does come into the market, then of course, we'd look at it very very closely. But we're all about value for our shareholders. Clearly, we know the asset, we've got a view on what the value is and so if it comes into the market, we'll look at it very closely.

**Mark Busuttil:** (J.P. Morgan, Analyst) Mark Busuttil from J.P. Morgan. I just wanted to unpack the media release, from overnight, just a little bit more and particularly, around BHP's decision to relinquish their rights on Scarborough. Now, if the resource upgrade came through - so, to such a large extent over the last couple of weeks and they talked about it so positively at their own petroleum briefing, I guess, the first question is, why were they so happy to relinquish those rights?

**Peter Coleman:** Well, they weren't happy to relinquish it, Mark. It was simply a negotiation around the toll. We ended up in a position where Woodside viewed the toll needed to be here, BHP wanted it to be here and their reasons were simply around making sure that they maintain margin, over the life of the project, so that whatever toll they were paying, it was resilient in the market place. They had a view where it should be. The equity was simply the last trading chip we came to, to be able to close that difference. I know you've been - you guys are probably reading gossip in newspapers and so forth. They were tough negotiations and so we needed something on the table that both of us valued. I valued it differently than what BHP did, but we were able to come to an accommodation where I'm comfortable with the toll that we're offering them. No, we're not giving away value. Yes, remember, we own 75% of the upstream.

The other part to it, of course, is we were getting parties who were interested in the upstream, who wanted more equity than we were able to offer. Actually, starting with 75% in the upstream and if we go out to market on that, we've actually got a bigger equity parcel and that will attract a different player into the market. We saw it as having two advantages. Gave us more equity, but equally, that we could sell if we wish to. But equally, we like the asset and so as you know, one of the most difficult things in this business is to actually get your hands on a world-class asset. We spend hundreds of millions of dollars in exploration and in M&A activities to get your hands on an asset. Now, we've got our hands on an asset, in our backyard, going through our facilities, I'm not sure that I necessarily want to sell unless somebody is going to pay me full price.

**Mark Busuttil:** (J.P. Morgan, Analyst) Just in regards to the sell down, you talk to you've conceded a little bit on the toll treatment charge to - for BHP to relinquish those rights. Does that make the sell down of Pluto Train 2 now more challenging? Can you maybe talk to the counter-parties that you'd be discussing that sell down to? Would it be other E&P companies? Or would it be infrastructure companies? Maybe around about the timing of it, because I think most people in this room thought the sell down would happen through the course of 2019. It now seems like it's a little bit later?

**Peter Coleman:** Yes, so one of the biggest impediments to a sell down, on an integrated basis for the upstream equity, was actually what the toll was going to be. Until we actually settled the toll, people were saying to us, well, we can't actually value what that downstream plant is going to be, so go settle the toll first. Remember, there's two tolling discussions that we've got to work through. One is with BHP, coming through Pluto Train 2. The other one then, of course, is with our partners in Pluto Train 1, Tokyo Gas and Kansai Electric, with respect to the use of Train 1. That discussion is still ongoing, but very close to being finalised. We had two things going on. People gave us the feedback very early on, get that sorted out and then we'll come and offer you a full price. We actually closed the data room, for a period of time, and we took the pressure off the deal team and said, well, maybe we won't get this done by FID because if we get it - trying to rush to an FID, it's an unofficial date, to be quite frank with you.

Anybody we signed up to come in anyway, we would have said to them, you must agree with our development concept, you are not coming in and getting voting rights to - so, you will vote with operator on the development concept. It became a bit of a moot point, actually, as to whether they came in before, or after, because they were going - we were going to require them to vote with us anyway, in that regard. We basically said, let's settle the data so people can come in. We'd been going out selectively to people we'd been talking to - potential customers and so forth. There's definitely interest there. But I need to now challenge myself on that, to be quite frank, about what we see is the value in the upstream. Now, we are definitely on a pathway to selling the downstream plant and we'd like to get down to 50% equity in that. That's probably more an infrastructure investor and of course, we have had unsolicited interest in that. We know what infrastructure type investors are looking for and we know the toll structure that they're looking for.

But again, we're not in - we don't need to rush to do that. We'll do that now. Rather than having it finished before FID, it's more likely to move into the later part of next year. Again, they wanted to see the contracts, they wanted to make sure those lump sum bids were solid and so forth and so on. All of the normal things while we're - of discount and take value out. We thought, as the project becomes de-risked, people are not paying full value for it, so we want to make sure they pay full value.

**Ben Wilson:** (RBC, Analyst) Hi Peter, Ben here from RBC. Peter, can I just ask you to step back to the IBD. Last year, when you were discussing Scarborough, having recently bought in, you spoke about one of the rationale was potentially deferral of Pluto development drilling, specifically, the 404-P block. I think you gave a number - maybe a $20 a boe

DevEx. My question is, has that number evolved at all? When you think about the economics of Scarborough, from a Woodside perspective, are you factoring in that deferral of Pluto DevEx drilling?

**Peter Coleman:** That's a really good question because the development of 404-P needs to start around 2026, '27, to start filling in the back end of Pluto. We're just still finalising our analysis on whether we want to develop 404-P, or let Scarborough come through it. That's some of the - we've got actually de-bottlenecking plans already for the Scarborough offshore, to be able to fill some of that. The development costs of 404-P are high. We haven't updated those development costs, but you can see the development costs of Scarborough are a fraction of what 404-P would look like. In our view, at the moment, Scarborough is very much competing for that additional capacity that will be available, in Train 1, out towards '27, '28, or thereabouts. That's still an open debate for us at the moment.

**Ben Wilson:** (RBC, Analyst) Thanks for that. Just a quick one - thanks for the granularity on Sangomar phase one CapEx. As you look at phase two, the next 250 million odd barrels, what sort of confidence level do you have, at this point, around that scope for phase two? Or will that evolve as you see phase one production?

**Peter Coleman:** Look, it will get de-risked, clearly, as we go through phase one. That was really the intention of why we developed phase one the way we are. Remember, phase one is going for the lower reservoir. The upper reservoir has about 3 billion barrels in place, but the sands are not connected. We'll drill anywhere between 24 to 27 wells penetrations through that upper reservoir as we develop the lower and of course, some of those wells will actually produce in that upper reservoir so we'll get a lot more information on it. We're also running probably the densest seismic survey that we've ever run for Woodside - the most technologically complex survey right now and we'll have that data available to us as well. We just waned to make sure that we don't over-capitalise in the field, but we'll get more than 20 well penetrations into this reservoir. Half a dozen of those wells will actually flow the reservoir so we'll be able to unlock it.

There's some numbers out, we'd support those numbers today. But we don't have - I wouldn't say we have a robust development plan and we won't have a robust development plan until we drill the phase one wells and we're able to do the well testing and of course, also, review the seismic.

**Ben Wilson:** (RBC, Analyst) Thank you.

**James Redfern:** (Bank of America, Analyst) Peter, James Redfern again from Bank of America. Back in June, at the site visit, you mentioned that the tolling fee for Scarborough was north of $2 and south of $2.50. Is that still the case?

**Peter Coleman:** I think that might have been North West Shelf. The tolling fee for Scarborough is north of $3.

**James Redfern:** (Bank of America, Analyst) North of $3 for Scarborough through Pluto Train 2?

**Peter Coleman:** Yes.

**James Redfern:** (Bank of America, Analyst) Yes, thanks. Then in terms of Sangomar phase one, what needs to happen to reach FID by the end of the year? Is that subject to FAR and Cairn selling down equity? Or FAR raising private - sorry, project funding?

**Peter Coleman:** Well, I'm going to let the joint venture partners speak for themselves because now, they're funding challenges of their own, not mine. Where we are with the process, at the moment, is we have just gone to a vote on submitting the exploitation plan. That occurred over the weekend. That vote - at the moment, we have three out of the four partners who have voted affirmatively for that. Now, we're working with the other - final partner to get their vote. They've got about 14 days to do that. That vote then will come just before the exploration of the PSC. So, to maintain the rights on the PSC, we have to apply for the exploitation plan and for the exploitation approval from the government.

So, we have to submit the plan and apply for the approval. That needs to be done before  December. So, the vote that we've just put in, as I've said, three of the four parties have voted in favour. The fourth one is considering their position but they've got 14 days.

**Damien Gare:** You have another question from the webcast here. It's from Sally Bogle at Interfax. She's asking are we intending to process in Scarborough gas through the interconnector and otherwise, do you have any plans to use other onshore gas such as Waitsia through the interconnector?

**Peter Coleman:** Well, first question is of course Scarborough gas won't become available until around 2024. Scarborough gas can be processed through the interconnector in slightly different lower *[Correction: higher]* volumes than Pluto, but it can be a processed through the interconnector. So, it does give us an option as well as Pluto starts to go into decline.

So, as you know, we've just completed or completing the Pyxis development, so it would give us additional capacity. Meg mentioned that Pluto A7 has just been completed. So, we have more than adequate well stock or well capacity at the moment at Pluto, far more than the plant can process. So, as we talk about streaming gas across through that interconnector, we have all of the well stock available to us at the moment and the offshore capacity, remembering the offshore capacity for Pluto is twice the onshore capacity of the plant. And that was built in in the original design.

So, it was always designed as Meg mentioned, for multiple LNG trains. The offshore has that in it. And so, we have spare capacity existing. We've just drilled the wells for that. Once the interconnector is up and running of course we'll be immediately able to stream across. That'll be Pluto gas when Scarborough starts up. Then we'll do some optimising around whether it's Scarborough or Pluto gas that goes across in there.

With respect to Waitsia of course we don't own Waitsia at all. Waitsia is separately in discussions with the North West Shelf joint venture about whether their gas can be treated at the North West Shelf. So that's a separate discussion.

**Mark Samter:** (MST, Analyst) Sorry, me again. This is probably a very stupid question, but is it true BHP is 100% take-or-pay?

**Peter Coleman:** Yes, yes. *[Note: see clarification from Sherry Duhe below]*

**Mark Samter:** (MST, Analyst) You obviously did the deal, but you generally don't want to - if you look, we're in the middle of winter and DES cargoes are going for $5.50. You're going to take more than three from them, this year five bucks out of the North West Shelf. I mean how are they incentivised to proceed with this project?

**Peter Coleman:** Yes, so the question is what's the toll and is it a take or pay or deliver or pay contract? Yes, it is. And you put in a quantity each year that you will process. And so that's all in the details of the agreement. With respect to BHPs ownership; BHP will continue to own the molecules out through onto the ship. And so, there won't be any transfer of custody of the molecules themselves. So, if BHP choose not to process and I'm not sure they actually can do that, but, they may. Then of course we'll continue to receive the toll and I'm sure Woodside would be happy to fill any spare capacity with our own equity production.

**Mark Samter:** (MST, Analyst) Just out of curiosity, with the tolling, and I get that's the cost of carbon and you have to cover the cost in the toll, but who books the carbon emissions from downstream production, will it be you or BHP for those molecules?

**Peter Coleman:** No, so the agreement, and it's a similar agreement at North West Shelf is the upstream party, whose gas is being processed will own any regulatory changes or price changes. So, they'll own the carbon commitment. So, the carbon commitment stays with the upstream. It doesn't sit with the downstream.

Now the liability sits with the downstream, meaning that's how the regulator will look at it, but the agreement passes it through to the upstream. The upstream has to expunge that liability.

**Saul Kavonic:** (Credit Suisse, Analyst) All right Peter, if I may, I might throw a few more in. Can you just confirm, does Scarborough trunk line capacity, is that seven and a half million equivalent or is that actually larger and can take additional volumes from new field tie-ins beyond Scarborough?

**Peter Coleman:** The trunk line capacity, nominal number Saul is 7.5 million tonnes. That's six and a half through the trains and one million tonnes into domestic gas. So, that's how you get the seven and a half million of equivalent. The bottleneck in it is the deep water part offshore. And so, whilst the Scarborough field itself is in roughly 850 metres of water depth it's on a plateau. As it comes off the plateau, it gets into about 1100 metres of water depth for a period of time. For about a third or maybe 40% of its distance.

That's a limiting factor is because the size of lay barge vessel that you need, once you go any larger in the size of pipe we have at the moment, you get down to one vessel in the world that can do it. And we certainly don't want to be in that particular situation. That's where it is today. The Scarborough team though already have de-bottlenecking options available to us. Those being tying the pipeline into the existing optional Pluto facilities. And then also twinning the line in the shallow water section. You get significant benefits with lowering back pressure.

So, we already know. We've already got line of sight to being able to increase that capacity. We want to, before we invest in it though, because it's a few hundred million dollars, we would want to make sure that we've got an offshore resource that's going to underpin it.

**Saul Kavonic:** (Credit Suisse, Analyst) On the offshore floater for Scarborough, how are you managing the risk with McDermott, just given where McDermott's market cap versus book value ratio is. They've got a pretty big book with Exxon and so on in the world, would probably be more priority clients?

**Peter Coleman:** Yes, so the question is how are we managing the risk with McDermott being the contractor for the offshore floating production unit for Scarborough? And of course, that contract is a mixture of lump sum and a provisional lump sum. McDermott is an excellent business. They're an excellent contractor and they've got excellent yards that have been able to work in.

Of course, they're in financial difficulties at the moment through their acquisition of CB&I and the liabilities that came with completing LNG plants in the US both at Cameron and at Shreveport. We've got an agreement with McDermott where we are looking at their books on a monthly basis. They've got certain covenants with us or triggers in which they need to inform us. But we're also developing backup plans in case we have to take over that contract.

We are still confident though that the base business, the core business is actually a very good one. What they're struggling with is this financial pressure because those projects that CB&I brought across weren't as complete as they thought they were and they've got some issues through the acquisition. But the core business is still the right core business.

You look then at options and who do you go to? Well, you can see there's actually not that many options out there because some of the other contractors; Technip and so forth, they're already splitting their business up as well, moving into a technology and moving into construction business. So, it's not that there's a large pool of contractors out there that can actually do this work and do it effectively.

So, we still believe in the core business staff of McDermott and even if they went into a chapter 11 situation and so forth, we're developing backup plans to allow them as they restructure their debt. So, it is something that's on our risk radar, on our risk matrix. There's no doubt about that. But today we think we've got an acceptable plan. The alternatives are not particularly enticing with respect to having to go back and contract and so forth.

**Saul Kavonic:** (Credit Suisse, Analyst) One last one if I may quickly; on your production chart where you've got production sitting around 100 million barrels next year, then dropping about to 90 in 2021 before picking up again; is that drop predominantly or solely due to a drop in the Northwest shelf or are there other contributing factors? And I notice that didn't include the interconnector, but if you include the interconnector, will that arrest most of that decline from 2022?

**Peter Coleman:** Yes, that’s a really good question. So, a 2021 it really comes down to how well the reservoir engineers can forecast. Now I am one, so I'm probably more sceptical than they are, but they are true believers in their forecast. The North West Shelf has a view it will start to go into decline in 2021. Equally, Greater Enfield has a short plateau period as well. So, some of that is Northwest shelf, some of that is Greater Enfield.

And yes, you're correct, that forecast does not build in any of the interconnector for us. And so that's why we're moving to get that interconnector built as soon as possible. That's why we decided to recently announce an FID on our part of that interconnector, which is a major spend.

The North West Shelf has got a much smaller spend. From memory it's probably around $60 million or thereabouts on their side of the fence. Am I correct Niall?

**Niall Myles:** 80, yes

**Peter Coleman:** Yes, about 80 on their side of the fence. So, you divide that by six and it’s not a large number for each of the participants. But just the receiving facilities. But the big one was getting a rig to get the permits and the easements set up and the pipe in the ground for us. The work on the North West Shelf is not as substantial.

**James Byrne:** (Citigroup, Analyst): James Byrne again from Citigroup. The last formal update that we had on the North West Shelf and Browse tolling agreement at your result in August, you'd mentioned that there are about seven outstanding issues, mainly around risk sharing; things like the North West Shelf goes into decline and how you compensate counterparties for that uncertainty.

Where are we today in terms of getting to an agreement that is signed? And as a corollary to that, just rereading the announcement overnight for the Scarborough Pluto heads of agreement to go binding you've got these unconditional contracts to be signed, I presume that that would be dependent on Browse to North West Shelf going ahead. Is that correct?

**Peter Coleman:** So, let me answer the second part first because it is easier. So, the last part of your question, no. So, there is no tie between what's happening at Scarborough or Pluto and what's happening at North West Shelf. So, there's no linkage at all between the two.

With respect to the agreements; what we announced overnight and we did it through the media because we wanted to get it out as quickly as we could to you. It didn't meet materiality thresholds for ASX. So, that's why we went through the media. And the reason for that mostly was it is non-binding. Now, don't read too much into non-binding. The agreement we have with them is very comprehensive. And so literally, all we're doing with BHP is papering it up. It is nowhere as complex as the number of issues that were required to be resolved at Browse and North West Shelf.

It’s a night and day comparison between the two. So, it's just simply to be honest with you, it's simply administrative. There are no negotiation things to be papered up. Those things have already been agreed and agreed in quite comprehensive letters between ourselves and BHP already, so that everything's agreed. It's just the legal work now to finalise it. And I expect whilst we mentioned March next year, my expectation is that it should be finalised much sooner than that into a binding agreement.

With respect to North West Shelf you're right, there are seven remaining issues. There's still seven remaining issues. I'd probably tell you four of those will get resolved very quickly and then we'll get down to the final three. We've really just engaged with what we call the Browse non-aligned partners, being Chevron and BHP in the North West Shelf on the drafting of the document. Of course, there are lots of editorial changes in that. They've just gone through that.

They've accepted that document and we've now got to sit back down at the table and finalise that. To be quite frank with you my focus has been on getting the Scarborough deal done and then also moving forward on Sangomar. And we just needed to let the North West Shelf deal just sit for a little while and people just consider their positions. But we'll reengage on that next week.

**Sherry Duhe:** Peter, could I just jump in with a tiny clarification on the question around take or pay? It's not quite at 100%. It is at a very high level, but it's not quite at 100%. Just to clarify on that.

**Peter Coleman:** Yes, that’s right. They will nominate what their quantities will be each year and it won't be 100% and Browse has got a similar agreement with North West Shelf. We'll come back to you in a minute Mark.

**James Byrne:** (Citigroup, Analyst): Just another question, and Damien you might want to give Sherry the microphone again, so I do have a question just around funding. It might help to go to slide 39 please.

So, I just wanted to just understand that balance that you're trying to find between your working interest in the project and your funding capacity. So, can you just run us through some of those scenarios or rather the process of your thinking at the moment? And if your capital investment profile is consistent with that shaded area, what are the levers that you want to pull first to be able to find your CapEx?

**Peter Coleman:** Yes, well let me have a go and then Sherry can jump in and clarify anything. I mean, they're really simple levers. It’s not that hard. The first one is, of course, we're looking at the phasing of the capital to see where we can phase the capital to move capital out so that hump isn't as pronounced and the revenue streams coming in. Of course, being the Interconnector is important for us to be able to get extra early revenue coming into the system. So that's on the revenue side.

With respect to then the capital itself and the capital management, you can manage that through your debt facilities and of course, while Sherry mentioned the debt facilities, it comes to a point where your limited on your debt facilities. It will be on what we decide is the right equity level, and again, we need to test the market on that and we will sell equity if we truly belief we're getting full value for the equity. I don't want to sell equity simply to manage capital if I don't- if I think I'm giving something away, particularly in these sorts of projects. I might sell equity in a lower-quality project but it's rarely that you get a project the quality of Scarborough coming along and close to where you are. So, that's your prize; you've got to cherish that.

Then of course, the final one then is looking at what dividend payment will be. Dividend doesn’t move the dial a lot, to be honest, on the total numbers. You have to accumulate that over time, which is why we turned on the dividend reinvestment plan so we could just accumulate - basically accumulating equity over time. But it's an efficient way of accumulating equity and for some shareholders it has particular tax advantages.

Then finally, of course, is going to shareholders with equity, and equity requirement. We've always said that trigger would be around the timing of Browse FID and I think we'll be in better shape over this next year to understand that that's a trigger we need to pull, but it would be on the back of also understanding what is our equity plan and so forth and we've gone and tested the market fully in that regard and then we know finally what the contracting standard is going to be. So, there's a few things that will come together over the next few months, probably around the middle of next year we'll be in a much better position to be able to say categorically this is where we think we'll go on some of those things.

[Inaudible question – microphone inaccessible]

Peter Coleman: No. No, each of those priorities have their own weighting at each particular point in time. Of course, all things being equal you would just love to be able to borrow money from somebody else and just fund your way through this but there is a point where our gearing is going to get too high for us as we go through the spend, so we're not going to be able to do that forever, and there's the cost of that capital as well that is sitting there bearing interest for you. I'd say all of those things are in the mix for us and we'll work through them sequentially.

We've probably got one or two questions left. Let's make these the last two questions.

**Daniel Butcher:** (CLSA, Analyst) Hi. Daniel Butcher at the CLSA. I just want to follow up on your Scarborough CapEx. It looks like you're increasing upstream capacity upfront, but I'm just wondering given the extra resource that might increase the life of the field by 15, 20 years, how much extra wells do you need to maintain that life over the life of the project and what sort of midlife CapEx or works required to do that?

**Peter Coleman:** Not a lot of extra wells. You can actually drain them from the existing well. We might find one or two wells, particularly as we go further north, we might need an extra couple of wells. You can see these are big-bore wells. There will be seven in the initial development. I think probably 10 - six in the initial development, probably a few more overall as you go through time. I would say only a couple of extra wells *[Clarification: Phase 2 of the Scarborough development may require up to approximately 6 wells]*. It's not a large amount to tap this, you'll be able to drain it from the existing points. The reason we haven't increased the capacity yet is you just have to settle a project and we've settled the project; let's get it moving out the door. This is all great news, you're right, it's extended the life of the field. Let's get these first parts moving, we already have plans for the debottlenecking then we'll start to mature those plans.

**Daniel Butcher:** (CLSA, Analyst) You might have partly answered this but just to clarify. I think sometime ago you said you might backfill Pluto to the tune of 2 or 2.7 million tonnes per annum and now Scarborough is only backfilling about 1.5 of Pluto in your current plans. What's behind that? Has the current reservoir got a longer life or producing better than you thought previously, excluding 404-P that you talked about before?

**Peter Coleman:** Well, developed Pyxis so we've brought some things forward as well. I think it will just look at the - as your timeline, what we've done is we've brought the tail end, because - so now we've looked at them, we can see well, maybe Scarborough is going to fill that plant pretty quickly, and what we're doing now is we're pulling the tail end as much as we can. We've actually accelerated the development of some of the resource with the expectation that we'll be able to produce it earlier and get it through the interconnector. That's the logic behind that.

Last question from Mark.

**Mark Samter:** (MST, Analyst) I was just - I know you're going to say publicly that the BHP toll is above $3 a million BTU. Can you just help me comprehend, are they just the worst negotiators on the planet? You can build newbuild capacity for cheaper than $3 a million BTU. So, how did they end with themselves getting a higher tolling fee than greenfield LNG capacity?

**Peter Coleman:** I don't know anybody who's doing greenfield for less than $3, and the number's north of $3. It's very, very competitive. I would say to you the overall leverage existing facilities, they're pretty good negotiators, there's no doubt about it, and the negotiation went over many, many months. So, we've got a return that our shareholders require;

we were firm on that, and where that risk could be. BHP were wanting to ensure that the risk of the upstream was properly recognised with respect to their return, so we came together on a number.

Remember, that toll I'm quoting you includes OpEx as well, Mark, so if you look at it on a capital and profit basis, then the number is below $3 but if you put the OpEx recovery component in there, then it's above $3. Of course, that's the advantage that we have now with train 2 is we'll be able to offset some of the OpEx on train 1 because train 2 - or sorry, the users will get charged some of that train 1 OpEx as well. That helps us with the profitability of the base project as well. So, no, it's very competitive. I think the difference is as you compare numbers, and you might have heard a number of $2 or thereabouts equivalent to North West Shelf, and then you say well, you've got a number at Pluto that's north of $3, the difference is at Pluto; that's it. That's it, so the offshore partners are not on the hook for any future capital in the plants.

Browse is a different model where of course the partners are on the hook for future capital and of course, it was a fully depreciated asset or very depreciated asset over time. Now, that future capital is built into the toll but there's a different risk associated with it, so naturally that component was less as well. But BHP get a spanking shiny new plant to be able to run their stuff through and they don't have to pay out any more capital because it's already inbuilt into the toll. So, they've de-risked there because they actually know what they're going to pay, whereas North West Shelf would be quite up and down and we've got an average over time for it.

[Inaudible question – microphone inaccessible]

**Peter Coleman:** Sorry. The question is the tenor of the tolling agreement? It's basically life of field, so it's based on the resource. It's not based on time; it's based on the type of resource going through it.

We'll wrap up the questions there. Thanks very much for coming and spending time with us this morning. I'm going to take from your questions that you're very interested in what we're doing. We think we've got - we're confident that we've got good plans in place. Obviously, there's a lot of upside here for Woodside to go and chase; we're in the right point in the market for it, as I said. We've been building our balance sheet, we've been building our team, we've been building our contractor base, we've been de-risking it through the types of contracting that we're going out with, we've done the subsurface work. The biggest risk for us now is market risk and understanding what the LNG pricing is going to be and of course, that's well advanced also. You'll continue to see decisions coming through with respect to finalising those commercial agreements.

So, thank you very, very much for your support and we look forward to continuing to give you regular updates on the progress of these projects. So thanks very much.

[Applause]

**End of Transcript**