Event Transcript

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Start of Transcript

Operator: Ladies and gentlemen, thank you for standing by and welcome to the Karoon Energy Bauna Acquisition conference call. At this time, all participants are in a listen-only mode. After the speaker presentations, there will be a question and answer session. If you'd like to ask a question at that time, you'll need to press star 1 on your telephone.

I'd now like to hand the conference over to your first speaker today, CEO, Mr Robert Hosking. Thank you, please go ahead.

Robert Hosking: Yes, good morning everyone, it's Bob Hosking. I'm sitting at the table with Mark Smith, he's our Exploration Director; James Wootton, P; Al Gordon, Finance; Scott Hosking, Finance. So, welcome and good morning. We're very happy to announce that we finally made an acquisition that we're very excited about. It's been some time we've been on the road trying to complete an acquisition, so buying 100% of Bauna in the Santos Basin, Brazil, is a very exciting move for Karoon Energy.

This asset has been one of the cheapest producing assets in South America, and we've been watching it for years and it's performed very well. It's still performing very well, 20,000 barrels a day and all the pumps are down, so it's still got a long way to go and it's right next door to our existing assets in Neon and Goia. So, when you put the reserve contingent resource of 68 million barrels, and next door we've got something similar, we've got something that is a Laminaria potential equivalent that Woodside used to operate in Western Australia. We own both these assets 100% at the moment.

We paid a price of $665 million, and the effective date, which is when we actually took ownership of the asset or took ownership of the production, is 1 January 2019, and the estimates are I think at the end of June they had just under a $100 million credit, $99 million credit to be taken off that, June 2019. We don't expect to complete the acquisition because of environmental issues with the ANP Brazilian Government until mid-early first quarter, second quarter 2020. So, we expect the effective date moneys to be in the region of $150 million to $200 million coming off the headline price. So, that will then put us back to a figure of US$450 million, US$500 million that'll be the total price paid. So, we paid a deposit of just under $50 million, $49 million I think it is, that was paid last night with the signing of the final agreements.

So, effective utilisation of Karoon's existing technical personnel and strong development and production experience, we've been working on having an acquisition for a few years now and we've been slowly building up some very, very experienced staff. So, we're in a very good position for the transformation of the acquisition when we start operating next year.

So, the oil is very, very light and we expect highly possible that we'll get a bonus over Brent of $1.00 or $2.00 a barrel. As I said it's located next to Neon and Goia, and the whole shooting match is quite a large amount of oil, up to 150 million barrels, could be a little bit higher, so it shows great potential for the Company. The cash flows that are coming out of Bauna are very strong, we'll let Al Gordon run you through those a bit more in a minute, and we're really excited. I mean it's got a five-year plan of very, very big positive cash flows.

Transaction summary, I'll hand you over to Scott for that.

Scott Hosking: Good morning, everyone. Bob covered a good chunk of the transaction summary there, but I'll just reiterate our position. We've acquired 100% of the Bauna field. The effective date is 1 January 2019, as Bob said, and the purchase price was $665 million, that's the base purchase price. As you will see, there is contingent consideration on top of that. That contingent consideration is at an average of $90 in 2019, $90 Brent price in 2019 and $100 Brent price in 2020.

The incremental cash flow that would be generated by those oil prices would easily make it a benefit for us in any instance going forward at those oil prices and paying the $50 million, so we really didn't have too much of an issue consenting to those. We have paid a $49 million deposit, as Bob said, and the transaction remains subject to ANP approval, and various regulatory approvals in Brazil, including taking an environmental licence and having our operatorship capability signed off for this bid round.

All of these things are all considered by us to be just the usual regulatory approvals. We don't foresee any issues with getting those and we do expect somewhere, just judging by the previous transactions that have gone through in Brazil and in these Petrobras asset sales processes, we expect it to be somewhere over six months and under 12 months to get the ANP approval, but we'll just work forward on that and you should be assuming that we'll settle the transaction in the first half of 2020. It's difficult to give you a better date than that, we've really just run off previous transactions that are similar.

As part of the transaction, there'll also be an assignment of the FPSO Charter and Services Contract as well as the charter of the FPSO from Teekay. We don't expect there to be any material change to the operations, so effectively Mark will run you through those operations when the time comes. But we don't expect to see a major change.

Just moving on then to the funding summary. So, as we said the purchase price is $665 million, there are four main components to that purchase price. We have existing cash reserves of $228 million, that'll be the June 2019 figure when it comes out next week. We currently have no bank debt. We have a debt funding component which is funded by a credit approved commitment from ING. That commitment is in place for an underwritten senior term loan facility. That facility is done on what I would just call pretty regular commercial terms. I wouldn't expect to see anything out of that when we do come to market with the final facility agreement.

I don't expect you to see any surprises in there, it's all a pretty stock standard thing. The debt facilities that have been going into Brazil, there are so many different European banks now running in - there's a good amount of competition and there's a good amount of demand. So, we see that was actually a relatively simple facility to put together. It does remain subject to confirmatory diligence and final documentation, which again I would say is reasonably standard for something like this. In the re-bid process, we had a fairly limited amount of time for completion or final completion of some of the diligence reports. ING did work with us all the way through that diligence base, so they're very well educated, and they went to credit on that basis, so there's limited work to still be done there.

Acquisition price adjustments, as we've said a couple of times here, we own the asset, or we take operating cash flows from 1 January 2019. That gives us a relatively big bonus to go along with. We have listed here $140 million to $200 million is the number that we expect to see there, that's really determined by when we settle the transaction, that's the primary change. We have used just regular oil price, the majority - sorry, we have the cash flows up to the end of June, and we're happy that that number stands and that we're modelling it accurately. So, we're quite happy about that, we didn't get any surprise there. Then really if there's any shortfalls, we will fund that with an equity raising to existing shareholders and new investors on any shortfall that's there.

Perhaps I'll just talk to corporate strategy. As stated through the last three years, we have been chasing production asset, and that really fits what we see as key pillar 1, which is acquiring a high-quality cash generating production asset, which is just about putting a base below the Company and providing us with the ability to go out and bring our current assets into production. Also go into just really targeted exploration, high-value exploration prospects that the company already owns, an example being our Peruvian drilling campaign. Effectively we see the future of the Company being in producing from this field and going into developing our own assets. You can see that this field is quite synergistic with Neon and Goia, and also really just focusing on just the best high-value prospects, looking of course number one a good production, development opportunities and then production.

So, going onto slide 7 there, I'll just hand over to Mark Smith and he can take you through Bauna assets.

Mark Smith: Good morning, everybody, looking at page 7, Bauna asset overview. It's located, BM-S-40 is located in the Southern Santos Basin. It's 50 to 60 kilometres from Karoon's Goia and Neon fields and 50 kilometres to the south to the Clorita exploration block. So, that's our hub that we're talking about. It's 200 kilometres from the Itajai shore base, and we're in about 225 metre water depth. So, we're on a shelf, fairly benign marine conditions, so a good setting with lots of other opportunities in the area.

The map on the right shows the outline of the fields, there's Bauna, Piracaba and in the darker green, the smaller undeveloped Patola field. The well current production is from six producing wells, there are three injection wells and one gas injector, you can see the little red line down to the south where we put the gas back in. The gas is about 280 standard cubic feet per barrel, so not a lot of gas but a bit and we can't flare it. All wells are subsea completions tied back to the FPSO located between Patola and Bauna there, and that as I said before is leased from Teekay Offshore. The FPSO has 80,000 barrel a day processing capacity and 600,000 barrels of storage. Currently we're utilising about 50% of that capacity.

The next page, page 8, looking at the geology. The map on the left shows a structure map with the highs in the red, and the blue outline shows the position of the oil water contact, and in the case of Patola, it's outlined in red. The Bauna structure is a bit simpler. Piracaba's got a few holes in it and they're where the sands have sunk down through shale layers below. All of this has been modelled, we've got a well constrained and well-matched production model.

The map at the bottom left is the seismic amplitude map, which highlights where the sands are. These are good quality Oligocene turbedite sands. On the left side, you can see these red channels coming in to the left side of Piracaba and also to the left side of Bauna with connector channels going out to Patola in the south there. So, these are turbedite channels, partially filled with sand that bring the sand out and then dump it over the area of the fields. We're looking at 10 to 40 metre net pay in discrete sand packages. You can see the Bauna well log there, they're blocky sands, they're great reservoir properties, greater than 30% with 2-6 Darcy. So, if you made a - you know how people make sinks out of stone? If you make it out of this stone, it would leak a lot, so it's very, very permeable stuff.

We've got high-quality oil, 33 API and gas oil ratio about 280. We've got very good 3D seismic with a strong amplitude response delineating the field extent and other features, so it's well understood. We've got from the analysis of all the productions so far, we've got strong aquifer support promoting high recovery factors. Bauna will probably get about 60%, Piracaba around 40% because it's a little more complex around those collapsed structures. We're looking at doing a 4D seismic survey so we can then assess where there's unswept areas, particularly in the Piracaba area.

So, going to the next page, page 9, we have established production and a strong potential for additional potential through ongoing investment. The graph on the top left, first bar 2018, shows the production then, it was 28,000 barrels a day, and it's dropped back now in 2019 to 19,000 to 20,000. The reason for that drop back is three of the submersible pump failures, so that's not a natural decline, the natural decline is at a far lesser rate from that. So, what we're looking at in the future is production increases going up to additional 13 from workovers and then tying in the Patola development, bringing it up to an average of 33 for 2022. The initial production at the start of that will be probably over 40,000 barrels a day.

Cumulatively the field's produced about 120 million barrels. The FPSO is high operational efficiencies, currently producing below potential due to the pump failures that I talked about. The average annual production is expected to grow to 33 in 2022, and we have got a highly marketable crude product light and sweet, likely to get a premium to Brent. On the right side we've got the reserve and contingent resources. Existing wells 53 million barrels 2P remaining. Contingent resources which is Patola, 2C case 10 million barrels, and recompletion of the SPS-57 well, which was the original well drilled. It had an extended well test the flowed about 5000 barrels a day. Subject to confirmation by the 4D seismic, there's potential for another 5 million barrels out of that, so the contingent sum there is 15. So, Patola itself is a discovered resource and it's ready for development, it's got 3D, it's well defined and that will be sanctioned following completion of the deal.

Moving onto base case growth projects on page 10, the plot on the right shows the waterfall chart. Initially there you've got the Bauna base case, add on Patola tie-ins, SP-57 tie-in and then Bauna Piracaba infill, and then we're adding on the Neon, and the reserves for this were described in separate releases followed by Goia. So, the vertical access is net oil resources, so you're looking at around 150 million barrels of resources in Karoon's Santos hub area. In addition to that, there's exploration opportunities there. There's Clorita that we'll be looking at as well as wells like up-dip Emu in the Neon Goia area, which have significant potential as well, which we'll describe in another presentation.

Now, on page 11, transition to operatorship, we have key team members in place with development and production expertise. We initially brought these guys in associated with the Neon and Goia development. We've got Jose Formigli who's got 30 years' experience, he was Chief Exploration and Production Officer at Petrobras and a member of their Executive Board and has a wealth of experience. We have Ricardo, or Abi as I call him, he's got 30 years of experience in offshore oil and gas exploration in Brazil. We've got an organisation which is outlined below, we've got many of the people already in-house to fill those boxes, with a few more to be topped up now that we've got the deal.

The FPSO operations, we have an agreement with the owners so it's got to be assigned to Karoon. There is a transition period that's arranged between Karoon and Petrobras, which we have to work through, that'll take at least six months, so there's a seamless transition to Karoon operatorship.

So, that sums up the opportunity technically. It's an excellent fit with Karoon, and I'll hand you over to Bob to talk about items on page 12.

Robert Hosking: Right, we are looking at strategic assets supporting the Southern Santos Basin Strategy. Some time ago, we looked at the - we were actually looking at Bauna, which was then owned by Petrobras, and we kept looking at the economics of it and were astounded by how cheap they were producing oil and what a good asset it was. We thought we'd try and duplicate what they were doing and that's one of the reasons that we took up a lot of acreage around the area.

So, the synergies with Bauna, Karoon's been active - we actually left Australia in 2007, looking for more economic assets because we kept tendering in Western Australia and coming second or third on tenders that were in the range of about $150 million or $200 million, and with the Federal Government. The last tender that we did over there at that particular point in time, which was about '06/'07, we put in a $200 million work program bid, and the guys from New York came in and bid $900 million, and we were just flabbergasted. Who was the winner in that, Mark? The guys with all the gas over there.

Mark Smith: Amerada Hess, was the biggest one.

Robert Hosking: I think it was Hess,

Mark Smith: We did four wells, they did 16.

Robert Hosking: Yes, so we saw South America as an opportunity that was a little bit behind Australia, and we ended up acquiring five blocks with I think it was a $40 million work program. Since that time, we bought in Pacific Rubiales and they picked up a $250 million share of the costs and we drilled about three or four wells. So, there's some big history of the area that we're in, and also at the same time watching Bauna and its operations, its economics, especially its economics. We've been watching this opportunity for a long time.

Anyway, with this comes the opportunity for further out assets, including Neon, Goia and Clorita, which will be having some 3D seismic run over it, and it looks very exciting. So, synergistically it's great, production hub will be the same so we can look at helicopters, we can look at drilling rigs, work boats, the whole shooting match, and staff and operational about 200 kilometres to the shore. So, having the flexibility from 100% ownership and operatorship puts us in a prime position to move forward.

In time, we'll most probably have partners joining us, and having these producing assets just puts us in a really good position to work out how our future partnership will end up. Also, along with this we've got very good tax efficiencies because of the work that we've carried out in the Southern Santos basin already, and it's in the region of US$70 million, which is quite large. A lot of those will still reoccur when we carry out more exploration. So, it's a very big transformational.

That would end the presentation. Do you have any questions? We'll open it up for questions please.

Operator: Thank you, so ladies and gentlemen, if you would like to ask a question, please press star 1 on your telephone and wait for your name to be announced. If you need to cancel that request, please press the pound or hash key. So once again it is star 1 to ask a question. Our first question comes from Ben Wilson from Royal Bank of Canada. Please go ahead.

Ben Wilson: (Royal Bank of Canada, Analyst) Gidday, Bob and Karoon team, congratulations on getting to where you've got to today. I just have a couple of questions trying to fill out a couple of the gaps looking forward. Are you able to provide a bit of a steer on effectively aggregate forecast CapEx to produce that additional 15 million barrels and for the well interventions to fix the ESPs?

Secondly, just I'll throw this one as well, I'm just keen on the remaining lease life on the FPSO there at Bauna and the aggregate cost associated with that remaining lease life on the field.

Robert Hosking: Okay, I'll hand you over to Al Gordon for that.

Al Gordon: Hi, Ben.

Ben Wilson: (Royal Bank of Canada, Analyst) Gidday.

Al Gordon: So, on costs, we'll kick off on that first. We estimate the remaining life of field OpEx per barrel in the order of around $18.00, $19.00 a barrel. On a CapEx side it's relatively CapEx light. I mean for the well interventions, a lot of that is treated as OpEx, and so that fits into the OpEx bucket. The Patola development though is really what drives the bulk of the CapEx figure. So, the right sort of number to think about on a life of field for the CapEx is roughly $3.50 per barrel, and that's over the producible barrels which includes the base, the existing wells plus Patola. The work over-costs, we've based those on replacing pumps, which on our analysis is roughly every three years we think we need to go in to replace pumps. That's based on an industry average, it's actually a little bit more conservative than the industry average life of the pumps.

Just in terms of gross dollar terms it's about $20 million a well to go and replace the pump in a well. For Patola, we obviously have a plan for Patola. That is subject to ANP approval and we'll be working through that as is the work over schedules, but for Patola specifically, in the presentation we've said there may be one or two wells. If we think about the two well program, it's about $130 million in CapEx is the number to think about.

Ben Wilson: (Royal Bank of Canada, Analyst) Thanks, Al, including the tie-back?

Al Gordon: Yeah, that's fully completed and tied in, yes.

Ben Wilson: (Royal Bank of Canada, Analyst) Okay, and then can I just clarify the life of field CapEx number you mentioned, does that exclude abandonment costs?

Al Gordon: That does exclude abandonment, yes, that's just purely a capital investment.

Ben Wilson: (Royal Bank of Canada, Analyst) Got you, that's very helpful, thanks. While I'm on, Bob, maybe I can ask you a bit of a higher-level question. As you get ownership of this asset and start producing the large amount of cash that will be produced out of it, is the intention initially that you'll build up cash ahead of a Neon, Goia development? Or can we start thinking about a dividend policy post-settlement of this transaction?

Robert Hosking: Well look, our first concern will be bringing in Neon and Goia into production so that we can possibly get our production over 50,000 barrels a day, but we have got sights on a dividend policy in the long range, but once you start getting production of over 50,000 or 60,000 barrels a day, as long as you can keep your debt in control, and we're really low debt per number of barrels. When you look at some of the bigger companies that were juniors and moved into the senior range, like Tullow and Premier, they're running debts of in excess of $2 billion for 70,000 barrels a day. We're just nothing in comparison to that at all. If we can keep that up, we could be looking at a dividend policy in the future.

Ben Wilson: (Royal Bank of Canada, Analyst) All right, that's great, thanks again guys, that's very helpful.

Robert Hosking: Thanks, Ben.

Operator: Our next question comes from Chris Morbey from Macquarie. Please go ahead.

Chris Morbey: (Macquarie, Analyst) Hi gents, congratulations once again on the successful acquisition. Just had a couple of questions. Firstly just on that FPSO that Ben asked before, just looking like the design life of that is about 15 years, it did start in 2013, so kind of implying that maybe you need another dry dock session coming towards the 2028 timeframe, and how that fits on with the well profile, the production profile that you're talking about?

Robert Hosking: We're targeting '22 for increasing production, and so if we target that time zone of '28/'29, I think that our production at that point in time would be starting to decrease, Mark?

Mark Smith: Yes, it tails out.

Robert Hosking: Yes, it tails out, so you'd be going into the tail end of production for the next five or six years after '28, taking you into '34.

Chris Morbey: (Macquarie, Analyst) Does that mean is it worth then undertaking the dry dock cost at that point in the timeframe?

Robert Hosking: A lot of that will be up with Teekay because there's a few other things happening with Teekay that I can't actually talk about at the moment and concerning our other leases. By that time, the big thing in the Southern Santos basin is that we do have Clorita and we do have other areas down there that could range from 60 million to 150 million barrels. So, you can see the synergy all the way through and it could be even FPSO synergy too in some of these deposits. Because they're all very similar. Mark, you can touch on that, running along the basin, the edge of the basin there.

Mark Smith: Well there's a lot of opportunities there. There's the ones we've identified in this discussion, but there's other exploration opportunities there that we're aware of that we might move on as well.

Chris Morbey: (Macquarie, Analyst) Fair enough. The other one was just around regulatory; I know that you did have issues three years ago. I think it came through the workers, the Oil Tankers Union. Are you seeing any sort of risk around that going forward on the regulatory front? You said it was fairly usual, but is there any risks we might see the unions get involved again?

Scott Hosking: This is Scott here, On the back of that process, that round of Petrobras sales in 2016, they had quite a few of these injunctions come in, and Bauna at that time was one of the only assets that didn't have a sale and purchase agreement in place. In the period since then and actually starting at that time, the local, effectively the local regulatory auditor put in place a process. So, it was the TCU, which is Brazil's Court of Accounts, put in place a set process for Petrobras. What we found, even through this process, is that Petrobras stuck very strictly to that process.

So, as we're going through in their rebids, ensuring they get the best price, if you look at any of the recent Petrobras asset sales, there's been several rebids, there's been any particular mix up in the process has resulted in new rebids and double checks. So, we haven't seen any of those injunctions come in, aside from there was one process about six months ago and the injunction lasted - went straight to the Supreme Court. The Supreme Court reviewed the process Petrobras followed and then put in place a ruling that stopped the injunctions, provided Petrobras followed the process.

Robert Hosking: That was three weeks ago, I think.

Scott Hosking: No, it was a little longer than that. So, we don't expect there to be injunctions, and even if there was, the Supreme Court has now ruled that any TCU followed process with Petrobras will just be shut down immediately. So, it did get to the highest court and was shut down, so we feel quite confident that injunctions are very unlikely.

Chris Morbey: (Macquarie, Analyst) Okay, excellent, that alleviates some of those concerns. Then my last one was on breakeven costs; I know you touched on it briefly with Ben before as well. But I think you mentioned first half of the year, end of June, there was about - free cash that had built up credit-wise of about $99 million, production of about 3.5. So, in terms of that it looks like roughly breakeven of the field's about $29.00 per barrel, is that about right?

Al Gordon: I think as a life of field breakeven, we expect less than $30. At the moment just on an operating cost basis, we see on our estimates, which are basically based on the Petrobras information that's been provided, is operating costs sit below $10 [C*larification: that this figure relates to monthly gross operating cost in $MM*].   at this stage for 2019So, I think it's a low-cost producing asset.

Chris Morbey: (Macquarie, Analyst) That includes the FPSO lease in it, does it as well?

Al Gordon: Yeah, that's the fully loaded OPEX.

Chris Morbey: (Macquarie, Analyst) Excellent, thanks very much, gents, and congratulations again.

Robert Hosking: Thank you.

Operator: Our next question comes from Sam Berridge from Perennial Value. Please go ahead.

Sam Berridge: (Perennial Value, Analyst) Good morning gentlemen. Just on the raising, be correct to assume any equity raising is going to be deferred until settlement and all those approvals has been gained? So, sometime 2020, would that be right?

Scott Hosking: I would say honestly I don't think that we would wait when we get to that shortfall, we'll have a decent feel for when we're nearing ANP approval. What we don't want to happen is we don't want to be up against the final financial close of the transaction and effectively then be going out for an entitlement offering or something like that. Primarily we want to look after existing shareholders. So, there is a timeframe around doing that. So, any equity that we raise is likely to be during that period, I would say that's how…

Sam Berridge: (Perennial Value, Analyst) Okay, so I mean other than best endeavours, are you going to be in a position to give any additional confidence other than what you've already described here today that this deal will settle in its entirety?

Scott Hosking: I think the only thing that you'll see between now and then is the completion of the final facility for the debt, and you'll see the final resources report, so the CPR will be out, that isn't actually too far away, that's really just then the result of having a short timeframe. Also, things like injunctions and things like that, within a month there's no history of there ever being injunctions a month after signing the transaction. So, if any issue's going to come up with the regulator or with any other conditions under the SPA, it will be in the first few weeks.

So, once we're out of that period, I would expect that you won't necessarily hear anything specific, but once we're outside that initial period, it's I don't want to say rubber stamped, but it's a very…

Sam Berridge: (Perennial Value, Analyst) Precedents strong.

Robert Hosking: Precedents are like 99% success rates getting through the formalities of the Brazilian Government for the purpose of assets in Brazil. There's [unclear] copies of them all too.

Sam Berridge: (Perennial Value, Analyst) Okay, and then just on the royalties, are there any other royalties over these assets other than the state ones?

Al Gordon: The royalty regime is there's a 10% royalty that's payable and then there's also, in Brazil there's a volume-based tax called Special Participation Tax, which kicks in obviously at thresholds. We see that as kicking in for a short period of time once we go through our workover program and develop Patola as well as part of it. It's not a lot of money that we're talking about that we see as being paid away to SPT. But that adds an additional 1% while you're paying SPT. So, for a brief period there it'll be 11% but the right number to think about in modelling is just straight 10% royalty.

Chris Morbey: (Macquarie, Analyst) Rightyo, got you, and obviously that goes over and above those circa $10-barrel operating costs and CapEx that you've mentioned already on the call?

Al Gordon: Yes, correct, that's right. [C*larification, this figures realties to monthly operating cost in $MM not per barrel. Average operating costs over the field life are expected to be approximately $19/bbl*]

Chris Morbey: (Macquarie, Analyst) Got you, I think that's it from me. You mentioned, sorry, the likely to get a slight premium to Brent. I don't suppose you can quantify that, can you?

Scott Hosking: No, just on the premium to Brent. Right now, it's a very high-quality oil, as Bob said. It's basically that pricing is based on the oil gets imported to Brazil, it's a similar quality to many of the other pre-salt crudes that come out of Brazil. Both of those trade on pretty similar premiums. We don't model the premium, we expect to see some sort of premium in the market, but we just model flat Brent for the [first]. We will have to export the oil. Part of this deal is we could have sold it locally but it's a better price to sell it internationally.

Really, we've priced that premium that Bob is talking about is just we see that as upside, and we priced it using existing reference prices for the local sales, as well as very similar crudes being sold internationally. This crude will actually probably trade even to the point of being in VLCCs] alongside that crude and going to the same refinery. So, it's a good upside, a couple of dollars. That'll be good but we model for flat Brent, and our marketing will be done by an international marketer. So, while we might manage logistics, we will have a major trading house actually marketing the crude for us.

Chris Morbey: (Macquarie, Analyst) Got you, thanks very much for that, guys. No further questions from me.

Operator: Thank you, once again if you'd like to ask a question, please press star 1 on your telephone. Our next question comes from Cam Hardie from Patersons Securities. Please go ahead.

Cam Hardie: (Patersons Securities, Analyst) Good morning, just probably a question for Scott. Is all the $250 million debt facility, is that available assuming the DD's all okay? Or are there conditions on accessing all of that $250 million?

Scott Hosking: That's a good question, Cam. So, the $250 million is the total credit approved facility, so that's the maximum available at this point. If we did end up with a borrowing base that exceeded that, I would actually just go back to ING and given the demand that we have from outside of ING to join, we would probably just extend the facility if needed. But technically it's the lower of the borrowing based on the $250 million. So, the debt facility hopefully will be quite close to that. It's unlikely that it will be exactly $250 million, but it'll be somewhere around there, and it's really determined by going into the oil price, hedging value and the timing of settling the transaction.

So, really those three factors roll it around a little bit. But if we have a bump in the oil price and we hedge a higher Brent price than the bank curve, then there's an ability to maybe even make it a little bigger than that. But it'll be - straight answer is it's the lower of the borrowing base and the facility amount.

Cam Hardie: (Patersons Securities, Analyst) Okay, and then just on that hedging, is there a requirement to hedge a certain percentage of your production?

Scott Hosking: There will be, it's not agreed yet, but there will be a requirement to hedge. I would assume that it will be at least 50% of the production will require hedging on a rolling basis, so at least 50% in the first year going forward. If it's anything like the facilities that we've come close on before, it requires a 70/50/30 type requirement, but we'll just see. It's not agreed, the only thing that's agreed is that we will have a hedging regime around it.

Cam Hardie: (Patersons Securities, Analyst) Okay, and just on the timing of the financial close. What's the critical path here? You touched on it, was it the environmental licences, or is the ANP approval - what's the one that's going to take the longest time here?

Scott Hosking: Well, technically, it's the ANP approval, because all of the other regulatory processes fit within that ANP approval timetable, so you need to pass through, and it all submits together into the ANP. So, things like the environmental licences need to be in and passed, transition arrangement from Petrobras to Karoon needs to be approved by the ANP. There's just various timelines within the ANP approval, but they all have to close up against the ANP approval. So, basically that means the ANP won't approve until the other sections are complete.

We have been working on many of those sections already, and it's just a process to complete it. We'll be moving it as quickly as possible.

Cam Hardie: (Patersons Securities, Analyst) Okay, just an operating question there, just a small one. The water production that's happening at the moment there and the FPSO's handling. You said 80,000 barrels I think it was, that's oil, isn't it? What's the water production like?

Al Gordon: There's oil and water, and the average water cut's about 50%, and the water's cleaned up and then re-injected, There's water injectors there.

Cam Hardie: (Patersons Securities, Analyst) Okay, so you're producing 40,000 barrels a day, 50% being oil?

Al Gordon: Yes, that's the average. That's pretty normal for fields like this.

Scott Hosking: That's where we see the capacity to tie other things like Patola and [bring] work-overs back in, bring production back up, but there is some capacity there to use.

Cam Hardie: (Patersons Securities, Analyst) Okay, got you, thank you.

Operator: Just one final call, if you would like to ask a question, please press star 1 on your telephone. There appears to be no further questions, I'll pass back to your speakers for any closing comments.

Robert Hosking: Okay. All right, well, if there's no further questions, we'll finish the phone call. Thank you very much ladies and gentlemen, and as I said we're very excited about the acquiring of the asset, so thank you.

Operator: Thank you so much. Ladies and gentlemen, that does conclude the call for today. Thank you so much for your attendance, you may now disconnect.

End of Transcript