SANTOS 2013 HALF-YEAR RESULTS
16 AUGUST 2013
CONFERENCE CALL TRANSCRIPT

Start of Transcript

Operator: Ladies and gentlemen, thank you for standing by and welcome to the Santos 2013 Half Year Results Presentation. At this time all participants are in a listen-only mode. There will be a presentation followed by a question and answer session, at which time if you wish to ask a question you will need to press star one on your telephone. I must advise you that this conference is being recorded today, Friday 16 August 2013.

I would now like to hand the conference over to your first speaker today, David Knox, thank you, please go ahead.

David Knox: Thank you very much Annie. Good morning and welcome to Santos' Half Year Results Conference Call. Joining me today on the line is my CFO, Andrew Seaton.

There are four important highlights in today's results. First, strong gas and oil prices lifted half year revenue to a record for Santos and we expect the second half will be even better.

Secondly, as our transformation of the business becomes a reality over the next 12 to 18 months the Santos team is underscoring its ability to deliver a project successfully.

We've made terrific progress on GLNG since reporting to you in February. PNG LNG is also in great shape. Both LNG projects are on schedule and on budget.

Thirdly, we're investing a lot of capital and the balance sheet and our funding position remains strong. That position will be further strengthened as PNG LNG starts to generate significant cash flow next year.

Fourthly, our explorers are delivering interesting options for post 2015 with exploration success in offshore Western Australia and also in the Cooper Basin.

In addressing our performance in more detail we're going to refer to the presentation released this morning and this is available on our website.

As you can see on the cover of the deck you can see the latest picture of the GLNG site on Curtis Island and the great progress that has been made since our presentation last February.

I am reaffirming today that both Papua New Guinea LNG and the GLNG projects remain on budget and are on track. There was no change to the first LNG date or budget for either project.

I want to now summarise the first half results. As I've done in the past it's important to start with safety on slide 3. Everyone at Santos was deeply shocked and saddened to learn of the fatality of a young man on 23 June. He was a Saxon employee who worked on drilling rig 185 in the Fairview field. The thoughts and deepest sympathies of everyone at Santos are with his family, his friends and his work colleagues for their loss.

Following the tragedy all Saxon rigs were shut down. Working with Saxon and the regulators an investigation is being conducted and the learnings have been acted upon. All the rigs have now restarted normal operations. For Santos and the industry it's a time for reflection and recommitment that everyone who works for us goes home from work without injury or illness. The Santos leadership team is fully committed to this goal.

Towards that end, and without in any way diminishing the tragedy in June I do note that we made some progress in the first half on improving our lost-time injury frequency rate to a six year low. This was achieved at the same time as we reached peak employee and contractor numbers across the GLNG project.

I now want to turn to slide 4 which summarises the result of the first half. As you can see, production was down slightly. This was mainly due to the higher level of planned maintenance activity in the Cooper Basin as we set the plant up for a higher production capacity in 2015 and beyond.

As we've already indicated we expect a stronger second half following the successful commissioning of Fletcher Finucane ahead of schedule and under budget.

The first half net profit was up 3% to $271 million after tax.

Turning to the second half, in addition to the stronger production outlook which we've already flagged there are three key milestones that you should look out for us to achieve. These are the introduction of commissioning gas to the PNG LNG plant. The raising of the second LNG tank roof at GLNG. You should keep an eye on the progress with our exploration program both onshore and offshore.

As I noted earlier, our exploration team has delivered with the drill bit. This means we're also securing new opportunities for growth which will go beyond the transformational LNG projects. I'm going to update you on these discoveries later.

With that brief overview I'm now going to ask Andrew to take you through the financials in some more detail.

Andrew Seaton: Thanks David and good morning to all on the line. I'll start my commentary today by describing how our financials will transform over the coming reporting periods. Production will grow each year for the next three years as our key growth projects are delivered. Our operating margins will expand as we increase the proportion of oil and oil linked products such as LNG in our sales mix and as domestic gas prices rise. As a result our operating cash flow will more than double in this time. Our financial flexibility will be maintained by virtue of our robust funding position. This will put us in a good position to increase returns to shareholders.

As we've previously flagged, we will review capital management initiatives as we approach PNG LNG start up next year.

I'll now briefly run through our first half results.

To summarise on slide 7, sales revenue was a record for the first half, notwithstanding a small decrease in production. Pleasingly, production costs were lower as our focus on savings continues. Exploration expense also declined following a run of discoveries in Western Australia. Reported net profit after tax of $271 million was 3% higher than in 2012. Excluding impairment reversals and other one off items underlying net profit was down 11% at $251 million.

Operating cash flow of $629 million was also lower, reflecting higher income tax payments, first time carbon tax payments and lower interest income due to lower cash balances.

Overall, given the transformation that we're now close to delivering this is a credible result and as we've indicated, the outlook is very positive.

The interim fully franked dividend of $0.15 per share is unchanged. The dividend reinvestment plan will continue with a 2.5% discount and will not be underwritten.

I'm turning now to production on slide 8. The 4% production decline reflects lower Australian and Indonesian domestic gas output, offset by increased production from Darwin LNG. Second half production is expected to increase significantly, benefitting from the start-up of Fletcher Finucane in May and also from higher Cooper gas capacity.

This last point is very important. In the first half the long term decline of Cooper gas production has been effectively halted. Cooper gas capacity is now growing for the first time in many years. This is evidence to us that the rising domestic gas price has now enabled us to reinvest in this key asset. Our guidance for production in 2013 is maintained at between 52 and 55 million barrels of oil equivalent.

Moving to slide 9. Sales revenues of $1.5 billion reflected increased oil sales and higher gas prices. Oil volumes increased by 17% compared with the first half of 2012. This more than offset an 8% fall in the realised oil price to US$113 a barrel.

Average gas prices across the portfolio were around 11% higher than in the corresponding period.

Moving now to slide 10. First half production costs were lower in both absolute terms and on a per barrel basis. We are pushing hard on bottom line performance. It's increasingly evident that the competitive business environment is leading to a more favourable operating and capital cost outlook. Recent strategic sourcing and competitive tender processes have delivered cost savings of around 15% on average and of over 30% in some cases. These benefits are being seen across the spectrum, including in materials and equipment supply, fabrication, construction and other related services.

This slide also highlights an accounting change that's resulted in higher production costs, albeit with no net impact on profit. The change is described on this slide and detailed further in the backup. It really makes for fascinating reading and I look forward to your many questions on this topic. As a result of this we've updated our full year production cost guidance. Our new guidance range is $670 million to $690 million, which allows for the anticipated $30 million full year impact of this accounting change. But again I stress that there's no impact on net profit after tax as a result of this change.

On slide 11, I want to make a few comments on the lower underlying profit for the half. The principal contributors were higher cost of sales due to the impact of carbon costs and higher third party purchases, and lower interest income. This was offset by lower production costs and lower exploration and evaluation expense.

Reported net profit of $271 million was 3% higher due to impairment reversals at Kipper and Sampang offset by a small impairment of the Tintaburra oil asset in Queensland.

Operating cash flow remained very strong, albeit below 2012 levels. Timing differences around tax payments, combined with lower interest receipts and the carbon tax were the key contributors. With growing production and strong commodity prices cash flow is expected to increase in the second half and in following periods.

On the next slide capital expenditure increased to almost $2 billion during the half as we continued to invest in our growth projects. The forecast 2013 spend of circa $4 billion will represent the peak year of capex ahead of the start-up of PNG LNG next year and GLNG in 2015.

As slide 14 shows, our financial flexibility remains strong. We have over $1.6 billion in cash plus over $3.2 billion in committed but as yet undrawn debt facilities. This means total liquidity today of some $4.8 billion.

Pleasingly we were able to maintain our BBB plus credit rating with S&P, notwithstanding the changed equity treatment on our euro hybrid security.

We have minimal refinancing risk with very little debt maturing this year and next. To further improve this liquidity position and to take advantage of lower credit spreads we're also extending the maturity of the $750 million in undrawn bank facilities shown here as coming due in 2015. The facilities will be extended to 2018 at a lower cost, with documentation expected to be completed by the end of this month.

In addition, the PNG LNG joint venture is in the process of securing supplemental debt facilities of US$1.5 billion. This process is progressing well and will be finalised in the second half.

In summary, the Company's financials are in great shape and the outlook for the Company is very solid.

On that note, I'll hand back to David.

David Knox: Thank you very much Andrew. As I said earlier, Santos is delivering its transformation projects on time and on budget. I'm really pleased at the progress we've made at both GLNG and PNG LNG since we reported last February. The evidence of that is tangible. On slide 15 you can see the train 1 propane condenser module in place on Curtis Island. This is the project's longest module at 74 metres in length. This module was unloaded across our MOF which is now fully complete.

The pipeline access agreements for both PNG and GLNG are all complete and there's strong progress on all the major project components.

I'll go into more detail on the LNG projects shortly but I want to talk first about Fletcher Finucane and our other production projects and I'm on slide 16.

At Fletcher Finucane our teams delivered first oil ahead of schedule and only 16 months after the project was first sanctioned. The project was also delivered under budget, the final capital cost was $470 million, 4% less than sanctioned at FID. It is the fifth development project we've delivered to budget and schedule or better in the past two years. Fletcher Finucane will be a key driver of stronger oil production in the second half of this year and, of course, this comes at a time of strong oil prices.

Importantly, Fletcher Finucane also extends the life of the Mutineer-Exeter field and the FPSO which you see on this slide.

John Anderson and his team in the west have already secured a rig to drill the adjacent Vanuatu prospect. Given success this could be tied back into our new subsea facilities.

I'm now going to turn to Asia and starting with Dua on slide 17. This project is now 55% complete. It is on budget and schedule for first oil in the first half of next year. Like Fletcher Finucane, Dua is a three well subsea tieback to an existing FPSO, in this case Chim Sao. Pipe lay was completed earlier this year and fabrication of equipment packages to be installed on the FPSO are also complete. Drilling of the development wells will commence in the fourth quarter. Dua will provide a further boost to our oil production in Vietnam when it comes online next year.

Turning to Indonesia on slide 18. Sanctioned in February this year Peluang is also being developed as a subsea tieback to the existing Maleo facility in Indonesia. The project is more than 20% complete. It too is on schedule for first gas in the first half of next year. As you can see in the photo, fabrication of the wellhead platform is well underway.

Peluang is our fourth operated asset in Indonesia. This is a country where we have a long and successful track record as an operator and deep experience. We are finding that our credentials in Indonesia are increasingly being recognised within the industry.

I would now like to turn to our mega LNG projects. I'm going to start with PNG LNG on slide 19. We affirm today that we're on schedule and budget. When completed next year you will begin to see the benefits of the transformation we've been working so hard on over the past five years. PNG LNG will generate substantial cash flows for Santos from next year. The project is now 90% complete on a value of work done basis and we expect commissioning gas from Kutubu to be delivered to the LNG plant in the next few weeks.

A key milestone in the first half was, of course, the completion of the Komo Airfield in May. Deliveries of equipment by Antanov are already approaching completion.

On slide 20, construction of the Hides Gas Conditioning plant is progressing well as the equipment delivered via Komo is installed. The onshore pipeline construction is progressing towards Hides with only 40 kilometres of the total pipe length remaining to be welded. Land access for this final section of work is now in place and as I noted earlier, access for the entire pipeline route is now complete.

Nitrogen purging on the pipeline from Kutubu to the LNG plant has commenced. This is in preparation for commissioning gas to start flowing into the plant in the coming weeks. Two of the eight Hides development wells are now complete, the third well is in the reservoir and the fourth well is underway.

On slide 21 we move to the LNG plant. Here the focus is changing from construction to commissioning. Activities are focused on train one and the common process areas to support fuel gas readiness. As I said earlier, commissioning gas is expected from Kutubu in the coming weeks. Commissioning activities are also underway on the LNG loading jetty arms. Installation of in tank LNG pumps is complete on the north tank and perlite installation is underway on the south tank. This is very good progress which underscores our confidence in the operating partner, Exxon, in meeting the schedule for first LNG next year.

Let's now turn our attention to GLNG on slide 22. Like the PNG project GLNG is on schedule and budget and will deliver its first cargo in 2015. GLNG is now more than 60% complete on a value of work done basis. You can see on this slide the big-ticket progress items that we've ticked off since I last updated you in February. We're really pleased with progress of GLNG from the drilling, to the pipeline and at Curtis Island.

I'm now going to step you through our progress over the next few slides. I'm going to start with drilling on slide 23.

We're drilling wells faster and cheaper. This year our average cost to drill and complete a well is $1.4 million. That's a 30% saving compared to our guidance at FID of $2 million per well, so of course this is music to Andrew's ears.

You often ask me about well counts. We're on track for our target of more than 200 wells by the end of this year. We drilled 119 wells in the first half and 90% of these were development wells. This program is in line with our market guidance for the ramp up, which remains unchanged; train 1 will be three to six months and train 2 will take between two and three years to fully ramp up.

Average flow rates from our Fairview wells remain strong and Roma pilot data is confirming well potential in line with our guidance of 0.5 TJ per day per well.

Upstream construction is also progressing well, as you can see on slide 24. Some 2,200 people are working on upstream construction across the CSG fields. This is a picture of Fairview Hub 4 taken earlier this month. This hub will have the capacity to process 250 TJs of gas per day.

A key focus for the construction teams is on the water handling facilities. The first at Fairview is already at the pre-commissioning stage. Two more water handling facilities, one at Fairview and one at Roma, are scheduled to be commissioned before the end of this year. These facilities will enable us to commence the all-important dewatering of the CSG fields on schedule.

Now turning to slide 25, construction of the GLNG pipeline is now proceeding at pace. Three key milestones were achieved in the first half. First, the private land access agreements were all signed, confirming private land access for the entire pipeline route. Secondly, we commenced tunnelling of the marine crossing in mid-April. I'm pleased to say this work is progressing ahead of schedule with 50% of the tunnel length already completed. Thirdly, we reached an agreement with BG to connect our pipelines. This was the first significant collaboration agreement between GLNG and BG and will enable our gas to flow at up to 600 TJ per day between the two projects.

The mainland section of pipeline is also going well with 84% of the right of way cleared and graded, 75% of the pipe has been strung out and over 23,000 joints welded. Overall we are on track to complete the pipeline in the second quarter of next year.

Now turning to Curtis Island where more than 2,000 people are currently working on the site. At the end of June, including the work being done at Bechtel's module yard in Batangas, train 1 was 66% complete and train 2 was 46% complete, both on a value of work done basis. Our team on Curtis Island delivered a number of key construction milestones in the first half, which you'll see on the slide.

The first LNG tank roof was successfully raised into place on schedule in June. The second tank roof is scheduled to be raised next month. As you saw, the MOF is complete and 30% of the modules required for train 1 have already been delivered onto site. The LNG jetty trestle is complete and work is continuing on the loading deck. So again, just as with PNG, the GLNG project is demonstrably on schedule and on budget. We remain on track for first LNG in 2015.

Now let's take a look at Santos's exploration program. I'm now on slide 28. As you've heard me say, exploration is the lifeblood of a successful E&P company. Our explorers are delivering valuable options for the future, with some excellent recent results. We've had four consecutive gas discoveries offshore WA and also encouraging progress in the Cooper Basin unconventional plays. I'll update you on these programs in the next few slides. Also in Asia we plan to drill the Hon Khoai well early next year, targeting oil in the Nam Con Son Basin.

So let me first turn to the Browse. In the Browse we have gas and condensate discoveries at Crown and at Bassett West and are currently drilling ahead at Dufresne. At Crown we've penetrated some high quality sands, 61 metres of net pay in the Montara, Plover and Malita formations and the well did not intersect a gas water content. Post-discovery 3D seismic mapping and geophysical studies are ongoing. We're also evaluating several other good quality prospects within the block.

Following Crown, the Jack Bates rig moved to the adjacent permit for 408P where our operator, Total, drilled the Bassett West discovery. Bassett West discovered eight metres of net gas pay in Jurassic sandstones with condensate present in the gas. Bassett West is a large faulted structure and improvements in reservoir thickness are anticipated in the adjacent fault block.

Total is currently drilling Dufresne-1, the next one in the campaign and we're expecting results in the next 60 days. Dufresne is targeting Jurassic aged reservoir sequences on a large structure, which is analogous to Crown and to Bassett West.

At the end of the day we think Browse is going to require collaboration to develop. We're well placed with many of the players in the region. Total, Inpex, Conoco and Chevron are all our partners in Western Australia and Northern Territory, which helps open doors to further partnerships as the industry seeks to unlock the Browse Basin.

I'm now going to move south to the Carnarvon on slide 30. The Winchester well discovered 58 metres of net gas pay in the Jurassic and Triassic reservoirs in the Dampier sub-Basin. The post-drill evaluation has now commenced, work to determine the resource range of the discovery and potential development options is underway.

The Bianchi well was a follow on from the Zola-1 discovery made with our partner, Apache, in 2011. The well successfully targeted a Triassic fault block. Bianchi is Santos's deepest gas discovery in the Carnarvon Basin. The well intersected 112 metres of net gas bearing reservoir in a series of thick stacked quality sandstone intervals. The success of deep well intervals has further highlighted the exploration and appraisal upside within the greater Zola complex. Further drilling is expected to delineate the resource potential.

I'm now going to move onshore to the Cooper Basin on slide 31. Australia's first commercial shale gas well, Moomba-191, continues to flow at two million cubic feet per day. That's 11 months after it was first connected to our Moomba plant. Now following the success of Moomba-191, three vertical/horizontal well pairs are planned in the Moomba Big Lake area. Two of the three vertical wells have now been drilled, the third well to be spudded this month. Following the vertical wells, the three horizontal drills will commence in September and we're going to start with Roswell-2. Fracture stimulation on the three horizontal wellbores will then commence later this year.

Our team's focus is on cracking the code on the REM shale section. This code cracking involves characterising the reservoir quality and then matching each reservoir with the most compatible completion type. This exciting work will continue into 2014.

Now in the Basin Centred Gas play, Gaschnitz-1, discovered gas outside structural closure throughout the entire 1,000 metre Permian section. Seven fracture stimulation stages were placed within selected sands across the full Permian section of the well. The well underwent post-frac clean up flows for a total of 25 days, with initial raw gas rates of more than one million cubic feet per day. A production log was run and the well shut in ahead of completion which is planned for September.

The results to date are promising with thick over-pressured reservoirs within the gas bearing Permian sequence. Fraccing behaviour is much more favourable than we expected, providing ample opportunity to adjust and improve fracture treatments. By flowing gas to surface the well has demonstrated that the play has a potential to be commercial and our aim is now to apply the right technology to unlock this resource.

The Gaschnitz discovery was followed by the drilling of Van der Waals-1, which has also confirmed gas outside of closure. A third well, Langmuir-1, is currently being drilled to further appraise the extent of the play. The learnings from the Gaschnitz frac will be applied to the stimulations of Van der Waals and to Langmuir, and both of these are planned for later this year.

As you can see, I think that we're at a really interesting position in our exploration program. Our explorers are clearly creating options for the future and doing it both onshore and offshore.

So in conclusion, I want to summarise our report to you today. We're at the threshold for the transformation of Santos to become a leading regional energy producer and partner. This is the vision that we described to you and the objective to which we've been striving over the last five years. We're confident that the four key takeouts from today's results confirm that we're on track to achieve that objective.

First, we had a solid first half and we expect the second half will be better. Secondly, we are reaffirming that our mega-projects are both on schedule and on budget. Thirdly, the balance sheet remains very strong and our position will be further strengthened as PNG LNG starts to generate significant cash flow next year. And fourth, and I think this is the real news in today's result, is that our explorers are setting up some interesting options for the future with four consecutive gas discoveries offshore WA and encouraging progress in the Cooper Basin. Overall, I assert that Santos is in great shape.

Andrew and I would now be very happy to take your questions and I'm going to pass back to Annie and can we have the first question please?

Operator: Ladies and gentlemen, if you wish to ask a question please press star-one on your telephone and wait for your name to be announced.

Your first question comes from the line of Mark Greenwood from Citi. Please ask your question.

Mark Greenwood: (Citi, Analyst) Good day, I have a question about GLNG. I was wondering whether you could provide us with an update on the contingency position for the GLNG project, similar to the update provided earlier this year. Of the $2 billion contingency how much has been spent, allocated and remains and lastly, the contingency that's being spent is for, I guess, portions of the projects that have been overrunning the budget. If there are portions that are underrunning, as you've indicated today for the well scope, then have you netted that off in terms of that contingency estimate, or does that provide additional buffer for the project budget?

David Knox: Yes Mark, you're quite correct. In the US$18.5 billion we have US$2 billion of contingency. Right now today we're 60% done on the project, it's making good progress and we've spent - or allocated 60% of the contingency out of that budget. We manage obviously the budget in its entirety, so whether there are unders and overs, they all go back into the pot and as I say, what's happening right now is we're tracking - the contingency spend is tracking the project progress very nicely, and that's obviously given me quite a bit of confidence as well in the budgeting in general.

Mark Greenwood: (Citi, Analyst) Okay and of the accelerated capex at US$2.5 billion that was announced last year, my understanding is a large portion of that hasn't yet taken FID, the Roma processing and also the Roma wells. Now that you've done more engineering work on that, how is the estimate of capex for that portion of the project versus when you announced it initially?

David Knox: Well, I think Andrew made a very important statement in his remarks. When we're going out to tender for big work, we're seeing circa of 15% drop in prices across the board. So as we go out on the major pieces of work going forward we are seeing that the sort of price pressures have come off and are starting to come down. So Mark, we are seeing an improvement in contract rates going forward and of course that's being combined with the fact that we've effectively now made very good progress at our three hub sites in the upstream, and a lot of the work we're going to do in the sort of next phase is in and around those hub sites. So it's going to build on the work scope which is already well on.

Mark Greenwood: (Citi, Analyst) Okay and just one more, if I could for Andrew, the comment was made that operating cash flow will more than double in the next three years. I just wanted to clarify that. I presume that's 2013 to 2016 and I was just wondering, Andrew, if you could give us an indication of what oil price and volume assumptions are inherent in that forecast.

Andrew Seaton: Yes, thanks Mark. I mean this is just indicative of the transformation that's going on within the company and it's probably no surprise to you that the operating cash flow grows greatly. I mean we've published production outlook previously and my comments today are consistent with that growing production outlook. So we're seeing production growth of around 50% through the period, as we see our LNG exports grow from about 0.3 million tonnes our share now to over three million tonnes in that timeframe. Also as our oil linkage in our portfolio grows from about 30% to about 70%, and that goes to the margin growth point that I raised before.

As far as the oil price inherent in that assumption, it's broadly consistent with market consensus oil price assumptions.

Mark Greenwood: (Citi, Analyst) Okay, thank you very much.

David Knox: Thank you, Mark.

Operator: Your next question comes from the line of Ben Wilson from JP Morgan. Please ask your question.

Ben Wilson: (JP Morgan, Analyst) Good morning, David and Andrew. I just have a quick question about your activities in the Carnarvon Basin and this question applies equally to the area around the Winchester discovery and also the Zola trend you've been delineated. As you stand now, what do you believe is the threshold size of the cumulative discoveries you're setting about making in both of these regions before you'd consider more options around commercialising?

David Knox: Well, as you can see from the map on slide 30, Ben, both of them are pretty well positioned. So they don't need enormous - to be enormously large to be commercial. The exciting thing around what I call - I called it the greater Zola complex and I did it for a reason. The Bianchi well and the Zola well are all part of the same structural setting. The Bianchi well is a fault block on the side of Zola, and it has a major implication for the whole of that Zola complex.

We haven't given you a size because frankly we've got some more work to do to fully delineate it, but clearly it's a very encouraging well that Bianchi well. It's deep in the basin, it's below Zola and it's found a significant hydrocarbon column. It's extremely well placed, as you can see, to come into either some of our existing infrastructure with Apache. Our interests are aligned with Apache in the greater Zola complex as well, which has also been a deliberate practice by both Apache and Santos. So I think that's a very exciting well for us and as I say, we're going to continue to evaluate that greater Zola complex.

The Winchester well is of course really south of the northwest shelf and is again well positioned close to infrastructure. You can see the Pluto pipeline runs just south of it and the Wheatstone pipeline will also run very close to it, and it's also not far south of the northwest shelf southerly infrastructure. So again, that's an extremely interesting well for us. We've found a good gas column, it's only an eight-and-a-half inch hole, we've got to do more evaluation. We haven't declared a size range at this stage but clearly it's something that we're extremely interested in going forward and we will be doing follow ups.

Ben Wilson: (JP Morgan, Analyst) Okay, well also David, what's the timing, potential timing of another well in that Winchester block?

David Knox: We haven't committed to that yet, but obviously having had a good result we'll be looking to get on with it as soon as we reasonably can and it's also subject to - you know, we have to work with our partners on that. So Ben, we haven't got a firm plan but having had this success I can certainly tell you we'll be encouraging John and his business unit to get the drill bit out as soon as we can reasonably do.

Overall, you know, what's happening here is these two wells in the Carnarvon have unlocked some new acreages and that's extremely exciting for Santos, and both of them are close to infrastructure.

Ben Wilson: (JP Morgan, Analyst) Okay, thanks David. I just had two quick questions for Andrew. Andrew, one, you mentioned the 300,000 barrels of oil in inventory that form part of your third party gas and oil purchase costs. Are you able to confirm that that is not in the third party sales figure? And perhaps just to explain how the accrual of that accounting works.

And secondly, if you've got a minute, just an update on timing around Kipper gas. What's your latest information there?

Andrew Seaton: Okay, firstly the easy one, Kipper gas is 2016 first gas then as far as the $30 million, you're right, that hasn't gone through the third party revenue line; it comes into the income statement through the increase in product stock line. So you see a $54 million increase in product stock; over half of that is this third party crude.

Ben Wilson: (JP Morgan, Analyst) Oh got you, okay. That makes sense. Thanks very much Andrew.

David Knox: Thank you Ben.

Operator: Your next question comes from the line of Adrian Wood from Macquarie. Please ask your question.

Adrian Wood: (Macquarie, Analyst) Yeah thanks. I've just got a couple of questions. First of all on GLNG, it looks like you're making good progress there with the accelerated drilling and the third party gas supplies obviously reduce some of the upstream risk anyway; you've got the BG tie-in and that kind of thing, they're pretty much on schedule. So the risks seem to be more around the cost than the schedule if there are any risks but on the cost side of course it's still a very vague picture in that you are still using 87 cent currency forecast and it is merely to a point in time rather than to a point of completion. Can you - given that we are 60% through and that's done on a value of work basis we should now have a fairly strong view to the finish line in terms of what the Australian dollar impact is going to be. Is there any way you can give us a sort of revised number for that US$18.5 billion based on what we've seen to date in terms of the Australian dollar?

Also can you just confirm how much of the capital cost, both upstream and downstream, for Trains 1 and 2 falls due after the end of 2015?

David Knox: Can I let Andrew answer the currency exchange and I'll take your second question.

Andrew Seaton: Adrian, what we try to do - it must be two years ago now and again last year- was we put out the capital cost assumptions underpinning the US$18.5 billion in native currencies. So we really gave you the roadmap and the information to be able to then overlay your own FX assumptions and come out with either a US dollar or an A dollar number depending on how you model it up. We're 60% of the way through the project; we're reaffirming the US$18.5 billion capital cost is on budget. I'm reluctant to give a running commentary on where the currency's going to end up in 2015. You've seen huge volatility through the first half of this year so I think again we've provided the building blocks for that. If you want to talk through that at all, Andrew Nairn or Nicole will be happy to run through that with you after the call.

Adrian Wood: (Macquarie, Analyst) Sure, okay. David, in terms of the amount that falls due post the end of 2015 and also just by extension, you mentioned a 15% reduction in tendering costs, can you just talk through what proportion of the GLNG budget has yet to be tendered?

David Knox: Yes. So Adrian, as we go forward we've given some guidance that obviously US$18.5 billion to the end of 2015 when the second train is ready for start-up; that's always been our guidance. We've given guidance beyond that to say that we think we'll drill something like 200 to 300 wells every year thereafter. It of course ultimately will not be every year; we'll do it for a few years and then I suspect we'll have the well stock that we need. We've also given some guidance that at some stage we'll have to add another compression station somewhere around 2020. So that should all be in the model. But overall I'd say the US$18.5 billion as we've always said is to the end of 2015.

As far as retendering, effectively we do have some retendering which is ongoing now which is for this next wave of projects. So yes, as I said earlier, I think it was with Mark on Mark's question, we do expect to see some reduction. That obviously gives us some headroom on our contingency which is a good thing and that's where we'll put it.

Adrian Wood: (Macquarie, Analyst) Okay and just one very quick final one and I'm wondering if maybe it's a little bit too early to be asking this question. But you have now drilled a couple of unconventional wells in the Cooper and you are getting some production there. Obviously there are some political access issues surrounding your Gunnedah acreage but are you able to talk through what in terms of commercial breakeven you're thinking that the Cooper Basin gas could come out at and whether that'll be above or below what you're expecting Gunnedah to be commercially?

David Knox: Well lots of questions and comparisons are extremely difficult. The key thing in - but let me just give you a couple of key points. The key thing in the Cooper is that we have a really good layout of infrastructure and Santos has an excellent position in that infrastructure being a 66% owner. That gives us a unique ability to commercialise gas that we do discover in the Cooper Basin and obviously we demonstrated that for the Moomba-191 well which has been connected in. So that gives a unique advantage. The same is true of the basin-centred gas, the Gaschnitz. Gaschnitz is not far from the existing infrastructure. We can tie that in. Now it's extremely early and I said in my remarks what we've done is we've cleaned up this well. We haven't even completed this well; all we've done is flow back the well and we got some good gas rates. The maximum gas rate we saw was actually two million standard cubic feet per day; it died down to about one and then we ran a production log. It's a good result but the main thing it's a good result is because it demonstrates that from a basin-centred gas well in the Cooper Basin Santos can flow gas to surface.

So what we'll now do is we'll complete that well; we will then drill - we've already drilled Van Der Waals; we're on Langmuir. We'll finish Langmuir and then we'll frac Van Der Waals and Langmuir and we will learn from what we did in Gaschnitz. The fracs went well in Gaschnitz but they weren't big fracs; they were moderately sized fracs. We'll learn from the frac design, we'll apply that to Langmuir, we will complete Gaschnitz and then say in six to eight months we'll be starting to understand what these wells are really capable of. But it's extremely encouraging that we've got gas to surface.

In parallel of course we're doing what we do in these three horizontal pairs around Moomba and Big Lake. Now you mentioned New South Wales. New South Wales is an area where we firmly believe that we've got good gas in the ground. Our challenge, and our message has been very firmly, that we need to get the gas out of the ground and we need to get it into New South Wales market and we committed the first 100 terajoules a day to that market.

We are asking the New South Wales government to stand behind the regulations they've set up and we support and basically to give us approval to really move forward. What I'd like to do is start to move forward with more pace than I currently am. We're in detailed discussions with them and I think we're making good headway right now but we really need to continue that momentum so that I can start to get the drill bit out, start to drill some more holes and also start building the initial water-handling facilities for the Narrabri project.

Adrian Wood: (Macquarie, Analyst) Great. Thanks very much.

Operator: Your next question comes from the line of John Hirjee from Deutsche Bank. Please ask your question.

John Hirjee: (Deutsche Bank, Analyst) Good morning everyone. My question relates to the very good drilling costs that you have done on GLNG where you've indicated that you've been 30% lower. Could you give us some indication in terms of the pilot Roma wells? Do you think those lower costs can be applied there or is it really this cost is really driven by the fact you're drilling in the sweet spot areas?

David Knox: The majority of our wells we drill are actually in the Roma area right now John. There are really two reasons why we're really seeing the costs come down. One is we have clear access to the land and we've got a clear programme - I don't exactly know but it sometimes runs three to six month - so that drillers have clear access to drill at least three to six months of holes in front of them. So that's given them a really good ability to optimise the programme and it also gives them some flexibility.

The second thing that's really driving our costs down is we're drilling pad wells. A lot of our wells are drilled either two to four or six wells from a pad and where we're not drilling pad wells we're drilling what we call minimum lease wells where basically you're not building massive leases; you're laying down mats and you're bringing the rig and putting it on mats and the actual pre-work you've got to do on the land is absolutely minimal.

So the interesting thing we're seeing here is as we go forward, and to a certain extent we expected to see it but we hadn't fully modelled it in, we're seeing the drillers are increasingly - when they get access to a really strong programme through getting land access sorted they're applying technology, they're lowering the footprint and they're driving costs out. We're not at the bottom yet but clearly we've probably taken 30% off; we've done another 10% now. We've probably got still some way to go here but it is a great story.

The reason it's so important ultimately is because if we can get the well cost down then it's going to make a very big difference in the out years in 2016 and beyond and it's really important for that purpose.

John Hirjee: (Deutsche Bank, Analyst) Yes I agree with that and the gist of my question is relating to the fact that at what point do you then start to confidently predict that those outer year drilling costs will start to be materially lower than you initially expected?

David Knox: I think we're already starting to model them in our files. We're already getting more and more confident. Previously we had some learnings modelled in but we're now incorporating more learnings modelled in. I think it was Mark I said to, we're putting - the drillers are running under budget; that's allowing us to put contingency back into the pot which is great. So that's also helping other things.

John Hirjee: (Deutsche Bank, Analyst) Okay, very good. Another question I have relating to the collaboration that you've announced with BG. The costs associated with that collaboration, are they embedded in the overall budget or are they separate to the costs for GLNG?

David Knox: No, they're in the overall budget. Obviously they weren't envisaged at the time we did the project but they're soaked up in the US$18.5 billion. The costs are fairly minimal. The fact the drillers have saved a bit of money you can say has given us the ability to put that towards connecting the pipes if you want to. But it's not that expensive. Connecting the pipes is a relatively inexpensive task and obviously we're sharing that cost with BG.

The piece of magic here for everyone to really understand is what this allows, we now have two pipelines, two upstream set-ups connected into two plants and we can exchange gas at 600 terajoules a day which is basically one train's volume. So that allows us - it gives us flexibility for both the projects to move molecules between each one, quite considerable amounts of molecules on a borrow and loan basis. So it gives us - lowers the risk for our LNG buyers, gives us more security and allows us to start to optimise gas flow almost between the two plants. So it's actually a really important initiative and it goes way beyond just the fact we connected some pipes.

John Hirjee: (Deutsche Bank, Analyst) Sure, thank you. My final question to Andrew. Andrew, you indicated that capital management options are going to be looked at prior to PNG LNG production approaches. In terms of the specifics of the timing, when will you tell the market in the context of - is it just before first production or is it when you get comfortable that commissioning has gone well?

Andrew Seaton: John, I guess the first comment is that increasing the dividend or other capital management would be a Board decision. So it's something that we'd need to - management would need to take a recommendation up to the Board on. That's the first point.

The second point I'd make is that we need to look at the performance across the business; we need to look at the performance of the major projects as we make that decision. So it's something that we've said we'll consider as we approach PNG LNG start-up next year. I'm not sure that I can be much more specific on that in relation to the timing but what I can confirm is our intention to really focus on increasing returns to shareholders who've been with us through this high capital intensive growth phase.

David Knox: Absolutely I'd support that as well.

John Hirjee: (Deutsche Bank, Analyst) Alright. Thank you Andrew. Thank you David.

David Knox: Thank you John.

Operator: Your next question comes from the line of Nik Burns from UBS. Please ask your question.

Nik Burns: (UBS, Analyst) Thanks guys. First question is for Andrew. I won't talk too much about the exciting accounting changes you've put through there for your production costs but I just want to talk about the DD&A cost. For the first half, if my calculations are right, you're looking at around about $15 per boe. You've left your full year DD&A guidance unchanged at $16.50 so if I read that correctly should we be thinking about DD&A in the second half of sort of $17.50 to $18 and if that's correct how should we be thinking about DD&A say come 2014?

Andrew Seaton: Nik, I think your maths is spot-on there. I think it was about $14.90 in the first half and to meet the $16.50 it'll be something closer to $18 in the second half. Really the impact there is Mutineer- Exeter and Fletcher Finucane. So the FPSO was offsite and offline until it started up with Fletcher Finucane in May and in the second half we'll get a full half's production of that WA oil. So that's what's driving it.

If you then roll the clock forward into next year, we haven't given guidance but I think you can see where the trend is heading that the second half will be higher than the first.

Nik Burns: (UBS, Analyst) Sure. There'll obviously be an adjustment once PNG comes on stream?

Andrew Seaton: That's right.

Nik Burns: (UBS, Analyst) Great. Second question just on Cooper gas. It didn't really get much of a mention in the results presentation but around APPEA James gave a presentation which outlined plans to I think drill 180 gas development wells in the Cooper and at the gross JV level spend $800 million on surface infrastructure. You also showed a chart showing a build-up in a gross Cooper Basin well head gas production capacity, increasing by around 30% from here until sometime in 2015. Just wondering some sort of guidance on when that well head production capacity will translate into actual gas production volumes?

David Knox: So the important thing here Nik is that the Cooper Basin business has gone through the inflection point. So we've seen over the last few months that it's started to climb back up that capacity curve. This is a very important moment for the Cooper Basin and an important moment for all of us at Santos that for the past probably 10 years we've seen a gradual decline in the Cooper Basin and here we are for the first time gone around through that inflection point and started to climb up.

James and his team are obviously working very hard to keep that pace going and the reason we're able to do it and the reason we're able to invest quite heavily in the Cooper Basin is obviously because we now have both domestic gas to supply but we also have the LNG market and the opportunities that that's brought. That's bringing a new price deck that allows us to go into what would previously be uneconomic areas and they're now economic and as I say what you're going to see is us turning the corner - we've already done that - starting to go back up the hill again, and building capacity. We will be investing as we've said in the new CO_2 train. That will come - that investment will start sometime next year and that will allow us to build the capacity that we perceive we're going to require and the East Australian gas markets are going to require in post '15, '16, '17 and beyond. So this is an extraordinary story for the Cooper and obviously it ties into what we're also doing there in the unconventional space to see if that has real potential and I think I'm signalling to you today that it's looking as if it has.

So that's what our strategy has been about and it's now being delivered in spades by the business units.

Andrew Seaton: To be clear Nik, you should start to see the increased production come through in the second half.

Nik Burns: (UBS, Analyst) Okay, perfect. Thank you very much.

David Knox: Thanks Nik.

Operator: Your next question comes from the line of Anthony Kavanagh from SG Hiscock. Please ask your question.

Anthony Kavanagh: (SG Hiscock, Analyst) Morning guys. Sticking with the Cooper Basin, you spoke about production. About nine months ago now you spoke about reductions of about 30% in costs in the Cooper Basin. Are you able to provide a bit of an update here as to how you've gone?

David Knox: Well I'll let Andrew speak to that because Andrew's head of procurement as well as CFO so he's probably best qualified.

Andrew Seaton: The 30% reduction in costs was on a per unit basis so the conversation that we've just had around increasing the capacity and increasing the throughput of the Cooper is the first part of that equation. So you tick that box. It's a high fixed cost business and so the more production that you can put through you get the economies of scale and the lower unit costs of production.

At the same time we are taking costs out. I gave the figure that David's quoted of 15% across the board. This is coming from strategic sourcing initiatives. So where we're looking at some of our key suppliers and looking at how we do business with our key suppliers and really looking at the entire supply chain in taking costs out of the business. Also it's just plain old competitive tendering, getting the competitive tension going between suppliers and not being afraid to change our long-standing suppliers if they're not coming to the party on costs. So the outlook is very positive for achieving these cost reductions across the board.

Anthony Kavanagh: (SG Hiscock, Analyst) Okay. Thanks for that.

David Knox: Thanks Anthony.

Operator: There are no further questions at this time. As a reminder ladies and gentlemen, if you do wish to ask a question please press star one on your telephone and wait for your name to be announced.

David Knox: If there are no further questions Annie I'd just like to thank everyone on the call. Look forward to seeing you all over the next couple of weeks and thank you very much for joining us this morning. We'll sign off.

Operator: Ladies and gentlemen, that does conclude our conference for today. Thank you for participating. You may all disconnect.

End of Transcript