Company Name: Sanchez Energy Corp
Company Ticker: SN US
Date: 2016-05-09
Event Description: Q1 2016 Earnings Call

Market Cap: 552.41
Current PX: 8.47
YTD Change($): +4.16
YTD Change(%): +96.520

Bloomberg Estimates - EPS
Current Quarter: -0.106
Current Year: -0.435
Bloomberg Estimates - Sales
Current Quarter: 142.333
Current Year: 557.091

Q1 2016 Earnings Call

Company Participants

- Garrick A. Hill
- Antonio R. Sanchez
- Christopher D. Heinson

Other Participants

- Neal D. Dingmann
- Ronald E. Mills
- Stephen F. Berman
- Jeff S. Grampp
- Kyle Rhodes
- Sean M. Sneeden

MANAGEMENT DISCUSSION SECTION

Operator

Good day, and welcome to the Sanchez Energy Corporation First Quarter 2016 Earnings Conference Call and Webcast. All participants will be in listen-only mode. [Operator Instructions] After today's presentation, there will be an opportunity to ask questions. [Operator Instructions] Please note, this event is being recorded.

I would now like to turn the conference over to Rick Hill, Interim Chief Financial Officer. Please go ahead.

Garrick A. Hill

Good afternoon, and thanks for joining us. Before we get started, I would like to remind everyone that we'll be making forward-looking statements during today's call. These statements can be identified by the use of words such as will, potential, believe, estimate, expect and similar terms or expressions. Our forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. These risks and uncertainties are described more fully in our documents on file with the SEC. Also note that an updated corporate presentation was posted to our website this morning. We will refer to some of the slides in that presentation during our discussion today.

Joining me as presenters are Tony Sanchez, our Chief Executive Officer; and Chris Heinson, our Chief Operating Officer. We'll start by turning the call over to Tony for an overview of the first quarter.

Antonio R. Sanchez

Thank you, Rick, and good afternoon to everyone on the call. Process improvements and efficiency gains continue to drive our performance, resulting in lower costs and strong production in the first quarter of 2016. This combination of lower costs and strong production has allowed us to achieve positive returns on our capital program, even in today's challenging commodity price environment, which provides us with a key competitive advantage in the form of a strong balance sheet. To that point, we finished the first quarter of the year with significant liquidity of approximately $662 million, which includes about $362 million in cash and an undrawn credit facility with $300 million of available borrowing capacity. As noted in our press release this morning, we've already met our 50-well per year drilling commitment at Catarina for the period that ends on June 30, 2016, and banked 13 wells towards the next annual drilling commitment as of March 31, 2016.

Because we have no debt maturing over the next five years and a bank of wells against our annual drilling commitment at Catarina, we had considerable financial flexibilities we'd like to execute our 2016 capital plan.

Additionally, we had demonstrated our ability to tap into strategic financing alternatives through our relationship with Sanchez Production Partners, which allowed us to raise approximately $430 million in cash last year, without issuing additional debt or equity securities. We believe additional strategic financing opportunities exist, and have identified other potential divestment targets with estimated value of over $800 million over the coming several years.

In the area of hedging, the company is well-positioned with approximately 100% of our expected oil production, and approximately 95% of our expected gas production hedged at $61 per barrel of oil and $3.12 per MMBtu of natural gas, respectively, for 2016. Our hedge book was valued at over $123 million as of March 31 of this year.

Turning to operations, the team has delivered exceptional results on a number of fronts and continues to impress. Our average production tops 56,000 Boe per day in the first quarter of 2016, which exceeded the high end of our guidance by over 8.5%. This represents an increase of approximately 26% over the first quarter of 2015 production despite a significant reduction in our capital spending.

Design and process improvements have led to shorter drilling times, lower costs and better type-curves at both Catarina and Cotulla, where our best wells were drilled at a cost of approximately $3 million in the first quarter.

At Catarina, this marks an improvement in costs of over 65% since acquiring the asset in 2014. Because the majority of our cost savings is the result of efficiency gains, we continue to believe these savings are sustainable even in a higher commodity price environment.

With respect to our midstream strategy, recall that last October, we announced a joint venture with Targa to invest approximately $115 million for a 50% interest in a 45-mile high pressure gathering line and a 50% interest in a new [ph] 200 million cubic feet per day to 260 million (04:58) cubic feet per day cryogenic gas processing plant.

As of March 31, 2016, we have spent approximately $56 million of that capital planned for investment in the Targa JV. The pipeline was completed in March and began flowing the majority of our Catarina natural gas production to a Targa operated plant in [ph] the (05:20) County.

And we expect the gas plant to be finished in service by – and in service by early 2017. The addition of these assets provides positive returns on a standalone project basis, and is also expect to provide a path to improve yields, lower processing fees and significant marketing benefit to Sanchez Energy.

This morning, we reiterated our 2016 capital, upstream capital spending guidance of $200 million to $250 million, with approximately 70% of capital spending expected during the first half of the year. At this level of capital spending, we expect to maintain relatively flat production levels when compared to 2015, with our average production forecast in the range 48,000 Boe per day to 52,000 Boe per day for the full year of 2016. With frontend loaded capital plan and moving to a one operator rig by mid-year 2016, the company expects second half of the year's production to decline by approximately 10% from the first half levels.

Before turning things over to Chris, I would like to say that I'm really proud of the exceptional performance exhibited by our team so far in 2016. Our ability to extend cost savings while achieving better well performance has been the key to building a better balance sheet and strong liquidity position.

I believe we are well positioned in today's market and look forward to leveraging our core competencies and financial resources to strategically grow the company over time.

I will now turn over the call to Chris.

Christopher D. Heinson

Thanks, Tony. I'll start by providing some additional highlights from our accomplishments during the first quarter 2016. And we'll then touch on details regarding the remainder of our 2016 program.

During the first quarter, the company brought online, 19 gross, 17 net wells. We currently have a total of 640 gross producing wells online, plus 17 wells currently in the process of awaiting on completion. As Tony mentioned, we had a strong first quarter operational. We produced an average of 56,500 barrels of oil equivalent per day during the quarter. This represents a 26% increase from the first quarter 2015 production results.

This is attributable in large part continued outperformance of recent well results through a continuation of field efficiencies, which are resulting in lower downtime. We've also continued to realize cost savings with respect to both capital and operating expenses. At Catarina, we delivered wells at an average of an approximately $3.3 million per well during the first quarter. At Cotulla, drilling and completion costs averaged approximately $3.4 million per well during the first quarter with both areas having wells as low as $3.0 million per well. These results are due in large part to a continued efficiency realization.

As referenced previously, much of our current focus with regards to cost savings is being directed towards our sustainability of our cost savings. This is being accomplished through our continued process optimization, as well as savings attributable to further migration into petroleum service.

During the quarter, we implemented several LOE reduction initiatives. At both Catarina and Cotulla, we put in service, private disposal wells. At Catarina, the disposal well is located immediately offset one of the main processing facilities and is connected by pipeline to the central gathering facilities, eliminating the need to ever put a barrel of water on the disposal [indiscernible] (09:04).

Additionally, we have adjusted our frac designs to be able to utilize produced water whenever available. This has reduced the disposal cost, as well as reduced our overall fresh water demand. Additionally, we have finished our elimination of diesel generators as a power source for artificial lift.

Our remaining generators are electric or gas powered. These two initiatives have reduced our annual OpEx by greater than $3.5 million per year. Comparatively speaking, LOE excluding midstream and gathering fees related to the Catarina midstream transaction, has been reduced by nearly 25% from the midpoint of initial guidance provided in 2015, due in large part from this continued focus we have on putting optimization process and design at the field level.

With respect to capital, we have similarly continued to focus driving on additional process and efficiency gains. Drilling has now recorded a spud to TD time of 4.35 days on a recent well with a lateral length of approximately 6,000 feet. This was accomplished at a cost of $36 per foot prior to running casing, and $66 per foot inclusive of production casing. This performance may be a record cost per foot for drilling a horizontal well in the Eagle Ford.

On the completion side, we are now completing 9 to 10 stages routinely per day without reductions to our frac volumes. Putting into perspective the gains that have been derived through efficiency, our well cost had been reduced from approximately €4.3 million a year ago to €3.3 million per well currently with less than a 10% change in service price over that same period.

At Catarina, we brought online, a significant number of new wells in South-Central area. We now have 15 total wells producing in the South-Central area of Catarina, of which, 11 were brought online this quarter. We also brought online, five wells in the area bridging Western Catarina and South-Central Catarina. Thus far, the wells on flow back are producing at rates and pressures in line with expectations.

As mentioned last quarter, a pilot well confirmed the presence of two target benches in South-Central Catarina, which we elected to develop simultaneously. During the first quarter, we have seen strong results from both distinct targets; 30 day rates for the 15 wells brought online to date have averaged greater than 1,300 Boes per day. These two zones are roughly 100 feet apart and separated by a [ph] frac barrier (11:45). Due to the unique geologic setting of the South-Central area, these two benches are best described as an Upper Middle Eagle Ford and a Lower Middle Eagle

Ford. Both benches appear highly productive with little rate and pressure differences between the two zones, thus far. We will continue to monitor the results of these zones. The confirmation of two productive horizons in the South-Central area is a positive new result. One of these benches appeared to be present in the area immediately north of South-Central Catarina. We are now drafting plans to appraise that part of Central Catarina in 2017.

During the quarter, we also drilled the pad in the area between western and South-Central Catarina. Although we expected the region to be productive, we questioned whether the production would resemble the 750 MBoe Western Catarina performance or the $1.1 million barrel equivalent at South-Central Catarina wells. The [indiscernible] (12:46) well pad was put online late in the quarter, and is currently exhibiting rates and pressures indicative of an area of high productivity. Performance is currently tracking the South-Central Catarina type curve. However, this region appears to have a slightly higher liquids yield and lower gas rate. We view this as an important result in our development of this area as this step-up provides strong confirmation that Southern Catarina fairway extends back towards the west.

Based on these results, development plans for the remainder of 2016 and 2017 will heavily focus on development of the region between South-Central Catarina and Western Catarina, as well as South-Central Catarina.

During the second quarter, we expect to receive additional results about the eastern step-up that could potentially further extend initial expectations for this area of the ranch as well. Touching on our capital program, during the first quarter, we spent approximately $90 million, largely on drilling and completions, keeping us on track to maintain a capital range of $200 million to $250 million for 2016. We currently had two rigs running in the Eagle Ford and expect to reduce to one rig towards the end of the second quarter. Due to efficiency gains in drilling and completions, we expect there is a chance production may come online a bit earlier than originally expected. Assuming this trend continues, it will likely result in a portion of third quarter and fourth quarter production being realized in the second quarter.

As mentioned previously, we've already met our 50-well drilling commitment at Catarina through the 2015-2016 commitment period and expect to have approximately 20 wells banked for the following year by June 30, 2016. As we begin to consider the capital allocation in 2017, this enables significant flexibility with respect to our drilling program as we would have the ability to meet our 2017 drilling commitment in Catarina with only one rig. Guarding our legacy assets, the majority of our acreage is currently held by production, allowing for any incremental drilling to be discretionary.

With respect to midstream, Phase 1 of the gas gathering line was complete and in service, and servicing the bulk of Catarina natural gas into our Silver Oak II plant at favorable gas rates, while the Raptor plant is under construction. We remain confident that completion of the gas plant should occur early 2017 and are beginning to realize substantial cost savings as compared to initial expectations. To-date, we have spent approximately $58 million on both the gathering line and gas plant.

During the quarter, we averaged approximately 56,500 barrels of oil equivalent per day, which was approximately 8.5% above the high end of our guidance range of 48,000 barrels to 52,000 barrels of oil equivalent per day. Reiterating what Tony has highlighted, we expect average production to be flat year-over-year with our production profile influenced by capital spending. As such, production is front-weighted this year with a step-down expected during the second half of the year due to reduced capital spending.

Additionally, as ethane rejection becomes common across our Catarina volumes in Q2, we expect minor reductions on a volume basis to our NGLs, but we expect to see an improvement on a net back [indiscernible] (16:15).

With those updates, I will now turn the call over to Rick.

Garrick A. Hill

Thanks, Chris. First quarter revenues were $79.8 million before hedge settlement, which includes $42.7 million from oil sales, $15 million from the sale of NGLs, and $22.1 million from natural gas sales. Including the effects of $53.1 million in hedge settlements during the quarter, our realized prices were about $52.71 per barrel of oil, $8.91 per barrel of NGL, and $2.89 per Mcf of natural gas.

And commodity price environment obviously remains challenging, but we've seen some signs of improvement recently. Additionally, as existing gathering agreements expire and the Targa JV reaches its stride, we see potential benefits from more flexible marketing arrangements and improved net backs on our Catarina production.

We continue to focus on improving our cost structure, which is crucial in today's more challenging environment. Our all-in cash operating cost, which consists of LOE, G&A and ad valorem taxes, exclusive of certain non-cash items, came in at about $13.32 per Boe during the quarter, which was in line with our guidance.

Capital spending totaled about $91.4 million during the quarter, which represents a 57% decline from the first quarter of 2015. We also made an additional equity investment of about $5.2 million in the Targa JV during the first quarter. And as Tony mentioned earlier, this brought our total investment in the Targa JV to $56 million as of March 31, leaving us with roughly $60 million of investment capital plan with the remaining construction through early next year.

With respect to guidance, we encourage investors and analysts to review our updated guidance, tables on slide eight of the corporate presentation. Here, note that we anticipate drilling operations to reduce to one active rig at mid-year, which underlies our plan to spend approximately 70% of our capital in the first half of 2016.

In this morning's press release, we provided second quarter guidance of 50,000 Boe – 52,000 Boe per day. For modeling and reconciliation purposes, also note that the Western Catarina midstream divestiture resulted in a deferred gain of $75 million. It is being amortized seasonally over five years, which resulted in a non-cash item of roughly $15 million impacting our LOE this year. We show this as a separate line item in our guidance.

On the topic of risk management, our current hedge position is 18,000 barrels per day of oil and 99,154 MMBtu per day of natural gas in 2016. After the quarter, we executed hedges in 2017 and 2018, which brings our hedge positions in those years to 1,000 barrels per day to 2,000 barrels per day of oil, and 76,562 MMBtu per day of natural gas in 2017, and 20,000 MMBtu to 30,000 MMBtu per day of natural gas in 2018. Additional details on our hedges can be found in the appendix to our corporate presentation and in our press release.

As Tony mentioned earlier, we showed significant liquidity of $662 million at March 31, which included about $362 million in cash and an undrawn credit facility with $300 million of available borrowing capacity. In March, we completed our spring 2016 borrowing base redetermination and executed amendments on our credit facility aimed at increasing our financial flexibility in today's market.

Our borrowing base is currently set at $350 million, and the elected commitment amount of $300 million will remain unchanged until our fall redetermination. Among other things, the amendments allow us to spend up to $300 million of our cash to repurchase securities, with a supplement of $100 million for preferred equity and $50 million for common equity. We also replaced our 2.25 times total secured debt to EBITDA covenant with a 2.0 times net first lien debt to EBITDA covenant.

We currently have no borrowings outstanding under the credit facility, and as of March 31, we are in compliance with our financial covenants with significant headroom on both leverage ratio and the current ratio.

Now, back to Tony for some closing remarks.

Antonio R. Sanchez

Thank you, Rick. We are intensely focused on reducing costs, maintaining operational flexibility and doing whatever may be required to ensure that we have enough liquidity to operate in 2016 and beyond, irrespective of commodity prices. While we have a robust drilling inventory that include the substantial opportunities set that shows positive returns, even at today's prices, we continue to focus on what we spend and how we use our liquidity in this environment.

Capital efficiency and the strength of our balance sheet remain engrained in the mindset of everyone in our organization. Sanchez Energy has built a successful company by acquiring underperforming assets, reducing costs and driving efficiencies. And we remain committed to delivering the kind of performance our shareholders have come to expect. I believe our asset base, core competencies and strong balance sheet provide us with key competitive advantages, whether related to future development or opportunities that may emerge as a result of distress in the industry.

I am proud of these results we delivered this quarter and encouraged by the momentum we have created so far this year.

Operator, that finishes our prepared comments, so we are now ready to start taking questions.

Q&A

Operator

And with that, we will now begin the question-and-answer session. [Operator Instructions] The first question comes from Neal Dingmann with SunTrust. Please go ahead.

<Q - Neal D. Dingmann>: Good afternoon. Tony, could you talk a little more on the potential $800 million divestitures, as to any clarity you can give on that? And then, along with that, are you thinking about – how do you think about acquisitions as well or sort of just transition to that?

<A - Antonio R. Sanchez>: Yeah. So, $800 million, I'd say is very high-level number, and I'd also use a very long-term around that when you're thinking about context. How we get to that number is we went through and understood our current asset base, both midstream gathering and upstream, and sort of spaced out over the next several years, what would be an MLP profile for any given assets. So, that's kind of the number we came up to and there is a range around that, so don't take it too specific, but I think the point is the number is big. And that large number is a key component to our financing strategy. We replaced a lot of importance on cash. When we look at liquidity, we don't only look at what's available under the revolver. We place more importance actually on the component of that liquidity that is cash itself. So, I would expect certainly, we're going to look towards our midstream gathering assets, and when they're ready, seek to divestment. And to do so within the context of some of the other requirements we have such as maintaining operating control of the assets and getting a fair price in a fairly expedient process, a dropdown really makes a lot of sense.

So, it's worked in the past and I see no reason to not continue to place importance on our dropdown strategy revival part of our strategy. As it pertains to upstream assets, we've looked – we've got some slides in our Analyst Day from last January that really look at sort of the part of a well life where it is flattened out and it's declined past its initial few years, and where it would be more akin to an annuity and looking forward to bringing that cash – looking at bringing that cash forward as a source of financing for ongoing development activities or as the equity portion of an acquisition.

So, some component of this from an acquisition strategy would serve to be the equity piece of a purchase, which the flip side of that means it mitigates dilution at the common equity levels of the company.

<Q - Neal D. Dingmann>: Okay. Got you.

<A - Antonio R. Sanchez>: Did that address your question, Neal?

<Q - Neal D. Dingmann>: That does. It's very good. And then, just maybe one, Tony, for you or Chris. More just on in the press release, you talked about now the extension between these two areas, obviously, between the South-Central and the Western area. Is that now – I mean, how are you thinking about that? It's just one sort of contiguous area, I mean, now? Is that what you were trying to say in that? I'm just trying to read between the lines there, I guess.

<A - Antonio R. Sanchez>: Yeah. So I'll start with that and Chris could get more specific, but by and large, the answer is yes. We've been very happy with the results we've gotten from a set of wells that we tested in that area that effectively consider it like a geographical bridge between what was traditionally the Western area of the Catarina asset and then our South-Central asset. And the wells in there are coming in much better than we had initially expected and are providing some interesting production profile characteristics that lead to increased focus this year and probably the next several years on that sort of Western South-Central area, we could call it. Go ahead, Chris.

<A - Christopher D. Heinson>: Yeah. Neal, what this is, is it really puts a piece together for us that was kind of an uncertainty. I mean, the pad that we're referring to is E15 pad. It sort of sits just about at the midpoint between where our Western Catarina development sort of ended and our South-Central Catarina development starts. So with that, there was kind of a gap of – it was close to 4 miles or 5 miles where we really didn't have any good production data. Now, this pad sort of bridges that gap and draws that risk way down. Now, so from a total inventory location standpoint, we really already knew these locations would be productive, so it's not like there is a massive new added location. But what you're seeing here is a replacement of some of the type curves that we had originally assumed were going to be at the Western Catarina kind of performance level now being replaced with a type curve that, although it's something slightly different than South-Central Catarina, is much more like South-Central Catarina in terms of IPs and total EURs. So, we expect the economics to be substantially improved over much of that area that sits in between sort of that Western and South-Central Catarina, and we're still going to be doing additional appraisal and delineation. So it's hard to give you a good number, but ballpark, sort of 50 wells to 75 wells that we thought were Western Catarina wells are probably more like South-Central Catarina.

<Q - Neal D. Dingmann>: And, Chris, do you have the two horizontals you spoke of? Is that in most areas now or is that just in that sort of original South-Central?

<A - Christopher D. Heinson>: I don't know about the two horizontals, but we've got – the E15 pads were the ones – that was the pad that we put on – a five-well pad that we put on halfway in between the two that we're talking about on the results. Now in the quarter, we also put on a lot of South-Central Catarina development wells, all of which have come online basically in line with those original expectations. So they're tracking the type curve [indiscernible] (29:09).

<Q - Neal D. Dingmann>: I'm sorry, Chris, what I mean is the two horizons that you spoke of, I'm sorry about that.

<A - Christopher D. Heinson>: Oh, okay, yeah. No, the two horizons we've gotten, roughly about 50-50 on our development wells are placed within those two benches.

<Q - Neal D. Dingmann>: All right. And then, lastly, Tony, I'm sorry about this, just your peer obviously had success here – early success with EURs. Any early thoughts for you and Chris on that in any of your acreage?

<A - Antonio R. Sanchez>: Sorry. Can you repeat that, Neal? We had success in the EURs you said or...

<Q - Neal D. Dingmann>: That obviously just early on, you just had your peer last week, EOG just talked about that last week in the Eagle Ford, obviously, a success with EURs and had some recoveries in their area. I didn't know if you all had looked at any pilots or just anything of your acreage is that going to be possible?

<A - Antonio R. Sanchez>: I mean, I think by and large, it's positive. We don't – we haven't really gotten into the specifics. We saw what they put out, it's very interesting. I think the first thing to do is to make sure you have wells to ultimately come back and try some secondary type recovery on.

And now, we have a large portfolio, and that portfolio of wells keeps growing. So over time, we are looking at it, certainly. We do – we are starting to do some analysis to work around which candidates – which wells would be better candidates for re-frac or other EUR type treatment and approach. We're not going to commit a lot of capital then until somebody else figures it out or until we have something meaningful to put our – to put some capital into back.

Another part I think that people don't realize is that's another benefit to dropping down the flatter wells to SBP is that we could go back and put a farm-in in-place arrangement between the two and have access to those wellbores again. So, we're not selling them to – the benefit of not selling to a third party is that we have them sort of in the broader group of companies here and we don't sell them off. So, those are wells and those tend to be the older wells that are flatter already, and probably the most likely for candidates for recompletion. And we could go back into those and access them, too.

<Q - Neal D. Dingmann>: Very good. Thank you, all.

<A - Antonio R. Sanchez>: All right.

Operator

Our next question comes from Ron Mill of Johnson Rice. Please, go ahead.

<Q - Ronald E. Mills>: Good afternoon, guys. Maybe just one expansion on some of Neal's questions. The E15 pad obviously brigs a little bit further west with more like the South-Central Catarina performance risk. I know that you also have a quite a bit of opportunities, you can globe it further North from your existing South-Central Catarina. Any plans to test additional parts of South-Central Catarina or what should we think about [indiscernible] (32:31) one rig is going to stay?

<A - Christopher D. Heinson>: Yeah, Ron. We've gotten something that I would characterize more as additional sort of a step-out appraisal going on in South-Central Catarina. We're going to be able to talk about that either by second quarter earnings or possibly by third quarter ops update. And that's more sort of in the existing play area for South-Central Catarina. We – all that's going to do is kind of confirm the presence of those zones that we talked about extending up an additional row or two to the north.

What we're looking at now, because one of those two zones looks like it may be present significantly further north, we're looking at setting up appraisal plans for it, but I wouldn't expect – although that well may be drilled at the very end of this year, I don't expect any results from the true Central Catarina appraisal until 2017.

<Q - Ronald E. Mills>: Okay. Good. And then from a – excuse me, you guys walked through kind of the production outlook, I think, Tony, you said the second half might be around 10% or so below the first with the less rig activity. Where is your production currently in – how many wells are you expecting to bring on here in the second quarter versus the first quarter?

<A - Antonio R. Sanchez>: Production currently is still at that 55,000 Boe, 56,000 Boe a day level. Wells coming on – in the second quarter, it's going to look a lot like the first quarter.

<Q - Ronald E. Mills>: Okay.

<A - Antonio R. Sanchez>: Yeah, so second quarter will look a lot like the first quarter, and then we're going to slow our capital spending. And there is a comment, 70% of the, call it, midpoint $225 million capital will be spent in the first half of this year. So you should expect a slow-up in a subsequent probably single – high single-digit drop in production going into the third quarter and fourth quarter. And you will probably see most of that in the fourth quarter.

<Q - Ronald E. Mills>: That [indiscernible] (34:50) next point. It seems like you still have the two rigs and you're still spending that much money, but most of that starts really for the fourth quarter end. And then does that $200 million range to $250 million range that you talked about in the past, does that contemplate you all putting another rig back to work at some point in early 2017?

<A - Christopher D. Heinson>: No. The $200 million to $250 million is just for this year's spending. Right now, it looks like we're going to be coming in right in dead center of where we had that projected. So obviously, we could stay within guidance and do a little bit of activity, but that – we have not made any decisions on whether or not to do that yet.

<Q - Ronald E. Mills>: Okay. Great. And then, just in terms of oil realizations, a little bit lower than what I thought. Was there something funny going on in the first quarter of LLS versus WTI or was it some – is it condensate related? I guess, I'm just trying to track down.

<A - Christopher D. Heinson>: Yeah. Ron, our gravity differentials have stayed relatively constant from fourth quarter to first quarter this year. So, it hasn't really been any kind of deterioration really from a crude basket standpoint, because our condensate is more or less the same prices as we have been. What we have seen fourth quarter relative to first quarter is a sort of, on a relative pricing basis, a continuation of a sort of a expansion of the differential or a shrink of the differential between WTI and LLS. And you can compound that with a negative role in the first quarter. We've actually got ourselves in a situation in the first quarter where, really, an unusual circumstance where our realized LLS price was actually negative to WTI, which is not typically the case, that almost previously, I don't know if that's ever happened. So, that's a little bit unusual for us in the first quarter of this year, and I certainly wouldn't expect that to continue. I expect the differentials between WTI and LLS have definitely come down. I think they're maybe $1.50, $2 right now. So that is definitely well, and that may continue going forward, but the roll effect that we saw this quarter may go back.

<**Q - Ronald E. Mills**>: Great. All right, guys. Thank you so much.

<**A - Christopher D. Heinson**>: All right.

Operator

The next question comes from Steve Berman of Canaccord.

<**Q - Stephen F. Berman**>: Thanks. Good afternoon. Staying on the topic of pricing for a second, you reiterated early in your comments, you could meet your 50-well commitment for next year with just the one-rig program. But is there a combination of oil and gas prices that would get you thinking about bringing that second rig back as we move through the balance of this year into 2017?

<**A - Christopher D. Heinson**>: Yeah. I'd say, Steve, by and large, $50 on WTI is kind of a – I'd say a baseline that we would want to see before we would begin to consider meaningful CapEx additions. We did put some hedges on it $50 last time it bumped up in that direction. So, if we're able to put more of that on in 2017 and maybe even start to chip away to 2018, anything more to that on the oil side will work at I would say $3 for gas.

<**Q - Stephen F. Berman**>: Okay. And then on the...

<**A - Christopher D. Heinson**>: And...

<**Q - Stephen F. Berman**>: Sure. Go ahead.

<**A - Christopher D. Heinson**>: Yeah, sorry. I wanted to highlight NGL pricing because that's – that was a weak spot for us this past quarter, it seems recovered. So, we think the second quarter will be stronger from an NGL pricing perspective, but we'll be able – we'll be monitoring that much more closely and it's harder to hedge. So, that's an important component of how we think about capital.

<**Q - Stephen F. Berman**>: Okay. And then on the drilling complete cost side, every time I think you can't bring these costs down, you keep bringing them down. So is there room on that $3 million number to get a two-handle on? And how much more blood can you squeeze out of that stone?

<**A - Antonio R. Sanchez**>: I think there will be a few wells that come in, in that [ph] 28, 29 (39:45) range, but you're right. I mean, I think that these are the – kind of the last drops to come out. In some of the shorter well laterals, we'll be probably more in line to hit those numbers. But from a process improvement standpoint, we are hitting it now, I think. I think there may be some $50,000, $100,000 here and there to take out, but we're actually now shifting towards sustainability of this price, of this cost structure. And making sure that we really lock that in and hold on to these gains rather than sort of get what's [indiscernible] (40:35).

<**Q - Stephen F. Berman**>: Great. All right. Thanks for that, Tony.

<**A - Antonio R. Sanchez**>: Thank you.

Operator

The next question comes from Jeff Grampp of Northland Capital Markets. Please go ahead.

<Q - Jeff S. Grampp>: Afternoon, guys. Congrats – definitely congrats on the recent success that you guys are seeing on South-Central Catarina. I guess just a question in terms of the 200 locations you guys have on, I guess, on slide 15 there, what would you guys consider de-risked for those million barrel plus type of EURs based on the dozen – plus 12 you have production on? And then, kind of building off of that, how should we think about upside in terms of – upside on the location count, given what you guys have seen from the stack development results, so far?

<A - Christopher D. Heinson>: Yeah, Jeff, right now of that original 200, so not including the sort of Western ones that sort of have been upgraded, I would say, I would say roughly about half of those are pretty well de-risked. I mean they meet SEC standards for proven reserves. By sort of the end of this year, we should have almost the entirety of that 200 locations more or less kind of de-risked, completely de-risked, so we're seeing good progress there.

As I mentioned a little bit earlier on the call, obviously, with the E15s, we're rethinking some of the type curves and the EURs that we had projected over a part of the west as well. There's – we do see it as likely that some of those EURs and more particularly, the economics are going to be sort of revised upwards and will probably resemble something that looks much more like South-Central Catarina going forward.

<Q - Jeff S. Grampp>: Okay. Perfect. Thanks for that. And then, kind of on the balance sheet side, Tony, any new thoughts in terms of buying back debt or second lien no issuances or anything like that? I know obviously, that yield changes on a day-to-day basis, but it seems like a pretty solid investment opportunity considering the risk profile and your liquidity situation.

<A - Antonio R. Sanchez>: Yeah, so I'll answer that question two ways. First, many of the amendments that we got done vis-à-vis our bank credit facility over the last couple of months provided us with a flexibility to engage in any of those transactions, and much more so that we had before. So, we've put the structure in place to do it. We have the liquidity to do it. Obviously, we haven't pulled the trigger on anything, and I think by and large, where our debt securities are trading now, that probably doesn't make – certainly doesn't make as much sense as we did even a few months ago. So, I guess, the short answer to that question is we are prepared and we would treat it much like any other investment and use of our liquidity.

And so it's somewhat of a balancing. I was really focused on how do we use our capital to expand our cash flow profile. And there is a lot of companies now that are in a restructuring mode, and having the liquidity and the cash to be opportunistic is very important. So we want to make sure that we don't tie that up long-term. But if the opportunity is so compelling to buy back our debt or to engage in a secondary issuance, we would, but it just hasn't really lined up yet.

Operator

[Operator Instructions] Our next question comes from Kyle Rhodes of RBC. Please go ahead.

<Q - Kyle Rhodes>: Hi, guys. Any color you can provide on the recent Cotulla well results just in terms of initial production rates and how they are tracking with your type curve?

<A - Christopher D. Heinson>: Kyle, yeah. We don't really have any real updates on those. Those wells take a while to clean up and we may talk about that sometime in the second quarter or third quarter.

<Q - Kyle Rhodes>: Okay. Got it. And then, just taking it forward a bit, you sound pretty confident that you're going to fulfill your 2017 Catarina obligations with just one rig. I guess, if you bring a second rig back, I mean, what are the inflection points in terms of oil price relative to gas and NGL prices where it makes sense to send that rig to the Maverick area versus Catarina?

<A - Antonio R. Sanchez>: Well, earlier, we put out oil at $50, gas at $3, and then NGLs, I guess, at 25% or 30% of WTI. So, as those three commodities swing in relation to each other, that would take us more disproportionately one way or another vis-à-vis up-dip oil or the gas condensate window of Catarina. So, as there is change, we can. I mean, the question of the 2017, that sort of the next cycle, all else equal, we like to keep the well bank of 15 wells to 25 wells at Catarina. The rig now is – we're drilling these in six days, right? So six days to eight days a well. So, one rig can drill upwards of 40 wells a year, right, just you do the math there. So we do have a lot of flexibility.

We don't need more than, call it, 2.5 wells that you provide for some downtime maintenance and things like that, I mean, rigs, in order to keep that well bank equal and growing. And that's on the conservative side. So, we'll monitor it and we'll make sure. I mean, typically, the way we do it, and we just want to make sure that by the first quarter of the year, we have already achieved the well commitment for that particular period because recall, the period is mid-year to mid-year.

<Q - Kyle Rhodes>: Got it. So, sounds like, as of right now, kind of in that $50 oil case and $3 gas case. And secondly, it would come back to Catarina first, is that fair to say?

<A - Antonio R. Sanchez>: We'll probably come back first quarter of next year. Yeah.

<Q - Kyle Rhodes>: Okay. Thanks, guys.

<A - Antonio R. Sanchez>: Yeah.

Operator

Our next question comes from Sean Sneeden of Oppenheimer. Please go ahead.

<Q - Sean M. Sneeden>: Hi. Thank you for taking the question. Just a clarification on the credit amendment that you guys had. I think there are two buckets there. One, I think, it's $150 million carve-out, which is an unrestricted sub. And the other is I think just the kind of generic $300 million basket. Just want to make sure that you guys are viewing it as indeed additive, so you can have a total of $450 million of buybacks. Is that the right way to think about it?

<A - Antonio R. Sanchez>: No. They're not on top of each other. The $300 million – and pardon me if I'm wrong, but the $300 million is in the indentures, right?

<A - Christopher D. Heinson>: No, the $300 million is the result of the amendments and that's the total across all subsidiaries. The $150 million is a carve-out specifically for the unrestricted sub, but it's within that $300 million

<Q - Antonio R. Sanchez>: So, we're not on top of each other there?

<A - Christopher D. Heinson>: Correct.

<Q - Sean M. Sneeden>: Okay. I appreciate that clarification. And then maybe, Tony, just kind of to follow up on one of your previous comments there, as you think about the balance sheet and just kind of leverage as we stand here today, is it fair to say, if we kind of look at where bonds are trading today and where the strip is, that the plan right now is really try to go into the cap structure organically and maybe try to be a little opportunistic on repurchases if you get a dip on bond?

<A - Antonio R. Sanchez>: I would say, by and large and all else equal, yes, that's the case. We've got a lot of liquidity in terms of cash. We have the ability to cap more. So keep in mind, our current midstream investments that are being funded with cash are the first candidates for monetization. So to bring that cash back, we would basically for no money out of that sand, in fact, probably a cash profit, we would get the benefits of a new gas processing plant, which is then going to affect our netbacks, which is going to affect our ability to continue to derive value from the gas sales stream on down the line. So we get all the benefits really for no money up – no money out for an extended period of time. So, yeah, I mean that's – that is the way we would look at it in a perfect world.

<Q - Sean M. Sneeden>: Okay. That's helpful. And maybe just one quick follow-up there. Can you give us a sense of what the EBITDA generation is from some of your midstream assets that you have in-house at this point or do you have kind of a sense what that might be?

<A - Christopher D. Heinson>: Yeah. We haven't disclosed that. And by and large, the reasons is we're still in the process of sort of closing the loop on how those contracts should be set up and what – the way we go about setting them up is as we get line of sight to a – an asset being in service and having ability to generate cash, we then price it out in the market and find out what a unrelated third-party contract would price at, and then see, does that make sense? Do the numbers kind of work for both sides? And then set up the contract accordingly, and then put it into the process of the independent committees at the two boards negotiating that out.

So, that's a longwinded answer to say no, but it kind of speaks to the process that's required to get that setup. But, I'd say on a rate base – on a unit-based basis, the – you think about it in terms of existing market rates in that part of the Eagle Ford.

<Q - Sean M. Sneeden>: Okay, that makes sense. And I think that's pretty helpful.

<A - Christopher D. Heinson>: Yeah, we don't back solve for a number that we want to get to on the cash side. We do it the other way. We say, what would it be in the market right now?

<Q - Sean M. Sneeden>: Great. I appreciate it. Thank you.

Operator

This concludes our question-and-answer session. I would now like to turn the conference back over to Tony Sanchez for any closing remarks.

Antonio R. Sanchez

Okay. I want to thank everybody for joining us this afternoon. I appreciate your continued interest and support of Sanchez Energy.

Operator

The conference has now concluded. Thank you for attending today's presentation. You may now disconnect.