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Q3 2018 Ultra Petroleum Corp Earnings Call

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PRESENTATION

Operator

Good day, ladies and gentlemen, and welcome to the Ultra Petroleum Corp. Third Quarter 2018 Earnings Conference Call. (Operator Instructions) As a reminder, this conference call may be recorded.

I would now like to turn the conference over to [Aaron Bedeford]. You may begin.

Unidentified Company Representative

Thanks, operator. Earlier this morning, we included in our news release results for the third quarter and updates for 2018. In this call, we will provide additional information with our prepared remarks along with reference to our updated investor presentation that was posted earlier today on our website.

I'd like to point out that many of the comments during this conference call are forward-looking statements that involve risks and uncertainties affecting outcomes, many of which beyond our control and are discussed in more detail in the Risk Factors and forward-looking statement section of our annual and quarterly filings with the SEC. Although, we believe these expectations expressed are based on reasonable assumptions, they are not guarantees of future performance and actual results or developments may differ materially. Also, this call may contain certain non-GAAP financial measures. Reconciliation and calculation schedules can be found in our website.

Thank you all for joining us today. With me on the call is Brad Johnson, our interim Chief Executive Officer; Garland Shaw, our Chief Financial Officer; and Jay Stratton, our Chief Operating Officer.

Now I'll turn the call over to Brad.

C. Bradley Johnson ***Ultra Petroleum Corp. - Interim CEO & Director***

Thanks, Aaron. Good morning, and welcome to Ultra Petroleum's third quarter conference call. Today, we will review the quarter's financial results, summarize our development activities in Pinedale and provide updated guidance for full year 2018. In addition to sharing our third quarter results today, we are very pleased to announce the appointment of 2 new senior executives to our team. David Honeyfield will be joining Ultra as Chief Financial Officer; and Andrew Kidd will be joining as General Counsel.

Mr. Honeyfield brings over 25 years of experience to our executive team, having previously served as CFO for 3 successful upstream E&P companies: PDC Energy, Jonah Energy and SM Energy as well as President and CFO of Intrepid Potash Inc. and other natural resource company. Mr. Kidd brings nearly 30 years of experience to Ultra, including serving as an independent Director for public and private corporations; GC, President CEO of Samsung Resources; and General Counsel for Quantum Utility Generation, Anthem Energy, and Constellation Energy Resources. These 2 appointments complete my efforts to build out a very accomplished, well-respected and high-performing executive team based here in Denver. With our new executive team in place and a transition of Ultra's headquarters to Denver complete, along with the hyper focus on enhancing the value of our world-class assets on Pinedale, we are positioned for tremendous success in the future.

Slide 4 provides a list of highlights for the quarter. Production for 3Q '18 average 734 million cubic feet equivalent per day, driven by very good run times on our base production and good results from vertical wells brought online during the quarter. EBITDA for the quarter totaled $120 million and cash cost totaled just over $1 per Mcfe.

As we discussed last quarter, we adjusted our capital budget for the second half of 2018 to focus more on vertical wells. In late July, we reduced our operating rig count from 4 to 3 and resumed drilling on pads solely dedicated to vertical development. As a result, we brought online 19 operating wells with an average 24 hour IP of 7.4 million cubic feet equivalent per day. Third quarter wells are tracking the midpoint of recent historical averages. We expect to see continued strong results from our vertical development program that is focused on the core of the Pinedale Field. Vertical well cost were reduced to a quarterly average of $3.3 million per well, down 10% from 2Q '18. In September, well cost average $3.1 million and I expect us to be close for that number for the rest of this year.

Our primary focus for the team is to further reduce well cost, and we expect to continue to bring down these costs materially going forward into 2019. We also brought online 3 horizontal wells in the quarter, all in the lower lines A1 interval. These 3 wells average 7.8 million cubic feet equivalent per day, below our expectations. Based on these recent results, we have suspended horizontal drilling until 2019. Meanwhile, we continue to advance the evaluation of our horizontal program and remain confident that further well data analysis and optimization will allow us to drill successful horizontal wells next year.

Jay will share more of these efforts later on in this call. With the close of the sale of our assets in Utah, we have completed our strategic plan to divest noncore assets and focus on Pinedale. Proceeds used from the sale were used to pay down the revolver, and we had a 0 balance as of September 30.

In October, the company announced that it entered into an agreement with certain noteholders that would reduce debt by approximately $250 million and extend the maturity of approximately $560 million of our bonds from 2022 to 2024. While the company is currently in good financial shape with over $330 million in liquidity and a development plan designed to generate our [live] within cash flows, we've been proactively and opportunistically addressing our capital structure to provide more flexibility in order to execute on our long-term business plans.

At this time, I will turn the call over to Garland to discuss our third quarter financial results and to provide an update on our hedging program.

Garland R. Shaw ***Ultra Petroleum Corp. - Former Senior VP & CFO***

Thanks, Brad. Beginning with Slide 5. The company produced an average of 734 million cubic feet equivalent per day or 67.5 Bcfe of total equivalent production in the third quarter, a decrease of 5% compared to the third quarter of 2017. Production volumes included 63.8 Bcf of natural gas and 624,000 barrels of oil and condensate.

Total cost of $2.44 per Mcfe, excluding stock compensation expense, were within our expense guidance range although higher than the midpoint. EBITDA cash cost of $1.03 per Mcfe were $0.04 higher than the midpoint of our guidance probably due to not closing the Utah sale until late in September rather than the end of August as we had forecast.

Including our hedges, our revenue per Mcfe for the quarter was $2.80. Before hedges, our realized average gas price per Mcf was $2.46, which equates to 85% of the average first amount Henry Hub price for the quarter. Our average realized oil price was $66.52 per barrel excluding hedges, or 96% of the average WTI oil price for the third quarter.

Our resulting EBITDA for the quarter was $120 million. Our EBITDA margin improved by $0.02 over the second quarter of 2018 due to improved pricing and a narrowing Rockies basis more than offsetting slight increases to cash costs.

Moving to Slide 6. The company continues to be well hedged for the end of 2018 and into 2019 to provide cash flow visibility. This slide includes our total volume and prices hedged by product for the remainder of this year during the first quarter of 2020. For the fourth quarter of 2018, we have both Henry Hub and Northwest Rockies basis hedges in place equivalent to over 80% of our expected production at a net price of $2.22 per MMBtu.

For our hedged volumes, as shown in the lower right part of the slide, after applying a 1.07 BTU factor, we get an average hedge gas price per Mcf of $2.38. When we figure in our oil hedges, the average price per Mcfe for these hedge volumes is $2.76. We have recently been adding additional hedges for 2019 and 2020 and we will continue to be opportunistic in adding hedges for those periods to support our operating objectives and CapEx program.

On Slide 7, we present our outstanding debt and associated maturities. As shown on the slide, we have no major maturities until 2022 when $700 million of unsecured bonds become due. After those bonds become due, we have the remainder of our $975 million term loan due in 2024 and $500 million in unsecured bonds due in 2025. We previously announced that our credit facility was reduced by $100 million as a result to the fall borrowing base redetermination. We did pay down our revolver in full during the third quarter. So with $13 million of cash and the $325 million available on the revolver, we had liquidity of $338 million on September 30.

With our objective of continuing to spend within cash flows, we believe we continue to have very ample liquidity to cover all interest expenses and to execute on our development plans for years to come.

As we announced on October 17, the company entered into an exchange agreement with holders of over $820 million of our unsecured notes, including $556 million aggregate principal amount or nearly 80% of our 2022 notes and approximately $267 million aggregate principal amount or over 53% of our 2025 notes. The agreement provides for the exchange of all these notes held by each of the supporting noteholders for new 9% cash interest and 2% picked senior secured second lien notes due July 2024, and new warrants of the company entitling each holder thereof to purchase one common share of the company subject to the share price condition and a warrant.

Under the terms of the exchange agreement, we are permitted to exchange up to 80% of the 2022 notes and 55% of the 2025 notes. Pro forma for the exchange agreement, our long-term debt should be reduced by approximately $250 million, 80% of the company's debt maturing in 2022 will be extended until July 2024 and our cash interest expense for the notes exchange will be reduced by approximately $14 million through the life of the new notes.

The requisite percentage of the revolving credit facility has approved the exchange agreement that are remained subject to approval by at least the majority of the senior term loan. As of today, a significant amount, but not a majority of senior term loan lenders, have approved the exchange agreement. If at least the majority of the senior term loan lenders do not approve the amendment by November 15, the supporting noteholders may exercise their right to terminate the exchange agreement.

As Brad noted, the company would like to opportunistically work with its debt holders to enhance their credit quality while improving the company's balance sheet. But the company does not need to do any liability management transaction at this time given its ample liquidity and no near term maturities.

Now I'd like to turn the call over to Jay for an operational update.

J. Jay Stratton ***Ultra Petroleum Corp. - COO***

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Thank you, Garland. Calling your attention to Slide 8. With over 4,000 vertical locations within the core of Pinedale, Ultra has a large inventory of locations that is resilient to low prices and provide significant upside with improved pricing. In 2018, average well performance has been strong with activity focused in the core of Pinedale.

During the third quarter of 2018, our operated vertical wells have generated an average IP of 7.4 million cubic feet equivalent per day. Initial results in Q4 have average IPs better than 8 million cubic feet equivalent per day, demonstrating the opportunity to high-grade locations through the inventory and the ability to deliver strong margins even in the challenged price environment.

With ample inventory of high-quality vertical locations, we will continue to execute on a solid group of program as we expand our understanding of the horizontal opportunities. We've included a table of single well economics at the bottom right of the slide. With a high-grade inventory of wells drilled in 2018, we have the drilling wells with close to 4.5 Bcfe EURs on average where returns have been good even with the lower gas prices in the Rockies. Better pricing offers meaningful improvement and returns and expands the economic inventory significantly.

We've also been focused on well cost reductions, accomplishing the 10% reduction this past quarter that focus on vertical only drilling on most pads. We expect that trend to continue for the rest of 2018 and into 2019. In the third quarter, we drilled 3 wells for less than $2.9 million per well. As Brad mentioned, we're focused on driving well cost lower and ultimately look to achieve averages below $3 million per well.

On Slide 9, we have a summary of the horizontal wells the company has drilled so far, including an update for the 3 horizontal wells brought online this quarter. The 3 wells brought online during the third quarter were planned in Q1 and spud during the second quarter. The average IP for the 3 wells was 7.8 million cubic feet equivalent per day. The horizontal data and analytical initiatives we've begun to execute have allowed us to begin connecting specific reservoir performance attributes to the performance of these and earlier wells. The 3 wells brought online were impacted to different extents by reduced rock quality, lower gas saturation in some sections of the laterals and for one well, depletion did offset vertical wells where we drilled the lateral alongside several existing vertical producers. This understanding is being incorporated into our broader evaluation program. Most of our horizontal wells drilled to date that target the Lower Lance intervals. The best wells drilled so far in the A1 zone, 90 feet below the top of the formation. These wells include some of the company's best wells to date. As we've experienced in the last 3 wells, the A1 zone is not immune to variability. However, the average IP of the first 6 wells is 27.3 million cubic feet equivalent per day and the first 4 wells listed on the table were all drilled to the east and their average IP is 37.5 million cubic feet equivalent per day, including the initial condensate yields for 15 to 25 barrels per million cubic foot, illustrating the horizontal opportunity we continue to pursue.

Last quarter, I introduce the company's efforts to improve its understanding of the horizontal potential in Pinedale by describing an integrated approach utilizing the existing data, new data, industry best practices and opportunities for applying innovative technology on Pinedale. Today on Slide 10, I want to provide an update on what we accomplish on this front in 3Q '18, what we plan to do in the fourth quarter for of '18 and then provide a look at for 2019.

The 3 wells we brought online during the quarter were lower performing. We have been able to understand the drivers to that performance and even confirm when we have encountered some of our performing work on a productivity per lateral length basis. We have been able to complete 2 technically independent seismic inversion pilots in the Lower Lance and give us confidence to expand an inversion study to advance our ability to predict productive pay in areas away from well control. We've added strategically chosen advanced prep physical logs that are enriching our understanding of the rock in areas we see the most potential.

In addition, we've been able to more broadly test our completion designs with 3 different fluid systems and understand other performance differences to use of chemical tracers. We will continue to advance our seismic inversion until the fourth quarter and have launched the updates for petrophysical and do geomechanical models. These updated models are being used in the advanced numerical reservoir simulation that's been engaged to tie our updated models with the varied reservoir performance we've seen in the Lower Lance target interval.

In the first half of 2019, we expect to have the initial results of our seismic inversion from a 20 square-mile area, incorporated in the advance earth model and first results from our reservoir simulation work of existing wells. Our focus is on an area where we can deploy our vast understanding into high graded horizontal locations. We also expect to complete up to 3 of our horizontal drilled uncompleted wells and continue the optimization of stimulation designs. Use of other analytical approaches with the existing and new data being acquired is also being contemplated and is expected to add understanding that will be leveraged into the 2019 development program.

Now I'd like to turn the call back over to Brad.

C. Bradley Johnson ***Ultra Petroleum Corp. - Interim CEO & Director***

Thanks, Jay. On Slide 11, you can see our capital plan continues to be driven by disciplined deployment of capital in pursuit of superior returns and increased visibility of cash flow. In the near term, while we further study and refine our models for horizontal potential, we are focusing on our vertical program which can deliver returns greater than 20% even at these depressed gas price realizations. Our inventory is extremely sensitive to small, positive moves in gas prices. And for every $0.20 of improved gas price realization, our unhedged EBITDA increases by approximately $45 million on an annualized basis.

For the rest of 2018, we plan to run 3 operated rigs all drilling vertical wells in the oil field, which we believe will provide consistent and repeatable returns. Full year capital guidance is now a range of $400 million to $415 million. We have focused our rigs on vertical wells for the rest of the year. These vertical locations have an average working interest greater than the horizontal wells we had previously planned for the quarter. So we expect fourth quarter capital to be $60 million to $75 million.

Production forecast adjusted for recent horizontal wells borrowing lane, coupled with volumes removed from deferred horizontals previously scheduled in the fourth quarter, had been adjusted in our updated forecast. As a result, we are tightening the range of production guidance for 2018 to be between 274 and 278 Bcfe. Expense guidance for the year remains on track and is summarized in the lower left part of this slide.

On Slide 12, we have added detailed expense guidance for the fourth quarter as well as an update to adjusted EBITDA for 2019. For EBITDA cash cost, we estimate $1.08 per Mcfe for the fourth quarter with the largest change quarter-to-quarter driven by higher projected production taxes due to improved natural gas pricing. With our hedges in place and updated strip pricing applied to unhedged volumes, we expect price realizations for the year to average $2.86 per Mcfe. Using updated expense from production guidance, we now forecast 2018 EBITDA to be $502 million.

At this time, I would like to thank both Garland Shaw and Garrett Smith for their leadership and hard work as executives serving Ultra Petroleum. Garland joined the company in 2006 and has served an increasing role during the last 12 years, including the role of CFO since 2014. Garrett joined Ultra in 2009 and has led our legal department for the last 9 years, including the role of General Counsel since 2016. I wish both of these gentlemen all the best in their next endeavors.

At this time, we will open the line for questions.

QUESTIONS AND ANSWERS

Operator

(Operator Instructions) Our first question comes from the line of David Epstein of Cowen.

David Michael Epstein ***Cowen and Company, LLC, Research Division - MD and Analyst***

Thanks for commenting on the exchange. Can you say anything else about sort of the odds of getting it done and what you think the term loan guys want? Is it about some fees? Or is it about asset coverage?

C. Bradley Johnson ***Ultra Petroleum Corp. - Interim CEO & Director***

David, thanks for joining. We shared an update in our remarks and we're not in the position to give any more commentary given that pending effort.

David Michael Epstein ***Cowen and Company, LLC, Research Division - MD and Analyst***

Okay. And you guys have -- every sort of quarter, you talk about maintenance CapEx for certain production level on a vertical only program. Any updated thoughts on that?

C. Bradley Johnson ***Ultra Petroleum Corp. - Interim CEO & Director***

Yes, looking forward with updates, our maintenance capital now is around $300 million, including the current cost for wells using 3.1 million per vertical wells. And that would be a maintenance capital program that would, at this time, only include vertical developments.

David Michael Epstein ***Cowen and Company, LLC, Research Division - MD and Analyst***

What sort of production base are you thinking that off of?

C. Bradley Johnson ***Ultra Petroleum Corp. - Interim CEO & Director***

We'll be hanging it off of fourth quarter '18 volumes.

Operator

(Operator Instructions) Our next question comes from the line of Matt Farwell of Imperial Capital.

Matthew Thomas Farwell ***Imperial Capital, LLC, Research Division - MD***

Just an extension on the maintenance capital question. Are you saying, suggesting that well cost should remain in the $3.1 million range for 2019?

C. Bradley Johnson ***Ultra Petroleum Corp. - Interim CEO & Director***

That's what we're using for our maintenance capital estimate at this time, assuming that $3.1 million holds. But as Jay had mentioned, we are extremely focused on reducing that. And our plan is to be below $3 million for 2019. But for now, for the fourth quarter of '18, we're using $3.1 million for our vertical well average. And that's the numbers we're using for coming up with updated maintenance capital estimates.

Matthew Thomas Farwell ***Imperial Capital, LLC, Research Division - MD***

And then you gave some clarification on the IP 24 rates per vertical wells. And they've been moving around. They sort of 7.7, 8.8 and now 7.4. Where -- what kind of number do you bake in for -- in your projection?

C. Bradley Johnson ***Ultra Petroleum Corp. - Interim CEO & Director***

So each one of our locations in Pinedale has a unique EUR that we've assigned. And therefore, each future location has a unique IP expectation tied to that hyperbolic decline curve is finding each well uniquely. When we post 7.4, we considered a very good number. That's right on track with what we've been doing over the last 5 years. We have potentially strong quarter in the second quarter of this year, where we average close to $9 million a day. IP rates are dependent upon where we draw in the field. All of our activity, most of this year and into next year will be in the core. And that core wells bring that consistent strong IP rates. But we do see some range of variability. And our chart that we included in our slide deck, you can see those curves, that's cumulative production. But we usually see 6 million to 8 million a day IP as average for the quarters. And we consider 7.4 a very good outcome for a vertical well performance. Slide 8 in our presentation, captures the summary of our vertical well program.

Matthew Thomas Farwell ***Imperial Capital, LLC, Research Division - MD***

Yes, I see that. And it has -- it had the CapEx range of a tops out at 3.1, which is where you're targeting.

C. Bradley Johnson ***Ultra Petroleum Corp. - Interim CEO & Director***

Correct.

Matthew Thomas Farwell ***Imperial Capital, LLC, Research Division - MD***

Even though it's 3.3 in the quarter.

C. Bradley Johnson ***Ultra Petroleum Corp. - Interim CEO & Director***

Just to add a bit to that. Because we had -- we posted 3.6 in the second quarter for our vertical wells as we were drilling concurrently horizontal wells and vertical wells on the same pads. That was deliberate. That was intentional in our part. That helped facilitate the premature horizontal wells earlier this year using the same pads and the same infrastructure. And that had many advantages to us with respect to execution. What it did bring as a disadvantage is it did stress the CapEx on our vertical program and caused capital to creep up on those wells. We made a big dent in that this past quarter, dropping it down to 3.3 as we ramp back to the vertical program. That didn't start until late July. So it wasn't the full quarter experience for vertical only free focus. So we finished out September, as Jay mentioned, the 3.1. I expect we're planning -- we're holding the teams accountable to drop that down even further. But for now, that's what we're budgeting, 3.1.

J. Jay Stratton ***Ultra Petroleum Corp. - COO***

Matt, this is Jay. I would just add to what Brad said. We're still absorbing those efficiencies from the horizontal program but the team is rapidly pivoting back to their previous efficiency in the vertical program. And as I mentioned, I think, in the comments, we've already seen in the past quarter, in third quarter, 3 wells below $2.9 million. And we have a larger mix of those types of wells in the fourth quarter. So we see an opportunity both for efficiency gains and also some technical gains from some innovation that's still occurring with the team.

Matthew Thomas Farwell ***Imperial Capital, LLC, Research Division - MD***

Are you seeing any inflation on cost to steel and fuel?

Garland R. Shaw ***Ultra Petroleum Corp. - Former Senior VP & CFO***

Steel and feel, we had experienced year-to-date. But both those items have pretty much flattened out at this point.

J. Jay Stratton ***Ultra Petroleum Corp. - COO***

Yes, that's true. When we have troubles, sometimes we'll incur higher cost for loss fluid, because we drill with oil based fluids. But by and large, the fuel costs for the drilling of the wells has remained fairly stable.

Matthew Thomas Farwell ***Imperial Capital, LLC, Research Division - MD***

That's helpful. And then one last question. If you could just comment on the improvement in differentials and what your outlook is?

Garland R. Shaw ***Ultra Petroleum Corp. - Former Senior VP & CFO***

Yes, this is Garland. We did see improved differentials recently. They've been moving in the right direction for some time. Back in October, there was a pipeline explosion in Canada that had very positive benefit on the differentials, and we continue to see that hang in. It's hard to say where things are going to go near term. We do continue to think differentials -- continue to improve into 2019 as we see pipes build taking gas from the Permian to the Gulf Coast and where gas going from the Permian to Mexico. So overall, we're still thinking that we return to more of a normalized differential long-term.

Operator

And I'm showing no further questions. At this time, I'd like to hand the call back to Brad Johnson for any closing remarks.

C. Bradley Johnson ***Ultra Petroleum Corp. - Interim CEO & Director***

Thank you. This concludes our third quarter conference call. I wish to thank everybody for joining us this morning. Goodbye.

Operator

Ladies and gentlemen, thank you for participating in today's conference. That does conclude today's program. You may all disconnect. Everyone, have a great day.