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PRESENTATION

Operator

Good day, everyone, and welcome to the Ultra Petroleum Corp Third Quarter 2017 Earnings Conference Call. (Operator Instructions) Please note, this call is being recorded. It's now my pleasure to turn the conference over to Sandi Kraemer. Please go ahead.

Sandra D. Kraemer - *Ultra Petroleum Corp. - Director of IR & External Reporting*

Thanks, operator. I'd like to point out that many other comments during this conference call are forward-looking statements that involve risks and uncertainties affecting outcomes, many of which are beyond our control and are discussed in more detail in the risk factors and forward-looking statements 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 on our website.

Now I'll turn the call over to Mike.

Michael D. Watford - *Ultra Petroleum Corp. - Chairman of the Board, CEO and President*

Thanks, Sandi. And thanks for all of you joining us today by phone. With me today is Garland Shaw, our Chief Financial Officer; and Brad Johnson, our Senior VP of Operations.

We're going to conduct today's call little differently than we have in the recent past, we'll provide you some detail on third quarter results, it's been the vast majority of the call affirming the quality of our asset, our inventory, our returns and our low costs. These 6 months since emerging from our in-court restructuring, have been more difficult than we foresaw, spinning back up our operations, continuing to deal with ongoing issues from a contested bankruptcy proceeding and moving from the courtroom back to profitable growth mode. This has been a transition time for us, and we have not done all things well. We have been uneven and our messaging with a lack of clarity at times. Today's conversation should go a long way towards clearing up any misunderstandings in the market, but the quality of our business and some new and exciting growth prospects related to horizontal well and potential.

I'd like to now briefly address our third quarter results and then spend the remainder of the call discussing the investor deck, we released this morning that we will be referring to during the call. We expect production for the full year 2017 to be slightly below guidance and come in between 276 Bcfe to 278 Bcfe. As I will explain, this reduction is due to issues caused by recent bankruptcy and third parties.

I'll provide some details now, we would like to emphasize my belief that most are one-time and non-recurring and fully isolated from overall inventory quality. First, a bit of important perspective regarding 2017. In Wyoming due to weather and regulation we are limited to building our drilling pads during the summer and fall after receiving a requisite approvals. During the summer of 2016, and with the company battling a contested bankruptcy proceedings, we were unable to properly prep enough pads to optimize our ramp up from 2 rigs to 8 rigs in 2017.

This meant that our 2017 drilling program led to some rigs being placed on legacy pads that were located in sub-optimal yet still economic areas along the eastern flank of our field. This will not be the case during our 2018 to 2019 drilling program, which is in some of the most attractive areas in Pinedale. We had additional issues impact our 2017 program, including the delayed arrival rigs and a failure to [higher stretch goal] of 98% field run time compared to our historic average of 95%.

Lastly, we didn't get any help from our partners as we had less [non] completions in Pinedale's. We had shut-ins in the Marcellus and issues with the enterprise gathering system in Pinedale.

Stepping back, we are still going to grow production in 2017 by 17% from the first quarter through the fourth quarter, while generating at least through the first 9 months, and through the full year positive EBITDA less CapEx through first 9 months cash flow is equal to CapEx, now we'll get a little CapEx, we would see that a bit in the fourth quarter.

Well, no one is happy, no one here is happy, coming up [light on] guidance. We are in a very strong position, now whether handicaps from bankruptcy behind us and we couldn't be more excited for everything happening at the company. We remained confident in our ability to grow production 20% in 2018, while living within free cash flow using a 100% vertical program, and we are extremely excited about our much recent horizontal well that is currently flowing at 21 million cubic feet a day, and is still increasing and it has a 10% oil cut. We believe this well is indicative of horizontal potential in the field, which could result in potentially 16 new horizontal wells, they are incremental to our vertical well inventory.

That said, we are not providing 2018 guidance at this time, as we continue to refine our view on 2 topics. First, potential moderation of growth to provide more balance between free cash flow and production/EBITDA growth. And the second, the impact of horizontals. There's worth noting that given the recent successful horizontal well result, we may even be able to grow at the same rates, but with more free cash flow generation. Switching gears, as I mentioned we'll now spend the rest of the presentation walking you through our Investor deck posted this morning.

So let's get started, I'm going to turn to slide 4, pausing just a second for it to come up on the webcast. Let me start with slide 4, and reinforce the message that we are a Tier 1 natural gas producer. We have an extensive multi-year inventory with attractive returns, and we want to provide much more clarity on that today. We delivered 70% EBITDA margins in the third quarter 2017 with low cash operating costs. Beyond our deep vertical inventory of natural gas locations, we have a significant resource expansion opportunity with horizontal wells drilled around the edges of the field. Not a cannibalization of existing vertical wells, but true resource and net asset value expansion with exceptional returns. Our Wyoming production is located in a part of the country with excess pipeline capacity, and we have no firm transportation costs. We have multiple pads of long-term growth and are sensitive to growth rates combined with free cash flow generation. And we are moving forward with the marketing of our non-core assets.

Since I've already discussed slide 5, let me turn to Brad and have him talk about several other slides.

C. Bradley Johnson - *Ultra Petroleum Corp. - SVP of Operations*

Thanks, Mike. On slide #6, Pinedale Drilling Progression, we show our activity in 2017, as well as they look ahead for the activity planned over the next 2 years. In 2017, the activity has been primarily on the east flank of the field. The activity in this area was not the result of high grading our inventory. Instead, we placed new rigs as part of our ramp up on pads that were available. Normally, we plan and construct pads up to a year before we drill them. However, due to the uncertainty surrounding our in-court restructuring, some of that predrill effort was on hold. We began our 4 to

8 rig ramp up earlier this year, rigs were deployed mostly to the east flank. And while the east flank typically delivers lower IP's and lower EUR's than average, we do experience higher condensate yields. Year-to-date liquid yields on new wells have averaged 12 barrels per million, [50%] greater than the field average. This increases in condensate provides meaningful boost to returns. Over the next 2 years, drilling rigs will move west toward the core and we expect vertical well performance to improve. We will preserve flexibility to continue east flank horizontal drilling should we decide to [drill] more tests in 2018, and we will continue to be return focused not IP focused.

On slide 7, we have summarized our inventory of vertical wells in Pinedale. Of the 4,900 future locations identified in our third-party reserve report, 1,900 of these 10-acre locations -- 1,900 of these locations are 10-acre and 3,000 locations are 5-acre wells. Our current development plan schedules the 10-acre wells to be drilled first, then a return to pad to develop the 5-acre wells. As a result of this sequence, 5-acre wells will cost less than 10-acre wells, because they will be drilled with preexisting infrastructure, including service pads and production equipment. We also anticipate the 5-acre wells will have a reduced completion scope. The combined cost savings is expected to be $300,000 per well. And at current commodity prices, we estimate nearly [1,100] wells have a return of 25% and another close to 500 wells with returns between 20% and 25%.

The next slide, slide #8 titled Pinedale Vertical Well Performance, provides a cumulative production for all the wells we drilled since 2010. Each curve represents an average of the first 12 months of production from wells drilled in that year. Some years exhibit performance above the 4 Bcfe type curve shown on the black dash line, some are below, and a couple of years essentially [paint] that type curve shown here. The main driver in a range of outcomes is the part of the field we happen to be developing in any given year. In 2014, the highest curve on this plot, we were drilling a significant amount of wells in the central and southern core of the field. In 2011, the lowest curve on this plot, performance was weighed down by activity on the flanks of (inaudible) area and also the drilling of some 5-acre wells. Earlier this year and going back to fourth quarter of '16, our development was concentrated on the east flank of Pinedale.

Now, let's consider the data from 2011 to 2014 on this plot. If one was reviewing this data 3 years ago, it would not have been appropriate to conclude that our inventory is dramatically improving by 30% by extrapolating the trend using wells from 2011 up to 2014. And likewise, the opposite headline of the grading inventory should not be supported by only analyzing data from 2014 to 2017. It [bodes] down to the area of activity in any given time frame. And as we showed on the previous slide, we plan for the rigs to move west toward the core in 2018 and expect performance to trend back to the average.

Onto the next slide, which is titled Most Accurate IRR's Derived from Actual Producing Days, slide #9. There is a significant amount of information on this slide, but I want to start with the main point. To get an accurate return realized in Pinedale and to obtain a better type curve of individual wells, one should account for actual producing days when using monthly data. In Wyoming, operators provide actual producing days to the state, and this data is available to all. Wells rarely start production on the first day of the month, thus dividing the monthly data by actual producing days yields a better estimate of the early performance. On this slide, we have termed the simple calculation PDR or producing day rate, and the data is plotted with red circles on the rate time plot to the left. We have also provided a math for the first month in the footnote. The blue squares on this plot are the monthly data divided by the calendar days of each month. We have termed this the CDR or calendar day rate. The disparity between the CDR and PDR data for the first month can lead to different type curve interpretations. The curve fit corresponding to the CDR data is the blue dash line. This line is labeled with a b-factor of 1.1 and a return of 28%. Contrast this curve fit to the one with red dash lines labeled PDR. Note that the different shape of the PDR fit accounts for the first month production more accurately. This PDR curve fit has a b-factor of 1.6 and the return of this curve calculates to 45%, that is a significant difference in returns. We have also plotted the daily data with a small black line in the left chart for reference. Note that this well has a max day IP of 8 million a day and that the daily data tracks the monthly data beginning with month 2. However, contrast the max day IP to the first month average that is associated with the PDR curve fit, which is 6.7 million a day, and also contrast it to the 4.6 million a day associated with the CDR curve fit. All of this data is accurate and correct, but the disparity in the first month occurs due to a result of binning the data by months versus by day, and this disparity can lead to type curve fits that have downward bias relative to a curve fitting of the daily data. This example is for a single well, but the disparity will also occur when aggregating and normalizing data for groups of wells, either by area, by [vintage] or by any other defined subset.

For wells in Pinedale and for all wells in Wyoming producing days are readily available to all. And so anyone who's pulling monthly data from Wyoming can also download the actual producing days. Then simple math provides for a PDR data set that can be used on single well curve fits as well as building type curves by aggregating and normalizing groups of wells. So why are we spending so much time on this concept. To validate our type curves, to validated our returns and to provide a solution for those using type curves that have inherent downward bias toward early performance.

Onto the next slide, slide 10, we show a summary of economics for our vertical wells that include an updated framework for single well economics in Pinedale. There are a few key items on this slide I'd like to point out. For gas prices, we are using a Henry Hub benchmark, including a 10% differential to a pound, and a sales BTU factor of 1.065. For total LOE, we are modeling $3,000 per well per month, and this includes all OpEx incurred at the asset level. And for CapEx, we've included a $300,000 savings per well on 5-acre locations. On the right side of this slide, we have provided sensitivities to well costs, EUR, gas price and a new sensitivity to condensate yield.

At this time, Mike is going to talk about growth potential of our vertical development in Pinedale.

Michael D. Watford - *Ultra Petroleum Corp. - Chairman of the Board, CEO and President*

Thanks, Brad. So we're going to skip all the way over to slide 15 in the deck. It's entitled 2018 Preliminary Growth Considerations. We -- it's a table constructed to show various production growth rates with associated EBITDA, CapEx and free cash flow, the growth rates are tied to a vertical well development program only, no horizontal program is considered in this table. We've constructed a table showing 15% to 21% growth rates at various Henry Hub natural gas prices, and you can see the CapEx with each growth percentage and our EBITDA and associated free cash flow. So we have many options to consider as we go forward, we just want to give you a sense of what the various alternatives are [forced] now before we consider adding in the significant benefits of the horizontal program. Again, I want to reiterate that we can grow production to 20% in 2018 within cash flow, if we choose to, given the apparent success of our most recent horizontal well, we have more option to consider. And we just have a mixture here of how we go forward.

With that I'm going to pause and pass it back to Brad to provide more clarity why on this call on the second quarter we decided to share with you our reallocation of 4% of our 2017 capital budget to drill a handful of horizontal wells.

C. Bradley Johnson - *Ultra Petroleum Corp. - SVP of Operations*

Thanks, Mike. So last quarter we shared plans to drill up to 3 horizontal well by the end of this year. I will show more about our current activity on moment. But first, let's go to slide 16, horizontal program potential, where we provide a summary of the potential we see based on recent results in ongoing study by our technical teams. The top of this slide we provide potential economics of a horizontal well in Pinedale. Inputs on the left include actual data from analogous wells. The result shown at the right are compelling with a potential for 70% returns F&D costs approaching $0.50, and a recycle ratio over 4x, at the bottom of the page, we have updated the potential resource that currently includes 1,600 potential locations around the flanks of Pinedale. We have also estimated that these locations would translate to 700 net locations to Ultra and that resource potential range of 19 Tcfe to 48 Tcfe, and the potential of each well having an NPV10 value of nearly $13 million each.

Of course, these numbers are unrest and are based on preliminary estimates, however, staggering potential does deserve additional study and investment.

On slide 17, we illustrate the concept of drilling horizontal flank wells from preexisting pads used for vertical wells. Additionally this horizontal program does not require incremental infrastructure to test and develop. We are doing this very operation on the Warbonnet 9-24 pad, right now. And did the same on our first horizontal well last year. The structure map on the right shows the horizontal locations relative to the core of the field. All of these locations, (inaudible) flank are additive to our vertical well inventory in any success we provide incremental net resource to the company.

Slide 18, illustrates the potential prospect laterals and multiple laterals to assume. At this time we have identified 8 target zones, 2 zones have been tested and produced, we are currently drilling towards a third target and the following well is set to test a second lateral in the same zone as our first well in this program. On the previous slide, our sticks on a map effort resulted in 50 drilling units, each having a pad location, they can be used for flank horizontal testing. With 8 target zones identified at this time and the 4 lateral zones per zone, we are currently estimating 1,600 gross locations.

On the next slide, slide number 19, we have a map of the horizontal activity in Pinedale. And on the east flank of Jonah Field. I'm going to spend a few minutes on this slide talking to the map and providing relevant information on these wells. I will be siting additional stats too many to post on this slide, so you will be able to find this additional information in a data table, they resides in our updated investor presentation posted to our company's website. So with the map on slide 19, let's start with the southernmost well, and we will work our way around the map in a clockwise fashion. First Jonah Energy's Antelope 91-29H well, this well first produced in January of 2014, a lot of what was landed in the Lower Lance A, and we estimate it's effective laterally to be 3,800 feet, this was started off slow with an IP of 3 million a day. This well also had a nearly 11 month period of production before reaching peak rate and then going on low decline. Despite a slow start and a relatively short lateral, this well is strong within EUR of nearly 11 Bcfe, this well was the first east flank extension of the Jonah Field, where historical vertical development was limited by economic constraints. This well also has a 30 barrel per million condensate yield, that translates to production being 15% oil in our neck of the words that is liquids rich. The next well, another one by Jonah Energy is the Antelope 341-19H, another successful test for these flank of Jonah Field, this will begin producing earlier this year and an impressive IP of over 12 million cubic feet equivalent per day including a condensate rate of 200 barrels per day. We estimate the effect of lateral length of this well to be 5,460 feet. We have estimated EUR to be 12 Bcfe based on 7 months of production, which yields the normalized recovery of 2.2 Bcfe/1000' of lateral. A third party recently published in EUR of 18 Bcfe for this well in a normalized that equates to 3.3 Bcfe/1000'.

Moving up to the Northern most well in this ma, you will see Ultra's first horizontal well in Pinedale (inaudible) from the Boulder 10-33 pad. We drill this well in 2016 and landed in the Lower Lance B, with an effective lateral length of 5,200 feet, total cost for this well was $5.8 million. Similar to the first well on these flank of Jonah Field, this well exhibited a low IP, low decline but a high condensate yield. After several months of producing we entered the well and set a plug that isolated the lower half of the lateral, from that test we determine that 70% of the production is coming from just 40% of that lateral. We believe that the completion of the (inaudible) was not effective, and we have implement and changes for subsequent wells. Using the data from the isolation tests, the well exhibits a normalized recovery of 1.2 Bcfe/1000.

Now let's move Southeast from this well, it brings us to the set of 3 horizontal wells in the Warbonnet 9-24 pad, this is a location of our 2017 horizontal program. Our first well, the A-1H target the Lower lance A, we successfully drilled and completed a 2-mile lateral, the frac consisted of 49 stages and the total cost is estimated at $9 million. We started flowback on this well on November 1, the well is currently producing 21 million cubic feet equivalent per day, which includes the condensate rate of 339 barrels per day. We continue to manage that show supported by a rigorous analysis of flowback parameters. I'm predicting max rate by the end of this month and we look forward to sharing that information soon. Obviously, we're extremely pleased with the result so far. Concurrent with the flowback of this well, we are drilling the intermediate section of our second horizontal well for this years program the M-1H, this well was planned for a 2-mile lateral in the Mesaverde formation. This lateral [restacked] directly below the M-1H 2,500 feet deeper. This well will take a little longer and probably cost a bit more, but it is targeting some of the most prolific sands that we typically encounter with a vertical development in this area.

The well should be drilled and completed by the end of the year with flowback occurring in January. And the last of those 3 well set, the A-2H will be spud by the end of this year and we'll target the same Lower Lance A -- target the same Lower Lance A in a row as the A-1H. The well will be landed 2,600 feet to the north and drill do east into the flank. So in addition to testing stacked [intervals] our program is also testing multiple laterals in the same zone.

Now, Garland is going to summarize our third quarter financial results.

Garland R. Shaw - *Ultra Petroleum Corp. - CFO and SVP*

Thank you, Brad. Moving onto slide 23, for the quarter production, revenues and EBITDA were higher than the second quarter in the previous year third quarter, as we showed you earlier, our overall production for the quarter was 71.1 Bcfe, which is a 5.9% improvement over the second quarter of this year and 2.5% higher than the third quarter of 2016. EBITDA of $153 million was up 16% compared to last year, we were negatively impacted by the judgment in bankruptcy court that determine we were liable for nearly $400 million related to amounts claimed by certain creditors for (inaudible) post petition interest. We had placed this full amount in a reserve account back in April. So we will have no incremental cash payments as a result of the judgment, which we have now taken the necessary steps to appeal. However, because of the judgment, we recorded $224 million of reorganization costs and $175 million of out-of-period interest expense. These additional cost items caused a net GAAP loss for the quarter of $328 million. Adjusted net income was $79 million. The average realized natural gas price of $2.87 per Mcf, including the effect of hedges was $0.25 per Mcf higher than in the third quarter of 2016. For the quarter, we had 50 Bcf or 74% of our gas production hedged at $3.34 per Mcf. The effect of the hedges in the quarter was a [13%] increase in our realized price. The third quarter of 2017 overall corporate price differential, when comparing average realized per Mcf prices without hedges to the first of month Henry Hub prices was $0.25 or 8% of Henry Hub as compared to 7% in the third quarter of 2016. We have remaining fixed price natural gas swaps in place for 17 Bcf for October of this year at $3.34 per Mcf. For 2018, so far we have hedged 27.5 Bcf using swaps and [collars] at an averaged floor price of $2.99 per MMBtu or $3.19 per Mcf. The average realized oil price for the quarter was $45.86 per barrel, which was $4.31 per barrel higher than for the same period last year. Our average differential for the quarter to WTI pricing was $2.28 per barrel or 5% of WTI, which is the improvement compared to the 8% differential for the same period last year. We were successful in increasing our liquidity during the quarter to just over $400 million through the issuance of $175 million in additional term loans at favorable terms and with an increase in commitments to our revolving credit facility by our bank group. We used the term loan proceeds to repay outstanding amounts on the revolver. We ended the quarter having funded debt of $2.2 billion with $20 million drawn on our $425 million revolving credit facility.

I'll turn the call back to Mike now for additional comments.

Michael D. Watford - *Ultra Petroleum Corp. - Chairman of the Board, CEO and President*

Thanks, Garland. So let me just quickly try to summarize what we've shared today. We believe we are a Tier 1 natural gas producer with extensive, attractive and predictable inventory. We've discussed our historical EUR's and future inventory, why we are drilling, where we are, and where we are headed in the upcoming years. We shared the results of using Wyoming State production data correctly and the impact on rate of return and EUR's. We enjoy low cost and high margins that were improved through the reorganization process, and we have no firm transportation costs. We have an exciting resource expansion opportunity with exceptional returns. Early identification of 1,600 gross horizontal well locations on the flanks of Pinedale is significant and material. With a preliminary estimate of NPV 10 at $12.8 million per location and a recycle ratio of 4.6x, the value creation is quite notable. And we are focused on balancing free cash flow generation with growth.

With that, we'll pause and ask the operator to open it up for any Q&A.

QUESTIONS AND ANSWERS

Operator

(Operator Instructions) And we'll take our first question from Mike Scialla with Stifel. Please go ahead.

Michael Stephen Scialla - *Stifel, Nicolaus & Company, Incorporated, Research Division - MD*

Mike, looking at your slide 16, the horizontal potential economics, if you do get comfortable with those numbers, say they look like they're accurate, would it be safe to assume that horizontal program is going to replace some of the vertical program for 2018 or to assume your [rig] ordering things on an IRR basis, those look like potentially better economics with the horizontals?

Michael D. Watford - *Ultra Petroleum Corp. - Chairman of the Board, CEO and President*

Yes. We certainly -- we're going to drill some more horizontal wells in 2018 without a doubt. We -- the way the planning was done for these first 3 was to first to test the Lower Lance A, which we've seen success down 6 miles south of us by the Jonah Energy folks, which would appear as we have a successful test. And then secondly to test the deeper Mesaverde zone, 2,500 feet beneath this one on the same pad to see if we can have another success. It is deeper, more expensive, but it is more overpressured and Brad can share the details about if you want to know. And then assuming we have success or not that we're going to drill another Lower Lance A well of the same pad, just to show the predictability of this as we go forward. So once we get all 3 of those drilled and completed, which will be probably late January, early February of next year, have some production time, we certainly want to wrap those results into what we do going forward, and we're going to have a different thought process as do we drill the wells based on full production and cash flow or do we continue do some more science and drill upper Lance wells and middle Lance wells and et cetera, and Brad can talk more about that, but we've got some decisions to make -- middle Lance and upper Lance, I'm sorry.

Michael Stephen Scialla - *Stifel, Nicolaus & Company, Incorporated, Research Division - MD*

Yes. Maybe a follow-up on that. Brad, how do you handicap those different zones you've got -- and I guess, what are the risks that you see with each?

C. Bradley Johnson - *Ultra Petroleum Corp. - SVP of Operations*

Sure. I mean, in the stack column of over 5,000 feet in the traditional Pinedale vertical development, there is a range of reservoir quality. We've identified 8 target so far that we think could be commercial. But for the moment, we are prioritizing targets based on quality. So the Lower Lance A, the Mesaverde are favorite 2 for the moment. When you talk about risk, the sands are there, they diminish somewhat, so the risk as we go off a flank is how much of the reservoir quality is preserved and how many sands we can connect with a horizontal well.

Michael Stephen Scialla - *Stifel, Nicolaus & Company, Incorporated, Research Division - MD*

And then with that first Warbonnet well, are you seeing any water production with that at all?

C. Bradley Johnson - *Ultra Petroleum Corp. - SVP of Operations*

Well. We've only -- we've recovered less than 10% of our low recovery, so we are making water, but it is frac water. So it will be some time before we get beyond recovering the frac load and then moving into a period of time where we know what sort of water production is coming from the reservoir. Just as a reminder, we are on day 7 of the flowback and less than 10% of low has been recovered.

Operator

We'll take the next question from Marshall Carver with Heikkinen Advisors. Please go ahead.

Marshall Hampton Carver - *Heikkinen Energy Advisors, LLC - Founding Partner and Director of Research*

Yes. Thank you. And congrats on the first well. And I think the presentation was very helpful this morning. A question on -- Mike, actually he asked my first question around what you could do in 2018? I guess, could you just give us a ballpark numbers on how many wells you could possibly drill in '18, on horizontal wells or how slow or how fast could you take the program?

Michael D. Watford - *Ultra Petroleum Corp. - Chairman of the Board, CEO and President*

You have to remember that we just have one well on for less than a week more or less. So we need to get the second well on, we need the third well on, so I don't think we'd be in a position to want to push and accelerate it very hard, until we -- you get into the February, March of next year to where you have these wells produce for handful of months and see what that production curve looks like. But first well took us 25, 30 days to drill. This well is going to take us longer to deeper, overpressured, if you just took one of your rigs, the rig line and drill horizontal wells, then you'd get 8 to 9 wells per year, maybe 10.

Marshall Hampton Carver - *Heikkinen Energy Advisors, LLC - Founding Partner and Director of Research*

And on the third party downtime for the fourth quarter, do you have any feel for how much that impacted production, like how many Bcf or [do you know] how long the downtime is going to last?

C. Bradley Johnson - *Ultra Petroleum Corp. - SVP of Operations*

Yes. This is Brad. So the third-party related to our gathering system, we see a Bcf of impact for the second half of the year and those issues began on August 30. They were small, but chronic, and they continued in September and October. They have been addressed and essentially resolved and that impact has subsided, but from a gathering system it was 1 Bcf.

Michael D. Watford - *Ultra Petroleum Corp. - Chairman of the Board, CEO and President*

The power issue with enterprise -- recurring.

C. Bradley Johnson - *Ultra Petroleum Corp. - SVP of Operations*

And so we saw line pressures go up a bit.

Marshall Hampton Carver - *Heikkinen Energy Advisors, LLC - Founding Partner and Director of Research*

About a Bcf to the second half of the year or a Bcf to the fourth quarter?

C. Bradley Johnson - *Ultra Petroleum Corp. - SVP of Operations*

Second half of the year, essentially equally split between third and fourth and even more specifically, September, October.

Michael Stephen Scialla - *Stifel, Nicolaus & Company, Incorporated, Research Division - MD*

Okay.

C. Bradley Johnson - *Ultra Petroleum Corp. - SVP of Operations*

[Straddling] the quarter.

Operator

(Operator Instructions) We can go next to David Epstein with Cowen. Please go ahead.

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

So did you say the 4 Bcfe related to the base production run time was you thinking you could get run time up to 98% versus a historical 95%. Did I hear that correctly and have you sort of, I guess, completely abandoned that or what happened?

C. Bradley Johnson - *Ultra Petroleum Corp. - SVP of Operations*

Yes. We have abandoned that, but that's exactly what we said.

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

So I guess, obviously, it hurts your production base a little bit versus previous expectations. I guess, some of the other items are onetime in nature, is sort of a reversal on some of those other issues like the non-op issue and the third-party gathering, is that sort of contributing to the 20% growth in 2018?

C. Bradley Johnson - *Ultra Petroleum Corp. - SVP of Operations*

Would you ask that again please?

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

Yes. I guess, previously you guys had been expecting -- I know they're sort of broad stroke numbers, but you had been expecting 20% production growth in 2018, living within cash flows off of 2017, I think. So it sounds like you're still on that ballpark of 20% growth for 2018, but I'm wondering why it's not again, maybe a little lift from the reversal of some of these onetime issues?

C. Bradley Johnson - *Ultra Petroleum Corp. - SVP of Operations*

Well. Let's just say we're hope to under promise and over deliver of that.

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

And one more if I could. On the Warbonnet 9-23-A, is it -- I guess, it's premature to guess what the EUR is or maybe it was in the presentation, I didn't see it?

C. Bradley Johnson - *Ultra Petroleum Corp. - SVP of Operations*

I don't think we have any EUR on 7 days of production.

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

That's fair enough. Is the $9 million D&C is that what you would expect for the long term or once you sort of get out of experimentation mode, does that come down at all?

C. Bradley Johnson - *Ultra Petroleum Corp. - SVP of Operations*

We expect those cost to come down over time.

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

And if I could just sneak in one more quick one, is there any -- relative to the Jonah wells, is there like a difference in how quickly these wells cleanup?

C. Bradley Johnson - *Ultra Petroleum Corp. - SVP of Operations*

I can comment on the cleanup. The first well that they drilled, it took a significant amount of time. We're not -- they don't have all the detailed data, but just looking at the monthly production, you can see that first well took 11 months to reach peak rate. The second well that I cited earlier, it reached IP much sooner, but I don't know the details of their flowback on that well.

Garland R. Shaw - *Ultra Petroleum Corp. - CFO and SVP*

Let me -- I do want to make one point. I don't think Brad shared this as he went clockwise around with the discussion of the handful of horizontal wells here is that the successful wells down in East Jonah Field, South Pinedale Field that are drilled by the Jonah Energy folks, if you look at where they're located, relative to where we just drilled this successful well, there is at least 6 miles between the two and then if you carry on to the north of the first well we drilled, they had some problems that we've discussed that's why we want another 5 or 6 miles. So the distance here we're covering already in terms of testing whether this concept is going to work and the economic is pretty, pretty significant pretty fast.

Operator

We'll take our next question from Rina Joshi, PointState Capital.

Rina Joshi

Thanks, guys. I thought the incremental disclosure in today's presentation was very helpful, and I wanted to spend a little more time on the potential horizontal economics that you outlined on slide 16. My first question is on the IP, from what it looks like you estimate an IP in your potential go-forward economics of roughly 11 million cubic feet a day versus the well that came on at closer to 22. Is there anything different with the Warbonnet well or are you just trying to build in some conservatism?

Michael D. Watford - *Ultra Petroleum Corp. - Chairman of the Board, CEO and President*

Sure. To be frank, we built these economics last week prior to the IP of our well, so we wanted to anchor the economics here, based on actual data observed by other wells. So we used the IP of 11 million a day from the Antelope well, certainly double the IP rate of our well. We would recalculate and come up with significantly better economics with much higher returns.

Rina Joshi

And then just to ask a little bit further on the well cost, I think this one came in at 9, in the past you would thought maybe you could get down as low as 6, based on your experience up till now, any thoughts on where that might come down to?

Garland R. Shaw - *Ultra Petroleum Corp. - CFO and SVP*

We do expect it to come down and our expectation is it will come down with each well we drill. This first well we did have some challenges, we had some flat spots on the day [dip] curve that we were focusing on and trying to improve. I think we can reduce our time 10% or 20%, and I see a couple of million dollars being shaved off of this cost as we go forward.

Operator

And it appears we have no further questions at this time. I will turn the floor to our speakers for additional or closing comments.

Michael D. Watford *- Ultra Petroleum Corp. - Chairman of the Board, CEO and President*

Well, we thank you all for spending time with us today. If you have any other questions, please don't hesitate to reach out to us soon. Thank you very much.

Operator

This will conclude today's program. Thanks for your participation. You may now disconnect. Have a great day.