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QEP - Q3 2012 QEP Resources, Inc. Earnings Conference Call

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OVERVIEW:

QEP reported 3Q12 net loss of $3m.

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CORPORATE PARTICIPANTS

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PRESENTATION

Operator

Good morning. My name is Keisha, and I will be your conference operator today. At this time, I would like to welcome everyone to the QEP Resources third-quarter earnings conference call. After the speakers' remarks there will be a question-and-answer session and instructions will be given at that time. As a reminder today's conference is being recorded for replay purposes.

I would now like to turn the conference over to Mr. Richard Doleshek, Executive Vice President and Chief Financial Officer. Sir, you may begin your conference.

Richard Doleshek - *QEP Resources, Inc. - EVP, CFO*

Thank you, Keisha, and good morning, everyone. Thank you for joining us for our third-quarter 2012 results conference call today. With me are Chuck Stanley, Chairman, President and Chief Executive Officer; Jay Neese, Executive Vice President and Head of our E&P business; Perry Richards, Senior Vice President and Head of our Midstream business; and Greg Benson, Director of Investor Relations.

In today's conference call, we will use a non-GAAP measure EBITDA, which is referred to as adjusted EBITDA in our earnings release and SEC filings and it was reconciled to net income in the earnings release in the SEC filings.

In addition, we will be making numerous forward-looking statements. We remind everyone that our actual results could differ materially from our forward-looking statements for a variety of reasons, many of which are beyond our control. We refer everyone to our more robust forward-looking statement disclaimer and discussion of the risks facing our business in our earnings release and our SEC filings.

We were quite busy in the third quarter with our North Dakota-acquisition-related financing, and although our balance sheet reflects the transaction, because we closed the purchase at the end of September, the acquisition had no impact on our third-quarter income statement or operating results.

In terms of reporting our results, we filed our Form 10-Q with the SEC yesterday and we issued a combined operations update and earnings release in which (technical difficulty)

Operator

Excuse me. This is the operator. Can you hear me? If you can hear me, please respond. If your line is on mute, please un-mute. Hello? This is the operator. Can you hear me?

Richard Doleshek - *QEP Resources, Inc. - EVP, CFO*

-- result the entire change in the mark-to-market value of our derivatives portfolio run through our income statement instead of through other comprehensive income.

In addition, the impact of subtle derivative contracts is no longer included in the revenue section of the income statement, but is now reported below the operating income line.

We also rebucketed our revenue streams such that we now report the NGL revenues for our Midstream business together with the NGL revenues from our E&P business.

And finally, recall that in the fourth quarter of 2011, we changed the presentation of transportation expenses. Historically we had netted transportation expenses against revenues. We are now reporting these expenses in a separate line item in the operating expense section of the income statement, and have recast historical revenue and product price data to reflect this change in presentation, and will be happy to provide additional information about the changes in how we report our financial results during Q&A.

Turning to our financial results and comparing the third quarter of 2012 to the second quarter of 2012, the story was marginally weaker financial performance at both QEP Energy, our E&P business, and at QEP Field Services, our gathering and processing business. QEP Energy reported record equivalent production of 81.5 Bcfe, up two Bcfe from the second quarter this year, and net equivalent price realizations that were essentially flat with the second quarter, the aggregate impact of which was offset by higher expenses.

Field Services' third-quarter results were lower than in the previous quarter, primarily due to lower NGL volumes and prices.

Our third-quarter EBITDA was $328.7 million, which was $10 million or 3% lower than in the second quarter of 2012, and down $25 million from the third quarter of 2011. QEP energy contributed $263 million or 80% of our aggregate third-quarter EBITDA and Field Services contributed $68 million or about 20%.

QEP Energy's EBITDA was down about $3 million, while Field Services' EBITDA was down about $3.5 million from the second quarter of 2012. Factors driving our third-quarter EBITDA included QEP Energy's production, which was 81.5 Bcfe in the quarter, two Bcf higher than the 79.6 Bcfe reported in the second quarter of 2012. The quarter's production was 15% higher than the 70.7 Bcfe produced in the third quarter of 2011.

Of note, oil and NGL volumes accounted for 21% of our equivalent production. Oil volumes were 1.44 million barrels, up 10% from the second quarter, and NGL volumes were 1.39 million barrels, up 7% from the second quarter of 2012. Combined oil and NGL volumes were 2.8 million barrels in the quarter, up 56% from the 1.8 million barrels of combined volumes in the third quarter of 2011.

The Northern region production was up 16% from the second quarter of 2012, driven by gas and NGL volume growth at Pinedale in the Uinta Basin and oil production increases in the Williston Basin. Southern region production was down 9% from the second quarter to the third quarter, driven by a 10% decline in our Haynesville production and a 15% decline in NGL production in our Midcontinent region. As a result, for the first time since the spin, our southern region contributed less than half of our equivalent production.

QEP Energy's net realized equivalent price, which includes a settlement of all of our commodity derivatives, averaged $5.14 per Mcfe in the quarter, which was one penny higher than the $5.13 per Mcfe realized in the second quarter of 2012 and $0.44 lower than the $5.58 per Mcfe realized in the third quarter of 2011.

The lower equivalent price reflects field level prices that were $2.64 per Mcf or 22% higher than in the second quarter of 2012, but NGL prices that were $27.83 a barrel or 21% lower than in the second quarter. Field level crude oil prices were down slightly from the second quarter at $81.60 a barrel.

QEP Energy's commodity derivatives portfolio contributed $92 million of EBITDA in the quarter compared to $117 million in the second quarter of 2012 and only $45 million in the third quarter of 2011. The derivatives portfolio added $1.13 per Mcfe to QEP Energy's net realized price in the third quarter compared to $1.47 in the second quarter and $0.63 in the third quarter of 2011.

QEP Energy's combined lease operating transportation and production tax expenses were $125 million in the quarter, up from $117 million in the second quarter of 2012 and up from $109 million in the third quarter of 2011. On a per-unit basis, combined lease operating, transportation and production tax expenses were $1.54 per Mcfe in the third quarter compared to $1.47 in the second quarter and $1.55 per Mcfe in the third quarter of 2011.

Finally, QEP Field Services' third-quarter 2012 EBITDA was $68 million, which was $3.5 million lower than the second quarter of 2012 and $17 million lower than the third quarter of 2011. Processing margin was up $1.6 million or 5% in the second quarter of 2012 as a result of $6 million of higher processing revenues and $4 million of lower shrink in operating and transportation expenses in the quarter, which were offset somewhat by 16% lower NGL sales volumes and 8% lower realized NGL prices.

NGL volumes were lower as a result of ethane rejection in some of our gas processing plants for a part of the quarter and a full quarter of the Iron Horse plant in the Uinta Basin operating under a new fee-based processing agreement with QEP Energy for their volumes.

Gathering margin was down $4 million or 8% in the quarter compared to the second quarter of 2012 on lower gas gathering volumes and lower other gathering revenues. Volumes were 1.41 million MMBtu's per day, which had an average gathering fee of $0.34 per MMBtu.

We reported a net loss in the third quarter of $3 million, driven by a $57 million loss on the mark-to-market value of our derivatives portfolio. In spite of the $95 million of losses in the last two quarters, the total unrealized gain for the derivatives portfolio for the nine months of the year is a positive $33 million. The unrealized gains and losses are non-cash items and we adjust for them in our EBITDA calculation.

In addition, sequential DD&A expenses were up $20 million to $234 million in the third quarter as a result of increased production from our Williston Basin properties in Pinedale.

For the first nine months of the year, we reported capital expenditures including acquisitions on an accrual basis of $2.5 billion. Capital expenditures for E&P, drilling and completion activities were $970 million, and capital expenditures in our Midstream business were $141 million for the first nine months of the year. In addition, we spent $1.4 billion on acquisitions of oil and gas properties during the year.

With regard to our North Dakota acquisition, we booked approximately half of the purchase price to the proven properties and the remainder to unproven properties, and we will move assets from the unproven category to the proven category as we execute our development program for the acquired properties. And Chuck will have more commentary about our capital expenditures in a moment.

Finally, with regard to our balance sheet, at the end of the quarter, total assets were $9 billion and shareholder equity is $3.3 billion. Total debt at the end of the quarter was $3.2 billion, which is a 1.2 times multiple of our trailing 12 months EBITDA pro forma for the acquisition.

Our debt at the end of the quarter consisted of $2.2 billion of senior notes, $300 million drawn under our term loan due 2017, and $664 million outstanding under our $1.5 billion revolving credit that matures in 2016.

In September, in conjunction with the acquisition, we issued $650 million of senior notes due 2023 which carry a coupon of 5.25%. It was the largest notes offering in the Company's history, and also the lowest coupon in the Company's history, including those that were issued when we were an investment-grade subsidiary of Questar prior to the spinoff in 2010.

The agencies affirmed our Ba1/BB+ ratings for the offering and reiterated their stable outlook. As we discussed when we announced the acquisition, our current leverage levels are outside of our steady-state run rate comfort zone for leverage, and Chuck will discuss our strategy to delever the balance sheet in his prepared remarks. I will now turn the call over to him.

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

Good morning. Richard has already hit the highlights of our third-quarter results, so I will briefly touch on some operational highlights from the third quarter and our plans for the remainder of 2012. I will talk about our progress on our path toward deleveraging. I will review our plans for 2013, and then we will move on to Q&A.

Let me give you a little more color on our operational results from the third quarter and our plans for the remainder of 2012. As I do so, I would ask that you refer -- if you can refer -- to the slide presentation that accompanied our release, which was posted on our website yesterday afternoon along with our earnings release.

As Richard mentioned, we closed our $1.4 billion acquisition in North Dakota's Williston Basin Bakken/Three Forks play on the 27th of September, and we've now taken over operations from the seller. We currently have two rigs working on the acquired South Antelope properties, and we expect to begin to ramp up rig activity as we get our multi-well pads designed, permitted and constructed.

We've also begun to make changes in the well design that we believe will allow us to deliver $11 million of lower gross completed well costs going forward. Note that we inherited a handful of wells that were in progress that were designed differently from our standards, so we won't see an immediate decrease in well costs until we work through that inventory.

Earlier this month, we completed and turned to sales the first QEP-operated well on the South Antelope acreage since the close of the acquisition. The [Coomer 1-67H], a Three Forks well, came on at a very strong 24-hour initial production rate of just over 2500 BOE per day. See slide five for a reminder of the location of our South Antelope acreage, and slide six will show you the location of the Coomer well.

On our Fort Berthold acreage, we completed and turned to sales five new wells during the third quarter. Three of those wells were in the middle Bakken, two were in the Three Forks formation. Four of the wells were located on a single pad which is in the southwest portion of our acreage, and all of them came on with extremely strong rates, with average 24-hour IPs of over 2100 BOE per day.

The fifth well, which was designed to delineate the Eastern edge of the middle Bakken reservoir in our leasehold, came online with a 24-hour IP of just slightly under 1000 BOE per day. This well also had some oil foaming issues related to an experimental frac fluid that we used on that well, which we are no longer using, which we suspect also contributed to a constrained initial rate.

Since the end of the quarter -- and this is something new that is not in the release -- since the end of the quarter, we have completed and turned to sale seven additional wells on our Fort Berthold acreage, three middle Bakken and four Three Forks wells. The last five of these new wells to sales were from the first pod on our 10-well Independence pad, which is located on the extreme northwestern corner of our acreage. And all of these wells had excellent 24-hour IPs of 2400 barrels a day to 2900 barrels equivalent a day. So these wells are quite strong and we really can't distinguish between the flowback results from the Three Forks wells or the Balkan wells.

During the third quarter and into the current quarter, we've been able to deliver completed wells on the reservation at an average gross completed cost of about $11 million. Note that we now currently have three rigs running on our Fort Berthold acreage. You can see slide seven in our slide deck for more details.

At Pinedale, we are on track to complete about 100 wells this year. Recall that as we announced earlier we decided to defer completion of 14 wells that are drilled and cased at Pinedale into next year to take advantage of the contango and natural gas prices. See slide eight for more details on Pinedale.

In the Uinta Basin, we continue to make good progress on the Red Wash/Lower Mesaverde liquids-rich gas play. We've now completed 29 of the 40 new wells planned in the play for this year, including some additional 10-acre and 20-acre spaced pilot wells to help us figure out the optimum well density for full field development. Slides nine and 10 show more details on our Uinta Basin plan. I'd also note that we have another active rig in the Uinta Basin drilling horizontal and vertical oil wells.

In the Powder River Basin in Eastern Wyoming we completed two new Sussex wells during the quarter. You can see the details of those well results on slide 11.

In the Midcontinent division, we have a number of QEP-operated wells in progress in the core of the liquids-rich portion of the Cana Shale play, where we are focused on drilling up our leasehold on 80-acre density. We will commence completion operations on the first group of wells later this month, so they won't go to sales until quite late this year. We're also drilling 80-acre density wells on another nearby section that will be completed very early next year, so they won't have an impact on production until the first quarter of 2013. Both of these sections are in close proximity to some very strong well results which have been reported recently by other operators. You can see the location of our activity on slide 12.

Turning to the Granite Wash, Marmaton and Tonkawa plays, we reported a number of operated and nonoperated well results, including three wells in the Granite Wash in which we have a 51% interest that came out at some very impressive 24-hour initial production rates. One of the wells at over 5600 BOE per day and two other wells that came in at over 3500 BOE per day. All three of these wells were completed in the Missourian (inaudible) Kansas City formation, which is immediately beneath the now -- I guess I could say infamous Hogshooter zone that has been talked about extensively by others. All of these horizontal wells are drilled in the area that are targeting crude oil and very liquids-rich natural gas horizons. Slide 13 will give you more details in the location of those wells.

Finally, as you already know, we've ceased drilling activity in the Haynesville play. We shut down our last rig there early in the third quarter. To take advantage of the contango in the forward natural gas price curve, we have elected to defer completion of the last five wells that we drilled and cased in the Haynesville play until next year. Slide 14 will show you some details on the Haynesville.

At QEP Field Services, we are on track to invest roughly $170 million in 2012 in a few major projects as well as a number of smaller ones. Construction is proceeding very smoothly on our Iron Horse II cryogenic processing plant, which is a new 150-million cubic foot a day plant located in the Uinta Basin in Eastern Utah. And we expect that plant will be operational late this year or very early next year.

About half of the capacity of this new plant is contracted to a third-party producer under a fee-based processing arrangement, while the other half will be used to process QEP Energy's gas volumes from the Red Wash/Lower Mesaverde play under a fee-based processing arrangement.

Construction also continues on our 10,000 barrel per day NGL fractionation facility at the Blacks Fork complex in western Wyoming. The expanded facility is designed to provide additional options for marketing purity propane, iso and normal butane and [gasoline-ranged] products to what are oftentimes premium value local, regional and national markets that we can access either by truck or from expanded rail-loading facilities at the plant. We expect the new fractionator to be in service toward the end of the second quarter of 2013.

Now let me turn to our deleveraging activities. As we discussed in our August conference call when we announced our $1.4 billion Williston Basin acquisition, our pro forma trailing 12-month ratio of debt to EBITDA at the close of the purchase increased to a little over two times, which as Richard has already said is above our comfort level of 1.5 times or less.

To get back inside the 1.5 time ratio, we need to raise approximately $1 billion in cash through asset monetizations, which we said that we expect to accomplish by the middle of next year. As we described in the August call, there are several options that we are considering to raise cash. One, the sale of selected noncore upstream assets. Two, a royalty trust, a VPP or similar vehicle engineered around cash flows from selected upstream assets. Three, a partial sale to a financial partner of an ownership interest in our Midstream business; and/or four, a Midstream MLP around our gas gathering and processing business.

Both before and after the announcement of the deal, we had spent a lot of time studying the pros and cons of each option and various combinations of the different options. And earlier this week, we reviewed our analysis with our Board. The analysis isn't as straightforward as you might think. We struggled with the conflicting goals of maximizing the immediate cash proceeds derived from monetization transactions to meet our self-imposed deleveraging timeline of mid-2013 versus maximizing overall value creation.

By far, the simplest and quickest way to delever would be to sell a minority stake in our Midstream business to a financial partner. On the other hand, the MLP IPO option arguably creates higher long-term value, but it presents several unique challenges not associated with the financial partner path.

First, there is a market-imposed upward limit on the size of an initial offering, somewhere around $500 million; but the sweet spot is arguably half that size. Second, to maximize MLP value creation, a smaller IPO which focuses on more rapid growth in distributions would lower initial proceeds and therefore hamper our ability to hit our leverage target and timeline.

We've also considered monetization transactions around some of our noncore E&P assets, and while we've ruled out royalty trust and VPPs, we have identified several assets that are noncore to our future E&P growth strategy which might be more valuable in the hands of others.

So where are we today? After reviewing our analysis with the Board, they have authorized us to retain advisors to help us run down parallel paths with our Midstream business, one focused on identifying potential investors for sale of a minority interest in Field Services, and the other path focused on an MLP IPO.

On the Upstream side, we will hire a different advisor to assist us in selling some select noncore E&P assets. I know all of you on the call today would like to know which assets we are considering for divestiture, but for competitive reasons, I would rather not discuss the specifics or our expectations around the proceeds at this juncture.

So let's look forward to 2013. In yesterday's release, we gave initial guidance for our 2013 capital investment program along with forecasted production and EBITDA. I should note at the outset that the guidance we gave yesterday assumes a steady-state business, doesn't take into account the impact of any asset monetization as either cash proceeds or production and EBITDA impacts.

I'd also like to draw your attention to the updated derivative position table in yesterday's release. As we indicated in August when we announced the acquisition of the Williston Basin properties, we have aggressively taken steps to lock in strong prices on a significant quantity of future crude oil production from the acquisition.

Now let me give you a little more color on our 2013 plans. First, as we've described to you in the past, we set our capital program for the year to live in and around our forecasted EBITDA. Note at the midpoint, we're only slightly outspending 2013 forecasted EBITDA. And second, we do not set our capital program based on a production growth target, but instead production growth is an outcome of our capital allocation process. We allocate capital based on returns, and as such, we've allocated about 56% of QEP Energy's 2013 forecasted capital to the highest-return project in our portfolio, which is the Bakken/Three Forks crude oil development program in North Dakota. This program assumes that we'll ramp our current five-rig program to an eight-rig program by midyear 2013.

At Pinedale, we anticipate running three rigs next year, down from six this year. Pinedale will get about 17% of QEP Energy capital allocation next year.

The Midcontinent Granite Wash, Cana, Marmaton, Tonkawa programs will attract about 16% of QEP Energy's capital next year, driven in large part by the high level of anticipated nonoperating drilling activity in these plays, while the Uinta Basin will attract about 9% of total capital as we continue to develop the Lower Mesaverde play with a two-rig program, and a one-rig program will target additional Green River formation oil development.

We expect that QEP Field Services' capital investment will decline from 2013 levels as we near completion of the Iron Horse II plant at the end of this year and the Blacks Fork fractionator expansion project in the middle of next year.

We view this as a pivotal year for QEP as we dramatically shift the production mix from one dominated by natural gas to one that is more balanced. For 2012, we forecast that QEP Energy will grow production about 15% on a six-to-one natural gas equivalent basis, but that's not the whole story. This year, we expect QEP dry natural gas production will only be up about 5%, while crude oil production will grow about 67% and NGL production will be up almost 100% over 2011 levels.

For next year, for 2013, we forecast overall production growth on a six-to-one basis will be about 4%, but crude oil production, the highest-margin product in our production slate, will grow about 70% over 2012 volumes and NGL volumes will grow over 30%. As we have indicated previously, with no drilling activity forecast in our Haynesville division, we forecast dry natural gas production just from that area will decline about 30%, from about 110 Bcfe this year down to about 75 Bcfe next year.

So as a result, we think total natural gas -- dry natural gas volumes for QEP Energy will decline about 10% in 2013 compared to this year.

While we don't run our planning process or manage our business with an absolute production target in mind, we do realize that some investors and analysts focus heavily on production growth. I would argue that to properly value each component of the production stream, a 20-to-one ratio of equivalency between natural gas and liquids is a more appropriate way to look at industry production volumes. And if you do so, QEP's year-over-year production growth for 2013 would be about 21%.

We are focused on profitable growth, and I view EBITDA margin expansion and EBITDA growth as more important than absolute production growth. Despite significant headwinds created by the rolloff of a good portion of our natural gas derivatives positions at the end of this year, a dramatic year-over-year decline in forecasted NGL prices, narrower gas processing margins and declining dry gas volumes, we still forecast a very healthy midteens year-over-year growth in EBITDA in 2013. And I want to remind you that the high-quality gas assets in our portfolio haven't gone away. We are simply managing growth in these assets by shifting capital to the higher-margin crude oil and liquids-rich gas projects in our portfolio until natural gas prices recover.

As part of our capital allocation process, we force ourselves to look at a multiyear program in each of our businesses. We realize we can't successfully manage an E&P business by focusing on one year alone, especially since much of the capital invested in drilling next year will have a much more dramatic impact on 2014 and beyond.

I don't like giving multiyear guidance, but I feel compelled to give you a sense of where we are headed over the next couple of years. Looking at the current forward commodity prices, and with all the caveats of the safe harbor language, we anticipate QEP Resources' 2014 forecasted EBITDA could be approximately $1.9 billion, which would be up about 20% from our 2013 guidance midpoint. We expect crude oil production to increase about 50% over 2013 levels, NGL production to be up 20% and natural gas volumes will be down about 4% compared to 2013 levels.

On a six-to-one basis, total net equivalent production in 2014 would grow about 10% over 2013 levels, and on what I think is a more realistic 20-to-one ratio, our production would be up about 23%.

So in 2014, we expect that EBITDA margins expand again in the face of a backward-dated crude oil price curve and a slightly improving natural gas price environment. And importantly, we believe that we can drive this steady, profitable growth with a capital investment program that lives in and around forecasted EBITDA.

In summary, I and we are very excited about QEP's future. This year, we made great progress on organically shifting our production mix toward higher-return crude oil and liquids-rich gas production from our existing asset base. And with the newly-acquired Williston Basin assets, we are now poised to accelerate crude oil production volumes in the years ahead.

We have a great set of assets and some of the most talented and dedicated women and men in the industry managing them. I am confident that with their efforts, our Company is well positioned to drive profitable growth from our portfolio of high-quality assets in 2013 and beyond.

With that, Keisha, let's open the lines for questions.

QUESTIONS AND ANSWERS

Operator

(Operator Instructions) David Tameron, Wells Fargo.

David Tameron - *Wells Fargo - Analyst*

The Bakken, if I look at -- just trying to get a feel for 2013 -- if I look at on slide five, you had a little inset graph that showed the Bakken ramping at the end of the year to just under 20,000 barrels, 19,000 to 20,000 barrels. How do we think about that trajectory for 2013?

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

It is embedded in our crude oil production guidance which we gave you, and obviously, the single largest crude oil contributor is the Bakken. We will get some minor volume growth out of the Uinta Basin, David, and out of condensate volumes from the Midcontinent. But the primary driver of the year-over-year growth statistics that I gave you is going to be the Bakken.

I think it is important to think about the way we are going to continue to develop the Bakken, both on our legacy Fort Berthold acreage as well as the newly-acquired Antelope acreage. All of the wells going forward will be drilled from pads. We've landed on a development program of four well pads on the newly-acquired acreage and multi-well pads on the Fort Berthold acreage, some of them with as many as 10 wells. Although the 10-well pads will be developed in two five-pod development pods so that we can get at the wells and complete them after we drill five wells.

So as a result of the shift from single-well drilling to pad drilling, the production growth is going to be lumpy. We are going to see wells -- as many as four wells or five wells trapped under drilling rigs that will be waiting on completion. And then we will move the rig off and we will have a bunch of new wells coming on very quickly and a dramatic spike-up in production.

So we don't give production forecasts on a quarterly basis, and we do so deliberately because of the volatility around the completion of wells and pods, both at Pinedale and now in the newly-acquired acreage as well as the existing Bakken acreage.

We are going to see a similar phenomenon, by the way, in the Uinta Basin, as we shift the pod development there. And it is all for the sake of driving down individual well costs and enhancing returns on invested capital. But it is going to be difficult for you sell-side guys to forecast production volumes as a result. But I think that if you look at our year-over-year production guidance, you will see the forecasted growth.

David Tameron - *Wells Fargo - Analyst*

All right. And you had a bunch of -- I know you had issues in prior quarters with water handling and infrastructure. Is that -- have you got over the hurdle on that, or where do you stand as far as that being a limiting growth factor?

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

I don't believe it will be a growth factor. It has been primarily a limitation in driving down well costs. We have wired around some of the issues on the reservation with some temporary fixes. The owner and service provider of the midstream gathering services on the reservation is very focused on coming up with permanent solutions.

It is going to involve putting more pipe in the ground and adding additional pumps. But for the interim period, I think we are okay there. It is getting better. And with the addition of the new acreage, it gives us some flexibility on timing of when we drill wells where and the ability for the Midstream infrastructure to catch up with us on the Fort Berthold reservation.

David Tameron - *Wells Fargo - Analyst*

Okay. And the last question and I'll let somebody else jump in. On the monetization comments, it sounds like there is more than one lever, especially if you go the MLP route, that you will need to pull to get to the number-- to get to your $1 billion dollar number. But are all those proceeds going to be used strictly for delevering, or would some of those possibly be used to accelerate growth and throw some more CapEx at the program next year?

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

David, in our board meeting -- it's interesting you raised this, because several of my directors asked if a moderate outspend was appropriate. And I think both Richard and I and the team would feel comfortable with more moderate outspend after we are delevered, and that is one of the reasons why we are focused on trying to get the balance sheet in good shape. Because then we would feel less nervous about overspending EBITDA by a significant margin to drive oil growth.

The other thing just to keep in mind is, just like we saw in the Haynesville, when we basically ceased activity -- by the end of last year, we were down to a couple of rigs in the Haynesville -- and we saw the lingering, sustained production plateau and now it has turned and started down. The same inertia in production growth occurs as you're trying to ratchet up the Bakken.

We are going to do it in an orderly fashion. On the newly-acquired acreage, we just completed a spacing hearing, an uncontested spacing hearing for eight wells per development unit, 1280-acre development unit. We've now engineered our pads so we know exactly how we are going to lay them out, and we are in the process of settling with the surface owners to start constructing those pads. We will be acquiring rigs with skid packages so that we can turn into basically a whole manufacturing shop in North Dakota and really drive the production growth.

But there is going to be a little time lag while we ramp up and we are going to do it in a very orderly fashion so that we ramp up while controlling and hopefully driving down well costs going forward.

David Tameron - *Wells Fargo - Analyst*

Okay, that's helpful. I'll let somebody else jump in. Thanks.

Operator

Brian Corales, Howard Weil.

Brian Corales - *Howard Weil - Analyst*

To follow up on the financing, are you still kind of expecting the timeframe kind of middle of next year to have capital raised or to have a decision made? What are the thoughts there?

Richard Doleshek - *QEP Resources, Inc. - EVP, CFO*

I think we expect to have certainly a portion of it accomplished. If we hop on the MLP IPO path, the trek to the SEC is somewhat outside of our control. And the smart people that we talk to say four to six months on that path, but it could be longer. But I think certainly by the middle of next year, we will have a portion of what we are trying to accomplish in the books.

Brian Corales - *Howard Weil - Analyst*

Okay. And to follow up on that, is the MLP, is that purely to raise capital, or is there a point to try to unlock some value as well? Is that more the point of potentially doing an MLP?

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

You heard us -- we've been, I think, fairly consistent with regard to our concerns that the Midstream business is not properly valued inside QEP. And the biggest issues we had over the last year and a half was the use of proceeds. If we are going to endure the [brain damage] of creating another publicly-traded vehicle, we need to have a use of proceeds and we need to be able to manage the tax aspect of it.

So the ability to delever (inaudible) asset debt that we believe is currently undervalued into a better valuation market certainly plays into what we are trying to do. The challenge is, as Chuck alluded to, the value optimization exercise doesn't get us as far down the path of raising proceeds because of the size of the MLP IPO market relative to what we are trying to do in terms of cash proceeds. So there is a little bit of balancing act going on with regard to proceeds versus optimum size of that IPO if we go that way.

Brian Corales - *Howard Weil - Analyst*

Okay. And just one final one, switching tunes, more the Bakken. Can you all talk about once you added those seven wells, can you kind of talk about what your production is currently in the Bakken?

Richard Doleshek - *QEP Resources, Inc. - EVP, CFO*

Brian, I can't give you a current number this morning. I could -- I don't have it with me. As we brought these wells on -- one of the other things I should point out as sort of a follow-on to David's question and an answer to yours is -- when we bring on a pad, a pod of wells on a pad, like this recent Independence well, we bring them on one at a time, clean them up and then shut them in while we flow back the next one. Because we are dealing with, as you can imagine, in addition to 2300 to 2900 barrels a day of crude oil, we are also dealing with large quantities of flowback water in the early days of the well. So we can't, in essence, open up five brand new wells and start flowing all five of them back simultaneously and cleaning them up. So we sequence the flowback.

And the idea here is to flow the wells back at fairly high rates during the early life, the first four or five days of the well, to get the water off of the well and also to hopefully recover as many of the actuator balls, the frac balls that open the sliding sleeves, and get them out -- basically get as much of the junk out of the wellbore, the horizontal lateral, as we can.

And then what we are doing is we believe that managing the flowing pressure and therefore reducing the rate in order to maintain higher flowing bottom-hole pressure, just as we did in the Haynesville, is probably the right way to manage a Bakken well going forward.

So we are going to experiment with different choke sizes and try to find an optimum choke size for flowing these wells back over the longer duration, after we get the junk out of the hole from -- after the first four or five days of production.

As a result, what you will see is a wave of new production come on from well one on the pod. It will get shut in. Well two comes on. So we have sort of a normalized couple of thousand barrels a day of incremental production. And then after all the wells are relatively cleaned out -- they will still make a fairly high water cut -- then we can open all five wells on a pod up or all four wells on the new Antelope acreage up at a more constrained rate, 1200 barrels a day, 1000 barrels a day. I don't know exactly where we are going to end up. That is what the reservoir engineers are working on right now.

But we will get these, if you can imagine, this stair-step production profile as we put on new wells. And of course, in the background, the older wells continue to decline, which leads to a fairly lumpy profile. But by the end of the year, we should be, as we show you in that cartoon, at 20,000 plus barrels a day coming out of the fourth quarter.

Richard Doleshek - *QEP Resources, Inc. - EVP, CFO*

And, Brian, that phenomenon that Chuck described about that lumpiness is reflective of what you saw in our DD&A rate this quarter with that Independence pad coming on. We jumped up our DD&A rate a good bit just reflective of that sort of stair-step function of production coming on. We are also going to have DD&A come on with those higher cost wells.

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

And a third comment, just to sort of try to fill in the blanks and what I didn't say in the prepared remarks, the wells that we brought on in the third quarter, four of them were on a single pad. And they were brought on in that same sort of sequential fashion that I described for the Independence pad. And we really saw very -- we saw one month of benefit from the combined production stream in the third quarter from those four 2000 barrel a day plus wells as a result.

Brian Corales - *Howard Weil - Analyst*

Okay, guys. Thank you.

Operator

Hsulin Peng, Robert Baird.

Hsulin Peng - *Robert W. Baird - Analyst*

Good morning, gentlemen. A clarification question. So the first one, in terms of regarding your midstream partial -- evaluation of the option of a partial sale versus an MLP IPO, are those two mutually exclusive or will you go parallel -- will you still consider both?

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

At this point we are considering both. And as I said in my prepared remarks, the simplest one that maximizes proceeds would be to do an outright sale to a financial partner of a minority interest in the midstream business. We could run a process and identify potential buyers and do it relatively easily. We don't have to go through the SEC filings, we don't have to go through the comment periods, etc., etc.

As Richard pointed out and as I pointed out, the public market route arguably creates a higher value, and we are still struggling to get our heads around the way MLP investors think. Because we think about the business in terms of EBITDA multiples, and MLP investors and MLP management teams think about yield. So there is a totally different sort of mindset that we are having to meld our E&P brains around as we evaluate the MLP option.

But just if you think about it simply, if we go to the MLP route we would like to go with a smaller IPO, which might raise $0.25 billion or so, which would get us only a quarter of the way to our targeted delevering. So it's possible we may entertain a minority investor at the outset and then go down the MLP route afterward. That's one thing we've thought about and we will model.

And then don't forget we are also considering divestiture of some non-core E&P assets. And all three of those things are in process, and we are evaluating the ultimate pathway, and trust me, as soon as we figure it out, we will let you guys know.

Hsulin Peng - *Robert W. Baird - Analyst*

Okay, that sort of answered my second question in terms of timing. And then the second question I have, is given that your liquids production will increase going to future, I was just wondering if you can -- because I know directionally, costs such as LOE, those cost metrics should go up because oil is harder to -- more costly to produce. But can you help us with some -- the magnitude of what cost metrics would look like especially for 2013?

Richard Doleshek - *QEP Resources, Inc. - EVP, CFO*

I'll give you some directional numbers. I don't have the aggregate number to give you. But for example, our legacy production, which is where the Bakken is, it costs us about $1.80 in LOE to produce the molecules.

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

That's on an Mcfe basis.

Richard Doleshek - *QEP Resources, Inc. - EVP, CFO*

On an Mcfe basis. And that is about three times our average rate. So if you do the calculus -- and I don't have the numbers in front of me -- as we shift from what was an 80/10/10 split in the first nine months of 2012 to a more 70/20/10 split, that shift in production, if you just kind of do the gross numbers, is going to move us more toward that $1.80 per BOE -- for Mcfe for LOE. And so you should have an expectation of seeing LOEs shift.

It is not going to be as dramatic as if -- just because the percentage change and the production composition isn't as dramatic, but it is going to move in that direction.

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

So, yes, let me add a little bit more. And I think when we report these numbers on a volume-weighted average basis, it also -- you need to also keep in mind the decline in dry gas volumes. Because the lowest-cost producing wells in our portfolio are flowing gas wells, whether they be the Haynesville or Pinedale, et cetera.

So as we drive growth, the relative weighted-average LOE is going to go up as crude oil increases as a percentage of the total in our production mix.

In addition, if you just think about it, producing oil wells are much more troublesome than gas wells. Gas wells require very little intervention over their lives. You just put them online, you may put plungers in them; but the workover cost, the well intervention costs are much lower. Whereas crude oil wells, the first thing we have to do -- we flow them for a while, the first thing we have to do is run tubing in them and install pumps. We have to from time to time pull that tubing, replace pumps.

We have various issues with wax buildup or with brine and salt precipitation in some wells. So they are just much more troublesome as far as operating cost is concerned and therefore the LOE is higher.

The other thing that Richard didn't mention, which as you are doing your modeling that is very important, is that obviously we are we are receiving a much higher price on an Mcfe basis for our crude oil. So production taxes are higher. The DD&A rate is going to be higher, because the well costs per unit are higher. So the overall production costs, both cash and non-cash, are going to increase as our percentage of oil and our total production slate increases.

Richard Doleshek - *QEP Resources, Inc. - EVP, CFO*

I don't think it would be out of the ballpark if you looked at our per-unit LOE and said that that number increases by 20 plus or minus percent for 2013 as a result of the shift.

Hsulin Peng - *Robert W. Baird - Analyst*

Okay. That's very helpful. I generally understand exactly -- I agree with exactly what you are saying; just trying to understand the magnitude of it. And then my last question is regarding your 2013 EBITDA forecast. Can you tell us what NGL pricing assumptions you are assuming in that guidance?

Richard Doleshek - *QEP Resources, Inc. - EVP, CFO*

We are basically using the forward prices for ethane, propane, butane, et cetera -- iso normal, butane and gasoline. They're basically -- let's see -- let me give you the ethane price, about $0.43 a gallon; propane about $1.08. And I don't have the butane and heavier components broken out here, but their pricing relationship has not been as volatile, and butane and heavier has not been as volatile as the C2s and C3s have.

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

And on average, it is between 35% and 40% of our net realized crude price, plus or minus.

Hsulin Peng - *Robert W. Baird - Analyst*

Okay. That sounds good. Thank you so much.

Operator

Brian Singer, Goldman Sachs.

Brian Singer - *Goldman Sachs - Analyst*

On the Midstream assets, do you regard control and maintaining control as strategic given that you are de-emphasizing the Pinedale, or would you consider selling more than a minority interest? And separately, where does the Haynesville stand in terms of its strategic importance?

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

The answer to the first question is that we absolutely believe that control of the Midstream assets is important. We've seen in examples, most recently in the Williston Basin on the Fort Berthold Reservation, of what happens when you don't control the infrastructure between the wellhead and the point of sales of either oil or gas. And so as we examine options for deleveraging, one of the overarching objectives, in addition to raising cash, is maintaining operational control on that Midstream business. So it is absolutely important to us and it is something that I think all of our directors share the view that it is strategically important for QEP going forward.

The question about the Haynesville, the Haynesville asset is a very high-quality dry gas asset. We are deemphasizing it in the current price environment. We are not allocating very much capital at all, just a few percent of our total budget next year, to complete the wells are standing cased to bringing them online into the contango of the forward gas price curve. So in terms of importance today, the Haynesville is not attracting capital because we have much higher-return places to invest.

But I would say that it is a great asset. It's an asset that we now have completely held by production, and it is a part of our portfolio that awaits a return to higher gas prices and/or lower completed well costs. And a combination of those two things or a dramatic change in one or the other could cause it to attract significant capital allocation in coming years.

Brian Singer - *Goldman Sachs - Analyst*

That's helpful. Thanks. On the Bakken, I think you mentioned earlier you expect the five-rig program to go up to eight rigs by mid next year. What do you see as kind of the limit logistically in terms of a rig count there, where you wouldn't have to worry about cost inflation or execution? Is it eight rigs or do you ultimately see yourself being able to run more on the assets that you now have?

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

We could probably get to 11 to 12. We are not going to get there overnight, obviously. I still have -- I have a long memory, and I still remember the early days at Pinedale where we tried to ramp up to 14 rigs. I think that was 2004, and it was a nightmare.

So the ramp-up will be orderly. It will be driven by pad drilling and by optimization of well delivery, and obviously, we are going to focus keenly on individual well costs. But we could run 11 or 12 rigs out there as a maximum case. And we've looked at -- we've modeled that case. But it's really the shape of the ramp-up that you should focus on, Brian, and we guide to the middle of next year to have the eight rigs out there.

What I hope to be able to do, and there's a lot of people that feel the love, is that we get there sooner than June or July, (multiple speakers) they are listening in.

Brian Singer - *Goldman Sachs - Analyst*

And lastly, when you think about the upstream, non-core upstream asset sales, any sense on what the EBITDA or production impact would be? I know you don't want to be specific on where those assets are, but the EBITDA and production impact from those sales.

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

If I start giving you that number, then you will back into what the assets are, because I know you are a smart guy. So, Brian, at this point, we are just beginning the process. So as we move down the road and we get into a marketing mode, I'm sure with your network you will find out what assets they are. Everybody on the phone will. But for various strategic reasons, I would rather not go there right now.

Brian Singer - *Goldman Sachs - Analyst*

Okay, but no reduction to production from E&P upstream assets have been contemplated in your guidance, I think you mentioned, just to reconfirm.

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

Let me -- maybe I didn't say it right or you didn't process what I said because it was poorly written, because I wrote it myself. But the guidance that we have given does not contemplate any asset sales or any reductions associated with a partial monetization of the Midstream business or sale of non-core upstream assets.

Because we don't know to yet, A, the timing around when those are going to happen, and, B, exactly what we are going to do. So rather than give you some imagined guidance, we give you guidance from the steady-state business based on the capital plan that we've laid out in front of you, both in our release and in my prepared remarks today.

Brian Singer - *Goldman Sachs - Analyst*

Yes, that was my takeaway, so that's helpful, that to the extent you are selling E&P assets that your CapEx and, assuming they are producing assets, your production guidance would go down.

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

Well, don't necessarily assume that, because it may allow us to reallocate capital to other parts of our portfolio where we can continue to drive growth.

Brian Singer - *Goldman Sachs - Analyst*

Got you. Thank you.

Operator

William Butler, Stephens.

William Butler - *Stephens - Analyst*

Do you guys have any thoughts on NGL prices and realizations for next year, why that would vary from the 35% to 40%? And you said that was of your realized crude oil price -- is that correct?

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

Correct. Brian, I think that we've tended to err on the side of conservatism maybe on the propane side, because we don't have good visibility yet on winter. And obviously, one of the biggest surprises, at least for me, when we were forecasting 2012 EBITDA out of our Midstream business, was the collapse in the second quarter of this year of the propane market as a result of the lack of a winter and no demand for propane as a heating fuel. Which, as you know, resulted in cascading problems with the ethane markets as a result of propane being substituted for ethane in the petrochemical complexes.

So as a result, knowing how bad it got in the second and third quarter of this year, we've been fairly conservative in giving guidance, especially around our assumptions on propane.

As you know, there are some projects underway that will help ameliorate the future storage issues for propane by allowing for export to markets outside of the US. Those projects have been delayed somewhat, but they will help next year in hopefully mitigating the potential inventory buildup that we saw this year.

The other thing that would help is a good, cold winter to continue to draw down the existing stocks and get us back into the more typical storage levels that we've seen historically.

On the ethane side -- and as you know, Brian, ethane is -- William -- I'm sorry -- I've got -- I wrote down Brian -- it's William. Sorry, William. I'm still thinking about Brian Singer. Sorry about that.

William, as you know, we are -- our Midstream business, our processing business is an ethane-dominant product slate. And as a result, the volatility in ethane prices has a tremendous impact on our non-fee-based revenues and EBITDA. And we expect that ethane prices will continue to be very volatile, and that they will tend to follow natural gas prices more closely than crude oil prices just due to the supply-demand balance. We are basically fully supplied for ethane in the market, and we have the direct access via contracts for transportation and fractionation to the highest-value market in North America for ethane, i.e. Mont Belvieu. But that doesn't help a lot when there is a wave of new ethane volumes coming into the market.

The other thing that is impacting processing margins -- and it is something that we forget about, because we just tend to just look at the absolute price of the NGL products and not think about the frac spread -- is the dramatic increase in forward natural gas prices, which has effectively squeezed the ethane margin and propane and all the other NGL component margins and keep-whole processing arrangements, where now we are looking at a roughly $4.00 forward gas price, whereas this year we averaged about $2.50 for the year.

So just think about that on a BTU basis as you back out the cost of shrink in fuel. It's going to make a tremendous impact on processing margins going forward.

William Butler - *Stephens - Analyst*

And so could you quantify -- I think you all indicated in the press release and may have on the call that you expect operating income in the Midstream business to be down next year. Any sense of -- or willingness to quantify that, some ranges for us, based on your guidance?

Richard Doleshek - *QEP Resources, Inc. - EVP, CFO*

I think there are two things that are going to go on in the Midstream business. One of them is the reduced gathering [stream] volumes that are going on in our northwest Louisiana facilities as a result of the Haynesville decline, and Chuck alluded to that. So a 30% year-to-year decline. And so you can sort of kind of calibrate into what that translates to with regard to what is going to happen in northwest Louisiana.

And then second, the timing of the plants coming on is going to -- the plant and the fractionation facility coming on is going to sort of mask what would be pure price and frac spread compression that goes on next year. But I think if you think about a number that is plus or minus 15% from where it was -- 15% to 20% from where it was this year, that is probably not a bad outcome, if you tweak your model right.

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

And that is based on our what we hope are fairly conservative assumptions around NGL prices and frac spreads. And it is our best guess on where we are today and, when we think about the macro, where we are headed.

William Butler - *Stephens - Analyst*

Great, that's helpful. And one last question, if I can. What is your current stance towards additional upstream acquisitions?

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

We are in the market. We are looking. Obviously, when we made the announcement back in August of our Williston Basin acquisition, we said that we were continuing to look for opportunities to do additional asset acquisitions to bolster our portfolio of crude oil inventory -- crude oil development inventory projects.

We -- and that is one of the reasons why we are so focused on delevering the balance sheet, to reload our debt capacity so that we can be aggressive in the acquisition market. Because intuitively, my sense is that there are going to be a number of opportunities over the next 12 to 18 months that we want to be in the market and evaluating and be able to capture if we find the right opportunity.

William Butler - *Stephens - Analyst*

And then would those have sort of the same criteria as previously in terms of in basins you all are already in, et cetera, being crude oil, not NGLs, et cetera, assets versus corporate?

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

You must have listened to the call that we did in August. Yes -- well, yes on all of those things. Operated chunky acreage, if they are resource plays, contiguous acreage in basins that we know, where we have boots on the ground. Unless it is a corporate transaction where we acquire not only the assets but the people to operate them. Because in places like the Permian Basin, for example, which is a crude oil dominant basin, we don't have a soul on the ground there and I think it would be very difficult for us to onboard a significant asset and be able to operate efficiently when we don't have any presence there.

William Butler - *Stephens - Analyst*

That's great. I just wanted to confirm that that thought process hadn't changed. Okay, thank you all very much.

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

Hopefully not since August. But it has not. Thank you.

Operator

Brian Velie, Capital One South.

Brian Velie - *Capital One Southcoast - Analyst*

Quick question. As you were talking a moment ago about the Bakken rig count escalation in out years, going from eight to 11 or 12, I'm trying to get my head around what the efficiencies would allow in terms of a declining well cost over maybe a couple year period. If you are at 11 now, do you kind of see a path forward to get to 10 or nine or what is the opportunity there?

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

That's a great question, and I don't know whether I want to try to answer it or not. Yes, what I would say to you is that if you look at every basin in which we have developed a core position, Pinedale, Haynesville, we have a demonstrated track record of being able to drive down both drilling times and completion cycle times. We've gotten better faster as we've moved away from Pinedale and gone to other places. So the acceleration of the learning curve and the ability to do it over a handful of wells rather than over hundreds of wells is something that I can point to.

But what I cannot predict is the service cost inputs. Because if you think about it at Pinedale, we went from over 60 days to drill a well to 14,000 feet, and we've got a record now at 8.6 days. It's just a remarkable accomplishment -- to a similar depth.

And from 2002, 2003 to the third quarter of 2012, the input costs for well construction, from every component, from diesel fuel, steel casing, bits, muds, every component of the well construction process, pressure pumping, proppant, everything, has probably doubled since 2002, 2003. And we have been able to offset that doubling of all the raw material and service inputs and drive down the cost of the completed wells by 65% or 70%. It's an unbelievable accomplishment just to offset the inflation of cost, let alone drive down the cost.

Can we do that in a play like the Bakken? Well, we think we are one of the best whole manufacturing companies in the industry, and I have every confidence in our team's ability to drive down cycle times. And in a flat price environment, that means a well cost reduction.

How much? I would be fibbing to you if I gave you a number, because we just can't predict what service costs will do in the future. It is highly dependent on commodity prices. If we see oil prices stay flat, then I would expect service costs could stay flat or even maybe decline some. If we see crude oil or natural gas prices spike up by 30% or 40%, then we could easily see a similar increase in service costs. So it's very difficult for me to sit here and give you a number, other than I can state unequivocally that we have one of the best teams out there at drilling and completing wells, and given all of the caveats about service costs, I have confidence we can drive down well costs.

Brian Velie - *Capital One Southcoast - Analyst*

Okay, that's fair. Thank you for the color on that. Appreciate it.

Operator

Andrew Coleman, Raymond James.

Andrew Coleman - *Raymond James*

The one question I had was looking at your Haynesville decline, you guys break out in your release Cotton Valley, but I assume for that, Cotton Valley and Haynesville are synonymous.

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

Yes, Andrew, we lump them both together because they are in an operating division and so we report them as Haynesville/Cotton Valley. But the primary driver -- the Cotton Valley wells are already out on sort of the exponential part of their 6% to 8% exponential decline. The Haynesville wells are still coming down at a much steeper embedded decline rate, if you look at the total production volume there. So that is the primary driver of the year-over-year 30% decline, is the decline in Haynesville wells. Then -- and then the relative proportion of volumes, as you can see from our production chart, is dominated by Haynesville as well.

Andrew Coleman - *Raymond James*

Okay. And thinking about the eight rigs you guys are looking at getting to in the Bakken, did you discuss kind of the breakdown between, I guess, your Fat Cat, South Antelope and Fort Berthold?

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

We haven't, and I would think of those rigs as a cloud that will move primarily between the two southern assets, the Antelope and the Fort Berthold assets. The Fat Cat area has relatively lower EURs, lower well costs, slightly less returns than either of the Fort Berthold or the South Antelope area.

What the new acquisition gives us, Andrew, is the flexibility to move rigs back and forth. The two concentrated block of acreage are only about 12 miles apart, so we can jump back and forth between them to optimize around completing pods of wells on pads, et cetera.

But notionally, I would think around three rigs running for most of the time on the reservation, and the other five running on the newly-acquired acreage. But sometimes there may be eight running on the newly-acquired acreage and none on the reservation, as we move rigs out to complete wells and before we move them to the next pad.

Andrew Coleman - *Raymond James*

Okay, great. Thank you very much.

Operator

James Spicer, Wells Fargo.

James Spicer - *Wells Fargo - Analyst*

Switching gears for a minute to the Powder River, just wondering how you view the results of your two recent wells drilled up there in the context of that first well, which came in at a higher rate. And then secondly if you could just update us on the permitting situation out there, that would be great.

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

Okay, the two subsequent wells were obviously not as high a rate. The second well, which was the first well that's mentioned in the release, had a mechanical problem. We apparently had a sleeve -- it was a slotting sleeve completion, and we apparently had a sleeve near the heel of the well open early in the frac stages. We don't know if it was the first stage or four or five stages in, but very early in the frac stages. And we basically restimulated the same zone over and over again after that.

So what we saw was a well that came on at about, what, 600 barrels a day or so, from what appears to be -- was only maybe at most 30% or so of the lateral length. It may even have been from a single stage. And we could never really tell that for sure because what we did was, we've gone back in and we've drilled out all of the baffles and we restimulated that well. The well is now starting flowback and cleaning up again and we will see if it is any better. It is just now coming back online and starting to clean up.

But I was actually impressed by the rate, 600 barrel-a-day rate, from a partial wellbore there. And it's in a good area and it should have been a much better well than the reported rate.

The third well, or the second well in our release, was designed to test a thinner part of the Sussex in an area sort of -- to try to delineate the margin of the sand body. So we expected it to come on at a lower rate. We think it is probably still an economic well. It didn't come on as high of an initial rate, but it is producing at a -- continuing to produce at a pretty decent stabilized rate. But it obviously is helping us delineate the margin of the sand body.

And for your third question, we still don't have any permits. We are still struggling with the local BLM field office. They've got an almost two-year backlog now of permit applications from us and the other operators that are active in the Powder. And there is no new news of encouragement there.

James Spicer - *Wells Fargo - Analyst*

Okay. That's very helpful color.

My next question, just curious -- and it may be that these numbers weren't apples-to-apples to begin with -- but when you announced the Bakken transaction in late August, I think you announced that current production there was 10,500 barrels a day. The recent number you gave was 8600 barrels a day. Just wondering if you can reconcile those two.

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

First of all, those are BOEs, not barrels a day. And they are accurate. You look at it over at the period of time from the time we announced the transaction in early August, there were a number of wells that had just been completed. Those wells declined. And we just completed the first well after that announcement a few weeks ago, came on at 2600 barrels a day, I think. And we have another well waiting on completion. As we shift the pad drilling now, we will see that inventory of wells coming online accelerate.

But it is a normal -- it's part of this normal lumpiness that I described at the outset, where we'll have slugs of wells coming on and stair-step of production, with intervening periods where the production will decline. So there is nothing you should read into this about asset quality or operations or anything. It is just the normal sort of what I would call an inclined sawtooth of production growth as we bring on new wells over the ongoing development of the project.

James Spicer - *Wells Fargo - Analyst*

Okay. It makes sense. Thank you very much.

Operator

This concludes the Q&A portion of today's call. I will now turn it over to Mr. Stanley for any closing remarks.

Chuck Stanley - *QEP Resources, Inc. - Chairman, President, CEO*

Thank you, Keisha. At the conclusion, I would like to first say that we know that many of our friends along the East Coast have had a really tough week. I want you to know that your friends here at QEP are thinking about all of you, and we wish you the very best for a speedy recovery from the impacts of what is clearly a very destructive storm.

I'd like to thank you for calling in today, and I'd like to thank you for your interest in QEP, and we look forward to seeing you soon at upcoming conferences.

Operator

This does conclude today's conference call. Thanks for your participation. You may now disconnect.
