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QEP - Q4 2011 QEP Resources, Inc. Earnings Conference Call

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OVERVIEW:

QEP reported that 4Q11 net income from continuing operations was essentially zero.

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PRESENTATION

Operator

Good morning. My name is Carmen, and I will be your conference operator today. At this time I would like to welcome everyone to the QEP Resources fourth-quarter earnings conference call.

All lines have been placed on mute to prevent any background noise. After the speakers' remarks, there will be a question-and-answer session. (Operator Instructions).

I will now turn the conference over to Richard Dolesheck, Chief Financial Officer. Please go ahead, sir.

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

Thank you, Carmen, and good morning, everyone. This is Richard Doleshek, QEP Resources' Chief Financial Officer. Thank you for joining us for our fourth-quarter 2011 results conference call.

With me today are Chuck Stanley, 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 Scott Gutberlet, Director-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 it is reconciled to net income in the earnings release.

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

The close of the fourth quarter marked our first fiscal year of operations as an independent company since being spun off from Questar Corporation on June 30, 2010. During the year we had numerous important accomplishments and delivered record results in many areas.

In terms of reporting our results, we issued a combined operations update and earnings release yesterday in which we reported fourth-quarter and full-year 2011 results. We reported fourth-quarter 2011 production of 73.9 Bcfe, and full-year 2011 production of 275 Bcfe, 56% of which came from our properties in our Southern Region. Of note, crude oil and natural gas liquids made up 18% of our total liquid in production in the fourth quarter.

We reported a 19% increase in year-end proved reserves, to 3.6 Tcfe, of which 54% were classified as proved/developed, and 24% of which were crude oil and NGLs.

The SEC pretax PV-10 of those reserves was $4.8 billion, up 33% from $3.6 billion at year-end 2010.

We updated operating activities in our core areas and we updated our guidance for 2012. We lowered our EBITDA guidance to be in the range of $1.35 billion up to $1.45 billion, driven by significantly lower natural gas prices, and we decreased our CapEx guidance to be in the range of $1.3 billion to $1.5 billion, which is still in line with projected EBITDA. We also reaffirmed our production guidance to be in the range of 305 Bcfe to 310 Bcfe.

As you've heard us say in the past, the current year capital program generally has more impact in the following year's production than on the current year's production.

At this point in my discussion, I would remind everyone about recasting our historical results as a result of spinning off from Questar. As we drop off 2010's result we won't talk about that recast any more.

However, in the fourth quarter of 2011 we changed the presentation of transportation expenses. Historically, we have netted transportation expenses against revenues. But are now reporting these expenses in a separate line item on the operating expense section of the income statement, and have recast historical revenue and historic product price data to reflect this change in presentation. What you will see in our earnings release is higher total revenues, higher QEP Energy revenues, lower revenues at Field Services, and higher prices for QEP Energy's production and Field Services NGLs. We will be happy to provide additional information about this during Q&A.

Turning to our financial results and comparing the fourth quarter of 2011 to the third quarter of the year, [this story] was significantly stronger performance at QEP Energy -- our E&P business -- and slightly stronger performance at QEP Field Services, our gathering and processing business.

QEP Energy reported sequentially higher natural gas, crude oil and NGL production, and reported net realized equivalent prices that were 9% higher quarter to quarter.

Field Services results were marginally higher than the previous quarter due to higher NGL volumes and prices.

Our fourth-quarter EBITDA was $390.5 million, which was $37 million or 10% higher than in the third quarter, and up $92 million or 31% from the fourth quarter of 2010.

QEP Energy contributed $300 million or 77% of our aggregate fourth-quarter EBITDA, and QEP Field Services contributed $87 million or about 22%.

QEP Energy's EBITDA was up about $33 million, while Field Services' EBITDA was $[2] million higher than the respective third-quarter levels.

For the full year, our EBITDA was $1.387 billion, which was almost $0.25 billion higher than a year ago, in spite of realized natural gas prices that were 11% lower than in 2010.

QEP Energy's contribution was $1.058 billion, which was $131 million or 14% higher than 2010. And QEP Field Services contributed $320 million, which is almost $116 million or 57% higher than 2010, and almost double what it was in 2009.

Factors driving our fourth-quarter EBITDA includes QEP Energy's production which was 73.9 Bcfe in the quarter or 5% higher than the 70.7 Bcfe reported in the third quarter of 2011. The quarter's production was 19% higher than 62.1 Bcfe in the fourth quarter of 2010. Of note, oil volumes were 1.2 million barrels, up 28% from the third quarter, and NGL volumes were 1.04 million barrels, up 16% from the third quarter of the year.

QEP Energy's net realized equivalent price -- which includes the settlement of all of our commodity derivatives -- averaged $6.08 per Mcfe in the quarter, which was 9% higher than the $5.58 per Mcfe realized in the third quarter of 2011, and 7% higher than the $5.70 per Mcfe realized in the fourth quarter of 2010. The higher equivalent prices reflected a growing percentage of oil and NGLs in our production mix.

QEP Energy's commodity derivatives portfolio contributed $66 million of EBITDA in the quarter compared to $45 million in the third quarter of 2011, and $78 million from the fourth quarter of 2010. The derivatives portfolio added $0.90 per Mcfe to QEP Energy's net realized price in the fourth quarter, compared to $0.63 in the third quarter and $1.25 in the fourth quarter of 2010.

QEP Energy's combined lease operating, transportation and production tax expenses were $122 million in the quarter, up from $109 million in the third quarter of 2011, and up from $91 million in the fourth quarter of 2010.

LOE was up 10%, transportation was up 23%, and production taxes were down 4% in the fourth quarter compared to the third quarter.

The increase in lease operating expenses and transportation expenses were largely driven by the increasing oil and NGL volumes in our production mix.

Finally, QEP Field Services fourth-quarter 2011 EBITDA was $87 million, which was about $2 million higher than in the third quarter of 2011, and 66% higher than in the fourth quarter of 2010. Gathering margin was down $6 million or 13% in the quarter compared to the third quarter of 2011, due to reduced volumes associated with a short-term, third-party gathering/processing arrangement.

Gas-gathering volumes were about 1.4 million Mmbtus per day, and the average gathering fee fee was $0.30 per Mcf.

Processing margin was up $10.5 million from the third quarter of 2011 on 28% higher NGL sales volumes, 6% higher NGL prices, but offset somewhat by strength in expenses that were sequentially $2.6 million higher and transportation expense that was $2.2 million higher in the quarter.

Fee-based volumes were down 7% from the third quarter while processing fees were up 12%.

In spite of a 10% increase in EBITDA from the third quarter of 2011, net income from continuing operations for the fourth quarter was essentially zero, primarily as a result of a $195 million impairment of producing properties. The impaired properties were mature, higher-cost dry gas properties, the value of which suffered from the lower forward curve for natural gas prices.

Exploration impairment and abandonment expenses in aggregate were $205 million in the quarter compared to $8 million in the third quarter of 2011. DD&A expenses were $10 million higher in the quarter compared to the third quarter, and our provision for income taxes was a credit of $2 million in the quarter compared to $59 million of expense in the third quarter of 2011, due to the impairment charge.

Assuming no change in the tax code we still expect that we will not be a cash tax -- cash income tax payer in 2012.

For the full year we reported capital expenditures on an accrual basis of $1.45 billion, capital expenditures on E&P activities were $1.34 billion, including $48 million on property acquisitions, and capital expenditures in our Midstream business were $102 million for the year.

Late last year we announced a capital budget for 2012 was $1.5 billion. As a result of the current low natural gas pricing environment we are revising our 2012 capital program and believe our spending will be in the range of $1.3 billion to $1.45 billion, and Chuck will have more comments about our capital program in his prepared remarks.

Our balance sheet grew by about $650 million during the year. We reported total assets of $7.4 billion, net PP&E of $6.4 billion, common shareholder equity of $3.3 billion, and total debt of $1.7 billion which is a 1.2 times multiple of 2011 EBITDA.

We ended the year with $606.5 million drawn under our $1.5 billion revolving credit facility, which was up $206.5 million from the amount drawn at the end of 2010. And part of that increase in the revolver balance was due to refinancing $58.5 million of senior notes that matured in March under the revolver.

I will now turn the call over to Chuck.

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

All right. Good morning, everyone.

Richard has already reviewed our fourth-quarter 2011 and full-year results; I will try to add some color, and give you an update on our plans for 2012 and then move quickly to Q&A.

First, some highlights -- QEP Energy grew production 20% in 2011 to a record 275 Bcfe. That's an average of 754 million cubic feet of gas equivalent a day, and it was driven by great results in all of our operations.

Fourth-quarter 2011 production was 73.9 Bcfe or 803 million cubic feet a day. That's a 19% year-over-year increase from the prior quarter.

We are making good progress as Richard already noted, on growing oil and NGL production. QEP Energy crude oil and NGL production totaled 6.5 million barrels in 2011. That's compared to 4.2 million barrels in 2010, a 54% increase. And that growth is accelerating. In the fourth quarter of 2011, crude oil and NGL production totaled 2.2 million barrels, a 75% increase over the 1.3 million barrels we produced in the fourth quarter of 2010. And the percentage of our proved reserves represented by crude oil and NGL at the end of 2011 also followed this same growth trend. I will give you a little more color on that when I talk about reserves in a minute.

For 2011, QEP Energy grew Southern Region production 28% from 2010 levels, to a record 153.7 Bcfe. Midcontinent production, driven primarily by the liquids-rich plays of Cana, the Marmaton, Tonkawa and the Wash plays, was 46.2 Bcfe for 2011, up 14% from a year ago.

Production from the Haynesville and Cotton Valley area was 107.5 Bcf in 2011, a 35% increase from a year ago.

Importantly, Southern Region crude oil and NGL production grew 31% in 2011, to a total of 2.3 million barrels. And of that 2.3 million barrels, crude oil comprised 39% of the total Southern Region's liquids production.

In the Northern Region, production totaled 121.5 Bcfe in 2011; that was a 12% increase over 2010. Northern Region production was driven by a 16% increase in production from Pinedale, a 14% increase in Rockies' legacy production. And that was offset by a slight decline in the Uinta Basin volumes.

Northern Region crude oil and NGL production totaled 4.2 million barrels in 2011; that's a 69% increase over 2010. This dramatic increase was driven by a near doubling of our crude oil production in the Rockies' legacy division, primarily from the Williston Basin, and from the onset of NGL production at Pinedale that corresponded with the startup of the Blacks Fork II processing plant late in the second quarter of last year.

Crude oil comprised 68% of the total volume of liquids produced in the Northern Region in 2011.

Now let me turn to our 2011 year-end proved reserve estimates. As Richard noted, QEP Energy reported total proved reserves of 3.61 trillion cubic feet of gas equivalent at the end of 2011, and that's a 19% increase over year-end 2010 volumes. 54% of the total estimated year-end 2011 reserves were categorized as proved/developed. Of the total proved reserves, 67.5 million barrels or 11.2% on a 6 to 1 gas-equivalent basis was crude oil, and 76.6 million barrels or 12.7% was natural gas liquids. The remaining 2.75 Tcf was -- I'm sorry, 2.75 Tcf or 76% was natural gas. Crude oil and NGL comprised 24% of our year-end 2011 estimated total proved reserves. That's a 107% increase over a year ago, when liquids-only comprised 14% of our total proved reserves.

And in case you were wondering, the increase was simply not the result of booking additional PUD locations. QEP's year-end 2011 proved/developed crude oil and NGL reserves totaled 71.3 million barrels or about 22% on a gas-equivalent basis of the estimated 1.97 Tcf equivalent of total proved/developed reserves.

Also note the big increase in crude oil and NGL reserves combined with higher prices drove -- as Richard has already noted -- a significant increase in QEP Energy's pretax SEC PV-10 reserved value which at year-end 2011 was $4.8 billion. That compares to $3.6 billion at the end of 2010. And for those of you who prefer to use [smog] values, the standardized standardized measure of future net cash flows was $3.5 billion at the end of last year, compared to $2.7 billion at the end of 2010.

The QEP Energy team did a quite -- quite a good job of replacing production in 2011, and excluding price-related revisions we replaced 313% of our 2011 production. And the QEP drilling and completion capital for 2011 totaled approximately $1.29 billion. Of course, we will have a lot more detail on all of the reserved information in our 10-K, which will be submitted this afternoon and should be available on the SEC website tomorrow.

Turning to Field Services, our Midstream business had an awesome year, both financially and operationally. In January of 2011, Field Services commissioned and started up the 150 million cubic feet a day Iron Horse deep cut cryogenic processing plant adjacent to our existing Stagecoach hub in the Uinta Basin, in eastern Utah. This success was followed in mid-July with the startup of the 420 million cubic foot a day Blacks Fork II deep cut cryogenic plant in southwestern Wyoming. And of course that plant, as you all know, came on well ahead of schedule.

With the startup of Blacks Fork II QEP Field Services owns and operates gas processing facilities in the Rockies with an aggregate processing capacity of 1.37 billion cubic feet of gas per day. The startup of Iron Horse II and -- I'm sorry, Iron Horse and Blacks Fork II combined with near record frac spreads helped propel Field Services record operating and financial results in 2011.

We gave you a lot of details on our current drilling activities and results in our release yesterday, so I'm not going to repeat that information here today. Let me draw your attention to the slides that accompanied the earnings and ops release yesterday that are available on our website at QEPRes.com.

As you know, natural gas prices have dropped dramatically since we gave our initial production guidance and financial guidance back in November of last year. In response, we have made and will likely continue to make significant changes in our capital allocation at QEP Energy.

We've tried to summarize those changes graphically on slide four in the slide deck. You'll note the dramatic decrease in capital allocated to the Haynesville play. When we first gave guidance for 2012, we anticipated having two QEP-operated rigs working in the Haynesville play in 2012, and nonoperated activity in line with what we have been seeing late last year.

Today as we do this call, we are down to one QEP-operated rig in the Haynesville Shale, and if prices remain weak we will drop that remaining rig this summer when it finishes drilling 80-acre development wells in the section it currently occupies.

We are also assuming, based on recent AFE activity, that nonoperated activity will be greatly reduced below 2011 levels.

Note that we are now allocating 88% of our forecasted capital in QEP Energy to crude oil and liquids-rich natural gas plays. Our focus will be on driving crude oil production in the Northern Region in the Williston Basin, Bakken/Three Forks play, the Powder River Basin, Sussex/Shannon play, and in the Uinta Basin, the Green River oil play.

We are keeping our eye on widening regional crude oil price differentials, particularly in the Bakken. Caused by refinery turnarounds and tightness in takeaway capacity, we think that this will be a temporary phenomenon that should away with the restart of idled capacity -- refining capacity and additional takeaway capacity. But if the base's blowout persists, we will make adjustments to our capital allocation.

In the Southern Region, we are focused on driving crude oil and liquids growth in Tonkawa, Marmaton and Wash plays. We will also allocate significant capital to the liquids-rich gas plays in the Uinta Basin, Mesaverde and Pinedale in the Northern Region, and to the Cana Shale play in the Southern Region.

Our release gives you a lot of information on our current thinking on rig count in each of the key plays and other details. Jay Neese is here with us today, and I'm sure he would be happy to give you additional color on the individual plays and on our thoughts on our evolving capital plans at QEP Energy.

As for QEP Field Services, our capital plans haven't changed much from the program that we described to you back in November. We still plan to invest roughly $170 million in several major projects and a number of smaller ones. We will soon commence field construction on our next cryogenic gas-processing plant, Iron Horse II, in the Uinta Basin of eastern Utah. That plant, just like the original Iron Horse plant, will have an inlet capacity of 150 million cubic feet of gas a day, and we would expect that it will be up and running in early 2013.

Importantly, about half of the Iron Horse II plant capacity is contracted with a third-party producer under a fee-based processing arrangement. And the other half will be available to process QEP Energy's growing liquids-rich gas volumes from the Red Wash/Mesaverde play.

Field Services is also working on final engineering and design and cost estimates for a 10,000 barrel per day NGL fractionater on our Blacks Fork complex in western Wyoming. Combined with the existing 5,000 barrel per day fractionater at Blacks Fork, this facility is designed to provide additional options for marketing purity propane, normal and iso butane, and gasoline products to what many times are premium-value local and regional markets via our truck and rail loading facilities at the plant. Assuming final construction cost estimates come in in-line with their preliminary cost estimates, we will commence construction on this facility in a few months and the project should be in service toward the end of the second quarter of 2013.

I know many of you have asked us in conferences about NGL prices. And since the end of the year we have, in fact, seen a significant decline in NGL prices, particularly ethane.

Part of this softness is due to seasonal plant turnarounds in the ethylene complex, which exacerbates the tightness between ethane supply and demand.

And the relatively mild winter that we've had has also resulted in less propane being used in heating, which has had the knock-on effect of hurting ethane prices as some of the excess propane is being cracked to ethylene.

We saw similar price softness in ethane last year at this time due to plant turnarounds, but it feels a little worse this year, no doubt because of the increased ethane production and added pressure of excess propane availability.

It's important to note that the raw NGL product from our plants in the Rockies all ends up at Mont Belvieu, which is the premium market for NGLs. We contract for both transportation and fractionation capacity that facilitates our sale of purity products into the Mont Belvieu market. And despite the pullback in prices, field services processing margins remain well above historic levels.

In summary, at the macro level we are finally seeing some signs that dry gas drilling is slowing, as we and other operators continue to drop rigs in the Haynesville and other dry gas plays. But the supply response will obviously take a while and will lag the downturn in rig count.

Given storage levels, we've been very defensive on natural gas prices for the remainder of 2012, and as you've probably noticed in our release we've added additional derivative positions to protect against possible weakness, especially during the shoulder months in the fall. We now have derivative contracts covering 65% of our forecasted 2012 natural gas production.

Finally, as a person who talks to you about these great results, I have to tell you that none of this would be possible without the efforts that each and every one of our dedicated and talented employees. We believe with continued investment in our high-quality E&P portfolio and in our complementary Midstream business, executed by some of the best men and women in the industry, QEP is well positioned to drive profitable long-term growth for our shareholders in 2012 and beyond.

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

QUESTIONS AND ANSWERS

Operator

(Operator Instructions). Brian Corales.

Brian Corales - *Howard Weil Incorporated - Analyst*

Good quarter. Can you -- with the success you had in Oklahoma, I guess I would have thought we would see an increase in the capital budget there. Can you maybe talk about that a little bit?

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

Brian, this is Chuck. We are focusing on Oklahoma and looking at the opportunities to drive more capital in the business. There's opportunities to add a rig maybe in the Cana Shale play also as we see results in both the Marmaton and Tonkawa and in the Texas Panhandle wash plays -- particularly the shallowest wash plays where we've seen some very strong recent well results -- we can respond by continuing to reallocate capital away from dry gas and particularly the Haynesville, as we get better clarity on outside operated activity through the year.

We are not making that allocation today, because we just don't have good visibility around how much capital we will need to spend in the Haynesville. So we've been fairly conservative in our estimates at this point. But rest assured, we are focused and our teams are focused on driving liquids and crude oil production across our business, and we're looking for opportunities to redeploy capital to do that.

Brian Corales - *Howard Weil Incorporated - Analyst*

Okay. And then can you remind us, on the realizations with the NGL and potential condensate in the Red Wash, what the realizations are, say, at $3.00 gas?

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

The uplift from condensate and NGL for Red Wash?

Brian Corales - *Howard Weil Incorporated - Analyst*

Yes.

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

It's over $1.00. Yes, it's a little over $1.00. I can't give you the exact number, Brian, but if you take $3.00 gas, it adds at least $1.00 to the wellhead realization.

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

And Brian, about a third of that production volume that's going to come out of those Red Wash wells is going to be condensate and NGLs. So if you kind of do -- if you want to calibrate with whatever price you want for the liquids side, that should help you. Two thirds of the volume is gas, one third is going to be liquids.

Brian Corales - *Howard Weil Incorporated - Analyst*

That's helpful, okay.

And then finally, with your balance sheet, you know, obviously I'm sure you've looked at assets; have you all looked at or talked about potential share buybacks?

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

You know, we have. There's obviously a number of things we can do with cash. We could pay down our existing debt, we can increase the dividend. We can buy back our shares, or we can invest the capital in projects that we think generate better returns than our cost of capital.

And we think we still have in our portfolio, a number of opportunities that we are not funding, which generate better returns than the share buyback. And there's been a lot of studies done, I'm sure; a number of Harvard Business School PhD's written on the wisdom of share buybacks and the long-term impact on the share price. And I think the jury is out on whether or not share buybacks really generate meaningful long-term increases in stock price.

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

And Brian, I will add the CFO's perspective -- you know, liquidity in a down gas-price environment I think is a premium for us, and so I think if we had to figure out what to use our dollars for, I would prefer us to either keep lots of dry powder or to direct stuff to -- you know, liquids-rich stuff versus buying back shares. So that's my perspective.

Brian Corales - *Howard Weil Incorporated - Analyst*

All right, guys, thank you.

Operator

David Heikkinen.

David Heikkinen - *Tudor, Pickering, Holt & Co. Securities - Analyst*

I had a question for you as you think about heading through the year and into next year, as far as your liquids percentages. Where do you think you would exit this year with 88% of your capital going into liquids? And then the same thing next year -- some general thoughts around that would be helpful.

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

Well, David -- Chuck again -- if we just assume that the normal pattern of organic growth, it will be a gradual shift to higher and higher liquids content, maybe 25% or so by year-end, 30% by the end of 2013.

Part of that obviously depends on how hard we continue to pull back on gas-directed capital because, obviously, as we put less capital into the Haynesville, for instance, we will start to see declines in production in that property, and that will change the ratio as well.

David Heikkinen - *Tudor, Pickering, Holt & Co. Securities - Analyst*

And that kind of feeds into the, as you think about that liquids increasing, what is your base decline on your gas assets? (technical difficulty) next year?

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

Well, I can't tell you what it is on an asset-by-asset basis. We look at our aggregate PDP decline as 26% or 27% -- Jay?

Jay Neese - *QEP Resources, Inc. - EVP and Head of E&P*

A little bit more, 22%, 24%.

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

24%? Okay.

David Heikkinen - *Tudor, Pickering, Holt & Co. Securities - Analyst*

That's the first year, and then it will become more (multiple speakers) --?

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

And then obviously it flattens as you go into the out years.

David Heikkinen - *Tudor, Pickering, Holt & Co. Securities - Analyst*

Okay, that's helpful. And then in the Sussex and Shannon, I wanted to get some of your thoughts around offset well results, and then how many wells you could start drilling and permitting process around that, in the Powder?

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

Okay, I will take the last question first. The permitting process has been frustrating. As we have communicated in previous calls, almost every 640-acre unit in which we want to drill has at least an acre of federal minerals, and as a result we have to apply for and receive APDs from -- or drilling permits from the BLM. And it has been a very protracted process. And we and all the other operators are seeing the same delays in permit issuance. We have permits that have been filed with complete permit packages for over a year that we are still waiting on issuance.

So that is a challenge, and that is one thing that as we've said before, we don't want to move a rig in until we have a program that we can drill rather than just drilling one-off wells.

So we are waiting on permits. We are seeing some permits pop out the other side but it has been painfully slow.

Second question -- sort of in reverse order -- we've seen some very strong offset wells drilled by other operators in the play, primarily by one private company based in Tulsa who has done quite well, drilling horizontal Sussex wells.

There have been very few Shannon wells drilled, but if you look at the logs and you look at the production from the old vertical wells in the Shannon -- and by the way, David, there is a type log out in our Analyst Day presentation from last November that you can see the section, the geology looks the same. They are both deposited in the same sort of depositional environment, they both look the same on the logs as far as porosity and permeability. And the vertical well results in the area exhibit very similar drainage characteristics.

So, we don't see much difference geologically between the two; we just don't have any meaningful horizontal well results in the Shannon, unlike the Sussex where there are quite a few wells now.

David Heikkinen - *Tudor, Pickering, Holt & Co. Securities - Analyst*

Okay, and then one kind of follow-up question related to my prior question, is as you think about plants coming on, you just sanctioned another plant -- I mean, what is your QEP Field Services kind of targeted growth for that 1.37 Bcf a day of capacity? How does that grow over the next two or three years?

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

Well, I think if you, again, refer back to the presentation that Perry Richards gave in November, he elucidated a list of projects for the next four or five years that propelled a trajectory of sort of midteens growth in EBITDA and in the underlying businesses that would generate that EBITDA. It's lumpy, remember, because you can't build half a plant even though sometimes we would like to.

So you'll see some years where there will be substantial capital programs, other years where we will generate a significant amount of free cash flow.

David Heikkinen - *Tudor, Pickering, Holt & Co. Securities - Analyst*

Thanks, guys.

Operator

William Butler.

William Butler - *Stephens Inc. - Analyst*

Congratulations, guys. Looking at the recast of the financials on the impact to natural gas prices, as you look back now it looks real close to NYMEX with a decrement just on non-hedged basis. What is that attributable to? I would have thought that would be wider. Is there some rich gas in there that is helping that? How would we think about that going forward?

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

There is, William. I mean, if you kind of just -- you try to break all the pieces down, and if you think about what has happened to the basis differentials in the regions, over the last two years, the basis collapsed; we are seeing of a $0.15 two $0.20 basis. And then you think about Haynesville getting priced close to NYMEX, and you do the math on the percentage of volumes coming there versus the Rockies, and if you kind of do a BTU upgrade you're going to get the 20-ish kind of numbers that I think you are calculating. So it's just the BTU uplift versus -- and then the geographic locations and the shrinking basis in the Rockies.

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

Although really we see no difference in basis between the Rockies and any of the Midcontinent sales points today.

William Butler - *Stephens Inc. - Analyst*

Yes, it's all baked into the transport fee, then, right?

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

Yes, but the actual sales point pricing is basically exhibit very little difference across the country. There's very little basis differential.

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

And even in the fourth quarter we had some days where Rockies basis was positive relative to NYMEX.

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

That's exactly right.

William Butler - *Stephens Inc. - Analyst*

So that's a good number to use going forward, then -- sort $0.15 to $0.20 off?

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

Until it changes. (laughter)

William Butler - *Stephens Inc. - Analyst*

And looking at '12, thinking about your breakdown of gas, NGLs and crude oil, it looks like sort of implied you are looking at about 81% of production being gas. What do you think -- is that right, and then what do you think the split between NGLs and crude might be?

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

I think that's a reasonable number. 80% gas, 20% liquids, and 50/50 on crude oil and NGLs.

William Butler - *Stephens Inc. - Analyst*

Okay.

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

More or less.

William Butler - *Stephens Inc. - Analyst*

Okay. And then how do you all -- as you all think about 2013 and your ability to try to grow 10%-plus, or call it 10% to 15%, how does --? Given the current gas-price environment and the lack of capital going into the Haynesville, I mean, how does that impact your ability to continue operational momentum as Richard alluded to in his comments, going into 2013?

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

Well, obviously it's a challenge. You know, we are more focused on driving EBITDA growth, and obviously that's pushing us toward higher margins, and that necessitates drilling more oil wells and more liquids-rich gas wells, and steering clear of the Haynesville in this environment.

I think it's too early in the year to predict what the forward curve is going to look like going into 2013. We certainly are concerned about putting much capital in the Haynesville. And we will see what we can do with respect to driving growth from the liquids-rich gas portfolio as well as oil.

Moving more rigs into the Bakken, moving more rigs into some of these liquids-rich plays like the Wash plays -- prolific oil wells, but they also make a lot of gas. So I'm not discouraged with what I'm seeing in the portfolio as far as our ability to shift away from the Haynesville and not suffer dramatically from the declines that we know we will see there in 2013.

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

I think -- William, this is a little bit of color -- even if you saw production that was only a single digit growth from 2012, you would see margin expansion, you would see EBITD growth with the forward curve just because of the increasing mix of liquids relative to dry gas. So we would like for you not to get hung up on production growth, but look at EBITD or margin growth as well.

William Butler - *Stephens Inc. - Analyst*

Okay. And then thinking about stepping through the 2012 quarterly, what do you all feel comfortable with in the first quarter? Will we see more a sort of lag affect growth through gas for a quarter or two before it starts to fall off, and how do we need to think about the first quarter?

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

You know, we have never given quarterly guidance, and there's a couple of reasons for that. One, there are always operational things that go bump in the night that we can't prognosticate.

Two, we have seasonality in our production volumes as a result of our intentional shutdown and completion activities in the Rockies, particularly at Pinedale, due to weather. And weather becomes a fairly significant component, and when we start completion activity back up at Pinedale -- and those are significant volumes, and the liquids associated with that gas production is significant as well.

So we really would like for people to own our stock for more than a quarter, and we would like for you to think about growth over a longer time period, and that's why we steer clear of quarterly growth, and quarterly guidance.

William Butler - *Stephens Inc. - Analyst*

Okay, I appreciate that. Well, that's all I've got; thank you all.

Operator

Greg (inaudible).

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

Hello, Greg?

Operator

Greg, your line is open, if your phone is on mute, please unmute your phone.

Unidentified Participant

Sorry about that. So, you know, there's been a couple of questions obviously focused on the liquids growth. And there was a comment made during the prepared remarks that if gas prices remain weak, that you will drop the final rig in the Haynesville, maybe in the summer.

I guess my question is around, is the word weak an absolute or relative statement? In other words, let's say gas prices rally $1.00, $1.50, but you really have great results in your liquids plays this year. And we still have $90 up to $100-plus oil, and decent correlations of NGLs to oil, 50% range.

Would you look at that and say, look, the returns in the liquids are just too much; we are going to spend all our available cash flow on liquids, even if gas is in the money? Or do you look it at it more as diversification? How do you think about that?

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

Well, that's a great question and the answer is, if you think about our philosophy, we allocate capital to the projects that generate the highest returns. And a lot of the Haynesville drilling activity has been focused on saving leases, and more recently we've intentionally drilled some 80-acre space development wells in several sections across our acreage to get long-term production performance on those wells so that we can determine -- and I really believe that the only way you can determine the ultimate well density is through actual well performance over a multiyear period. So we are intentionally drilling some wells on 80-acre spacing now, even in the current gas price environment, to get long-term production data.

The answer to your question is, dollar-changing gas prices -- we would probably continue to down the path of driving liquids and oil production growth, because those are much higher returns. We give you quite a bit of granularity on the returns that we expect to achieve in our Investor Relations packet that and you can look at and you can see the sensitivity to gas price.

The final thought that I would leave you with on the Haynesville is we haven't -- we've seen some softening in service costs and, therefore, at least the beginning of traction on pushing down well costs, but the well costs are still quite high from what you would anticipate, given the downturn in rig count. And the reason is that the frac crews have moved away from the region and gone to other areas.

So when we think about the Haynesville program, I think it makes sense to look at it for a while in a higher gas price environment. And if we are going to back to it, I think we need to go to it with more than one rig or two rigs. It needs to be a meaningful program so that we can achieve the economies of scale that we had when we were running six rigs last year, because I think that's really the only way you are able to drive down well costs -- which could make the Haynesville even more competitive in our portfolio, if we could whack $1 million or $1.5 million off of the completed well costs. And even at the current gas price, you start to look at it. I don't think you actually jump headfirst into it, but you start to look at it in your portfolio and start arguing about allocating capital to it.

Unidentified Participant

Those comments sound very similar to some others we heard yesterday when we had another company in our offices, and they said with similar opportunities for liquids plays outside of the Haynesville, that they would need $5.00 gas to return to the Haynesville, given what they have on their plate.

In light of all your opportunities, if it continues to perform well in your growing liquids plays, is that a reasonable statement?

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

I can't opine upon what they said, but (multiple speakers) -- .

Unidentified Participant

But, I mean, for your situation?

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

It depends upon, it depends upon what happens to well costs, obviously. Completed well costs drive the economics.

Our returns, at our current well costs, start to make sense in the $4.00 to $4.50 gas price range, but as you pointed out, once you exit or once you turn down the activity level -- and as I pointed out to you, we would want to come back in with a meaningful program, not just one rig running in the play. So that would require us to have substantially higher EBITDA, and we think we will be driving that through our oil and liquids-rich program, and maybe we can fund additional capital in the gas plays in coming years.

Unidentified Participant

Great, that's good color, I appreciate it.

Operator

(Operator Instructions). Eli Kantor.

Eli Kantor - *Jefferies & Company - Analyst*

At a certain point last year, you had talked about potentially scaling up to five rigs in the Bakken. Can you give us a sense of what needs to occur within the basin for you guys to add activity there, and when that might occur?

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

Well, one of the things I had in my prepared remarks but I deleted for sake of brevity, was a discussion of working through our inventory that we had at the end of the third quarter, of -- at one point we had 12 or 13 wells standing, waiting on completion, and we couldn't get frac crews timely to complete those wells. We worked through that inventory in the fourth quarter, in what normally was the onset of winter, is typically a difficult time from an operational perspective.

And the feeling we have today is that services are generally more available, and the quality of the service delivery is better than it was last year. We are seeing that from both our own activity as well as from outside-operated activity. So that's encouraging, and in fact around this table we have had discussions about adding a fourth rig in the play as early as May, maybe late May or early June, and then stepping in with a fifth rig later in the summer.

But we want to make sure as we make those commitments, that we are able to deliver a completed wells and production associated with that incremental capital.

But the signs are encouraging. The only thing that tempers that is, as I mentioned in my prepared remarks, some concern over this temporary widening in basis differential for Williston Basin crude oil that we believe is directly related to refinery turnarounds and in some capacity, takeaway capacity issues that should be resolved here in the next month or two.

But other than that, we are focusing on trying to push capital to the Bakken/Three Forks play throughout the year, and obviously we will be updating you on our success in doing that as we go forward through the year.

Eli Kantor - *Jefferies & Company - Analyst*

Is your Bakken production primarily piped out of the basin, or is it transported via rail car?

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

It all leaves the wellhead by pipe. Some of it ends up in rail cars and some of it ends up in pipelines. We sell to a handful of different crude oil purchasers, and really we don't know exactly where the barrels go. Our estimate is, maybe 20% of it or so, 25% of it ends up going by rail, and the remainder by pipe.

Operator

Josh Silverstein.

Josh Silverstein - *EnereCap Partners - Analyst*

I was curious, just staying within the Bakken, the $9.5 million well cost that you guys were estimating for this year -- is that just based on, like, a 2- or 4-well pad, and do you think the 10-well pad will have cost reductions from that? Or is that kind of the estimate for that 10-well pad?

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

Josh, you get a little savings obviously, because you are just building one surface location. Just on the dirt work and the facilities. And you probably get a little savings in the rig moves and sequentially fracking wells.

It's -- we don't have enough experience yet in drilling pad wells to really have a good feeling on how much savings we are going to be able to deliver there. Earlier, I thought we would be on the able to cut $300,000, $400,000 out of completed well costs. We just haven't seen well costs stabilize enough to be able to really meaningfully measure that savings. And until we see the service costs and our well-delivery system sort of stabilize, it's hard to measure that savings.

Intuitively, it should be there, but I haven't seen it in the bills that are coming in.

Josh Silverstein - *EnereCap Partners - Analyst*

Got you, understood. And then moving over to the Red Wash play in the Uinta Basin, I know your focus has really been on the vertical wells; I was curious, during the kind of 40 wells that you guys are targeting this year, if there was going to be a handful of horizontal wells.

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

So, Josh, the Mesaverde play is a series of stacked, discontinuous sands that are very similar to the reservoir architecture that we see at Pinedale. They exist over about a 3,000-foot vertical interval, and so they really are not amenable to horizontal drilling and horizontal development. The sands are, themselves, discontinuous so you really -- you have the old bowl of potato chips we used to talk about all the time at Pinedale, and it is kind of a worn-out verbal picture of what goes on in the subsurface, but it's exactly the same issue.

So we do, however, drill a number of -- we've drilled in the past, in fact -- in fact last time I checked, we had the most horizontal oil wells in the Uinta Basin, by far. We've drilled, what? Close (multiple speakers) -- 46 horizontal wells to date. We plan to pick up a rig and drill some horizontal oil wells targeting thin continuous reservoirs in the Green River formation this year. And obviously, we will continue to watch the wells that we are drilling down into the deeper Mesaverde, because they will be cutting this entire oil-bearing Green River section and may present us with some follow-up opportunities to drill some development wells off of the control that we are establishing with those 40-plus Mesaverde Wells.

Josh Silverstein - *EnereCap Partners - Analyst*

Got you, that's helpful. And then just lastly for me, just thinking about the returns for the new Iron Horse II plant, the last Iron Horse [II] plant is obviously paying itself back pretty quickly. I was curious if the Iron Horse plant had the same type of economic metrics to it?

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

So, one -- a couple key differences. One is that the capacity of the Iron Horse II, about 50% of that or so, roughly half of it, is contracted on a fee-based processing arrangement with a third-party producer. And those fees are set to generate acceptable returns. I don't want to tell you exactly what those returns are, because then the fee-based contract contractor that we have signed up with will be calling.

But they generate -- it generates quite acceptable returns, and then the upside of the opportunity to accelerate the recovery to capital is on the frac spread. And Field Services is going to be negotiating with Energy on that capacity, and it might end up getting transferred to Energy. So the shareholder will see it.

You know, a good sense, Josh -- and Iron Horse I had a similar contract structure period, about half fee-based and half keyhole processing.

Iron Horse I paid out --

Jay Neese - *QEP Resources, Inc. - EVP and Head of E&P*

-- in a little over a year, a little bit over a year. We were just shy of a year, on payout.

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

Okay. So, using that as an indicator, that gives you a sense on contract mix and what it means for payout on Iron Horse II. (multiple speakers) assuming similar NGL prices, of course.

Josh Silverstein - *EnereCap Partners - Analyst*

Right. Great; thanks, guys.

Operator

(Operator Instructions). Winfred [Brauhau].

Winfred Brauhau - *- Analyst*

What ratio do you use to convert liquids into natural gas equivalent?

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

Winfred, this is Chuck Stanley. We are -- report those on the same ratio as crude oil, which is a 6 to 1 ratio. And clearly the value of those liquids is much greater. The SEC requires that we used 6 to 1 in all of our conversions for reserve reporting and for production volume reporting.

Winfred Brauhau - *- Analyst*

Well, it might not be of much use to argue with the regulatory bodies, if something is obviously totally out of whack, wouldn't it be time for the industry to to the SEC and propose a different conversion factor? Because if you use a 6 to 1 ratio, you vastly understate your liquids production.

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

Very valid point. (multiple speakers)

Winfred Brauhau - *- Analyst*

(multiple speakers) It's closer to 30 to 1, depending on what day we are looking at.

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

I agree with you. The 6 to 1 ratio has been invalid for at least 10 years. It got -- it was 10 to 1, 10 years ago, and it has progressively deteriorated since then. So we can make that argument. I mean, one of my colleagues in another company make it first and I will be right there behind them to back it up.

Winfred Brauhau - *- Analyst*

Well, the way I see it is, if something is invalid, no useful purpose is being served to disseminate to investors invalid information. And what I would like to suggest is, why don't you use netback per barrel and netback per million BTU in the ratio between the two, for converting equivalency?

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

Clearly a valid suggestion, something we will take under consideration.

Winfred Brauhau - *- Analyst*

Okay, that's all I have; thank you.

Operator

Andrew Coleman.

Andrew Coleman - *Raymond James & Associates, Inc. - Analyst*

Thank you and good morning. I was a little bit late getting on the call, so I apologize if you've already covered it, but seeing that you broke out the NGL stream and the reserves for this year, how should we think about forecasting the Midstream revenues versus the E&P revenues on a go forward basis? Should there be much of a change in how those are looked at?

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

You want to answer that, Richard?

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

Well, I think we've always tried to give you the color on the NGL volumes back in the notes in the 10-Q and 10-K, in terms of trying to build your model about how -- what the processing side of the black box and the Field Services stuff does.

I think with regard to the NGLs that we report, in the income statement and terms of the revenue side, those are only QEP Energy's NGLs, and then you have to go back into the footnote to look and see what the NGL volumes and value were for Field Services.

So, there's really no difference, in what we did in terms of breaking out the NGL volumes -- was to give you more clarity at the E&P company, what the composition of the liquid mix was.

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

Yes, this is Chuck. Just to add a little more -- as NGLs have grown, in particular from the Pinedale asset, we want to make sure investors can see those barrels and understand that they are not crude oil barrels that they are NGL barrels, so both -- both in the financial statements and also in the reserve report, we wanted to make sure that investors could see both our crude oil reserves and our NGL reserves associated with each of our properties.

Andrew Coleman - *Raymond James & Associates, Inc. - Analyst*

Okay, great. And --

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

And Andrew, there are no NGL reserves associated with Field Services stuff in the reserve report. The reserve report is just the E&P company.

Andrew Coleman - *Raymond James & Associates, Inc. - Analyst*

Okay. All right, I will make a note of that. And then I guess a question on the Bakken side of things. Do you see much opportunity to, I guess, add increased working interest, and as you -- or are you seeing many of your partners go non-consent? Or I guess given the tightness of activity, does that give you a better level of optionality to kind of go add little bits and pieces to your acreage position up there?

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

We haven't seen any partners go non-consent in any of our wells that I'm aware of, unless it's just maybe an individual or maybe a minimal owner that we are not leased. But the opportunity and on, there's not a lot of open acreage. So it would have to be through asset acquisitions that we would do it. There's just, there's not a lot of unleased minerals, and we haven't seen partners non-participate in wells.

Jay Neese - *QEP Resources, Inc. - EVP and Head of E&P*

There's very little open; there was a lease sale last week where a little bit of acreage on the [res] went for $13,000 an acre, so what is out there is limited and very expensive.

Andrew Coleman - *Raymond James & Associates, Inc. - Analyst*

Okay. All right, thank you.

Operator

Eli Kantor.

Eli Kantor - *Jefferies & Company - Analyst*

I just wanted to back to possible acceleration in Bakken activity. Safe to assume that additional Bakken capital would be initially funded by reducing Haynesville activity further? Would the reduction of the last Haynesville rig to be able to support two additional Bakken rigs, or would you be pulling capital from another area? And if so, what would the next area be to reduce activity in?

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

The first tranche comes from Haynesville; second tranche comes from Haynesville through our anticipation of lower outside operated activity. And then we start looking at the gas-directed drilling, and making decisions about which area we want to prune capital. And there are several areas that we can look at.

Both of the gas-directed plays that we are spending significant capital on this year, Mesaverde and Pinedale, generate quite good returns at existing prices. So we haven't gotten there yet because we think we can fund most of it through the cuts we are making in the Haynesville.

Eli Kantor - *Jefferies & Company - Analyst*

Okay, great, thanks again.

Operator

(Operator Instructions). No other questions at this time, sir.

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

Well, thanks, everyone, for calling in. We know it's been a busy conference call morning, and thanks for your interest in QEP. Scott Gutberlet, as usual, will be available to take your calls, and the rest of the management team is available if you'd like to have follow-up questions after the meeting. So, thanks again for dialing in today.

Operator

Thank you for participating in today's conference. You may now disconnect.

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