FINAL TRANSCRIPT

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PRESENTATION

Operator

Good morning. My name is Joanne and I'll be your conference Operator today. At this time I would like to welcome everyone to the QEP Resources second quarter earnings and operations 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)

Thank you, Mr. Doleshek, you may begin your conference.

Richard Doleshek - *QEP Resources Inc - CFO*

Thank you, Joanne, and good morning, everyone. This is Richard Doleshek, QEP Resources' Chief Financial Officer. Thank you for joining us for our second 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 Operations; Perry Richards, Senior Vice President and Head of our Midstream Business; and Scott Gutberlet, Director of Investor Relations.

With the close of the second quarter we marked 1 year of operations since being spun off from Questar Corporation on June 30, 2010. If you purchased QEP shares at the closing price on the first day of standalone trading last summer, and held the stock for 1 year, you've enjoyed a 43% appreciation in the value of your QEP shares. We are proud of what we've accomplished in our first year of independence and believe we are well positioned to continue to deliver profitable growth with capital spending in and around cash flow.

In terms of reporting our second quarter results, we issued a combined operations update and earnings release yesterday in which we reported second quarter and 6 months 2011 financial results. Reported second quarter 2011 production of 64.7 Bcfe, 57% of which came from properties in our newly-renamed Southern region, which we formerly referred to as our Mid-Continent region. We updated operating activities in our core areas including announcing the much-anticipated startup of our Blacks Fork II gas processing plant. And we increased 2011 EBITDA guidance to be in the range of $1.275 billion to $1.325 billion. Increased production guidance to be in the range of 265 Bcfe to 269 Bcfe. And increased our CapEx guidance to be about $1.3 billion.

As a reminder, in conjunction with our spinoff from Questar last year we distributed Wexpro Company to Questar. Accordingly we have recast our historical results to treat Wexpro's results as Discontinued Operations. In addition, we have recast QEP Field Services results, including revenues and volumes, to reflect Questar Gas Company as an unaffiliated company. Therefore, QEP's reported period to period results are comparable to each other. We will be happy to provide additional information about this during Q&A.

In today's conference call we're using non-GAAP measure, EBITDA, which is defined and reconciled to net income in our Earnings Release. In addition, we'll be making numerous forward-looking statements and 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 refer everyone to our more robust forward-looking statement disclaimer in our Earnings Release.

Turning to our financial results, in comparing the second quarter 2011 to the first quarter of the year, we started with stronger performance at QEP Field Services, our gathering and processing business, and marginally better performance at QEP Energy, our E&P business. Field Services benefited from the Iron Horse plant having a full quarter of steady state operations and continued robust gas processing margins. QEP Energy reported slightly lower total production but sequentially higher liquids production and slightly higher net realized equivalent prices. I'll remind everyone that our reported first quarter 2011 production included a positive 1.6 Bcfe out-of-period adjustment, which when removed results in the second quarter production volumes being essentially flat with the first quarter.

Our second quarter EBITDA was $336.6 million which was $31 million higher than in the first quarter, and up 22% from the second quarter of 2010. QEP Energy contributed $248 million or 74% of our aggregate second quarter EBITDA. And QEP Field Services contributed $87 million or about 26% of our EBITDA. QEP Energy's EBITDA was up slightly while Field Services EBITDA was up about 42% from respective first quarter levels. For the first 6 months of the year, our EBITDA was $642 million, which was almost $100 million higher than a year ago in spite of net realized natural gas prices that were 18% lower than in 2010. QEP Energy's contribution was $490 million which was $52 million, or roughly 12% higher than in the first 6 months of 2010. And QEP Field Services contributed $148 million, which was about $46 million or 44% higher than the first 6 months of 2010.

Factors driving our second quarter EBITDA include QEP Energy's production, which was 64.7 Bcfe in the quarter. Or 2% lower than the 65.9 Bcfe recorded in the first quarter 2011. However, the first quarter included a positive 1.6 Bcfe out-of-period adjustment, and when you exclude that adjustment production was essentially flat with the first quarter. The quarter's production was 20% higher than the 53.7 Bcfe produced in the second quarter of 2010. Of note, second quarter oil production was up 14% from first quarter production 2011.

QEP Energy's net realized equivalent price, which includes the settlement of all of our commodity derivatives, averaged $5.05 per Mcfe in the quarter. Which was 4% higher than the $4.84 per Mcfe realized in the first quarter 2011. And 6% lower than the $5.35 per Mcfe realized in the second quarter of 2010. QEP Energy's commodity derivatives portfolio contributed $37 million of EBITDA in the quarter compared to $42 million in the first quarter 2011 and $68 million in the second quarter of 2010. The derivatives portfolio added $0.57 per Mcfe to QEP Energy's net realized price in the second quarter compared to $0.63 per Mcfe in the first quarter of 2011 and $1.28 per Mcfe in the second quarter of 2010.

QEP Energy's combined lease operating and production tax expenses were $60 million in the quarter, up from $56 million in the first quarter of '11, and up from $47 million in the second quarter of 2010. LOE was up 5% and production taxes were up 14% in the second quarter compared to the first quarter. Per unit LOE metrics increased to $0.54 per Mcfe in the quarter from $0.51 in the first quarter 2011 but were essentially flat with the second quarter of 2010. Finally, QEP Field Services' second quarter 2011 EBITDA was $87 million, which was 42% higher than the first quarter of 2011 and 66% higher than the second quarter of 2010. Gathering margins were up $6.1 million or 13% in the quarter, driven by an increase in revenues associated with a short-term third-party gathering and processing agreement related to volumes that will ultimately be processed at the Blacks Fork II facility. Gathering volumes were flat at about 1.33 trillion BTUs per day. Processing margins were up $17 million or 67% in the quarter compared to the first quarter of 2011, on 6% higher fee-based processing volumes, 24% higher average processing fees, 31% higher NGL sales volumes and 20% higher average NGL sales prices. Offset somewhat by shrinkage expense that was sequentially $1.2 million higher.

Net income from continuing operations for the quarter was $93 million, up 27% from the first quarter of 2011 influenced primarily by sequential EBITDA growth. Changes in non-cash charges were roughly small between the 2 quarters. DD&A expenses were $4 million lower in the quarter compared to the first quarter of 2011 as a result of lower production volumes from our higher DD&A expense Haynesville properties. Exploration expenses and abandonment expenses, in aggregate, were flat in the quarter compared to the first quarter. And our provision for income taxes was $12 million higher in the quarter compared to the first quarter due to higher pretax income. Although we continue to expect that we will not be a cash income tax payer in 2011.

For the first half of the year we reported capital expenditures on an accrual basis of $674 million. Capital expenditures for E&P activities were $640 million which included $30 million on property acquisitions. Capital expenditures in our midstream business were only $33 million in the first half of the year, resulting from the timing of progress payments associated with the construction of the Blacks Fork II plant and the completion of our Iron Horse plant in the Uinta basin. We are increasing our capital expenditures slightly for 2011 to about $1.3 billion. And Chuck will have more comments about what is going on with our capital program in his prepared remarks.

In terms of our balance sheet, it's grown about 4% from year-end. Total reported assets were $7.1 billion. Net PP&E was $6.2 billion. The common shareholder equity is $3.1 billion. And total debt was just under $1.6 billion. We ended the quarter with $500 million drawn under our $1.0 billion revolving credit facility, which is unchanged from the amount at the end of the first quarter.

With that I'll hand it over to Chuck.

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

Good morning. Richard has given you the key results for the quarter. So I'll try to add some color, give you an update on our plans for the remainder of this year and then move on to Q&A. Let me draw your attention to the slides we've posted on our website at qepres.com that accompanied our release yesterday. I'll refer to these slides as I discuss our operational results.

Since our last call, QEP's completed 16 new Company-operated Haynesville shale wells. All wells had very strong results with initial rates in line with our previously announced IPs. We continue to buck the industry trend of escalating completed well costs. QEP-operated gross completed wells in the Haynesville shale averaged $9.1 million in 2011, down from an average of $9.3 million last year. Our lease saving activity is winding down. We now have just 1 QEP-operated section left to drill on in order to hold all of our QEP-operated leasehold by production. There are an additional 3 undrilled non-op sections in which we have a working interest, representing only 34 net acres that have lease expirations which range from middle of 2012 to late 2013.

Slides 3 and 4 give additional details on our Haynesville acreage, as well as drill times. We remain absolutely convinced that restricted rate flowback is the right approach to managing the Haynesville reservoir. As we've described to you in previous calls, there's a growing body of evidence that wells flowed back on restricted chokes exhibit flatter decline profiles once the wells exit the production plateau phase. We've included data in slide 5 that graphically depicts this observation. The graphs depict the 3 groups, each comprised of 4 wells, and each group operated by a different company. All of these wells are within a few miles of each other. All are in the sweet spot of the Haynesville core acreage. All are similar depth to the top of the Haynesville so similar pressures. All have similar lateral lengths. They were all completed with similar frac designs, number of frac stages, et cetera. So, in other words, the main difference between the QEP-operated wells and the other 2 groups is the fact that we produced our wells at a restricted rate flowback.

In the upper graph, we've plotted the average daily production rate on the Y axis versus cumulative production on the X axis. And as you can clearly see, the QEP average initial production rate was substantially lower than that of the other 2 groups. And that our wells stayed at a plateau rate of about 10 million cubic feet a day until they produced almost 2 billion cubic feet of gas each. And then they started to decline. But you'll notice that they declined at a much shallower slope than that of the unrestricted wells. You can also see the dramatic difference in forecast at ultimate recoverable reserves between the 3 sets of wells. Clearly the restricted rate wells are on track to recover substantially more reserves.

To me the more telling data is depicted on the lower graph on the same slide 5. Here, we've plotted the same 3 groups of wells, wellhead pressure on the Y axis and cumulative production on the X axis. As you can see, at any given point in the cumulative production history of these groups of wells, the restricted rate wells have more than double -- more than double -- the flowing pressure of the unrestricted wells. What does this mean? The higher flowing pressures are telling us that the wells are staying better connected to the Haynesville reservoir over time. And we think by restricting initial production rates that we don't draw down the pressure as much in the near well-bore portion of the propped fractures. And we think this is having a profound impact on the well performance and ultimate recoveries. Obviously shallower declines mean more reserves are recovered in the early part of the well's life. And that's having a big impact on the present value of the production stream. And higher EURs that we're now forecasting as a result of this shallower decline is having a positive impact on the overall well economics and on finding and development costs.

I can't help but note that this data also sounds a cautionary note that just a singular focus on headline additional production rates could be very misleading in terms of long-term well performance. Some of you raised concerns about the sequential quarter to quarter decline in the Haynesville production that we reported in the second quarter. Let me assure you we have no problems in the Haynesville. These wells that we are putting online today are every bit as good as the wells that we've completed in the past. We're simply trying to manage the overall growth in our dry gas production, while maintaining critical mass of drilling completion activity that has made us a cost leader in the Haynesville shale play. We plan to have 6 QEP-operated rigs active in the play through year-end as we now move on to pad drilling and field development.

At Pinedale, we've completed and turned to sales 52 new QEP-operated wells so far in 2011. As we noted in our release, average drill times at Pinedale continue to improve for 2011. Spud to TD times have averaged 13.8 days compared to an average of 17 days last year. And the bar keeps getting lower. Our record spud to TD drill time is now 10.6 days, down from prior record of 11 days. Thanks to drilling and completion efficiencies we now anticipate being able to deliver close to 100 completed wells at Pinedale in 2011.

While I'm on the topic of Pinedale, I'm sure you've all noticed the news about Field Services early completion of the Blacks Fork II cryo plant in western Wyoming. As you recall, this plant has an inlet capacity of 420 million cubic feet a day of raw gas. And at full capacity will recover close to 15,000 barrels a day of incremental NGLs net to QEP Resources. QEP Energy recently entered into a fee-based processing agreement with Field Services to process its share of Pinedale gas at Blacks Fork II. As a result, about half of the liquids recovered at this plant will show up as NGL production in QEP Energy. And the other half will show up as keepwhole volumes in Field Services. In addition to the significant economic uplift of recovering liquids from Pinedale gas, QEP Energy also booked liquid reserves at Pinedale at the end of the second quarter. An additional 190 Bcfe of proved reserves comprised of 47.2 million barrels of liquids minus the 86 Bcf of natural gas shrink that we lose when we process the gas in this cryo plant.

Let me caution you that the first few months of operation, both the liquids production and financial results from the Blacks Fork II plant will be lumpy. First, we need to dial in the new plant to maximize performance and liquids recoveries. And while the startup of this plant so far has been amazingly smooth, it's not unusual to have a few bobbles in the first few months of operation. Second, since the plant is up way sooner than we had anticipated, we will temporarily sell the first couple of months of NGL production from Blacks Fork II at Conway, Kansas. Our long-term transportation and fractionation deal at Mont Belvieu, Texas begins on October 1. And as everyone, I hope, realizes, Conway is a lower value market than Mont Belvieu.

Third, we have to provide line pack, NGL barrels and line pack, to fill the transportation capacity from Wyoming to Conway, Kansas first. And that's about 60,000 barrels. And then in October, when the Mont Belvieu deal kicks in, we'll have to provide an additional 230,000 barrels of NGLs to fill the line from Conway, Kansas down to Southern Texas. Please note that the line pack shows up on the balance sheets of both QEP Energy and QEP Field Services as inventory, not in the revenue line on the income statement. So the first few months of operation of this new plant won't be indicative of normal liquids production volumes or of revenue generation. As soon as the plant's up and running and stable, we've committed that we will put out an additional release with a lot more information on Blacks Fork II and the impact it will have on QEP Resources and subsidiary revenues and EBITDAX.

Now that Blacks Fork II is complete, and given the economic uplift of liquids recoveries on QEP Energy's production, the liquids that we'll be extracting at Blacks Fork II add over $1 an Mcf to wellhead realizations. We plan to add 2 additional rigs at Pinedale later this year to fully load the entire Blacks Fork cryo complex. Please refer to the slides that we've included in the release, slides 11, 12 and 13, that show Field Services assets. A nice photo of the plant. And then the location of the plant, which is about 100 miles South of Pinedale. Other QEP assets such as third-party pipeline and other infrastructure in western Wyoming.

Turning to the Anadarko Basin, Woodford or Cana shale play. We've completed and turned to sales 4 new QEP-operated wells since our last call, all with good results. And we have 3 QEP-operated wells waiting on completion. Also note we've added 2,300 net acres in the liquids-rich fairway of the Cana play since our last update. We now have 77,600 net acres in this play and we anticipate running 3 QEP-operated wells in the Cana for the remainder of 2011. Slide 8 shows more information on the Cana.

In the Williston Basin, North Dakota, since our last call we've completed and turned to sales 3 new QEP-operated middle Bakken and 1 new QEP-operated Three Forks well. We provided the rates for these wells in our release so I won't repeat them here. Please note that the rates from all 4 of these new wells were restricted. We're obviously pleased with the results of all 4, including another good data point on our Three Forks potential from the southernmost well that we reported on in our release.

To answer one of the questions, yes, our operations in North Dakota were impacted by weather during the second quarter. Not so much directly by the weather but by the cascading impact of the weather on all the other operators that are active in the Williston. We should have had all 4 of the wells that we reported in the release on at least a month earlier. And we probably should have had a couple more wells completed in addition to those. Clearly, that impacted our oil volumes during the quarter but we started with a much lower base so it didn't, it wasn't material to our overall production in the grand scheme of things.

As we noted in our release, we have 6 QEP-operated wells drilled and cased and waiting on completion. 3 of those wells are sitting under the drilling rig on our first 4-well pad. And so they will obviously be delayed and will be available for completion after the fourth well on that pad is down and cased. That well this morning is drilling below the intermediate casing point so we should see continued volume growth in the Bakken during this quarter.

As we discussed last quarter, we're in the process of permitting our first 10-well pad in the Williston. And depending on when we get the permits we should be able to add 2 more drilling rigs in the Williston Basin by year end. Our plan is to place both of these rigs on a single 10-well pad and commence drilling on that pad toward year-end. This approach will address one of our biggest current rate-limiting factors that is limiting the pace of our development in the Williston Basin. That's surface permitting.

As I explained last quarter, there's a couple important things to remember about pad drilling. First, they won't have any impact on 2011 operations since the rigs will show up late this year. It will take 6 or 7 months after the rigs move in on this first 10-well pad before we see the production response. So there will be a 6 or 7 month period of capital investment and no production from the uptick in this rig count in the Williston. Second, the production response from pad drilling, as we move forward and move off of the first 10-well pad on to the second, will be lumpy, as we bring on 10 new wells in a relatively short period of time followed by another hiatus of 4 or 5 months before completion commences on the next 10-well pad. Clearly, the addition of 2 more rigs in the Bakken drilling on 10-well pads will be a step change in our pace of development. We're now running 3 rigs in the play. 2 on the Fort Berthold reservation and one over to the west in our Fat Cat area. Slide 9 shows the details. Note we've included a little inset map on that slide that shows our Fat Cat area relative to the Fort Berthold acreage.

At the Granite Wash, Atoka Wash play in the Texas Panhandle, since our last call we've turned 3 new wells to sales and finished testing another well. Needless to say, we're disappointed with the results from both of the Moore wells, which are still cleaning up but they are currently producing less than 1 million cubic feet a day of gas from Atoka Wash reservoirs. These wells, which are called out on the slide, as numbers 12 and 13, were direct offsets to the original Moore well we drilled in the Atoka Wash, which is Well Number 6 on slide 10. And that well produced at over 8.3 million cubic feet a day of gas and 505 barrels per day of oil and NGL.

We are also surprised by the results of the Franklin well, which is Number 11 on the slide. That well produced water and no gas from a Cherokee zone. What's surprising about it is it's about a mile west and 200 feet updip from the Edwards well, which is called out as number 2 on the slide. Which initially 5.7 million cubic feet a day and 1,336 barrels per day of oil and NGL from the same interval, the same Cherokee interval. But clearly from a separate compartment or sand. It's just another confirmation that the geology of the wash is far from simple.

Some good news in the play, our most recent well, the Morrison 33 Number 6H, which is called out as number 14 on the slide, looks like a keeper. It's completed in the shallowest of the wash zones, the Caldwell. And on early flowback, the maximum 24-hour rate was 1,200 barrels a day of oil and 6.8 million cubic feet a day of wet gas. Or on an equivalent rate after processing, about 2,480 barrels per day of oil and NGL plus 5.5 million cubic feet a day of dry gas.

Our recent well results, combined with the offset operator results, confirm that the geology of these wash sands is very complex. And we can't afford to get ahead of ourself in delineating the limits of each target interval. So as the old saying goes, when you're in a hole the first thing you need to do is stop digging. We're dropping back to 1 rig in the play to make sure we fully understand results before we move on to drill additional wells.

On the exploratory front in the Powder River Basin in Wyoming, permitting is underway on our first horizontal wells targeting the Sussex formation sands. We'd anticipated drilling our first QEP-operated horizontal wells in the second half of 2011 but the timing of issuance of drilling permits, most of the wells we staked are on federal land and it has taken longer than we had anticipated. We would like to have enough permits in hand for a continuous multi-well program before we move a drilling rig into the area. So at this point, I think it's unlikely we'll commence drilling in this play until early next year. As a reminder, there had been a number of operators who have recently drilled horizontal wells in the Sussex and have reported rates of 700 to 1,500 barrels a day of oil. We have over 55,000 net acres in this play in the Powder River Basin with targets including the Sussex, the Niobrara, Frontier and other sands. Including significant acreage directly offsetting recent successful wells.

Field Services, our midstream company, as Richard described to you earlier, had a great second quarter and first half of 2011. Our processing business posted very strong results. Our new 150 million a day cryo plant, called Iron Horse, in Eastern Utah's Uinta Basin, was completed back in January and really hit full stride in the second quarter. While a significant portion of the plant is underpinned by fee-based processing arrangements with third-party producers, Field Services has been able to utilize the head space in the plant to process additional volumes on a keepwhole basis. As a result, the plant is running at full, and it made a significant contribution to second quarter and first half EBITDA.

I have to also say I'm very proud of the team of QEP folks and our EPC contractor OPD, or Optimized Process Design, that have delivered the Blacks Fork II plant well ahead of schedule and on budget. Not only was construction completed safely, there were over 355,000 total man hours for OPD and its subcontractors on this large project. Without a single recordable safety incident. But also we did that safe construction project while completing it well ahead of schedule. And the collaboration has continued as the team has started up the facility with a near flawless execution.

While on the subject of Blacks Fork II, I know you guys are all anxious to update your models to account for the impact of this project on the second half of 2011 results. As I mentioned earlier, we plan to issue a more detailed release after the plant is up and running. But let me caution you on 1 item. During the first half of 2011, as Richard mentioned, we were able to divert about 200 million cubic feet a day of gas away from the Blacks Fork complex to a third-party cryo processing plant on an interruptible basis. Doing so allowed us to execute the tie-ins and other activities of our new Blacks Fork plant with minimum disruption to production from Pinedale. The diversion of this gas also had a significant impact on Field Services' first half 2011 results. As Richard described, we reported these revenues in our gathering segment under a line item called other gathering revenues since the revenue wasn't generated by processing activities in the QEP plant, and we only received a percentage of the proceeds from the sale of the extracted liquids. So in essence, Field Services has already begun to benefit from cryo processing on a portion of the gas that will now load Blacks Fork II. As the plant is loaded, we'll see the other gathering revenue line diminish. And keepwhole processing revenues and QEP Field Services, as well as NGL revenues in QEP Energy will replace it. Because the new processing contract between QEP Field Services and QEP Energy, the net revenue generation for Field Services will be close to a wash with what we reported in the second quarter. So don't expect a big pop in EBITDA from Field Services in the third quarter.

From a macro perspective, the US market for NGLs, and in particular ethane, appears quite constructive. Just a few years ago the US petrochemical industry was moribund. And major players were mothballing plants and exiting the US for other parts of the world where gas and natural gas liquids were perceived to be more abundant. That's changed already this year. We've seen several major new petrochemical projects announced, and others are in the works. Thanks in large part to the shale gas revolution, liquids extracted from abundant American natural gas are extremely competitive globally.

Turning to the remainder of 2011, please note that with better visibility, yesterday we raised our full year 2011 production guidance. We now expect production will range from 265 Bcfe and 269 Bcfe, up from our prior 263 Bcfe to 267 Bcfe guidance. With Blacks Fork II coming online and our continued focus on capital allocation to oil and liquids-rich gas plays, we should exit 2011 with oil and NGL production comprising about 20% of QEP Energy total volumes. With the increase in production volumes, we now forecast our EBITDAX could range from $1.275 billion to $1.325 billion, up from previous guidance of $1.2 billion to $1.3 billion. We also raised our CapEx forecast by about $100 million to $1.3 billion. We gave you some color on the main drivers in the CapEx increase in our release. We continue to notch more efficiency gains in our core areas, so we're seeing individual well costs come down. But the absolute well count, and therefore CapEx, is increasing. Most of the increase is going to Pinedale and Haynesville where we continue to see strong economics at current commodity prices. We'll also invest additional capital as we prepare for 2 new rigs coming into Pinedale and 2 more in Bakken late this year.

As we embark on the second year as a standalone Company, both QEP management and our team of talented employees are very excited about the future of your Company as we continue to focus on driving profitable growth from our portfolio of very high quality assets.

And with that, Joanne, let's open the line for questions.

QUESTIONS AND ANSWERS

Operator

(Operator Instructions) David Tameron.

David Tameron - *Wells Fargo Securities - Analyst*

Good morning. A couple questions. You mentioned this, I'm going to ask it anyway. NGL, you talked about the NGL volumes and trueing up the model, and you guys having a press release. But in July, you put a presentation out that had equity NGL volumes going from 6,600 to, call it, 11,000 to 19,000 in '12. Was that based on a fourth quarter startup or was that based on the early start up?

Richard Doleshek - *QEP Resources Inc - CFO*

David, those volumes were daily volumes. So the right way to look at it is to say, now we have the plants on full fourth quarter so that 15,000-barrels a day is split between QEP Energy and Field Services. And you ought to do that for the full fourth quarter and then maybe a third of the third quarter.

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

You've got to take into account line pack, which I gave you the numbers on. 60,000 at Conway, another 230,000 from Conway to now Belvieu. So those are barrels that won't be sold but they'll show up on the balance sheet as inventory. And then there will be a ramp up in volumes as we get the plant lined out.

David Tameron - *Wells Fargo Securities - Analyst*

Okay, that's helpful. And then Chuck, you did mention Uinta Basin. Can you talk about Red Wash, current state? I know you guys had previously said you're evaluating potential sanctioning later this year. Can you just talk about where you're at on that?

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

Sure. We currently have 20 wells down and producing in the deeper Mesa Verde section, liquids-rich gas portion of the Red Wash unit. We're continuing to watch those wells. We are pleased by the results we've seen. I can't front run the sanctioning of the project until we have our Board meeting and talk about our 2012 and beyond capital investment programs. So we'll be having a conversation with our Board. We have an ongoing conversation with them about our results but we'll be talking about this project and the upcoming Board meeting next week. And we'll continue to discuss it with them in the fall. So we'll have an update, I would think, at traditional time when we talk about our approved capital budget and other items in November.

David Tameron - *Wells Fargo Securities - Analyst*

Okay. Let me ask, based on what you see today, what kind of rates of return would you be looking at for individual well economics, if this project were to be sanctioned?

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

There's 2 components to this, David. As I mentioned, it's wet gas, so there's a 2-step process here. We can process early volumes in the head space in Iron Horse, and then our Stagecoach plant, which is a refrig plant which obviously has lower liquids recoveries of the total liquids volume. The refrig component of processing at current prices, current forward prices, is a mid 20s return. And then when you go to cryo processing you get into the low to mid 30s return on current forward prices of gas, oil, and NGLs. So it's quite attractive project.

Richard Doleshek - *QEP Resources Inc - CFO*

I was going to say, we put out some numbers that talked about $1 to $1.25 F&D costs on a $2 billion to $2.5 billion investment per well. And so, you have to back into some of the numbers that Chuck just give you. And, again, we think we'll have a capital allocation in 2012 but it's not going to be full scale when we talk about the $0.25 billion a year investment until probably after next year.

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

And the reason for that is obvious. We can't grow production volumes in that project until we have the capacity to process it. So it's a parallel approach. And it takes, from the time we sanction the project, a year to a year-and-a-half to get a new cryo plant up and running.

David Tameron - *Wells Fargo Securities - Analyst*

Okay, last question and I'll let somebody else jump on. So if I'm thinking 2 Bs to 2.5 Bs a well for $2 million, $2.5 million, am I in the right ballpark?

Richard Doleshek - *QEP Resources Inc - CFO*

It's $1 to $1.25 F&D. The average EUR on a well is 2 Bcfe. And we think in full field development, we can drive the well cost down to about $2 million a well.

Operator

Brian Coralis.

Briain Corales - *Howard Weil Inc. - Analyst*

Hi, good morning, guys. Maybe just sticking with the Uinta Basin, can you make any comments as it relates to some of the other companies' release recently on the Uteland Butte or the shallow Green River oil?

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

First, we are a producer of Green River oil in the Red Wash field, and we have been. In the Red Wash field and Wonsits Valley field. And those are old fields. They were discovered in the '50s. And they were developed originally by Chevron and Gulf and then later Chevron operated both fields. We currently produce a little over 3,000 barrels a day of oil from the Green River formation. We have drilled, over the past 3 or 4 years, over 40 horizontal wells targeting thin carbonates, primarily, in the Green River formation. Which had been bypassed by the original development of the field by Chevron. And they've had quite good results. And we've drilled those wells and not really talked about them that much. They basically have backfilled decline of the existing old Red Wash and Wonsits Valley production.

We are excited about the opportunity to drill more wells in Red Wash field because the field to date has only recovered about 12% or 13% of the original oil in place. The production to date has barely scratched the surface on the amount of oil that's sitting in the ground in Red Wash. It's a quite complicated field. It's got a lot of discontinuous sands. It's been water flooded and we don't think it was water flooded particularly efficiently. So there's a lot of residual oil running around in these reservoirs that we really can't see in the existing wells which are drilled on 40-acre density. When we go in and start deepening wells, and when we start drilling new wells to tap the underlying Mesa Verde wet gas play, we will have an opportunity to see a lot more of the sands in Red Wash and probably find a lot of incremental oil in those reservoirs as we've developed the deeper Mesa Verde play. That's several years out.

Now, you asked about the Uteland Butte formation which is also a carbonate. It happens to be a dolomite. And it's present in the western portion of our acreage, 3 or 4 townships west of our core Red Wash and Wonsits Valley fields where we've historically operated. We've seen the results of the 5 or 6 wells that have been reported by another operator that operates the Monument Butte's field. We have a very small interest in Monument Butte. So we have seen those wells. And we have acreage immediately south of Monument Butte. It's roughly 30,000 net acres or so due south of Monument Butte. We've drilled 1 well into that Uteland Butte member. We just have early results on that well. It wasn't a particularly barn-burner well but we think there's room for improvement on completion technology. So we're continuing to evaluate our own acreage and look at the well results from the other operators that are targeting the Uteland Butte to the north of us.

Briain Corales - *Howard Weil Inc. - Analyst*

That's helpful, thank you. One more on the Haynesville. We saw a sequential quarterly decline. Could you maybe talk about, are you restricting the rates further? Are you seeing some down time? And how should we think about that going forward for the rest of '11 and into 12?

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

So the answer to the first question, we talked about restricted rates. We've got some wells restricted to 10 million a day. We have a family of wells restricted to somewhere about 5 million to 7 million a day. And the real question is, there is some optimization around the pressure drawdown and therefore the rate, and we're trying to figure out what that is.

The other thing we're trying to do is avoid creating large pressure sinks in the Haynesville reservoir that will cause problems when we go in and start drilling the wells on 80-acre, or whatever the ultimate density is. Because if we produce a lot of gas out of a section, if you just think about 1 horizontal well drilled in a section, and that well recovering 4 or 5 or 6 Bcf of gas, it creates a tremendous pressure sink right around that well. And if you come in later on and drill 80-acre offsets to that well, you create a sink for the fracture. So all of the fractures will tend to point toward that old depleted well, or partially depleted well. And therefore, you don't fully stimulate the surrounding rock and ultimately you don't get as much gas out of the section. So we're trying to manage production rates in these first wells in each of these sections in order to minimize pressure drawdown before we come in and develop the other 7 or however many wells we ultimately decide are appropriate for developing the Haynesville. And as a result, on any given day we may have 80 million or more of production curtailed in addition to the volumes that are on restricted rates.

So there's a lot of gas here that could be produced, if we so chose, that we are trying to manage. And we're doing it for 2 reasons. One, because we think it's the right thing to do from a reservoir maintenance pressure maintenance perspective. And, two, we're trying to manage our dry gas volumes because we don't think that producing our large volumes of dry gas is really the appropriate thing to do for our shareholders.

Operator

Brian Singer.

Brian Singer - *Goldman Sachs - Analyst*

Good morning. A couple questions on the Bakken. You mentioned not to focus on IPs but I probably should ask regarding the 2,650 barrel a day restricted IP in the Bakken. Is there anything you did differently on that well or is that just statistical better than average location?

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

I think it's good rock. It's really not comparable to some of our earlier wells because those were restricted even more as far as initial rate. The lateral length, it's a long lateral so it's very similar lateral length to some of our earlier wells. We are now pumping on average 30 stages. The earlier wells had less stages. But it's a very good well. It's within the range of outcomes that we would expect in the play. I wouldn't read anything into it other than that.

Brian Singer - *Goldman Sachs - Analyst*

Okay, thanks. And then as you prepare to bring on the 10-well pads in the Bakken mid next year, can you just update us on takeaway plans and takeaway costs? Do you see that as a constraint or are you already well set there?

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

I think we're in good shape there, Brian. We've got all of the eastern side of our acreage plumbed into the pipeline system that will ultimately gather the oil and gas. On the west side, the northern part of our acreage is plumbed in. The Southern Twins, as we call them, the two southernmost wells that we reported last quarter are not connected to the pipeline system. They will be late in the third quarter, early fourth quarter of this year, just because of the geography and their remoteness from the backbone system. But we'll have all of our production tied into both gas and oil gathering systems certainly well before the snow flies in North Dakota. I guess I shouldn't say that. It could snow this month there. But it should not be an issue as far as go-forward takeaway capacity.

Brian Singer - *Goldman Sachs - Analyst*

Great, thanks. And lastly, with all of the areas that you highlighted, including the new venture opportunities, how are you thinking about, if at all, divestitures or acquisitions?

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

First of all, I'd say everything that we have is for sale for the right price. So from a divestiture perspective, the door is open for offers on anything. And we'll consider offers. And obviously the analysis we do, Brian, is very straightforward. We look at the PV of investment capital in a project and drilling it out and producing the molecules versus the PV of selling it. If somebody comes along and offers us an attractive price, we will certainly entertain it. As far as acquisitions, we've continued to look for opportunities to add to our core areas in which we have operating expertise and critical mass. And so we've looked at both acreage acquisitions as well as just buying leasehold. And we've actually picked up some interest in core areas like Pinedale through partner and non-consent which was the cheapest reserves you can add. As far as totally new areas, we're not currently focused on anything outside of the areas that we've discussed publicly.

Operator

Subash Chandra.

Subash Chandra - *Jefferies & Co. - Analyst*

Yes, hi. First on the Haynesville. As you seek to limit volumes in the Haynesville and dry gas production, will you also seek to limit CapEx or reduce CapEx to the Haynesville?

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

Subash, there's a tightrope that we walk here between critical mass and the ability to manage the efficiencies of drilling and completion activities. And we really are seeing the results of that. And I think you'll see another opportunity for improvement here as we move to pad drilling and to really development of the Haynesville. And there is a minimum activity level that we believe is necessary and appropriate to maintain and continue to drive down cost. And that's around 6 rigs. And interestingly, as we get more and more efficient, we end up delivering more completed wells with the same activity level. And it becomes even more of a challenge for us to maintain the critical mass because we, frankly, don't need a dedicated frac crew because we can frac the wells so quickly that we end up windowing that frac crew out to other operators for part of the year.

Subash Chandra - *Jefferies & Co. - Analyst*

So the $9.1 million which was a year-to-date average, is that pretty representative of leading edge cost?

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

From what we see from other operators, we're a couple million dollars under the other operators that are right in our vicinity. I can't speak to what folks are doing in the shallower parts of the play. But in the core of the Haynesville I think our well costs are certainly, from the other wells that we participate in, well below the average.

Subash Chandra - *Jefferies & Co. - Analyst*

What I was asking is, is the $9.1 million, which is an average for the year, the latest wells you're drilling in that vicinity?

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

I see. I didn't understand you. No, I think what we have is an opportunity, I think, on the leading edge to get below $9 million per well gross completed well cost. How far below remains to be seen. There will be significant advantages and cost savings of working from pads to drill wells because, obviously, pad construction costs will be amortized over more than 1 well. Skidding a drilling rig versus rigging down and moving and rigging back up is clearly a significant cost savings. And then we get to work on multiple wells at the same time with a frac crew without rigging down the frac crew. All those things in aggregate, what do they represent? $0.5 million a well of gross completed well cost? Somewhere in that vicinity, maybe better. Every time I have prognosticated about well cost savings in our core plays like Pinedale, I've been rendered a liar by our team performance. And so I'm fully anticipating that will be the case here. So with that, I hope the folks that are listening in that work for me will take that message and go to work.

Subash Chandra - *Jefferies & Co. - Analyst*

The Haynesville question of whether it's exponential, hyperbolic decline, the charts you provided, what's the length of the production history? And what do you think, with your technical background, when do you think we get that answer in such an overpressured gas shale resource?

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

It's been a topic of a lot of discussion around our shop. The oldest wells now have been on about 36 months or so, maybe a little longer. And we have seen some evidence of a switchover from the exponential part of the decline to the hyperbolic component. But it hasn't been as profound as you might expect. And so how this reservoir will perform as we go out into the later years remains to be seen. One of the things that we've done by restricting pressure is we're seeing much better reservoir support, as you can see from that lower graph on slide 5, where the flowing pressures are still much higher. So we're delaying the hyperbolic response as we maintain back pressure on these wells. So it may be a very long time before we see it. But the interesting thing is, if you look at the cumulative production, this group of 4 wells has cum-ed over 4 Bcf, and on average our PUDs are booked at 6 Bcf. And we're still seeing these wells flowing at well over 4,000 pounds, close to 5,000 pounds of flowing pressure. So we're a very long ways from the demise, if you will, of these wells, even if they continue to produce on a more exponential decline profile. I think that's probably where you're trying to go here.

Subash Chandra - *Jefferies & Co. - Analyst*

Yes. Would you go as far as to say the answer doesn't really matter if you recover the cost of the well and then an appropriate margin long before you know the answer of how that well is going to finish itself off?

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

Yes, although I would -- I agree with that, from a purely economic perspective that's correct, although ultimately the EUR could be negatively impacted. There have been enough shale wells that have been produced over long periods of time, both vertical wells and horizontal wells. And just knowing the rock properties. The well will eventually turn over to hyperbolic decline. It's just a question of how far out in the cumulative production history that is. This is really tight rock and it will ultimately break over. It's just at this point, it's hard to forecast as we just don't have enough long-term production data.

Subash Chandra - *Jefferies & Co. - Analyst*

Just one more question on that front. Do you think there's anything exceptional in the Haynesville given its pressure gradient that maybe changes the rules from other shale plays?

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

No, other than the issues around fracture closure. Whether or not you can maintain a prop fracture. And I don't think that that's unique to just the Haynesville. A lot of these shales have similar pressure gradients and would have the same underlying questions.

Subash Chandra - *Jefferies & Co. - Analyst*

Okay, and final question for me. The Red Wash, 2 Bcfe, what first month production does that back into?

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

These wells come on at relatively modest rates. A couple million cubic feet equivalent a day for the average first month.

Operator

Duane Grubert.

Duane Grubert - *Susquehanna Financial Group - Analyst*

Yes, with Susquehanna Financial. Chuck, could you re-detail those quarter 2, end of quarter reserve adds that you mentioned related to the Black Forks plant? And does that give us any encouragement that that number will grow by the end of the year? And why or why not?

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

Duane, it's about 33 Bcfe of net reserve adds. I'm sorry -- 190 Bcfe, thank you, Scott. 33 million barrels equivalent of net reserve adds. 47 million barrels of liquids minus 86 Bcf of natural gas. So the numbers, that's 33 million net barrels of adds. The reserves that we booked are a combination of enhancement to our PDP reserves plus the revision or addition of liquids reserves to the PUDs. So will that grow at year-end? Not a lot. We'll see some additional conversion of PUD to PDP reserves but the absolute quantum probably won't grow significantly.

Duane Grubert - *Susquehanna Financial Group - Analyst*

Okay. And I assume that's a combination of quantifying liquids which are higher value than gas, and you take out the shrinkage. But is it also the matter of having a longer life of the field because your economic limit has changed?

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

Yes, you get a slight increase in the reserves as a result of longer well life, lower abandonment rate. But most of it is an increase in the liquids volume, just as the recovery of liquids from the cryo plant.

Duane Grubert - *Susquehanna Financial Group - Analyst*

Okay. And can you update us on hedging and whether you're making any changes to that? And maybe your outlook on gas markets and how that makes you think about allocating your capital?

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

We've hedged a substantial portion of the remainder of this year's gas production. Our stated philosophy on hedging is that we would strive to be about 50% hedged on forecasted production by the end of the first quarter of the current year. We obviously are over that on gas this year. And we're about 72% hedged on gas. And part of that is that we were guarded on third quarter gas prices as storage build, and we went into the shoulder season between the cooling season and heating season, or generating season and the heating season. We look at the gas markets and still believe there's an oversupply. We think that there are some fundamental reasons why that oversupply situation will correct itself. As operators pull away from drilling high-rate dry gas wells and move to focus on liquids-rich plays which have higher liquids content but lower initial and total dry gas production. So there's some structural changes going on, on the supply side, that are fundamentally favorable. And then, of course, at current prices, the gas burn in the electric power sector is quite substantial. And we think that will continue. But it's going to take a while for the market to balance and as a result we're continuing to layer on hedges. $5 gas generates very acceptable returns on invested capital for us. And given the opportunity to layer on hedges at that price, we're going to continue to do so. Primarily to protect cash flows on the downside so that we can maintain drilling activities in our core areas and continue to drive down cost.

Duane Grubert - *Susquehanna Financial Group - Analyst*

Okay. And then finally, I've had people point out that you used to have a slide specific to Oklahoma that's no longer in the deck. I don't know if that's something to read into but maybe if you could comment on what you're thinking about Oklahoma?

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

In the Granite Wash slides? Yes, we've combined the 2. We had both the Texas and Oklahoma stuff on the same slide. We didn't have any activity in the Oklahoma slide so we just pulled it out. We are actually going to drill several wells over in the Oklahoma portion in the Colony Wash and Hogshooter areas later this year as well as some wells targeting the Marmot and Tonkawa in the western part of Oklahoma which actually wasn't on that slide. I wouldn't read anything into it. We're trying to economize on paper as we try to send out the release.

Operator

David Heikkinen.

David Heikkinen - *Tudor Pickering & Co. - Analyst*

Good morning. So thinking about NGL realizations from Blacks Fork, are you currently shipping on spot to Conway?

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

No. First of all, remember we're line packing today and we will be for a while. And then we'll sell under a contract, a short-term contract, monthly contract, at Conway.

David Heikkinen - *Tudor Pickering & Co. - Analyst*

Okay. And then will you go to Mapco to Mont Belvieu in October or how do you think about that capacity add?

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

We have transportation arrangements, firm transportation arrangements, from Blacks Fork all the way to Mont Belvieu. And it's a more complicated transportation arrangement. I would be happy to go into it offline with you but it involves exchanging some barrels and things like that. But we have firm capacity all the way to Mont Belvieu and firm fractionation capacity at Mont Belvieu. And we're selling purity, ethane and other products out of the tailgate of the fractionator.

David Heikkinen - *Tudor Pickering & Co. - Analyst*

So you'll see uplift. Third Quarter you'll have spot and then you'll get an uplift, assumably, going from Conway to Mont Belvieu.

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

There's a substantial discount especially for ethane prices at Conway versus Mont Belvieu. If you just look at the $0.30 or so difference in ethane prices.

David Heikkinen - *Tudor Pickering & Co. - Analyst*

And then just going into the Pinedale and thinking about the convergence of non-consenting and increasing rig count, do you all think about the ability to really increase working interest, tying the going to fixed rigs? Or are those at all connected? And why are partners non-consenting?

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

I'll answer the last question first. The reason partners are non-consenting is their own business. It's a capital allocation decision, I guess. But you have to remember they see different economics than QEP does because we benefit from the liquids recovery currently, and we will benefit even more with the Blacks Fork II plant. So when you look at overall economics of the shareholder, our well economics, wellhead realizations and therefore Pinedale well economics are substantially better. The addition of the 2 rigs is not to drive more non-consent although we'll take whatever interest we can get in these wells. It's to backfill the Blacks Fork I cryo plant. We'll move all the gas over to the new plant that we are currently processing in Blacks Fork I and we'll have some head space that we can now fill in the original plant, that we want to fill as quickly as possible. We obviously didn't want to have the rigs out there running and have a bunch of gas built up that we couldn't cryo process. But now that we have good visibility on the plant, and we know that that head space is available, we'll do what we can to fill it as quickly as we can. That will be a 2012 volume increase and really it'll take us 12 or 18 months to fill it completely.

David Heikkinen - *Tudor Pickering & Co. - Analyst*

And you won't have any changes to your normal cyclicality of completion schedule just to try to fill that center as you look at '12?

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

No, it still takes economic sense to shut down completion activities during the coldest months. It's just crazy to try to keep frac water hot and keep frac crews going from late November to some time in March depending on how severe the winter is.

Operator

Your next question is from the line of William Butler.

William Butler - *Stephens Inc. - Analyst*

Hi, how are you doing guys? On your exit rate the liquids, the 20%, about how much should we expect to be from NGLs versus oil?

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

It's about 50/50, I think, roughly.

William Butler - *Stephens Inc. - Analyst*

And then on your Red Wash area, is that still about 120,000 net acres you all have there?

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

Yes, the total acres, our Uinta Basin acreage position is 120,000 acres. The Mesa Verde fairway in Red Wash is 25,000 or 30,000 acres. And then I talked about the Utland Butte area, south of Monument Buttes we've got another. In that subset of that 110,000 acres another 20,000 or 30,000 acres there that's perspective.

William Butler - *Stephens Inc. - Analyst*

Okay. And then the timing of that 10-well permit up in the Bakken, when do you all expect that? It sounds like it's still several months off.

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

We've got all the on site work done. We're just waiting for the actual sub surface well permits. They're in the part of the permitting process which has generally been 60 to 90 days. So we should be seeing those some time late in the third quarter. And then after all that, we got to get the 2 rigs out there. And we want those 2 rigs to show up as close to the same time as possible because we drop them onto that 10-well pad, each one of them is going to drill 5 wells. And we would rather not have 1 rig finish 2 months before the other rig because then we've got all that capital trapped. Because we can't start completion on that 10-well pad until both rigs are off. It's just not enough room to safely conduct fracture stimulations with 1 of the 2 pods of wells still occupied by drilling rig.

William Butler - *Stephens Inc. - Analyst*

Got you. And then up there, that Fat Cat area, how much of the 90,000 acres does that make up?

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

About 15,000 acres or so.

William Butler - *Stephens Inc. - Analyst*

And then are you developing on that near term or when should we expect results?

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

We have a rig out there now. We have 1 well down and cased there that we'll be completing here in the next few weeks and we'll continue to drill out there for a while.

William Butler - *Stephens Inc. - Analyst*

Okay, great, thanks. And then lastly, your Pinedale economics that you all have, do they reflect post Blacks Fork II with the NGL pick up?

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

No, they do not. They will change as a result of the conversion. And keep in mind that up until July 1, basically, all of the gas at Pinedale was being processed by QEP Field Services on a keepwhole arrangement. And QEP Field Services was keeping all of the liquids for its account. With the revised processing arrangement, QEP Energy will now recognize those liquids in the E&P company and the economics associated with the value uplift from those liquids will inure to the benefit of QEP Energy. So we'll revise the type curve and the economics in our upcoming slide deck.

William Butler - *Stephens Inc. - Analyst*

Okay. And then 1 last question. It looks like your Woodford Cana EURs went up. What is that attributable to?

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

I think we are just seeing average well results from our wells and from those of offset operators continue to come up. The early average was pushed down, frankly, by learning curve on how many frac stages to pump, how big of a frac stage, total stimulation frac job, should be pumped. And as a result, the early EURs were substantially negatively impacted, by design. We still think we have, on that range of EURs, I think we still believe that we have that we operate that 12 Bcfe well, which is right smack in the thickest part of the core of the Cana. And that is the high side on the reserves in the play to date, at least from the results we've seen.

Operator

Hsulin Peng.

Hsulin Peng - *Robert W. Baird & Co. - Analyst*

Good morning, everyone. Chuck, I was wondering if you can talk about, given that you have so many plays that you are currently evaluating, can you talk about whether you plan to stay within cash flow for 2012 or how do you think about that?

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

Hsulin, thanks for the question. The short answer is yes. We believe that we can continue to drive profitable growth in this Company while living in and around cash flow. We've alluded to several projects in Field Services. A new plant potentially to handle volumes of wet gas growing in the Uinta Basin. So we could see some lumpiness in investment around our Field Services business that might drive a slight outspend in that segment. But we think in general we can continue to grow production in the midteens and grow the Company in the midteens trajectory, while living in and around cash flow.

Hsulin Peng - *Robert W. Baird & Co. - Analyst*

Okay. And then the second question is, I'm sorry to ask about Blacks Fork II EBITDA again. So you mentioned that third quarter we should anticipate a EBITDA bump, but I was wondering in terms of once it's fully ramped up, while maybe not in fourth quarter, do you anticipate that to be a fully ramped number? Or when will it be fully ramped up?

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

Fourth Quarter should be clean performance where we're running the plant. And again, all things being executed perfectly, we're running the plant at optimal recoveries. We've got the plant fully loaded with as much gas as we can process in it. And then we are operating under our long-term transportation and fractionation agreement at Mont Belvieu, so we're selling into the highest value market. And so you should see clean numbers in both Field Services and Energy in the fourth quarter. With the exception of line pack, as Perry corrected me. With the exception of 230,000 barrels or so of line pack that will show up on the balance sheet in October as we fill the line from Conway down to Mont Belvieu. So we will help you normalize for that when we release the numbers.

Operator

Brian Bailey.

Brian Bailey - - *Analyst*

Good morning, gentlemen. You guys have actually answered all of the questions throughout the course of the Q&A so thank you.

Operator

Drew Venker.

Drew Venker - - *Analyst*

Hi, guys. You mentioned a number of oil plays in Oklahoma you plan to test. Can you talk about how much of your acreage across Oklahoma you think could be perspective for those plays?

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

Drew, it's hard to give you that kind of granularity on a call. We haven't really disclosed our acreage position in the Tonkawa or any of the other oil plays in western Oklahoma. We're still in the process of acquiring leaseholds so I'd rather not go into too much detail while we're still in the leasing mode there. But we have a decent inventory of acreage across Oklahoma. And you can see that acreage number in our 10-K disclosure. It's not all prospective for Tonkawa or Marmaton or other plays but it's a decent-sized acreage position. I'll just leave it at that.

Operator

Carl Brown.

Carl Brown - - *Analyst*

Hi, guys. I was also interested in getting a look at the new Pinedale economics. So I guess we'll have to wait until you update the slides in terms of the new PV-10 calculation?

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

Yes, we'll be, obviously, out on the road at various conferences. It's on Scott Gutberlet's to do list for this afternoon. So we'll get the new IR slide deck updated with that information, as well.

Carl Brown - *- Analyst*

Now, on the rate of return portion of that slide, is it as simple as just sliding up the X axis by $1? I think you mentioned the net effect of all of this is an increase in the realized price of about $1.

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

Yes, it's over $1, but that will give you directional indication.

Carl Brown - *- Analyst*

Okay. And on the margin, have we been slowing down in terms of completion activity and also drilling activity in anticipation of Blacks Fork coming online?

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

No, not particularly, other than the fact that we're currently running 4 rigs in the Pinedale since early this year. So relative to last year, we had 6 rigs for most of last year, 5 rigs in the fourth quarter, and then we went to 4 rigs early this year. So there has been a deliberate slowdown of rig count. But if you think about it in terms of the number of wells we're completing we're forecasting about the same number of wells for 2011, about 100 wells this year versus 103 last year. So not really a difference in well delivery pace.

Carl Brown - *- Analyst*

The 6-rig program, is that temporary to fill in the plant or is that something that you would see maintaining for the out years given the new economics?

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

I think we could stay at a higher level of activity and deliver more wells at Pinedale now that we've got the plant up and running, and it will certainly enhance the overall economics.

Carl Brown - *- Analyst*

Okay. And can you remind me in the CDA approach to drilling up Pinedale, when do we start to hit the sweeter portion of the anticline where you're getting the most productive wells? Is that something that's a year or 2 away or is it further out?

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

If you think about it in terms of 100 wells a year, it's probably 4 or 5 years out. If we accelerate the number of wells we're delivering then we get there a little sooner.

Carl Brown - - *Analyst*

Okay. And 1 quick question on Haynesville. Will you have by year-end enough data to potentially change the EUR assumptions on your Haynesville acreage, which I presume would also have an effect on your DD &A rate for next year? Or is that something that you need more data and it happens either the following year or can you update it mid year?

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

We've got 1 80-acre pilot that's currently been drilled and has been online for, what, Jay? -- 6 months now? 9 months or so. And those wells are performing quite nicely. They look, for all the world, like the first well drilled in the section. They're not showing a significant deterioration in performance or forecasted EUR. So you'd like to have, obviously, more than 1 data point across your acreage. This is an ongoing internal discussion on when do we make a change in our booking methodology for increased density. And how much hair cut, to be safe, do we give to the infill wells?

Just a reminder, we're booked at 2 wells maximum per section, or 2 locations maximum. If we have 1 producing well we have another PUD. But we have a maximum of 2 wells per 640 acres. Clearly the economics and the performance support a much higher well density, 8 wells per section or maybe even more. And we're just not sure yet on exactly how many wells that is. At some point, those wells do interfere with each other and you do see a deterioration in per well EURs. That's the reason we had not been aggressive about raising the PUD EUR, even though, if we look at our average PDP well, it's probably greater than 6 Bcf of EUR, the forecasted recoverable reserves to the producing wells. Because of the anticipation that ultimately we're going to book this field up on increased density at 8 wells a section or more. So we've been conservative. I would rather increase reserves over time as we see production performance to support it, and piloting of infill wells to support it, rather than having to reduce proved reserves as a result of bad outcomes from development activities. Does that answer your question? I was sufficiently vague. I didn't tell you when because we really don't know when yet. This is a conversation we need to have with Ryder Scott obviously.

Operator

Josh Silverstein.

Josh Silverstein - - *Analyst*

Hi, good morning guys. A quick question on the Cana. After some pretty significant growth in 2009 and 2010 it looks like it's flattened out in the 30 million to 40 million cubic feet per day range. Just curious why that was given it looks like you guys and industry has picked up activity there.

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

Part of it is just timing around completion. Our well completions and the completions of the other operators, as you will recall, we have an average 20% working interest in the Cana. A lot of the production growth is being driven by third-party activity in which we have a working interest. And you get just lumpy well delivery as you do in a lot of different plays. And as a result you see a little flattening. But the activity continues. The well count, net well count continues to increase and we'll see some lumpiness as we go forward. A little bit of the activity obviously impacted by weather and by the damage at Devon's plant by the tornado that came through the Cana play a month or so ago. And that obviously will be corrected here shortly. But other than that, there's nothing to read into that other than just typical well scheduling and well delivery.

Josh Silverstein - - *Analyst*

Got you. And then I was curious in the same play what the split might be between liquids versus dry gas down there and if you see the liquids portion gaining control as you start to drill into more the condensate and NGL areas.

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

If you'll refer to slide 8, we have colored bands there that show the location of the dry gas window. And that comprises about 22% of our total leasehold. And then the 2 green areas, the dominant portion of our leasehold is in the condensate and liquids rich gas area. That's about 60% of our acreage. And then as you move updip you really go into what looks to be a fundamentally different petroleum system. It is really basically an oil reservoir with associated gas. It may still have a retrograde component to it but it is basically wells that come on at relatively low rates but are dominantly oil wells. The industry drilling activity, I think, is very similar here to every other resource play. What you're seeing currently is industry drilling activity that is driven solely by drilling 1 well per section in the sections that each of the companies owns an interest in, in order to save leasehold with established production. And so we're seeing a large number of wells being drilled in that red area, as people focus on saving leasehold. Even though I would submit to you, at current well costs and current gas prices, given the rates that these Cana wells come on at, the economics are marginal in the dry gas window. People are just focused right now on saving leases. I think that what you'll see as time goes on, once the leases are saved, is people will move into, the industry is going to move into the liquids-rich portion of the play and probably focus in the core area where the shale is the thickest.

Richard Doleshek - *QEP Resources Inc - CFO*

And Josh, today about 70% of the production out of that area is gas, 30% is liquids.

Josh Silverstein - - *Analyst*

That's helpful. And then on the Bakken in that 10-well pad, can you just remind us of the design between how many Bakken versus Three Forks wells and what the spacing might be there between the wells?

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

It's half and half. It's 5 Three Forks wells and 5 middle Bakken wells. And the spacing is odd because if you think about it, the wells emanate from a single surface location and so they are very close together as the wells leave the surface pad. Well less than, on average it's a little over 500 acres of average well spacing for each of the 2 reservoirs. But in the near pad part of the well, the spacing is probably less than 160 acres. And that's just a function of the well trajectories that we can efficiently drill as we move away from the pads and given the surface restrictions that we have since our acreage is primarily under Lake Sakakawea, and we have limited surface locations that we can occupy to drill 10-well pads.

Josh Silverstein - - *Analyst*

That's helpful. And then lastly just down in the Granite Wash, I know you guys are going down to 1 rig there. What else really needs to be done down there to try to figure out if this play could be at least a little bit more consistent from well to well? Do you need to go and continue testing additional zones or do you need to have additional seismic data down there? Just curious about that.

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

It's drilling results, Josh. Seismic data won't help you. You can't, quote/unquote, see these sands. And even if you could, quote/unquote, see them you wouldn't be able to tell if they were water-bearing or gas-bearing. The architecture of the individual horizon, like the Cherokee we talked about in my prepared remarks, where you can drill a well less than a mile away, and structurally high or updip to an existing gas producer, and produce 100% water. Means that it's a very difficult area to predict pre-drill results. And what happened to us in the Morrow wells, we had 1 very good Atoka well and we put 2 rigs right next to that well and drilled 2 subeconomic wells. Is an indication that you really can't go too fast here. So there are some areas that we now have I think enough subsurface control that we feel pretty good that we can drill in between existing control points and not encounter water and get reasonably predictable results. There are other areas, in particular down to the South, in what we call the Methodist Home area, where we need to be very careful about how many wells we drill out in front of getting new well results because of the negative surprises we've seen. So it's really drilling results and not technology. There's no technology that we can apply here that will derisk this thing other than drilling.

Operator

[Dave Tap].

Steve Tap - - *Analyst*

Hi, it's Steve Tab. I see you're a very busy guy and you seem to be accomplishing a great deal. And all your questions, though, are from the standpoint of your supply side of the Company. I'm wondering what your view is of the demand side for natural gas, especially in the increased interested climate change and the increased need for electric power? What do you see developing in the way of demand for natural gas in the areas of the US that you're involved in, or the US in general?

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

Steve, that's a great question. I touched on it earlier. I think in power, first of all, clearly, the future source of significant incremental demand for natural gas is going to come, at least in the foreseeable future, from the power sector. You're absolutely right. Natural gas relative to coal emits 50% of the CO2 of coal when used in power generation, significantly less SOX and NOX. And of course another area that's been of concern under regulation of coal-fired power plants is mercury emissions, and natural gas is essentially mercury free. So as a result, from an environmental and from a climate change perspective, natural gas is the fuel of choice of the fossil fuels.

As you know, there's 400 gigawatts of installed gas-fired power generation capacity in this country. And it's being utilized a little over 25% of its installed capacity today. So there's ample opportunity with the existing gas-fired power plants to increase demand just by further increasing utilization of those facilities. And at current natural gas prices, relative to coal prices, modern high-efficiency combined-cycle power plants that have been built in the last 10 or 12 years are competitive with high-efficiency coal plants, all the way out on the baseload part of the dispatch curve. So natural gas not only has environmental advantages but it also has significant economic advantages, as power generators look to replace aging coal-fired Power Plants around the country.

We're talking to you today from Denver, Colorado. The state of Colorado has seen a significant move toward retirement of aging coal-fired power plants that are fingered as a substantial contributor to the current air quality issues along the Front Range, the eastern front range of the Rocky Mountains here in Colorado. And those old plants are being replaced by gas-fired power plants which will generate electricity in the baseload for the utility here in Colorado. So we're optimistic over the intermediate term that power demand, gas-fired generation demand, will be a substantial contributor to natural gas demand in North America.

Steve Tap - - *Analyst*

What percentage is it now of the natural gas going into power plants and what do you foresee in a couple years from now?

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

I think the current burn is about 18 Bcf a day or so. And obviously, with only a little over a quarter of the current capacity being utilized there's an opportunity for multi-Bcf a day increases in demand. If we just retired a portion of the oldest, least efficient, unscrubbed coal-fired power plants in this country over the next 5 years, we could see an increase of 5 or 6 Bcf a day in natural gas demand, just from that alone. And that ignores any increase in overall US electricity demand.

Operator

There are no further questions.

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

Okay. I'd like to thank everyone today for dialing in and for your interest in QEP Energy. We'll be out on the conference circuit so we look forward to seeing you very soon.

Operator

This concludes today's conference call. You may now disconnect.
