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PRESENTATION

Operator

Good afternoon. My name is Jackie, and I will be your conference operator today. At this time, I would like to welcome everyone to the QEP Resources first quarter earnings release and operations update 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. Richard Doleshek, you may begin your conference.

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

Thank you, Jackie, and good morning, everyone. This is Richard Doleshek, QEP Resources' Chief Financial Officer. Thank you for joining us for QEP Resources' first 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.

As you all know, this is our third quarter as a standalone Company, having been spun off from Questar Corporation on June 30, 2010, and I believe we continue to deliver very good operating and financial results. In terms of our first quarter results, we provided an operations update on Monday. We issued our earnings release yesterday. In our operations update, we reported first quarter 2011 production of 65.9 billion cubic feet equivalent, 59% of which came from our Mid-continent operations. We updated our operating activities in our core areas, and we increased 2011 production guidance to be in the range of 263 to 267 Bcfe. Yesterday in our earnings release, we reported first quarter 2011 results and updated 2011 guidance.

Just to remind everyone, in conjunction with our spin-off 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, and we will be happy to provide any answers you might have in our Q&A.

In today's conference call, we will use a non-GAAP measure EBITDA, which is defined and reconciled in net income in our earnings release. In addition, we will 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.

Turning to our financial results, in comparing the first quarter of 2011 to the fourth quarter of 2010, the story was higher production offset by lower net realized equivalent prices at QEP Energy, our E&P business, and stronger performance at QEP Field Services, our gathering and processing business, as a result of the Iron Horse plant coming online and higher gas processing margins. Our first quarter EBITDA was $305.8 million, which was $7 million higher than the fourth quarter of 2010 and up 14% from the first quarter of 2010. QEP Energy contributed $242 million or 79% of our aggregate first quarter EBITDA, and QEP Field Services contributed $61 million or about 20% of our total EBITDA. QEP Energy's EBITDA was flat, while Field Services' EBITDA was up about 17% from their respective fourth quarter 2010 levels. Factors driving our EBITDA include QEP Energy's production, which was 659 -- 65.9 Bcfe in the quarter, and included a positive 1.6 Bcfe out-of-period adjustment. The quarter's production was 6% higher than the 62.1 Bcfe produced in the fourth quarter and 28% higher than the 51.5 Bcfe produced in the first quarter of 2010.

QEP Energy's net realized equivalent price, which includes a settlement of all of our commodity derivatives, averaged $4.84 per Mcfe in the quarter, which was 6% lower than the $5.13 per Mcfe realized in the fourth quarter of 2010 and 12% lower than the 5.51 per Mcfe realized in the first quarter of 2010. QEP Energy's commodities-driven portfolio contributed $42 million of EBITDA in the quarter, compared to $78 million in the fourth quarter of 2010 and $9 million in the first quarter of 2010. The derivatives portfolio added $0.63 per Mcfe to QEP Energy's net realized price in the first quarter, compared to $1.25 per Mcfe in the fourth quarter and $0.17 per Mcfe in the first quarter. As a point of reference, the average swap price of the 2011 gas derivatives portfolio is about $0.35 per Mcfe lower than the 2010 gas derivatives portfolio average swap price.

QEP Energy's combined lease operating and production tax expenses were 60 -- or $56 million in the quarter, essentially flat with the fourth quarter of 2010 and up 10% from $51 million in the first quarter of 2010. LOE was down 7%, and production taxes were up 13% in the first quarter of '11 compared to the fourth quarter of 2010. With the higher production volumes in the quarter, per unit LOE metrics declined to $0.51 per Mcfe in the quarter from $0.58 per Mcfe in the fourth quarter and $0.57 per Mcfe in the first quarter of 2010. And finally, QEP Field Services' first quarter EBITDA was $61 million, which was 17% higher than the fourth quarter of 2010 and 22% higher than the first quarter of 2010.

Gathering margins were up $5.5 million or 14% in the quarter compared to the fourth quarter, driven by increased revenues associated with a short-term third-party gathering and processing agreement related to volumes that will ultimately be processed in the Blacks Fork II facility. Gathering volumes were flat at about 1.3 [billion cubic feet] (corrected by Company) per day. Processing margins were up $2.3 million or 10% in the quarter compared to the fourth quarter of 2010, on flat fee-based processing volumes, higher processing fees, and higher NGL sales volumes, offset somewhat by shrinkage expense that was sequentially $3.5 million higher.

Net income from continuing operations for the quarter was $73 million, up 13% from the fourth quarter of 2010 and influenced primarily by non-cash charges. DD&A expenses were $17 million higher in the quarter compared to the fourth quarter of 2010 as result of increased production volumes from our higher DD&A expense Haynesville fields. Exploration, impairment, and abandonment expenses in aggregate were $23 million lower in the quarter compared to the fourth quarter 2010, as we had the expense associated with our unsuccessful Borie prospect test in the fourth quarter and quote-normal-unquote expense in the current quarter. Our provision for income taxes was $6 million [higher] in the quarter compared to the fourth quarter of 2010, due to higher pretax income, although we do not expect to be a cash income taxpayer in 2011.

With regard to capital expenditures for the first quarter, we reported capital expenditures on an accrual basis of $315 million. Spending on E&P activities was $298 million, which included spending $22 million on leasehold acquisitions. Spending in our Midstream business was only $16 million in the quarter, resulting in the timing of progress payments associated with the construction of the Blacks Fork II plant, which is scheduled to be in service in the fourth quarter of 2011 and the completion of our Iron Horse plant in the Uinta Basin. We are also affirming our capital budget for 2011 at about $1.2 billion.

Our balance sheet was relatively unchanged from year-end. We reported total assets of $6.8 billion, common shareholder equity of $3 billion, and total debt of $1.6 billion. We ended the quarter with $500 million drawn under our $1 billion revolving credit facility, and the increase in borrowings from the revolver at year-end included funding the $58.5 million of senior notes that matured March 1 and making the March 1 semiannual interest payments in our senior notes.

With that, I will turn it over to Chuck.

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

Good morning.

As Richard noted, on Monday and Tuesday, we issued separate releases covering our operations and financial results. I will try to add color to those releases, give you an update on our plans, and then we will move ahead to Q&A.

First, let's review some highlights from our operations. QEP Energy Group production, up 28% in the first quarter of 2011 to 65.9 Bcfe compared to first quarter of 2010, which was driven by good results in all of our core areas, but particularly in the Mid-continent region. As we noted in the release yesterday, our current quarter included a 1.6 Bcfe volume that was from a prior period that resulted from an adjustment in our ownership in a federal unit in the Uinta Basin, which obviously distorts the comparison of year-over-year and quarter-over-quarter operating results. If we adjust for the ownership changes, our first quarter production would be up about 25% from the first quarter of 2010 and up almost 4% from fourth quarter of 2010.

Rockies production grew to 27.1 Bcfe in the quarter, and taking into account the ownership adjustment, Rockies production was up about 1% year-over-year and down about 11% from the fourth quarter. As you all remember, we typically defer completions at Pinedale and elsewhere in the Rockies region during the coldest months of the winter, which obviously had an adverse impact on first quarter production volumes. And this winter's especially cold weather also impacted first-quarter production volumes in the Bakken due to poor road conditions that constrained our ability to truck oil.

Our western Mid-continent region, driven primarily by liquids-rich Cana and Granite Wash plays, the production was 9.5 Bcfe in the quarter, or approximately 25% higher compared to the first quarter of 2010 and essentially flat with the fourth quarter of last year. Eastern Mid-continent production, dominated by our Haynesville Shale play in northwest Louisiana, totaled 29.3 Bcfe in the first quarter. That's a 58% increase over the first quarter of 2010, and we are up about 26% compared to the fourth quarter of last year. As we noted in our earnings release, on an accounting basis, the Mid-continent region contributed 59% of QEP's first quarter 2011 production volumes, and that's up from 51% in the first quarter of 2010 and 54% in the fourth quarter of last year.

Let me draw your attention to the slides that were posted yesterday along with our operations release out on our website at qepres.com. I will refer to the slide numbers as I discuss the operational details.

Since our last call, we've turned to sales 10 new QEP-operated Haynesville Shale wells, all with very strong results, initial rates that are in line with our previously announced well results in the play. We continue to constrain or choke back our Haynesville wells during flowbacks, so our initial production rates from recent wells are not comparable to the wells that we've announced earlier, back in early 2009, or the results of some other operators who are not constraining flowback. We are absolutely convinced with the more data that we see on these wells that constraining flowback is the right approach to managing the Haynesville reservoir. There is a growing body of evidence that suggests that these constrained flowbacks result in flatter decline profiles once the wells exit the production plateau phase. This shallower decline should also positively impact ultimate recoverable reserves from each well, and it has a quite significant impact on overall well economics, because obviously with a shallower decline, we are bringing forward production that would occur much later in the well life into the more current periods.

We continue to buck the industry trend of escalating completed well costs in the Haynesville. QEP operated gross completed well costs averaged $9.1 million in the first quarter of 2011, down from an average of $9.3 million last year.

Our lease saving activity is winding down. We now have 5 QEP-operated sections left to drill to hold all of our operated leasehold by production. There are an additional 9 undrilled sections in which we have a working interest that are -- represent about 640 net acres that are operated by others, and those 9 sections have lease expirations ranging from the middle of this year through early 2014. Also note that we picked up an additional 1,150 net acres in the core of the Haynesville play since our last call, and this interest is in sections where we are actively drilling new wells. We currently have 6 QEP-operated rigs working in the Haynesville play. You can refer to slides 3 and 4 for more detail.

At Pinedale, you will recall we shut down our well completion activity during the coldest months of the winter. We recommenced well completion activities in mid-March, and as of yesterday, we had a -- completed and turned to sales 16 new Pinedale wells so far in 2011. We continue to be focused on driving down completed well costs with our relentless focus on drilling and completion cycle times. As we noted in our operations update on Monday, our average drill times at Pinedale continue to improve. First quarter 2011 spud to TD times average 14 days, compared to a 17-day average last year.

And the bar keeps getting lower. You will also note that our record spud to TD drill time is now 11 days, down a half a day from the previous record of 11.5 days. We have recently rigged down and moved another of our Pinedale rigs up to North Dakota to drill Bakken and Three Forks wells, but thanks to the drilling efficiencies as I just described, we anticipate still being able to deliver 90 to 100 completed wells at Pinedale in 2011, with just four drilling rigs operating for the balance of the year. You can refer to slides 5 and 6 for more details on Pinedale.

Turning to the Anadarko Basin, Woodford or Cana Shale play, we've completed and turned to sales two new QEP-operated wells since our last call. The results of these wells are detailed on the operations release on Monday. Also note that we've added an additional 7,300 net acres in the liquids-rich fairway of this play since our last update. We now have 75,300 net acres in the play. We currently have 3 QEP-operated rigs running in the Cana play, and you can refer to slide 7 for a map that has more details.

Up in the Williston Basin in North Dakota since our last call, we've completed and turned to sales 2 new QEP-operated middle Bakken horizontal wells. One well, which was located on the up dip eastern edge of the middle Bakken fairway, had a peak rate of about 600 barrels of oil equivalent per day, and that was on a restricted flowback. We were flowing the well back in bad winter conditions, and we were unable to truck the flowback water. If we adjusted for the -- sort of the normal flowback on normal choke size, the well would have had a rate upwards of 900 barrels of oil equivalent a day.

The second well, which was up in the northern extension of our acreage at a peak rate of 1,500 barrels of oil a day from a short lateral, we are now running 2 rigs in the play. We have a third rig that's moved up from Pinedale. It's rigging up and it will be drilling soon. As we noted in our operations release, we are in the early phases of scoping and permitting our first 10-well pad in the Williston Basin. Depending when we get the initial permits, we should be able to add 2 more drilling rigs to our Bakken program, bringing the total to 5, sometime around year-end. Our plan is to place the 2 rigs on a single 10-well pad, and once the wells are drilled and cased, we would move the drilling rigs to the next 10-well pad, and then we would commence completion operations on the first pad.

This approach obviously addresses one of the biggest rate-limiting steps in pace of development of our Williston Basin acreage, and that's been surface permitting, but there are a couple of important points to remember. First, these operations won't have any impact on 2011 production. It will take 6 or 7 months after we move the rigs on to the first 10-well pad before we see a production response, so there will be 6 or 7 months of capital investment cash outflow and no production in -- uptick from the increase in rig count. The second -- the production response from pad drilling will be lumpy, as we bring on 10 new wells in a relatively short period of time. And then we will have a period of 4 or 5 months after we complete those wells before we bring on the next group of wells from the next 10-well pad.

I should point out that this is not our first multi-well pad drilling in the Williston. We have already drilled 2 middle Bakken, Three Forks II well pads, one of which we reported last quarter with a Three Forks and a middle Bakken well. We have another 2 wells drilled waiting on completion, both a pair of middle Bakken and Willis -- and Three Forks wells, and we currently have 1 rig drilling on our first 4-well pad. But clearly, the addition of 2 more rigs drilling on 10-well pads would be a step change in the pace of development of our Bakken/Three Forks assets. We will keep you posted on our progress on permitting and the timing around introducing the 2 new rigs as we progress through the year.

Also note that we've finished [connecting] our wells on the east side of the lake to an oil and gas gathering pipeline system, and we will be connecting the producing wells on the west side of the lake later on this spring. So we won't be talking about weather impacts on Bakken production next winter. Slide 8 has details of our Bakken play and also gives the location of our first proposed 10-well pad.

At our Granite Wash/Atoka play in the Texas Panhandle since our last call, we've turned 2 new QEP-operated wells to sales. We talked about the individual well results in our operating release, so I won't recite them again here. Needless to say, the Simmons well, the Simmons 209H well, which came on at little over 3 million cubic feet a day, was a disappointment. Our recent well results, combined with the results from that of offset operators, confirm that the geology of the washes -- that wash sequence -- is complex, and that we don't want to get ahead of ourselves in delineating the limits of each of these target intervals. As a result, we may dial back our rig count in the Granite Wash play from the 3 rigs we currently have working to make sure that we fully understand the results of one well before we commence drilling the next one. We will be happy to answer more questions about this in Q&A. Also refer you to slides 9 and 10 for additional details on the washes.

Turning to the exploratory front in the Powder River Basin of Wyoming, we've got permitting underway on a number of horizontal well locations that will target the Sussex formation sands. We anticipate drilling our first QEP-operated horizontal wells in the second half of 2011. The exact number of wells that we get down this year will be dependent on timing of the issuance of drilling permits. Most of the wells that we have staked have at least a portion of the leasehold on federal land, and that means that permits will take considerably longer than those permits that we receive for wells that are drilled on private or state lands. As a reminder, several operators have already reported good horizontal well results in the Sussex formation, with initial rates of 700 to up to 1,500 barrels of oil per day. We've got over 55,000 net acres in the Powder River Basin/Niobrara/Sussex/Frontier formation play, including significant acreage position directly offsetting some of these recent successful wells.

Turning to our Midstream business, QEP Field Services had a strong quarter, thanks to fee-based gathering volume growth combined with strong frac spreads in our gas processing business. Field Services' EBITDA, as Richard mentioned, was $61.4 million in the first quarter of 2011, up 22% compared to the first quarter of 2010 and 17% compared to the last quarter. The Iron Horse cryo gas processing plant in eastern Utah started up, and it's performing well. As a reminder, the economics of this plant are underpinned by fee-based contracts with third-party producers. We anticipate the new plant should contribute about $15 million of EBITDA for 2011.

We are also making good progress on the construction of our Blacks Fork II cryogenic plant in southwestern Wyoming. All the major equipment and vessels are now on the ground, and the major components are being assembled. We will soon enter the slower, more complicated phase of plant construction. That's the wiring of all the instruments and controls that make the plant run. When completed in the fourth quarter of this year, Blacks Fork II will process gas that is dedicated for life from QEP-operated acreage on the northern third of the Pinedale Anticline, the largest gas field in the Rockies. The Blacks Fork II plant will have a capacity to recover an incremental 15,000 barrels a day of NGL net to QEP resources, and it will obviously be a substantial contributor to QEP resources EBITDA.

You will note that with better visibility from the remainder of the year, yesterday we raised our full-year 2011 guidance. We now expect our production to range from 263 to 267 Bcfe. That's up from prior guidance range of 258 to 265 Bcfe, and with an increase in production volumes, we now forecast our EBITDAX could range from $1.2 billion to $1.3 billion. That's up from previous guidance of $1.115 billion to $1.23 billion. And while our capital allocation is moving around a bit in response to well results and chasing higher returns, we still forecast our capital investment program to be about $1.2 billion, which we believe will fund our forecasted growth while doing what we said we were going to do, and is that live in and around forecasted EBITDAX.

Before I open the line to questions, I would like to take this opportunity to recognize Jim Harmon, a long-standing Director at Questar and now QEP, who will retire from our Board at our annual meeting next month. Jim first joined the Questar board back in 1976, and he served until 1997, when he resigned to become Chairman and President of the US Export-Import Bank. After completing his service at US Ex-Im, Jim was reappointed as the Director of Questar in 2001, and he served in that capacity until the spin-off of QEP last June, when he resigned from the Questar board and became a Director of QEP Resources. Jim's breadth of experience in both the private and public sectors in banking and corporate finance and as an investment portfolio manager has made him an invaluable corporate director, as well as the coach and mentor to a succession of managers, including me. On behalf of the shareholders, directors, and management teams past and present, we would like to thank Jim for his advice and counsel and selfless dedication to QEP and to our predecessor company over the past 35 years and wish him well in his many ongoing business and philanthropic endeavors.

As many of you know, David Trice, a former Chairman and CEO of Newfield Exploration Company, is standing for election as the QEP Director at our annual meeting next month. We look forward to welcoming David to our Board and to his guidance and advice as we shape the future of QEP in the years to come.

With that, Jackie, let's go ahead and open the lines for questions.

QUESTIONS AND ANSWERS

Operator

(Operator Instructions). Your first question comes from the line of David Heikkinen.

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

Good morning, David.

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

Just thinking about your capital budget and balancing EBITDA, and then you talked about reallocating capital, kind of geologically driven in the western Oklahoma plays. Can you talk some about -- with oil prices up, what are the intervals or thought process of what you are going to reallocate capital to and how that actually fits together from here forward?

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

Sure. First, as I said in my prepared remarks, maybe not as eloquently as I can say it extemporaneously, the Granite Washes -- the washes in both the Atoka and Granite Wash -- are not shales, and therefore, what we are seeing from well results, both our well results and then wells which we have an interest that are operated by others, is a much less predictable, much less uniform response. We have been disappointed with a couple of the sort of edge wells that we've drilled in the Atoka. We have seen strange behavior in the shallower, lower -- or higher quality, higher permeability, higher liquids content reservoirs, including water over gas and all kinds of strange spatial relationships that we are not quite sure we understand.

So, rather than drilling five wells in a row and then seeing the completion results simultaneously and realizing after the fact that things were not as we had interpreted them, we decided we are going to slow down. So we are probably going to pull one or two rigs out of the Granite Wash play, continue to drill with one rig in the areas around wells that we've already drilled that we feel comfortable with the interpretation. You know, I point out that the deeper washes, the Atoka washes, which still contain liquids, more liquids than we had originally anticipated, do not generate the returns that the shallower -- what we call Cherokee and Caldwell intervals do. The Atoka washes are in the sort of mid-20s after tax returns. The shallower stuff is over 100%. The issue with the shallower horizons is just the inventory and making sure that A, we don't over drill the reservoirs, and B, that we again sort of see each well result before we drill the next one.

So where will we take the capital? We are going to allocate capital in the mid-continent to other plays in which we have ownership interests that are liquids-rich and in particular, oily plays in western Oklahoma. And I will leave it at that for right now. We will have more details as we move the rigs into the plays and get some well results, but we have seen well results from others in several of these plays that indicate that we should have a good program going forward.

It may not, by the way, be the exact same rigs that are currently drilling in the Granite Wash. We could probably get away with a little smaller rig that moves faster in several of these plays. But you should think about it in terms of capital allocation toward more liquids, toward more oily plays in the mid-continent region. And as I also mentioned, we don't know yet exactly on timing, but we would hope to add a couple more rigs in the Bakken toward the end of the year. It may be November, it may be December before we get those rigs there. So it won't be a big shift in capital, but we could see a little bit of shift away from gas and toward Bakken drilling as well, depending on timing of permits.

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

How much -- how many dollars are we talking about moving around?

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

100, 150, somewhere in that range.

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

Okay.

And then on the leasing side, you invested $22 million for 1,150 acres in the Haynesville and 7,000 acres in the Cana. Can you give a split as far as additional opportunities to continue to do these bolt on-type leases and kind of what your expectation or kind of a range could be for leasing this year?

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

It's really hard to forecast, David. At the outset, I will say that we had anticipated roughly 50 -- $45 million to $50 million of capital allocated to leasehold acquisition this year. Obviously, we have been very successful in picking up acreage in the Cana. And as you know, in the Cana play, a lot of the leasehold acquisition is driven by forced pooling, which gives you an opportunity in and around the proposal of a well in a section to acquire additional leasehold. And it's been through that mechanism, as well as just straight up leasing, that we have been successful with.

It's hard to predict for the remaining quarters whether we will continue that pace or not. I sort of doubt it, because the opportunities are getting less and less as time goes on. In the Haynesville, there have been some sections where there have been mineral owners who have held out until the last minute before a well is drilled, hoping for the historic highs of lease bonuses, and then have tumbled to the current reality of the value of their mineral leases for lease bonuses as drilling rigs move in. Again, when you look at our maps, there is just not a lot of open acreage out there that is left to be acquired in our core area. We are not going to go out and start leasing in another area away from our core drilling activity, but it makes sense to acquire the odd leases that we can to further consolidate our core areas.

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

Okay. Thank you.

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

Thanks.

Operator

Your next question comes from the line of Brian Singer.

Brian Singer - *Goldman Sachs - Analyst*

Thanks. Good morning.

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

Hi, Brian.

Brian Singer - *Goldman Sachs - Analyst*

Chuck, there has been a lot made regarding cost inflation in the Bakken that is negating rates of return a bit. As you think about adding two rigs, can you talk to what your expectations are for cost inflation and well costs and any benefits that you get via shifting to a 10-well pad?

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

That's a good question, Brian. Certainly, I think that -- there's a couple of observations.

One, an operator who has one or two rigs operating in a play in the Bakken is an example, but I would submit to you that it's any resource play, has a very difficult time driving down well costs, because you just don't have the economies of scale that will allow you to command premium services and to sort of control your destiny. So, I would submit that our current well costs and our historic well costs in the play have been an indicator of that very fact. And what we are hoping to do is by getting to five rigs, get to a critical mass where we can begin to command better services, obviously, get better people and more focus on our drilling and completion operation in the area. That's just adding to the rig count and adding to the delivered completed well count. I think we will get some economies of scale that way.

And then moving to pad drilling, obviously, you save costs on physical construction of the pad, as opposed to just drilling single-well pads or two-well pads. You also save in rig move, because we will use rigs that are set up with skid packages. In fact, we just moved a rig up from Pinedale that has a skid package under it, so we will be able to avoid having to rig down and rig back up and the associated cost there. And then, once the rigs are out of the way, we will be able to work on multiple wells with a frac crew, rather than mobing and demobilizing a frac crew.

So what does all that mean? $0.5 million, $0.75 million in savings, if we assume constant service costs from what we see today on a per well -- gross per well completed well cost. Knowing the performance of our drilling and completions folks, that's a start. And I think that what we then do is we get the right heads focused on the -- on driving down the cost, and I hope we see the same sort of performance improvements and cost decreases that we have seen in our other core plays.

Brian Singer - *Goldman Sachs - Analyst*

Great. Thanks. And to reiterate, the constraint there in terms of the timing of when you're bringing those rigs on is the permitting, or do you also see some difficulty in being able to add the rigs and the crews?

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

Well, it's a chicken or the egg thing. We are going to have to bring a couple of new rigs in, they may not be new rigs, they will be new rigs to our portfolio. And we are trying to balance the timing around this first 10-well pad permit, and it's just getting the surface permitted and getting the pad built. And committing to the rigs to get them moved into the area, because they are probably going to come from -- obviously, outside of the Williston Basin, because there's not a single rig available. You know, I think -- looking at the two separate components, the two moving parts, we are looking at sometime around November, and that would be the perfect storm, where both the permits and the rigs show up simultaneously. And that's why I sort of hedge and say by year-end. The rate limit except -- will be getting that first permit -- for that first surface disturbance permitted, and we are already focused on that. Needless to say, from the stakeholder perspective, pad drilling is much preferable to single-well locations, and so we are seeing favorable response from all the stakeholders involved, as we move toward permitting this first 10-hole pad.

Brian Singer - *Goldman Sachs - Analyst*

Great. Thanks.

And lastly, a big picture question. Now that you are nine months or so into being a separate company and with the -- perhaps a bit more momentum in some of the liquids plays, can you talk to A, your interest in pursuing acquisition opportunities of some size from here, and B, interest among other companies in your assets, and C, any mitigating tax implications around corporate or asset acquisitions or sales?

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

I will take the first -- I'm not sure if that's one or two questions, and I will toss the final one over to Richard.

We obviously have a new ventures group. We are constantly looking at opportunities to either get into new plays or expand our presence in existing plays. And it's all about economics, Brian. What we find is that when you include the premium acquisition costs of buying another company's assets, especially in these liquids-rich and oil plays, by the time you embed the acreage costs and you look at the total returns that are -- that you would forecast from wells drilled in these plays, the overall project economics just don't compete with some of the things we currently have captured in our portfolio. Including things that we are in the early phases of starting to delineate, like our liquids-rich gas play that we've talked about some in the Uinta Basin, other plays in the Rockies that are liquids-rich that we are in the early phases on, but from a -- we've already captured those resources, and it's very difficult to see new acquisitions compete with the returns of some of those captured projects. We've also got other opportunities potentially to invest in our Midstream business that generate very attractive returns, and so we have multiple avenues of growth within our portfolio without taking the sort of transaction risk associated with asset acquisitions.

On the M&A side, it's the same thing. Certainly, we don't have a felt need to go out and do a corporate acquisition, either, in order to achieve our stated objectives of growing in sort of the mid-teens zip code over the next few years. And so that is the -- sort of the take on both asset acquisitions and corporate acquisitions. We are going to continue to look for opportunities to bolt on to our existing core footprints in some of these plays, because there are opportunities to do that. But those are relatively modest dollar amounts compared to, obviously, going big time into a new play.

And then I will let Richard answer the last question.

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

Hi, Brian.

I think there is a market misperception out there that there is a sort of a two-year standstill in terms of M&A activity, in terms of being acquired or making an acquisition using our stock. As long as there is a fact pattern that the service doesn't interpret as having the spin been done with the knowledge there was a transaction in mind, we are good to go. So, for example, if we want to be -- if we are going to be acquired by some major company that we weren't having discussions with prior to the spin, then that's a clean transaction, and it won't bust the Section 355 treatment. The types of transactions that would cause a bust in the tax-free spend are pretty limited, and it should not really be a concern for anybody out there.

Brian Singer - *Goldman Sachs - Analyst*

Great. Thank you.

Operator

Your next question comes from the line of David Tameron.

David Tameron - *Wells Fargo Securities - Analyst*

Good morning. Nice quarter.

Chuck, can you talk about the liquids? I think last quarter you said 15% to 20% was kind of the target by the end of 2011, liquids versus gas. Can you just talk about when you -- that progression, and is that still a good number?

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

Yes, David.

When we look at our sort of beginning year ratio, it's around 10%, so -- exit rate from last year about 10% oil energy yield and 90% dry gas. If we look at sort of the average for the year, we are thinking we will be in that sort of 14% to 15% average for the year, and that would imply that we would exit nearly double where we entered. Of that, so the 15% -- we go from 10% last year to 15% for the year this year on a cumulative basis, which would imply about a 20% exit rate. As for next year, we haven't really put out any forecast. We just sort of think about the trajectory of growth. We will probably average about 20% next year, I would think, and that's very early and sort of looking at rolling forward our drilling programs into next year. And that's assuming that we continue to deliver mid-teens aggregate production growth, compound average production growth.

The other thing you might be interested in, this year, the average barrel is about half in -- will probably average about half NGLs. Next year, with our forecasted growth in the Bakken, it will probably come down about 5% or so, be about 45% NGLs. But of course, we are going to have a lot more NGLs coming on in -- from Pinedale as the Blacks Fork sycophant comes on in the fourth quarter.

So, does that sort of answer your question direction? Richard, do you have --

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

Yes, and David, let me just chime in for a second.

The way we rounded numbers, to just give you one significant decimal point on the production, you know, if we were actually give you the full number, the fourth quarter of 2010 was 1.27 million barrels versus the first quarter of 1.15 million barrels of liquid. That's about a 9% decrease, but when you look at the 1.3 versus 1.1, it looks like it's a 15% decrease. And so, first quarter is two days shorter, et cetera, et cetera, et cetera. I think the decline from the fourth quarter to the first quarter looked optically uglier than it really was in reality.

David Tameron - *Wells Fargo Securities - Analyst*

Okay.

And then there was -- I'm not sure if you addressed this or not, but there was a lot of concern that your Bakken production -- and obviously, weather impacted it, timing impacted it. But can you talk about just -- on the average rate, a lot of people were comparing that December number to a first quarter number. Can you talk about -- kind of average 4Q to 1Q, if we smooth it out over three months, what that would look like?

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

So it was 1,997 barrels a day in Q4 and 1,914 barrels a day in Q1, so it's a modest decline.

The other thing, we But we also delayed completion on wells, because obviously, we could -- we had road conditions that were just basically impassable for about three weeks. We lost frac dates as a result of not being able to keep the roads open to haul water and to move frac crews in and out of several of our locations.

Is that the wrong number? Is that right?

David Tameron - *Wells Fargo Securities - Analyst*

Okay. Yes.

And one more, just going along the liquids thing. Care to discuss at all the Uinta Basin and kind of what you've done in the Red Wash and rich gas NGL component there? Can you just talk about what's -- what the latest and greatest is there, and what your plans are, going forward?

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

Well, there's a couple of things going on in the Uinta. Obviously, we have not talked a lot about our drilling activity, but we have drilled a bunch of wells over the past few years targeting the shallow black wax reservoirs and in the Green River formation. A number of horizontal wells, multilateral horizontal wells, that has kept our production volumes from the black wax reservoirs relatively flat over the past couple of years. We've got an inventory of additional opportunities there. We are waiting on some permits to restart drilling in a couple of areas.

But we also have, in the Red Wash field, which is an old 1950s-vintage field that was originally developed by Chevron, and then the adjacent field immediately to the west, Wonsits Valley, a large accumulation of oil, similar to other oil fields in the Uinta Basin operated by others in the same sort of geologic sand -- discontinuous sand bodies, stacked pay. One of the interesting things is, we look at the production history from the Uinta Basin, the cumulative production since the 50s until now has only recovered a little over 12%, 12% or 13% of the oil in place in that oil field. And so there is a tremendous opportunity to go in and try to harvest the unrecovered oil. And the field has been water flooded. The water flooding that was done was not done very thoughtfully, so there is oil that has been moved around, and as a result, it's going to take additional well bores to find that oil, because the field was originally developed on a 40-acre spacing, and there's a lot of real estate in between those 40-acre wells in which that oil can move and hide, literally, from the existing well bores.

So, that's sort of a background. Now, the question that you asked was about liquids-rich gas. Underneath this oil field, underneath the Red Wash oil field, is a section of discontinuous sands in a formation called the Mesa Verde. That formation has been actively developed immediately to the south of us by EOG in an area they call Chipeta and by Anadarko in an area called the Greater Natural Buttes area. And well results there -- they've talked about it a lot, and I won't advertise for them, but they've had excellent well results. And one of the interesting aspects of the Mesa Verde section is it's quite liquids-rich, and there's free condensate as well as liquids-rich processible gas, and we are processing some of that gas right now in our new Iron Horse plant for third parties.

But we have drilled by re-entering old oil wells, about 20 deepenings into this Mesa Verde section, and we have been very encouraged by the early results from those wells. We've had a couple of wells that have been on now for almost two years and a handful of wells that have been on for about a year, and so we are watching these wells to get a better feel for long-term well performance and ultimate reserves. And so far, it all looks quite encouraging.

And so the next step will be to make a decision to go into full development mode, and that's a fairly significant decision, because it will require us to commit a pretty sizable chunk of capital to the drilling, and -- but we will also have to start building a new cryogenic gas processing plant in order to handle the growing volumes of liquids-rich gas from the play. That's something that we are likely to make a call on sometime in the second half of this year. And we just -- it's really been me who has been holding one foot on the brake and one on the accelerator, making sure that we are comfortable with the well results we've seen and the repeatability of it, because it's not just a decision about moving in a few rigs and drilling a bunch of holes in the ground, it's also a capital allocation decision on putting more capital to work in our Midstream business.

David Tameron - *Wells Fargo Securities - Analyst*

And so you're -- it sounds like on the development side, you're talking like a four- to five-rig type -- would that be commercial development, and then a build a plant on top of that?

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

Well, you know, you could start out with a couple rigs. These -- we've got a -- how many re-entry candidates in aggregate?

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

Close to 100.

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

Close to 100 -- that's Jay Neese, by the way -- close to 100 old wells that are drilled down to roughly, what, 6,500 feet or so -- cased, that were originally part of the oil field development that we can go in, squeeze off the existing perforations in the existing oil reservoirs, and then drill deeper. And that's, by the way, what we have done in all but one of the 20 wells we've done so far. They have all been deepenings. So they are cheaper, so we can go in with a couple of rigs, and obviously, if you are not drilling 6,000 feet of scenery, you can punch out a bunch of these deepenings fairly quick. And we can start with a couple of rigs and have a meaningful result fairly quick while we are starting to build a plant, and we can back fill some of the existing capacity. In the Stagecoach plant, which you will recall we completed a couple years ago, which is a refridge plant, so we will get partial liquids recovery, but in order to really get the full economics from this project development, we will need a cryoplant to process the gas.

David Tameron - *Wells Fargo Securities - Analyst*

Okay. I will let somebody else jump on. Thanks for the color. I appreciate it.

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

Thanks, David.

Operator

Your next question comes from the line of Hsulin Peng.

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

Hi, Hsulin.

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

My question is regarding your production costs. In the first quarter, year-over-year (inaudible) the cost improvement is pretty good. I was wondering if you can give us some trends for the rest of 2011 and potentially into 2012, especially on the LOE and DD&A rate front.

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

Yes. So, Hsulin, if you go back and you look at it sort of over the last eight quarters, you will see that typically, there is a quarter-to-quarter dropoff in the fourth quarter of the previous year to the first quarter of the current year associated with slow down and completion activities and production activities in the northern tier of the -- of our property base. This year, again because of the increased production volumes coming out of the mid-continent, we didn't have as large a dropoff, but on a per unit basis, it was a pretty substantial dropoff. And so, as we've gotten better with water handling, as we've gotten better with our chemicals, et cetera, I think this cost trend that you see is sustainable on a per Mcfe basis, so you ought to feel pretty good about using that number. You are going to see the absolute dollars sort grow with production, but on a per Mcfe basis, I think we feel pretty good about our LOE -- our cost structure as representative in the first quarter.

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

Okay. That's great.

And then the second question is more overall interest. Not specific to Bakken, but overall, what are you seeing in terms of service cost trends across your whole portfolio?

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

I think it's fair to say that there is a lot of pressure on both drilling rig day rates, especially drilling rigs that are in that sort of sweet spot for all of the plays. The 1500-horsepower rigs with 1500- or 1600-horsepower pumps with top drives that are capable of drilling wells of depths of 15,000 to 20,000 feet. So it's basically the rigs that drill almost all of our wells, with the exception of a -- some the wells we are drilling in the Uinta Basin and Vermillion Basin this year, maybe we can use a smaller rig in the Sussex and a handful of the wells that we are drilling in the mid-continent region. But for the most part, the Cana, the Haynesville, the Pinedale, Bakken, Granite Wash, they all take this 1500-horsepower rig, and that's the rig that's in high demand, and obviously, there's pressure on day rates, although we have not seen dramatic increase in day rates.

The other thing I would point out to you is that on a day rate basis, the component of rig costs is not the biggest driver on well costs. On the pressure pumping side, there is obviously a huge demand for pressure pumping services. And what we see is a lot of cost pressure in the areas that you would anticipate, in the areas where the activity level is the highest. So the Bakken and the Cana are two areas where we are seeing substantial pressure on costs. And what we are doing is there is what we have always done, which is, we are fighting to drive down the cycle time and improve efficiencies to offset any cost escalation.

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

Okay. So can you quantify that escalation, that cost escalation a little bit? And second thing is that, in terms of the well costs you have listed on your slides, do you still feel -- do you do still feel good about those costs assumption for each play?

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

Well, yes. And we've updated some of the well costs in several of the plays to reflect what we anticipate from a cost escalation standpoint. Let me hasten to add that, for the drilling and completion folks who work for me who are listening in on this call, that is not an expectation. That is a target from which we will try to drive down costs. So we are just -- we are trying to keep you up to date on what we are seeing on cost trends.

And if you go back and look at the previous operation slides, you can see the escalation. I don't have the -- they were talking about 10% to 15% increases in a couple of these plays, maybe a little more. But we are already -- I have already said to our folks that those increases are not acceptable. And so I have some comfort from other places in which we are active that once we get the books focused on it, we will figure out ways to drive those costs down.

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

Importantly, though, we did drive down costs. It didn't go up in Pinedale and Haynesville.

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

That's right, and that's the model that we are using in other places. Thank you, Jay.

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

Okay. Great. Thank you so much.

Operator

Your next question comes from the line of William Butler.

William Butler - *Stephens Inc. - Analyst*

Hi, Chuck. Great quarter, guys.

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

Thank you.

William Butler - *Stephens Inc. - Analyst*

First question, looking at your guidance for the rest of the year, if you compare it to the first quarter, it sort of looks flat for the full year versus the first quarter. Can you give us a little help? Is there going to be a second quarter dip kind of related to some of the Bakken completion issues, or is it going to be relatively flat quarter-to-quarter? Can you help us with sort of the production ramp from here?

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

It stays more or less flattish. I mean, if you look at the numbers, we are managing growth. We are not trying to drive growth in our dry gas plays. And so when we are talking about our production volume range for the year, it's not a stretch. I will just -- I will leave it at that.

Now, within individual areas, you will see declines. When you think about Pinedale, we come out of the winter at Pinedale, and we came out in mid-March here. And Pinedale will continue to decline until we get enough wells online to arrest that decline, sometime -- and usually, it happens pretty late in the second quarter, and then Pinedale production will turn around and head back up. And that's always going to be the case. And that's a decision that we've made, not because we were required to under regulations. We could frac right through the coldest part of the winter, but it's one that has led us to this lower well cost, because we are not fighting extreme weather with completion operations. So there will be area-by-area changes in production volumes, but in aggregate, we are going to see flat to increasing volumes over the year for QEP resources.

William Butler - *Stephens Inc. - Analyst*

Okay.

And then, you all -- I just want to make sure I heard this right -- on the NGLs versus oil, you said NGLs for the year you expect would be half of your total liquids volume on just the E&P side?

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

Yes, it's about that.

William Butler - *Stephens Inc. - Analyst*

So it was about a third in the first quarter, so that is going to kind of hop up here for the last nine months?

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

Right. And part of that is, we had a decline in NGL volumes in the mid-continent region in the first quarter. We had a number of wells waiting on completion that came on late in the quarter in places like Cana. We had another well that actually came online over the weekend -- last weekend that's still cleaning up. It's in a liquids-rich part of the play. We are going to have volumes increasing from Pinedale, and Pinedale, as you know, has got some condensate, but it's mostly NGL volumes. So those volumes will drive an increase in the mix of NGL versus crude oil.

William Butler - *Stephens Inc. - Analyst*

Okay.

And then finally, talking a little bit more about the Cana/Woodford. With the additional acreage you all have added -- or can you give us an update on -- you've got three rigs there now. Are you planning on increasing that rig count throughout the year, and where in particular would you focus your drilling?

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

Well, we currently have three rigs in the play. We are waiting and watching to see some development activity up in the northern -- what we call Tier 2 area, but -- which from recent well results, looks like the play is extending in that direction. It would be toward that area that we might add rigs. But it's a little early at the end of the first quarter to say when and where we will do it in the play.

The reality is, we are getting a significant vicarious growth in production from that area, just because of the significant increase in drilling activity by our partners and non-operated interests across the play. And that has spread pretty broadly across the play, although as you can see from the map that we posted, there is still a large concentration of drilling activity, lease-saving drilling activity in that Tier 1 area.

William Butler - *Stephens Inc. - Analyst*

Okay. Great. That will do it for me. Thanks, guys.

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

Thank you.

Operator

Your next question comes from the line of Joe Allman.

Joe Allman - *JPMorgan - Analyst*

Thank you. Good morning, everybody.

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

Good morning, Joe.

Joe Allman - *JPMorgan - Analyst*

Hi, Chuck, in the Vermillion Basin, could you tell us what's going on there, and are you drilling shallower wells, and what's the scalability?

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

So in the Vermillion basin, everybody remembers the Vermillion Basin from three or four years ago, and in that case, we were targeting the Niobrara equivalent shale, the Baxter Shale. And obviously dry gas, some liquids, but not a substantial liquids component. We drilled a handful of vertical wells, we attempted a couple of horizontal wells, with mixed success. There is still a huge amount of resource in that Baxter Shale in the Vermillion.

What we are doing is targeting the shallower -- it's almost -- I could just rewind what I said about the Uinta Basin/Vermillion -- or Uinta Basin/Mesa Verde play and move it to the Vermillion. Similar depths, although slightly shallower depths, better rock quality, higher liquids content. It's basically around old fields, Canyon Creek field is the primary area that we are focusing on. There is also the Hiawatha field and the Trail field.

And those are producing properties that go back to -- almost to the origin of Questar, 1930s-vintage leases. Big structures, big huge domal structures, and they have been developed on the crest, but not really fully developed. But we own substantial acreage in and around those fields, and we've drilled -- we've actually recompleted some of the old -- not old, but some of the Baxter wells that we drilled a few years ago, and we have been very surprised at the rates that we have seen from these Mesa Verde sands, both volumes and the quality of the gas, the liquids content of the gas. So we plan to run off there sometime in the second half of the year and drill four vertical wells, relatively shallow vertical wells, to test the periphery of our acreage, to understand the down dip extent of this play. But there is quite a bit of running room, quite a bit of scalability, similar scope and scale to the Uinta basin, so multiple Tcfe of potential.

Again, and I hate to sound like a broken record, but it's the same chicken or the egg thing. We need to have some -- we need to see some well results and get comfortable with repeatability, which we are again pretty encouraged by, because there has already been a lot of drilling out there, and in fact, our former affiliate, Wexpro, has been drilling out there very recently and announced some really nice wells just this quarter. But also, we will have to build a plant out here. We currently --Perry, you have a Vermillion Basin plant that has a capacity of?

Perry Richards - *QEP Resources, Inc. - SVP & Head of Midstream Business*

About 45 million.

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

It's a cryoplant. But we would have to build a substantial gas processing complex to handle the growing volumes. In fact, as Wexpro continues to develop their asset, they would underpin part of that expansion as well. Just like the Uinta basin story, this is one where there is an opportunity to invest in drilling additional development wells and there is also an opportunity to build additional processing.

I would point out that in this area we are -- it's a remote area. We are -- we have been working on for the past five years, an environmental impact statement for future development. I'm told that the first draft is due imminently. I have been told that for the past four years. It will take some time before we can move forward there with full scale development. Obviously have some things to talk about toward the end of the year on the results from those wells.

Joe Allman - *JPMorgan - Analyst*

No, that's helpful, thanks. And in terms of the Pinedale anticline, are partners going non-consent more now than previously?

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

We seen some non-consents from our partners in particular some of the flank wells that we were drilling. It's interesting. We see different economics than they do because we get an uplift in the value of the gas from, obviously from processing. One of the large partners does not. So it is -- it's a significant bump in returns as a result of the value of the liquids with the frac spread.

Joe Allman - *JPMorgan - Analyst*

And I guess -- okay, and what's the impact of that to you? I guess that helps you.

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

It's like a free acquisition.

Joe Allman - *JPMorgan - Analyst*

Yes. And does the partner get to back in after a certain percentage?

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

It depends. They have multiple options. Jay, do you want to?

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

They have the option to either go out for a non-convertible override or go non-consent. In most cases, they have been going out for the override. As Chuck mentioned it's an acquisition that we just drill to earn.

Joe Allman - *JPMorgan - Analyst*

Okay. That's helpful. And then in terms of the Bakken, Chuck, ultimately how many wells per section do you think you will be drilling there?

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

That's a good question. I have had that question before. And I will say the same thing. We don't know for sure. Three per reservoir per section. If you are thinking it in terms of just a short lateral and 640, so if you do 1,280 you will basically have three wells per section. Per reservoir.

Joe Allman - *JPMorgan - Analyst*

Okay. That's helpful. And then just a couple quick ones. Then the cost that you are showing in these operation slides you have got, are they actually current costs? Or is that -- does that include where you want to get to?

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

Actually, they reflect what we think the current costs will be on wells that we are drilling today, and no, they are not where we want to get to, in some of these plays they are unacceptably high, and our focus is on trying to drive them down. For wells like the Haynesville and Pinedale, they are -- they are sort of trailing average costs. Their current costs for Bakken and for Cana we have already identified some ideas on ways to drive down the Cana well cost. We will have to see if we can do it. But they are actual costs.

Joe Allman - *JPMorgan - Analyst*

That's helpful. And then in terms of your differentials, you didn't change your guidance for differentials. Were the first quarter differentials wider than what you thought? Maybe I'm using the wrong benchmark, or not including some transportation costs in there or something.

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

No, as far as NYMEX to local sales point, no. So they are about where we would think they would be.

Joe Allman - *JPMorgan - Analyst*

Okay, because it appears to me when, if I use, say, Bid Week or if I use NYMEX, or Henry Hub spot, it seems that the regional differentials were actually lower but you came in I think against Bid Week, like $0.77 or something like that differential. I wonder if I'm missing something in there.

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

Joe, we are netting transportation and gathering costs out of revenue streams. So when you look at that, our EBITDA 335 net realized field price in the first quarter, it will be basis adjusted as well as transportation adjusted. It's not just a pure deduct from NYMEX, just basis only. It will have transportation and gathering out of it.

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

We can walk you through that math offline, Joe.

Joe Allman - *JPMorgan - Analyst*

Okay. That's helpful. Lastly, your increase in EBITDA that you are looking at for this year from prior guidance, how much is production and how much is oil price?

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

I think we raised our range of oil prices $10 across the line. So it's about -- it's mostly oil. The EBITDA increase was mostly oil and it's about one-third volume and two-thirds price, something like that.

Joe Allman - *JPMorgan - Analyst*

Very helpful. Thank you.

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

Yes.

Operator

Your next question comes from the line of Andrew Coleman.

Andrew Coleman - *Madison Williams - Analyst*

Had a couple questions I want to throw in there just to go back to the processing side a little bit. With the Black Forks Two plant, how much of the volumes that go through 420 million a day will be QEP volumes versus third-party volumes.

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

It's about half.

Andrew Coleman - *Madison Williams - Analyst*

About half and half. And as you --

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

The other half -- let me be clear. So we take the liquids QEP Resources receives the liquids on the gross volume, but about half of it is gas that comes from QEP Energy Production. Is that clear?

Andrew Coleman - *Madison Williams - Analyst*

So from a forecasting standpoint, half of the volumes we would actually will be able to strip out from in fact your gas production and might be an E&P sort of segment revenue and the other half will be a QEP Field Services sort of revenue?

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

You are asking a leading question. We have not yet submitted a contract between the two affiliates to push those barrels around. But that's an active discussion that is going on that we will have to land on in the next few weeks. I guess my inclination is we were going toward a contract that would be a fee-based contract between QEP Energy and QEP Field Services with respect to their volumes going through the Black Forks plant which means a portion of the volume, about half of the volumes will show up in QEP Energy as production volumes, and other half of the volumes will show up over in field services as an increase to their basically processing liquids volume.

So that has a couple of implications. One, we shown some numbers that push the volumes back and forth. We had a slide, and I think we have a slide in our IR deck that shows all of the volumes in field services. Once we land on the contract, we will update you. Scott is talking about, maybe we will put a press release out to get everybody thinking the same way so that you can adjust your models, forecast for each of the two segments.

So the other thing that obviously is a ramification on being able to book additional reserves in QEP Energy at Pinedale, if we sign a fee-based arrangement between QEP Energy and QEP Field Services, which will allow us to book a substantial component of liquids at Pinedale that's currently unbooked. We will also be able to update you on that once we scrub the numbers a bit. Just another aside, if we look at the current -- if we can instantaneously start the plant tomorrow, which there is also a lot of tension around that, the plant would generate about a quarter of a million dollars, about $250,000 a day of EBITDA. And that would be -- that would be bifurcated roughly $125,000 or so to Field Services and $125,000 to QEP Energy.

Andrew Coleman - *Madison Williams - Analyst*

Alright. That's very handy. That's one thing we were scratching our heads about. Shorter term with the Iron Horse plant, those are all fee-based and that's mostly third party and we don't expect to see a huge impact to volumes on the field services side in the near term, because that theoretically is --

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

We've got a little head space in the plant that's not being occupied by the fee-based volumes that help, pardon the pun, juice the first-quarter EBITDA from the plant. It's about 40 million a day of head space that we are using in there today. So that has given us an uplift over just the fee-based revenue and we don't know whether or not that head space will be filled up next quarter or this year. It's related to the forecasted production from the customers who contracted for the space. Until it's full, we are utilizing that head space to process our own gas.

Andrew Coleman - *Madison Williams - Analyst*

Okay. Then lastly I guess thinking about this ramp going from about 10% liquids and NGLs to the 20%, I'm guessing that the incremental growth then in it front of the Black Forks Two start up is primarily the gas you are producing down in the Cana which is being processed by other folks.

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

Yes, that's right. It's mid-continent liquids growth. We will get obviously some growth out of the Bakken as we turn more of these wells to sale. It's a big component of the liquids growth coming out of the mid-continent.

Andrew Coleman - *Madison Williams - Analyst*

Thank you very much.

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

Thank you.

Operator

(Operator Instructions). Your next question comes from the line of Josh Silverstein.

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

Hi, Josh.

Josh Silverstein - *EnereCap Partners - Analyst*

Hi, good morning. Couple questions related to the Bakken. You talked about being able to hook up your wells to some new pipelines up there. I was curious what the capacity for those pipelines would be and then related to the ten well pad, kind of curious you talked about a lumpiness in production, how you might hook up those wells to sales. Is it going to be two wells at once, and as those decline you start to add more wells on to capacity.

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

The gathering -- these are gathering lines. So this is a large field area gathering system, and so I don't know what the total capacity is. If you look at new wells coming on, if you think about the ten well pad, we frac a couple of wells and bring those on, and then you start working on the next two wells. The first two wells will start flowing back to sales, say they average 1,500-barrels a day a piece, so there's 3,000 barrels, by the time, and the decline is fairly steep.

By the time you get next two wells on you are already seeing decline in the first two wells, so you will end up with an aggregate volume of 6,000, 7,000-barrels a day coming off that new pad by the time you finish that last well on a gross basis. Then it begins to decline, and you add another layer on top of that. So again, as we go forward with the ten well pads and get a better estimate around the timing of completion of the wells, we can help you update your models on that as well.

Josh Silverstein - *EnereCap Partners - Analyst*

That's helpful. Then over in Pinedale, as you guys are now starting to move across the sections and then move up, can you update us as far as what you are seeing in terms of EURs and IP rates on average?

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

We are developing Pinedale from south to north under the supplemental EIS that we entered into a couple of years ago, and what we are seeing is basically the average results that you will see across the field, because we were drilling flank wells, crestal wells. Combination over the year, and we don't expect to see any substantial variation for the next few years as we go from south to north. In general, as you move toward the northern part of the Pinedale Anticline, up in the area that we call Stewart Point which is sort of the northern third of our yellow acreage on our ops release slide number five, that is the home of some of the highest EUR wells in the entire field. The biggest well in the entire field is up in that area, and it's over a 20 Bcf well.

We would expect to see the well results on average get better, because if you look at that slide five and look at the map, you will notice that the field is wired to the south so there is -- there are more flank locations, lower EUR, lower IP flank locations, and then as you go to the north, the structure gets tighter and you have a narrower band of the lower EUR flank wells and obviously as I already mentioned, the crestal wells are the best wells in the entire field. So that should lead to an improvement over time in the well results. The other thing just to remind you, we are not yet sure what the ultimate density should be up in the northern area or along the crest as we move to the north because there is a reason why the best wells are in the area. It may be that they are draining a larger area than five acres. We may end up drilling the northern part of the crest on ten acre density or maybe something even a little looser, 12 or 15-acre density, we just don't know yet.

One of the things we have done if you look up in the northern area you will see a cluster of a handful of wells drilled on tight density, and those wells are designed to answer that very question. And so over the next couple of years, well before we get to that area, we will know better about what the right spacing is in that high EUR area.

Josh Silverstein - *EnereCap Partners - Analyst*

Great. That's helpful. Thank you.

Operator

(Operator Instructions).

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

Well, it sounds like we don't have any further questions. I like to thank you all of you for calling in today and also thank you for your interest in QEP. We will be available for follow-on calls, Scott Gutberlet, our IR Director, will be sitting by his phone. Thanks again everyone. Have a good day.

Operator

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