Southwestern Energy Company

Q1 2010 Earnings Conference Call
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Steve Mueller; Southwestern Energy Company; President, CEO
Greg Kerley; Southwestern Energy Company; EVP, CFO

Analysts
Jeff Hayden; Rodman and Renshaw; Analyst
Brian Singer; Goldman Sachs; Analyst
Ronnie Eiseman; JPMorgan; Analyst
Mike Scialla; Thomas Weisel Partners; Analyst
Scott Hanold; RBC Capital Markets; Analyst
Jason Gammel; Macquarie Research Equities; Analyst
Brian Kuzma; George Weiss; Analyst
David Heikkinen; Tutor, Pickering, Holt & Co.; Analyst
Bob Christensen; Buckingham Research; Analyst
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Nicholas Pope; Dahlman Rose; Analyst
Daniel Guffey; Thomas Weisel Partners; Analyst

Presentation

Operator: Greetings, and welcome to the Southwestern Energy first quarter earnings teleconference call. At this time, all participants are in a listen-only mode. A brief question-and-answer session will follow the formal presentation. (Operator Instructions). As a reminder, this conference is being recorded.

It is now my pleasure to introduce your host, Mr. Steve Mueller, President and CEO for Southwestern Energy. Thank you. Mr. Mueller, you may now begin.

Steve Mueller: Thank you. Good morning, and thank you for joining us. With me today are Greg Kerley, our CFO, and Brad Sylvester, SWN's VP of Investor Relations.

If you have not received a copy of yesterday's press release regarding our first quarter results, you can call 281-618-4847 to have a copy faxed to you.

Also, I would like to point out that many of the comments during this teleconference are forward-looking statements that involve risks and uncertainties affecting outcomes, many of which are beyond our control and are discussed in more detail in the Risk Factors and the Forward-Looking Statements section of our annual and quarterly filings with the Securities and Exchange Commission.

Although we believe the expectations expressed are based on reasonable assumptions, they are not guarantees of future performance and actual results or developments may differ materially.

We had a good -- a very good quarter financially. Our earnings and cash flow growth were outstanding, which highlight the value of our industry-leading, low-cost structure. However, while our production grew by 41% during the first quarter, we experienced operational and weather-related field issues in our Fayetteville Shale play which impacted our production volumes. As a result, 26 fewer wells were placed on production than originally scheduled at March 31st, impacting our first quarter production by approximately 3 Bcf.

We have adjusted our production guidance for the second and third quarters and remain optimistic that our fourth quarter production guidance is still achievable at this time.

Now, to talk a bit about each of the operating areas -- earlier this week, our gross operating production in the Fayetteville Shale reached approximately 1.3 Bcf per day, up from about 850 million cubic foot per day a year ago. While it now seems that most of the issues are behind us, we did have operational and weather-related field issues, which affected our results during the quarter.

Approximately 47% of the wells placed on production during the quarter were the very first well in a section and 65% of the wells were along the shallower northern and far eastern borders of the project. Both of the first sections -- both the first section wells and the shallow well locations were the highest of any quarter in the Company’s history by at least 13% and 20%, respectively.

As might be expected, the initial rates from the wells on the edges of our producing area are less than the central and deeper areas, but we continue to improve and achieved initial production results that were better than previous quarter averages for all of these border areas.

Weather and challenges encountered in the more remote locations with the first wells in the sections resulted in placing a total of 26 fewer wells on production than what we had originally anticipated, impacting our production by about 3 Bcf for the quarter.

As we discussed in the last call, we have added two additional horizontal drilling rigs during the first quarter and expect to catch up to our original operated well count by the third quarter of 2010. We are currently running 24 drilling rigs in the Fayetteville Shale, 16 that are capable of drilling horizontal wells, and 8 smaller rigs that are used to drill the vertical sections of the wells.

During the first quarter, our horizontal wells had an average completed well cost of $2.8 million per well, average horizontal length of 4,348 feet, an average time to drill to total depth of 12 days from re-entry to re-entry. This compares to an average completed well cost of $3 million per well, average horizontal length of 4,303 feet and an average time to drill to total depth of 12 days from re-entry to re-entry in the fourth quarter of 2009.

Wells placed on production during the first quarter of 2010 averaged initial production rates of 3.197 million cubic foot per day, down 14% from the average initial production rates of 3.727 million foot per day in the fourth quarter of 2009.

When looking at our results through April, we have already placed nearly 50 wells on production at an average initial production rate of approximately 3.6 million cubic foot per day.

The quarterly decrease in production had one additional factor than the drilling mix or the number of wells in the first welled section. Beginning in late 2009, we began what sometimes is called green completions whereby wells are placed directly on production very early in the flowback period, so that incremental gas volumes are captured.

As a result of the wells being placed on production earlier, the initial pressure the well is flowing against is higher and the recovery of the completion fluids is slower. This will capture more gas, but we estimate initial production rates could be reduced by approximately 5% to 10%, depending on the quality of the well.

We continue to test tighter well spacing and at March 31st, we had placed over 375 wells on production that have spacing of 700 feet or less, representing approximately 65-acre spacing or less, and have previously concluded that 10 to 12 wells per section is the minimum number of wells needed to efficiently drain the reserves.

The most recent information from this larger group of wells indicates interference of less than 10% compared to earlier estimates of 10% to 15% from the smaller well set. We continue to focus on optimizing the well spacing for the play and plan to test over 44 different pilots with well spacings that will range from 200 to 450 feet apart as part of our 2010 drilling program.

To wrap up our discussion on the Fayetteville Shale, we are now providing new production data on our zero-time production plot of wells with drilled lateral lengths over 5,000 feet as shown in our press release. With over 60 wells included in the sample, we are encouraged by what we were seeing thus far.

In our East Texas operating area, production was 9.6 Bcfe, up from 7.8 Bcfe a year ago. We participated in drilling 11 wells in East Texas during the first quarter, six of which were James Lime, three of which were Haynesville horizontal wells and two of which were Pettet horizontal oil wells. Initial production rates from the James Lime that were placed on production during the first quarter averaged 6.6 million cubic foot per day and we placed one well on production from the Haynesville Shale during the quarter at an initial production rate of 22.1 million cubic foot per day.

Initial production rates from the four Pettet oil wells that were placed on production during the quarter averaged 292 barrels of oil with 2.6 million cubic foot of associated gas per day.

In our conventional Arkoma program, we participated in three wells and our production from the area was 4.9 Bcf compared to 5.8 Bcf last year.

In Pennsylvania, we have approximately 151,000 net acres in Pennsylvania prospective for the Marcellus Shale. We are currently drilling our second well for 2010, the Ferguson-Keisling #1-H in Bradford County. We plan to complete both wells drilled to date during the second quarter and they should be on production as early as June. At least 15 wells are expected to be drilled by Southwestern in 2010.

In our New Ventures program, we announced in March that we had granted -- we have been granted exclusive licenses to search and conduct an exploration program covering over 2.5 million acres in a province of New Brunswick, Canada, to test new hydrocarbon basins. As the winner of the bids, our financial commitment over the next three years is approximately $47 million. More than 80% of the work commitment is gathering and processing of geochemical, gravity, magnetic and seismic data. The initial phase of the data gathering is planned to start before the end of 2010.

In closing, natural gas continues to under-perform the rest of the commodities and like all of you, we're carefully watching both the imbalance of supply and demand and the industry's reaction to that imbalance. We have already made some adjustments to our capital allocations to emphasize our best projects.

We also remain confident that our low-cost operations, financial strength and flexibility to pursue our drilling program in the Fayetteville Shale give us staying power through the tough times and the ability to add significant value for our shareholders even in the current low-gas-price environment.

I will now turn it over to Greg Kerley, our Chief Financial Officer, who will discuss our financial results.

Greg Kerley: Thank you, Steve, and good morning. As Steve noted, our financial results for the quarter were excellent, with earnings up 37% and cash flow up 12%. Our improved results were driven by our strong production growth and continue to highlight the high quality of our assets and our industry-leading low-cost structure.

We reported earnings for the first quarter of $172 million or $0.49 a share compared to adjusted earnings in the first quarter of 2009 of $125 million or $0.36 a share, which for comparative purposes, excludes a non-cash ceiling test impairment recorded in 2009.

We also reported discretionary cash flow of $418 million, up 12% from last year, and we were nearly cash flow neutral for the period, as our cash generated from our operating activities funded 94% of the cash requirements for our capital investments.

Our production totaled 90 Bcf in the first quarter, up 41% from the prior year and we realized an average gas price of $5.42 an Mcf, down $0.50 per Mcf from the same period last year.

Operating income of our E&P segment was $250 million during the quarter, up 39% from the same period last year, excluding the non-cash ceiling test impairment, as the significant growth in our production volumes more than offset the decline in our average realized gas price. Our commodity hedge position increased our average realized gas price by approximately $0.55 an Mcf in the first quarter.

We have approximately 48 Bcf of our remaining 2010 projected natural gas production hedged through fixed-price swaps and collars at a weighted average floor price of a little over $8 per Mcf. We recently increased our hedge position in 2011 and also added some hedges in 2012. We hedged an additional 55 Bcf of our 2011 forecasted gas production through costless collars at a floor price of $5 per Mcf and an average ceiling price of $6.42 and approximately 29 Bcf of our 2012 forecasted gas production at a floor price of $5.50 per Mcf and an average ceiling price of $6.54.

We have one of the lowest cost structures in our industry and we continued that trend in the first quarter of this year as our lease operating expenses per unit of production were $0.78 per Mcf during the quarter, unchanged from last year.

Our general and administrative expenses per unit of production declined to $0.29 per Mcf in the first quarter, down from $0.31 last year due to our increased production volumes.

Taxes other than income taxes were $0.14 per Mcf in the quarter compared to $0.13 in the prior year.

Our full cost pool amortization rate also declined, dropping to $1.41 per Mcf in the quarter from $1.82 in the prior year. The decline was due to a combination of our ceiling test impairment recorded in the first quarter of 2009 and our lower trending finding and development costs.

Operating income from our Midstream Services segment increased by 37% in the first quarter to $38 million. The increase was primarily due to increased gathering revenues related to production growth in the Fayetteville Shale play, partially offset by increased operating costs and expenses. At April 25th, our Midstream segment was gathering almost 1.5 billion cubic feet of gas a day through over 12,000 miles of gathering lines in the Fayetteville Shale play, compared to gathering approximately 900 million cubic feet per day a year ago.

We invested $474 million during the first quarter of 2010 compared to a little over $500 million in the first quarter of 2009 and drew down our revolver balance by only $20 million during the quarter. At March 31st, we had $345 million borrowed on our $1 billion credit facility and an average interest rate of 1.3% and had total debt outstanding of a little more than $1 billion. This leaves us with a debt-to-book capital ratio of 29% and a debt-to-market capital ratio of only 7%, which is one of the lowest in our industry.

That concludes my comments. So now, we'll turn back to the operator and he'll explain the procedure for asking questions.

Questions and Answers

Operator: Thank you. We will now be conducting a question-and-answer session. (Operator Instructions). Thank you. Our first question is coming from Jeff Hayden of Rodman and Renshaw.

Jeff Hayden: Good morning, guys. A couple of quick ones -- well, it looks like the performance of the Fayetteville wells had a nice bump up in April versus what it was in Q1. Just wondering what were the differences there? Was there a difference of geographic mix, higher percentage of longer lateral wells, anything like that going on which kind of influenced the performance?

Steve Mueller: Before I answer that, let me make one comment. I think Greg said we had 12,000 miles of pipe out there. We actually have 1,200 miles of pipelines.

Greg Kerley: Yes, sorry.

Steve Mueller: So if anyone asks that question, we don't really have 12,000. But as far as the April wells, there is a little bit mix in April. We have some rigs drilling on the southern end of our acreage, again, kind of peripheral. But where that northern and far east are in the 2,500 to 3,000-foot depth range, when you go to the far south you're at a 6,500-foot depth range. Two things happen there. You're going to get a little bit better rates down there, but it's going to take you a little bit longer to drill it. So while we averaged 12 days to drill wells in the first quarter, in April it's something like 14 days to drill a well, because there's-- some of those wells are a little deeper. So there is a little bit of a mix issue. And that just brings up how things have kind of developed over the next few quarters. Both first quarter and second quarter we will have a significant number of our wells capturing the first wells on the section. And so, there is going to be a different mix from first to second and there is going to be a different mix compared to last year and the previous quarters we had also. And we're just going to have to work through that and talk through it as we go through those mixes.

Jeff Hayden: Okay. And just kind of looking at the potential locations you guys have in the play, how much of it do you think is in kind of the central area and other kind of deeper areas of the play versus how many of your locations are in the shallower part of the play right now?

Steve Mueller: Yes. I don't know about the actual mix. I think the best way to do it is go look at our website and look at our presentation. And there's a page in there that shows where our midstream is at. And that will tell you what we've tested to date, just where that midstream infrastructure shows on that map. And you can get a feel for what's been tested today, and then you can kind of look at what still needs to be tested. There is a significant amount of new capture that we're going to have do in the middle of our acreage on the eastern side. And then, we've got some of this peripheral capture that we'll do as well. Probably the best way to give you a feel for the overall mix, our northern acreage is very similar to what Petrohawk has done. They've got a lot of things on the north end and if you look at what their performance has been, you can kind of think about that. It was what our acreage would be there. On the far east, that's where Chesapeake has a lot of their production. You can look at their performance and get a feel for what those wells might do.

Jeff Hayden: Okay. And then, one more and I'll jump off. I may have missed it, but did you guys give any updated expense guidance?

Steve Mueller: As far as LOE or those kinds of things, no.

Jeff Hayden: Okay. Thanks a lot, guys.

Operator: Thank you. Our next question is coming from Brian Singer of Goldman Sachs.

Brian Singer: Thank you. Good morning.

Steve Mueller: Good morning.

Brian Singer: A couple of questions. First, on the down spacing, can you add any color on more specifically what's giving you more confidence in the less than 10% communication versus your higher levels previously, and talk a little bit about the aerial extent of where do you see potential better spacing?

Steve Mueller: It really has to do with the number of days we've had the wells on production. When we first made kind of the--we needed 10 to 12 wells per section call back last--back in the third quarter of last year. I think the longest we had any wells on were basically 90 to 120 days. Now, we've got several months more production, so we've got a better shape on those curves. And so, it doesn't look like there is as much interference as we first thought.

Brian Singer: Okay. Is that the result then of a much flatter production profile, or do you feel like you were being conservative earlier and wanted to wait to see more before kind of putting out a 10% or less kind of number?

Steve Mueller: Well, we actually saw in that early part of the performance that 10% plus. So that--we did see that. That wasn't being conservative. That was just data. And it's data again today. And part of that, again, the initial mix that we talked about had just over 100 wells and we're talking about 375 wells now. So you're covering a bigger area with those number of wells and getting more information on them. And it looks like you're going to have a higher EUR. In general, at--when you're talking about the spacing, unless you're very, very close together on the wells, the IP shouldn't change much. It's all in your EUR estimate. So when we were talking about the fact that we had something greater than 10% and now we're less than 10%, it's that EUR and it's that back-end of the curve that you're projecting off of that initial production.

Brian Singer: Geographically, are you definitively ruling in anymore areas of your acreage for tighter spacing? I think you focused a little bit more on the southern--south central portion previously.

Steve Mueller: You mean as far as tighter than the 10 to 12 wells per section?

Brian Singer: Or--yes, that's right, or even the 10 to 12 wells per section - that or tighter.

Steve Mueller: Well, we're comfortable on average that 10 to 12 wells is going to work just about across our entire acreage. We haven't tested everything yet, but what we've tested, we're comfortable with that. With these 44 pilots that we're doing, that would be--also be spread across the entire acreage. And let me emphasize we're trying to get 44 pilots done. To actually do the pilots, you need to get 100% participation by all of the partners in the well. And so, it may end up to be 40, maybe a couple more than that. But we're doing that right now to get that project. In those cases, we will be testing that tighter spacing. And I fully expect that ultimately you're not just going to do 10 to 12 wells across the entire area. You're going to have some areas that's tighter and some that will be the 10 to 12.

Brian Singer: Great, thanks. And lastly, can you just comment on any of the--more on the operational side of the issues that delayed some of the wells? And is there any risk that that continues over the next couple of quarters?

Steve Mueller: Well, the simple answer to the first part of your--or the second part of your question is--risk of it happening--once you run across the kinds of issues that we had--and I'll describe a little bit of them here in a second. Once you run across those issues, you pretty much design a system that you won't get those again. But the real thing and the reason that I put in the letter--or put in the press release and put in my comments that I was disappointed is that we're trying to build a system that's robust enough that what we say we can do, we can actually do. And we missed last quarter and I'm disappointed in that. And so, we have to continue to work on building a robust enough system. Now, having said that, the kinds of things that happened to us last quarter, some of them were decisions by us. And one of the things that happened, if you remember back in the third quarter, we had Boardwalk pipeline issues. We took some of the rigs that we operated, did maintenance on those. We also took some of those spudder rigs that do the vertical portion of the wells and laid those down. And then, whenever the Boardwalk pipeline issue was resolved we were going to pick those up.

Well, we went to pick them up. It took about 30 days longer to pick them up than we thought. Some of that was them; some of that was us. It just took a little longer. In some cases it's our pipeline. The reason that we put 50 wells already on in April, which is a record for any month, is that we had to lay a 20-mile pipeline. We thought that 20-mile pipeline would be in in mid-February. If it's in in mid-February, we hit our target. We got delayed about 15, 20 days on that pipeline. Part of that was weather, but most of it was just the number of crossings and the various things we had to do from a surface permitting standpoint, both with the owners of the surface and with the state and the various agencies, and we lost 20 days. In those kinds of cases, both of those ones I described, those are behind us. Those aren't going to happen. But again, it just tells you we are not quite as robust in our system on how we're predicting and we'll get that fixed.

Brian Singer: Thank you very much.

Operator: Thank you. Our next question is coming from Joe Allman of JPMorgan.

Ronnie Eiseman: Hi. Good morning, guys. This is actually Ronnie Eiseman. I had a question. Going forward for the next couple of quarters, do you have a rough estimate of what the mix will be for the percentage of wells drilled in the northern and eastern areas?

Steve Mueller: I really don't at this point. And the reason we don't, we're always trying to work seven, eight months in advance, but for instance, some of these wells have to go to hearings. If you don't get the wells in the hearing, it doesn't just affect the one well, but it affects everything that hooks up with those rigs. And so, you're always changing the mix and exactly where they're going. So probably the best I can say is, during the second quarter we will be doing a significant number of acreage capture. It looks like it will even be more than we did in the first quarter. But where exactly those are at, I can't tell you the exact mix on that. There'll still be some up in the north and some in the far east, though as I said, we're also drilling some wells on the very southern end of our acreage, also.

Ronnie Eiseman: Great, thanks. And the green completions - of the 106 wells brought on in the first quarter, how many of them were green completions?

Steve Mueller: Most of those. And let me just talk quickly about the green completion. Some people call it green completion because you're not releasing some of the gas into the atmosphere or burning flames on the gas, and so there's some environmental component to it. I think of it as green completion and that's why I said in here some people call it green. It's just economically green for us to do that. We'll--we capture about 15 million cubic foot of gas by going directly or very early into the system. That 15 million cubic foot of gas is about $2 an M to capture that gas. And if you put it in perspective, we'll drill 500 wells this year. And while 15 million cubic foot doesn't sound like much, that's 7.5 Bcf this year alone of gas that we would have flared that we're going to capture and that's a significant amount.

So the idea was capture that gas, and you might ask why we were not capturing it--why we hadn't captured it before. And that goes back to our robust system. We had to put a special team in place. You have to move a lot of equipment around to do this, and we're just at that stage where we can start doing that part of the process.

Ronnie Eiseman: And of the 122 wells in the fourth quarter, how many of those were green completions?

Steve Mueller: Very few.

Ronnie Eiseman: Okay.

Steve Mueller: We started doing this in December.

Ronnie Eiseman: And then, again, the 106 wells brought on in Q1 versus the 50 brought on in April, did the weather delays delay within the quarter when those wells were brought on? Were they more backend loaded within the quarter?

Steve Mueller: Yes. Yes. And I mean, that basically is why we missed our guidance.

Ronnie Eiseman: And with the additional rigs running this year to catch up, is there an effect on CapEx?

Steve Mueller: Well, I mentioned that we reallocated capital a little bit. We have decisions that we can make about our Fayetteville drilling later in the year. Four of the rigs--actually five of the big rigs of the 16 that are running, we'll be able to make decisions of whether we want to keep those running through the year or not. Starting in late June and going through November we can lay down those rigs on various contracts. But what we've done on the capital budget, we've reallocated dollars to Fayetteville Shale. It's economic on any kind of forward curve you're looking at or anything we've got. And we're planning right now to run those rigs through the year.

In Pennsylvania, we were a little slow getting the rig to work there. We wanted to get the rig out there the first of January. It didn't get out there until the middle of February. So we've reallocated some of that Pennsylvania money that's not going to get invested to the Fayetteville Shale. And then, we've also backed down on a little bit of our new venture dollars, so we can run those rigs through the year in the Fayetteville. So we've done some minor changes. Overall, that's a total of -$50 to $60 million out of $2.1 billion that we've moved around. But the whole idea was get the money working where you've got the best projects at this gas environment.

Operator: Thank you. Our next question is coming from Michael Scialla of Thomas Weisel Partners.

Michael Scialla: Good morning, guys.

Steve Mueller: Good morning.

Michael Scialla: I want to ask you about the 5,000-foot laterals. How much are those costing and what percentage of your acreage do you think you can drill 5,000 feet or more on? And maybe how the economics of those compare to the shorter laterals.

Steve Mueller: The 5,000-foot laterals probably are in about the $3.5 to $3.6 million range today. And that's drilling--that's basically a one well in a section type number. As you get to a pad, I fully expect that's going to go down a little bit. But--and let me just also put that in comparison. In the shallow, where we're drilling 4,000 or 3,500-foot laterals and it's only 2,000-foot deep, those are $2.5 million wells. So that's really the range that you've got. On the numbers of 5,000-foot laterals we have, in the very shallowest portion of the area, we're probably not going to do 5,000-foot. Probably in the 4,000-foot range. In the far east, you've got a lot more faulting. I don't know if we can quite average 5,000-foot laterals in the far east. But as we look into the future and just look at the geometries, it looks like we're going to have to average better than 5,000, somewhere between 5,000 and 6,000-foot on average across most of our play, to optimally invest the dollars to get the most gas out of the ground. So I think a large part of it is going to be 5,000-plus.

On the other hand, and you didn't ask the question, but what's the odds of having a bunch of them at 6,000 and what's the odds of a bunch of 8,000 or 10,000? The real average is somewhere in that 5,000 to 6,000-foot range. We will drill some wells, especially where there's skinny fault blocks, that will be longer than that. And we've already drilled a couple of wells over 8,000 feet.

Michael Scialla: It sounds like from an economic standpoint though the optimal--you're kind of zeroing in on this 5,000 to 6,000-foot range.

Steve Mueller: That's what it looks like today.

Michael Scialla: Okay.

Steve Mueller: And let me add, the reason it looks that way, if you try to lay out a grid of say 10,000-foot laterals, you can put a bunch of 10,000-foot laterals out there, but then there's a bunch of what we call white space. There's spots on the map that you can't get to with 10,000-foot laterals. And what you need is a bunch of 2,000 and 2,500-foot laterals to do that. And you end up averaging at 5,000-foot anyway.

So when we start looking at it, it looks like that 5,000 to 6,000 foot is the range for that laterals.

Michael Scialla: Any additional acreage you'll need to drill these longer laterals?

Steve Mueller: Well, we've got permission -- there's two things the State has worked with us on recently. We got permission in December to basically do wells across sections so that you can drill and hold sections, due to the various things under -- there's some details of the State rules, but we can do that administratively now.

When we were doing it last year up until December timeframe we would have to take those wells to the Commission and get their approval, and now we can just do that as a regular administrative process.

The other thing the State has done for us recently, as we started doing these green completions we realized that the peak production may not be in the first 10 days. And the State's rules were you had to give the top production rate in the first 10 days, top 24 hours in the first 10 days. We've now got that, I think it's 45 days we have to get the top rates. And they've changed that back in early January. So those are the two most recent changes they addressed.

Operator: Thank you. Our next question is coming from Scott Hanold of RBC Capital Markets.

Scott Hanold: Thanks, good morning.

Steve Mueller: Good morning.

Scott Hanold: So, I think you guys kind of covered most of the stuff, but in terms of looking at your spending plans, specifically on the Fayetteville Shale, have gone forward, and I guess what the gas strip looks like right now. Obviously, you made the case that the wells that you're drilling are economic, given that even at these strip prices, how do you think about the full development mode of the Fayetteville and how you hedge that sort of on a go-forward basis?

Steve Mueller: Well, it looks like today that we could have an extended period with relatively low gas prices. And when I say relatively low, is that a high 4 or a low 5 or a mid 4, but it's probably not 6 and 7s.

We are very economic when we're doing both Fayetteville Shale and Pennsylvania, and the real thing that's keeping us from going faster or doing something different is more the cash flow side of the overall equation.

First quarter we only borrowed an additional $20 million, so we're real close to cash flow neutral, even with the prices we had in the first quarter. And so as we start to get to cash flow neutral and get some extra dollars, we will put those to work.

We're not going to try by ourselves to solve the gas problems that the nation has got. So if we've got economic projects to do at whatever price that's out there, and we've got the dollars to do it, and we can do it in a strong financial situation, we're going to go do it.

Scott Hanold: Okay, and when you think of sort of that longer term picture, is there any consideration of eventually going out there and building your own fit for purpose rigs in the Fayetteville based on what you know now, that would be much more optimal than what maybe you're running at this point?

Steve Mueller: Whether we build them or someone else builds them, that'll definitely happen. The next rigs we'll add will be built for purpose. We've actually got two of them operating. The rigs we picked up, two of those right now, walk, they're AC powered, and we're using them on the down spacing work where we're drilling more wells than one on a pad. And the most advanced of those rigs are right now averaging less than seven days per well to drill wells on pad work.

So there is a big difference between the 12 we're doing right now and that seven, and we'll add rigs as we add rigs, that's exactly the way we'll work it. Now, whether we're buying those rigs or someone else is building them and owning them and supplying them to us, we'll make those decisions as the market goes forward in the future.

Scott Hanold: Okay, and one last question, I should have asked this before the last one. But back to the hedging aspect, what is your all plans in terms of what you do on a go-forward basis with hedges? Where do you feel comfortable at layering these in, and the preference for swaps versus collars? How should we think about your policies going forward?

Steve Mueller: I don't know if there's a swaps versus collar preference, but we just in the last week put on some hedges, as Greg said, that they're \$5 to \$5.54s, and 2011 and 2012. We make a lot of money at \$5 or above, and so you'll see us putting on hedges when we can. And we won't hedge obviously our entire production in those years, but we'll hedge enough so that we know we can make good money and head on down the road.

Scott Hanold: Excellent. Thanks, guys.

Operator: Thank you. Our next question is coming from Jason Gammel of Macquarie.

Jason Gammel: Thank you, guys. I wanted to come back and ask a couple more questions about the green completions to make sure I understand the overall affect on the performance of a well.

I understand producing into a higher pressure early on is going to have a negative affect on the IP rate, but when we're thinking about ultimate recovery of the well, I understand you're capturing incremental gas at the beginning, are you really doing anything to the ultimate recovery of the well? Is it lowering the decline rate that you see, say, 30 and 60 days out? Any help you can provide on that would be useful.

Steve Mueller: It might, and we're still trying to gather all the data -- it might on a 30-day number, for instance, flatten it out a little bit. I would guess by 60 days, as I said and that's one of the reasons the State changed the rule to 45 days, somewhere in between 15 and 30 days you've pretty much got all these wells cleaned up the way they should clean-up.

And at that point it's no different than when you originally did the well and put it into the same kind of system. It has the same back pressure on it from there, so it performs the same. So EUR is going to be bigger by 15 million cubic foot is basically the answer, and it's spread-out a little bit different in that first 30 to 45 days, and that's about all there is to it.

Jason Gammel: So just as a follow-up then, is a lot of this just essentially the reporting requirements of the State, and I mean it seems to me that the effectiveness of the well is actually improving a little bit --

Steve Mueller: Yes.

Jason Gammel: -- even though the stated IP is worse?

Steve Mueller: Yes, we're making money, so, yes, just for those who follow the IP it's going to be a little bit down and that's all we want to tell people. It shouldn't affect hardly our 30-day, at all. Like I say, you might see a little affect, it shouldn't affect our 60 for sure, so and that's one of the reasons we have all three columns on the table.

Jason Gammel: Okay, great. That's useful. And then maybe just one more, if I could? Just from a tactical standpoint, and I think you've partially answered this, but having such a high percentage of the wells in shallower areas of the play coming on during the quarter, was that simply a function of where you could get the rigs at specific points in time where you had permits? And I think you've already answered this, but what sort of mix would you expect to see moving forward in the shallow sections versus the deeper sections?

Steve Mueller: Yes, I did answer the part about the mix. We really don't have a good handle because that's kind of dynamic of exactly how much. Certainly in the second quarter you're going to see more on the shallow and far east than you did last year at any point in time. But how that compares to the first quarter, it'll be down a little bit, but is it down 10% or 20%, I don't know. We'll just have to -- but there's a little bit of difference between the quarters.

Now, I forgot the other part of your question?

Jason Gammel: Just from a tactical standpoint what led you to bring on so many wells in those lower productivity areas?

Steve Mueller: Oh, it really had -- we started moving rigs that direction late last year because, number one, we had to capture some acreage. But, number two, we wanted to learn more about how we apply some of our current production fracing techniques and see how much better wells we could get.

And consistently in the shallow and far east areas, we're getting better wells than we had in previous quarters or previous times we've been out there. And that was key to us to learn that now, and also then set us up so we can go out there and do some of those down spacing tests. You've got to have some wells out there that have a history on them that are your type wells that you compare against, and we needed to get a recent type well in those areas, and then we'll move out there and do some of that testing.

So part of it had to do with getting ready to do down spacing. Part of it had to do with making sure our techniques we're using could actually get better wells. And part of it had to do with acreage capture.

Jason Gammel: That's very helpful. Thanks, Steve.

Operator: Thank you. Our next question is coming from Bryan Kushman with George Weiss.

Brian Kuzma: Hey, good morning, guys.

Steve Mueller: Good morning.

Greg Kerley: Good morning.

Brian Kuzma: I just wanted to make sure I understood, so you -- the difference on the 30-day rates from fourth quarter to first quarter, that's mostly due to the mix, that's not due to the green completion?

Steve Mueller: There's a little bit of green completion in the IP, but the biggest portion of the IP is mix, yes.

Brian Kuzma: Okay, and I know you don't know exactly what you guys are going to drill this year, but like of your 900,000 acres you say 125 are kind of in the Arkoma Fairway. How does the rest split out between, you know, like core, northern and eastern, roughly?

Steve Mueller: And on the far western side we've got about 150,000 acres that's federal unit. That federal unit, there's a couple of wells we drilled a few years ago, there's a private piece of land in the federal unit that we can get on to, but there's only a couple of wells that are in that federal unit. We'll drill a couple more wells this year, but there's 156,000 acres there.

When you look off to the far east, there's -- I'm trying to think about how many sections -- but there's a couple hundred sections that we need to get first well on a section on, and each section is 640 acres. So that's what's going to be happening over really the next year-and-a-half to two years, far east and some of the southern acreage portions of it.

And then as you mention, there's that 125,000 acres that's already held by production with our conventional Arkoma. That 125,000 acres has only a couple of Fayetteville Shale wells on it, and that'll -- we'll get to that once we get all the acreage captured and we can start work in that direction.

Brian Kuzma: Okay, and then like how much acres do you think is up north, like the Petrohawk type well?

Steve Mueller: Well, if you just look at our map, it's across the whole map. If you look at our map, the structure runs basically east, west, and gets deeper as you go to the southern side. So the southern side of our acreage is about 6,500 feet. The northern side is about 2,000 feet. And so it'll just grade from that 2,000 all the way down to 6,500. The dead central portion is 3,500 and 4,000 feet.

Brian Kuzma: Okay, I got it.

Steve Mueller: And I will say that if you look at any of our maps in any of our presentations, there's on the eastern side there's a couple lakes. We don't have a whole lot of acreage up north of those lakes, that's why we've got a little cut-out in our little shaded area we've got on that map.

Brian Kuzma: Okay, and then like when I look at your zero time plots that you guys charted here, you guys said that you had 375 wells that are less than 500-foot spacing. Is it fair then to say that there's like 375 wells in the zero time plot which are -- have production rates which are 10% lower? You see what I'm saying there?

Steve Mueller: That would be -- yes, that would be true. It -- yes, in general. I mean I --

Brian Kuzma: And those wells were drilled in the past year?

Steve Mueller: Yes, for the most part.

Greg Kerley: Yes.

Steve Mueller: If you think about 2009 we had about 200 acreage cast of wells and we had about 400 wells that were doing the 600, 500 to 600-foot spacing. So, yes, you're seeing a reflection, and you'll see it really in the last -- when you look at any of those plots, whether it's 3,000 foot or 4,000 foot plots, you'll see those in that first 365 days or 180 days, dependent on which wells.

Brian Kuzma: Okay, and then when I compare like the 4,000-foot curve to like the 5,000-foot curve, it doesn't like appear to be linear, and I was just curious, it looks like there's some sort of decreasing marginal returns?

Steve Mueller: You mean as far as the -- are you talking about the linear? Because at the end of there we get fewer wells that jumps up, or linear -- how do you say linear?

Brian Kuzma: I'm sorry, I was referring to like the first 100 days --

Steve Mueller: Right.

Brian Kuzma: -- it looks like there's more recovery for lateral foot on the 4,000 foot, but I didn't know --

Steve Mueller: Now, they're pretty parallel once you get past the very beginning there, so I'd have to see if there actually is more recovery per lateral foot. I haven't looked at that.

Brian Kuzma: But help me understand the 5,000-foot laterals were drilled in the deeper areas, so they may have been a little bit different geologically?

Steve Mueller: Not necessarily deeper areas. They wouldn't be drilled in the very shallowest portions, that basically a couple of miles across the north end of that. But from 3,000 foot or so down to 6,500 foot they could be drilled anywhere in there.

Brian Kuzma: Okay.

Operator: Thank you. Our next question's coming from David Heikkinen of Tudor, Pickering, Holt, and Company.

David Heikkinen: The new ventures areas then, obviously, you've talked about Canada and have been continuing to allocate some capital away from there. Is that allocating capital away from leasing or drilling? Or how should we think about any of the -- how you allocate capital and new ventures?

Steve Mueller: Well, we didn't have any drilling allocated this year for new ventures. What we had this year was leasing and buying data, seismic gravity, magnetics, those kinds of things.

What we've done, basically, is delayed some of the information gathering part of it, some of the seismic net that we were going to get, and some of our leasing, until somebody figures out exactly where we're at and what we're leasing, we can delay some of that too. So both of those things are going on.

David Heikkinen: So it's not that things are getting more competitive and the values are going up, it's just that isn't delay -- that isn't changing your leasing plan?

Steve Mueller: No. No, we -- no, it's not a competitive issue.

David Heikkinen: Okay. The -- on the Fayetteville, just trying to dissect this a little bit more in thinking about the Petrohawk type curve in the northern acreage. Can you talk about what you think, across your 889,000 acres what an average EUR will be for -- you're talking more 5,000 foot laterals now than you used to. So where do you think things are going from an average EUR on -- in the Fayetteville?

Steve Mueller: You kind of mixed metaphors there. You had 5,000 foot laterals and average EURs and those kind of things. What's on our reserve report today is 2.4 Bcf on our PUDs, and we've got about 1,200 PUDs on the reserve report.

Certainly, you look at that, the plot, if we average 5,000 foot laterals, it will be higher than that. And, in general, our best wells, as an industry, we've drilled, I think we're over 10 wells now at 6 million a day IPs. All of those had very high fours, into 5,000 foot range. So I think it's just not a perfect extrapolation, but those 5,000 foot laterals, as you get a longer lateral, you're going to contact more rock, as long as you frac it the same way, your EURs are going to go up.

Operator: Thank you. Our next question's coming from Bob Christensen of Buckingham Research.

Bob Christensen: Did you guys express any kind of interest in the Common Resources sale? Did you bid? look? And what are your impressions of that sale?

Steve Mueller: Well, no comment about whether we bid, looked, or did those kinds of things. And as far as impression, my understanding is the closing's in May. And one of the things -- one of the reasons we did not change any capital, when I talked about the little capital changes, we didn't really change any capital in east Texas, is we just needed to get the thing closed. For those who don't know, Common has sold their east Texas portion of their assets. Those east Texas portion, we have 50% of part of that. I think they sold 29,000 acres. We have 50% of about 20,000 acres, a little less than 20,000.

So whenever they have the closing, we need to talk to the new operator, and the new operator and us need to get together and figure out how we're going to develop going forward and figure out their plan. So that's about as much as I know about Common right now.

Bob Christensen: You're saying the drilling capital could be there with new participants, perhaps?

Steve Mueller: I just don't know. We've just got to get to closing, let them get to closing, and then we can find out really what they're going to do.

Bob Christensen: My follow-up is what is your reaction -- maybe Greg answers as well -- to some of the joint ventures, alliances struck in the Marcellus Shale of Pennsylvania, as of late?

Steve Mueller: Well, since you asked for Greg's, we'll let Greg react.

Bob Christensen: Okay, Steve.

Greg Kerley: Well, I think there are some interesting numbers that we've seen that continues to kind of climb up there, and it definitely gets everyone's interest. We like our acreage we have in the northeast portion of the play. It's where the shale is, some of the thickest areas. And we think that we have at least that kind of value, probably a lot more value in our acreage up there, what we believe we have, as we continue to develop it.

Steve Mueller: Let me add that of ways that we would finance or bring in some dollars, JV, probably, in the Marcellus, isn't real high on our list. JV almost anywhere is not real high on our list. There's a lot of operational and a lot of people issues that go with all of that. So while we kind of are interested in what's going on and prices keep going up, which values our acreage higher, we're not really looking for JVs at this point in time.

The other side of it, we're not buyers at those prices either. While we like what we have, we think we can put our dollars toward better someplace else.

Bob Christensen: Thank you.

Operator: Thank you. Our next question's coming from Dan McSpirit of BMO Capital Markets.

Dan McSpirit: Gentlemen, good morning, and thank you for taking my questions. Turning to New Brunswick, can you speak to well control in that part of the world, really what drew you to that part of Canada, maybe some history of drilling in New Brunswick?

And then secondly, can you speak to how it is you plan to dissect the opportunity, given your massive, massive land position, of course, recognizing that it's very, very early innings?

Steve Mueller: Right. Well, in New Brunswick, there's a lot of shallow wells drilled many, many years ago. But there's actually two fields. They're on the southern part of what's generally called the Maritimes Basin. It goes offshore and then comes onshore in New Brunswick. Those two fields, there's one gas field, it -- with what they know about it today, it's about 250 Bcf, but it's being drilled now, so it could get bigger. It's a conventional field. There's another small oil field that was found in the early 1900s. And, really, those two fields tell you that there's gas and oil in the system. And I need to back up and talk a little bit about how we got into it.

We started working on New Brunswick almost a year ago after looking at several different shales in a lot of different places in the US and in Canada. Thought that there might be in a Maritimes Basin a chance for a deeper shale, called the Frederick Shale, and started doing some work.

As we looked at the southern basin that had the oil and gas in it, we would re-process to a bunch of magnetic data. And as we looked north, it looked to us like there were some basins that could be there that had the depth to basically cook the Frederick Shale both for an oil objective conventionally, maybe, oil objective for the shale, maybe, gas objectives conventionally and gas objectives for the shale.

And the industry really hadn't seen that in the past. The industry's general interpretation was, as you went north from these producing fields and where this producing field area was, that the basin shale was way up and would be 5,000 foot or less in depth. We're seeing things on the magnetics that make us indicate may be as deep as 20 or deeper, 20,000 foot or deeper depths.

That's what kind of keyed us into it. And that also tells you a little bit about what we're going to do in the future. What we have to do is confirm that there really are deep enough basins there that we could have the right thermodynamics to really cook the rock the way we want it cooked.

And so what we'll be doing is doing some more gravity magnetic work. That tells you the shape of the basin, gives you a feel for depth of the basin. We'll be doing geochem, surface geochem work on the entire area. I think they're talking about 2,500 stations or something like that, over the next year and a half. And then we'll lay out a seismic program that once we figure out where the deeper portions are, we can shoot some seismic and see what the rock looks like in those areas. And then towards the end of that three-year term, we've got one well as a commitment to drill.

So over that three-year period of time, we're just going to be delineating what we think is a basin and learn as much as we can about it, and then drill some wells and figure out how it goes from there.

Dan McSpirit: Thank you.

Operator: Thank you. Our next question's coming from Nicholas Pope of JP Morgan Securities.

Nicholas Pope : It's actually Dahlman Rose. Good morning, guys.

Steve Mueller: Good morning.

Greg Kerley: Good morning.

Nicholas Pope: Real quick. Just was curious, you said 15 wells being drilled at -- in Marcellus this year. How many of those do you all think you're going to be bringing online during the year?

Steve Mueller: Well, except for the very last ones drilled in December, we should get most of those online during the year. We are currently permitting and laying a short lateral to get to where we're drilling today. All the drilling's going to be within a few miles of the point we're at today. So once that line gets there, we'll be drilling and fracing and putting in that line and go from there.

Nicholas Pope : All right. And then just in terms of the capacity do you all have capacity to get the gas out of the area? You all have plenty of capacity right now?

Steve Mueller: Yes. We have been -- we have committed in the past to about 20 million a day firm. And then we are committing to other gas right now for the end of this year and then into 2011. We're comfortable we can get the gas out, certainly at the pace we're drilling now.

Nicholas Pope : Okay. That's really all I had. Thanks, guys.

Steve Mueller: Thank you.

Operator: Thank you. Our next question's coming from Daniel Guffey of Thomas Weisel Partners.

Daniel Guffey: Hi, guys. You mentioned previously you've drilled some 8,000-foot laterals. I was wondering if you could provide any 30 and 60-day rates. And then also, if you guys have given an EUR or have an internal estimate on EUR for these wells.

Steve Mueller: Well, first off, as I said, when we've done the 8,000-foot laterals, they've been unique situations where we've drilled in a fault block that you couldn't do two 5,000s or you -- it was -- there was some characteristic that fault blocked at 8,000 made sense. Because of that, they're going to be somewhat limited.

From an IP standpoint, those are fairly high IPs. Those are going to be the five million a day type, plus, IPs. EURs, though, it depends on the fault block and how small the fault block is and those kind of things as to whether the EUR matches with that initial rate that you have.

So I don't know that those are representative themselves of what you could do if you were just out in an open area and drilled and 8,000-foot lateral.

Daniel Guffey: Okay. So, I mean, you mentioned, I guess they're special situations. So how many 8,000-foot, or more, laterals do you expect that you'll have. I mean, can you even say --

Steve Mueller: I don't even know if I can guess that. We've done three or four. I think we've got three that are in the 8,000-foot range, 7,500 to 8,200, right now. And depending on where you're at, if you're over in kind of the eastern area, you may do one a quarter or something over there. If you're over farther to the west or central area, you're not going to do very many of them.

Daniel Guffey: Great. Thanks, guys.

Operator: (Operator Instructions) Thank you. There are no further questions at this time. I'd like to hand the floor back over to Mr. Steve Mueller for any closing comments.

Steve Mueller: Thank you, operator. And thank all of you for listening to the conference call. There's just two last things I want to say. We are disappointed as a company in the quarter because we missed the guidance. And, as I said, that tells you something about robustness of the operation, and we're working on that.

We are not at all disappointed in that table. And I'll tell you, every once in a while, something will come up and say, well, should we do the green completions, because it may affect the table. And that will last about 30 seconds, because we look at the economics and say, of course we do that, we'll explain the table as we go through.

And if you look at that, the table, well, at surface, yes, we had less IP than we had last quarter. That average three million a day IP in the areas we're drilling, compared to what we would have averaged a year ago in those areas, is tremendous, and we're excited about that. And I just want to make sure that all of you know that we are excited, even though the table looks a little different. And then you come back to, do we ever have discussions whether we should have that table in there or not in there? And as I said in the past, that table's a learning curve, not just for our company, but for the entire industry to follow the kinds of things that happen as you drill these kinds of plays out, and it's going to be there forever, and we'll be happy to explain it as it comes up, whether it's up on one of those numbers or down on one of those numbers as we go through.

So, like I say, there is some disappointment. It's a little bit disappointment. When you think about it, 41% production increase, across the board better financials than we've had, only borrow $20 million, and had over three million a day production rates for the quarter in Fayetteville, we had a great quarter.

And with that, I thank you and look forward to the next several quarters.

Operator: Thank you. This concludes today's teleconference. You may disconnect your lines at this time. Thank you all for your participation.