Southwestern Energy Company
Q4 2009 Earnings Conference Call
Friday, February 26, 2010

Officers
Harold Korell; Southwestern Energy; Executive Chairman
Steve Mueller; Southwestern Energy; CEO
Greg Kerley; Southwestern Energy; CFO

Analysts
Scott Wilmoth; Simmons & Co.; Analyst
Jeff Hayden; Rodman & Renshaw; Analyst
Scott Hanold; RBC Capital Markets; Analyst
Mike Scialla; Thomas Weisel Partners; Analyst
Brian Singer; Goldman Sachs; Analyst
Bob Christensen ; Buckingham Research Group; Analyst
Rehan Rashid; FBR Capital Markets; Analyst
Jared Sturdivant; O-CAP Management; Analyst
David Heikkinen; Tudor, Pickering & Company; Analyst
Joe Allman; JP Morgan; Analyst
Nicholas Rose; Dahlman Rose & Company; Analyst
Brian Kuzma; Weiss Multiple Strategy; Analyst
Dan McSpirit; BMO Capital Markets; Analyst

Presentation

Operator: Greetings, and welcome to the Southwestern Energy Company Fourth Quarter Earnings Conference call.

At this time, all participants are in a listen-only mode. A brief question-and-answer session will follow the formal presentation. In the interest of time, please limit yourself to two questions. Afterward, you may feel free to re-queue for additional questions. If anyone should require operator assistance during the conference, please press star zero on your telephone keypad.

As a reminder, this conference is being recorded.

It is now my pleasure to introduce your host, Harold Korell, Executive Chairman of the Board for Southwestern Energy Company.

Harold Korell: Good morning, and thank you for joining us. With me today are Steve Mueller, our Chief Executive Officer, and Greg Kerley, our Chief Financial Officer.

If you've not received a copy of yesterday's press release regarding our fourth quarter and full-year 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 Forward-Looking Statements section of our annual and quarterly filings with the SEC.

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.

Well, 2009 was an exceptional year for Southwestern Energy. We saw several milestones this year, including setting new records for production, reserves, reserve replacement, and cash flow, all in a year where we saw natural gas prices that were at a seven-year low.

We celebrated our fifth anniversary of the Fayetteville Shale play, while also reaching a production milestone of 1 Bcf per day from the play.

We drilled and completed our 1,000th well in the play, on our way to completing many more in the years to come.

Finally, we continued to have an industry-leading low-cost structure as our finding and development cost of $0.86 per Mcf and lease operating expense of $0.77 per Mcf in 2009 are among the lowest in the industry.

This is all pretty amazing when you consider that it was just five years ago when we set all this in motion with the discovery of the Fayetteville Shale.

Meantime, in our other areas, things are continuing to go well in our East Texas, James Lime and Haynesville activities, and in Pennsylvania, where we have just started an active drilling program.

I will now turn the teleconference over to Steve for more details on our E&P and Midstream activities and then to Greg for an update on our financial results, and then we'll be available for questions.

Steve Mueller: Good morning. As Harold stated, we had an outstanding year in 2009, and our operational metrics are some of the best in the industry.

Our production grew by 54% to a record 300 Bcfe-equivalent, primarily as a result of the growth from our Fayetteville Shale, where our production grew 81% to 243 Bcf. We also produced 35 Bcfe from East Texas and 22 Bcf from the Arkoma Basin.

Our year-end proved reserves increased by 67% to a record 3.7 Tcf-equivalent. Approximately 100% of our reserves were natural gas, and 54% were classified as proved developed, down 8% from 62% in 2008.

We are also one of the few companies that have recorded net positive reserve revisions as the improving performance from our Fayetteville Shale wells more than offset negative price revisions due to low gas prices and some performance revisions in our East Texas and Arkoma Basin programs.

For the last three years, our reserve replacement has averaged over 500% of our annual production. We replaced 592% of all of our 2009 production at a finding and development cost of $0.86 per Mcf-equivalent, including revisions. Excluding revisions, we replaced 561% of our production at an F&D of $0.91 per Mcf.

Now, I'll talk a bit about our operating areas.

The Fayetteville Shale continues to deliver exceptional results. We invested approximately $1.3 billion in our Fayetteville Shale drilling program during 2009, adding 1.8 Tcf of new reserves at an F&D cost of $0.69 per Mcf. This included net upward reserve revisions of approximately 238 Bcf as our improved well performance more than offset negative revisions due to lower gas prices. The finding and development cost excluding these revisions was $0.80 per Mcf.

Total proved net gas reserves booked at the Fayetteville Shale play at year-end 2009 were 3.1 Tcf, more than double the reserves booked at the end of 2008.

The average gross proved reserves for the undeveloped wells included in our year-end 2009 reserves was approximately 2.2 Bcf per well, up from the 1.9 Bcf per well at the end of year 2008, and based upon our current drilling phase, we have approximately two years of drilling inventory booked as PUDs.

During 2009, we continued to improve our drilling and completion practices in the Fayetteville Shale. Our horizontal wells had an average completed well cost of $2.9 million per well, compared to an average of $3 million per well in 2008, as a decrease in our drilling times and other savings more than offset a 13% increase in lateral length.

Our average initial producing rates improved 25% over last year, as well as placed on production during 2009 average initial production rates of approximately 3.5 million cubic feet per day, compared to the average initial production rate of 2.8 million cubic feet per day in 2008.

Mid-year 2009, we celebrated reaching 1 Bcf per day from the Fayetteville, as gross production from our operated wells climbed from approximately 720 million cubic foot per day at the beginning of 2009 to approximately 1.2 Bcf a day at year-end.

Recently, we've had some delays due to operational issues and the colder weather that have caused 25 fewer wells to be put in production during the last few months than originally planned.

As a result, we have added two additional drilling rigs to help us catch up on our projected well count, which we expect will happen sometime in the third quarter.

We are currently running 22 drilling rigs in the Fayetteville Shale play, 16 that are capable of drilling horizontals and 6 smaller rigs that are used to drill the vertical sections of the wells.

In our East Texas operating areas, we had excellent results, posting production growth of 10% to 34.9 Bcfe, with reserves of approximately 330 Bcfe at year-end.

In 2009, we invested approximately $167 million and participated in 46 wells in East Texas, of which 33 were successful and 13 were in progress at the end of the year, resulting in a 100% success rate.

We continue to have good success in our James Lime carbonate play and through December 31, 2009 have participated in a total of 77 horizontal wells. Of those, 43 were operated by us and placed on production at an average gross initial rate of 9.8 million cubic feet per day.

We also kicked off our drilling program targeting the Haynesville and Middle Bossier shales in Shelby and San Augustine counties in 2009 with very good results. After our first horizontal well production tested at 7.2 million cubic feet per day in the first quarter of 2009, we have drilled four additional wells in the Haynesville Shale, which production tested 13.4, 16.7, and 21 million a day, and 18.1 million per day, respectively.

Additionally, we completed our first well in the Middle Bossier formation, which production tested at 11.3 million cubic feet per day.

We are currently completing our 6th Haynesville well, the Red River 620 #1-H, and drilling two additional Haynesville wells in the area, the Red River 619 #2-1H and the Owens #1H, both of which will be completed sometime in the second quarter.

In total, we have approximately 42,300 net acres we believe are prospective for the Haynesville and Middle Bossier shales, and our average gross working interest is approximately 61%.

In addition to the James Lime -- Haynesville and Middle Bossier targets, we have placed our first Pettet oil well on production. The Acheron #2-H was placed on production in January at initial production rates of 465 barrels of oil per day plus 2.5 million cubic foot of gas. We are currently participating in two Pettet wells, which are being completed.

In our Conventional Arkoma program, we had approximately 208 Bcf of reserves at year-end 2009 and produced 22 Bcf, compared to 24.4 Bcf in 2008. Our production decreased during 2009 primarily due to the significantly lower capital investments in the area, as compared to 2008.

In 2009, we invested approximately $40 million in our Conventional Arkoma drilling program, participated in 20 wells, of which 15 were successful, 3 were in progress -- and 3 were in progress at year-end, resulting in an88% success rate.

At December 31, 2009, we had approximately 149,000 net acres in Pennsylvania prospective for the Marcellus Shale. Our undeveloped acreage position as of December 31, 2009 had an average remaining lease term of five years, an average royalty interest of 13%, and was obtained at an average cost of $594 per acre.

During 2009, we invested $40 million in Pennsylvania, almost all of which was for acquisition of acreage, including approximately 22,800 net acres in Lycoming County that was purchased for $8.7 million, or $382 per acre.

We are currently drilling our first horizontal well since 2008 in Pennsylvania. The Heckman Camp #1 well is located in Bradford County, and first gas production is expected in the area in the second quarter of 2010.

In summary, we're very pleased with the results in 2009, and our planned capital investment plans for 2010 continue to build on that success. While we are very proud of our accomplishments in 2009 and over the past five years, we also know that we have much work to do. We know that our disciplined approach to capital investment, focus on organic growth, and financial flexibility will keep us extremely well positioned during both the good and the challenging times. We are looking forward to what lies ahead in 2010 and the many years to come.

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

Greg Kerley: Thank you, Steve, and good morning.

As Harold and Steve said, we had an exceptional year in 2009, both operationally and financially, despite natural gas prices falling to their lowest levels in seven years.

For the calendar year, we reported net income of $523 million, or $1.52 per share, excluding a $558 million after-tax ceiling test impairment of our oil and gas properties during the first quarter of 2009.

Cash flow from operations before changes in operating assets and liabilities was up 23% to $1.4 billion as our production growth more than offset the effects of significantly lower natural gas prices.

For the fourth quarter, we reported earnings of $158 million, or $0.45 a share, a 51% increase over the prior-year period, as the significant growth in our production volumes more than offset the decline in our average realized gas price.

Our production totaled 89 Bcf in the fourth quarter, up 55% from the prior-year period, and we realized an average gas price of $5.29 per Mcf, down from $5.93 in 2008.

Our commodity hedge position increased our average realized gas price by approximately $1.50 per Mcf in the fourth quarter.

We currently have 66 Bcf, or approximately 16%, of our 2010 projected natural gas production hedged through fixed price swaps and collars at a weighted average floor price of $8.02 per Mcf. Our detailed hedge position is included in our Form 10-K that we filed yesterday.

Operating income of our E&P segment excluding the non-cash ceiling test impairment was $750 million in 2009, compared to $814 million in 2008.

For the year, we grew our production to 300 Bcf-equivalent and realized an average gas price of $5.30, which was down approximately 30% from the prior year.

We continue to have one of the lowest cost structures in our industry, with a full cycle cash cost of approximately $2.14 per Mcf in 2009 and a three-year average of $2.75 per Mcf. This includes our F&D costs, lease operating costs, production taxes, G&A, and interest expense.

As Steve noted, our finding and development cost was $0.86 per Mcf in 2009, including revisions, down from $1.53 in 2008.

Our lease operating expenses per unit of production were $0.77 per Mcf in 2009, down from $0.89 in 2008. This decrease was primarily due to the impact that lower natural gas prices had on the cost of compressor fuel during 2009.

Our general and administrative expenses per unit of production declined to $0.35 in Mcf in 2009, down from $0.41 in 2008. This decrease was primarily due to the effects of our increased production volumes, which more than offset the effects of increased payroll, incentive compensation, and other related employee costs, primarily associated with the expansion of our operations in the Fayetteville Shale.

We added a total of 335 new employees during 2009.

Taxes other than income taxes were $0.11 in Mcf in 2009, down from 13% -- $0.13 in the prior year due to the lower commodity prices and the change in the mix of our production volumes.

Our full-cost pool amortization rate also declined, dropping to $1.51 per Mcf in 2009 from approximately $2 in the prior year. The decline was due to a combination of a ceiling test impairment recorded in the first quarter of 2009, our lower finding and development costs, and the sale of natural gas and oil properties in 2008.

Operating income for our midstream services segment doubled in 2009 to $123 million. The increase was primarily due to increased gathering revenues related to production growth in the Fayetteville shale, partially offset by increased operating costs and expenses.

At December 31, 2009, our midstream segment was gathering approximately 1.3 billion cubic feet of gas per day through 1,137 miles of gathering lines in the Fayetteville shale play, compared to gathering 802 million cubic feet of gas per day a year ago.

We invested $1.8 billion during 2009, approximately equal to our investments in 2008. And we expect that our total capital investments for 2010 to be approximately $2.1 billion. There is clearly uncertainty today regarding natural gas prices, so our capital plans will remain flexible. If we see a repeat of the low gas prices we saw in 2009, we'll actively manage our capital program and make reductions in our 2010 plans. However, if gas prices rebound during the year, we could increase our planned investments and accelerate the development of the Fayetteville shale by adding additional drilling rigs.

We have a strong balance sheet with significant liquidity and financial flexibility. At year end, we had 325 million borrowed on our 1 billion revolving credit facility at an average interest rate of 1.1% and had total debt outstanding of a little less than 1 billion for the company. That left us with a debt to book capital ratio of 30% at year end and a debt to market cap ratio of only 6%.

That concludes my comments. And we'll now turn it back to the operator who will explain the procedure for asking questions.

Questions and Answers

Operator: Thank you. (Operator Instructions). Our first question is from the line of Scott Wilmoth with Simmons and Company. Please go ahead with your question.

Scott Wilmoth: Hey, guys. Just following up on the flexibility of the CapEx budget. Could you put some magnitude around it? Say we're on a $4 gas price for 2010. What type of magnitude of decrease in the CapEx budget would we have and ultimately what would that do to guidance?

Greg Kerley: Well, if you look at the guidance that we've kind of already prepared and sent out publicly in December, there's about a $300 million swing in our cash flow, if we were to average $4 versus $5. So you would see us reduce our capital program to try to stay fairly in the same range that we expected for our total net borrowings for the year.

Steve Mueller: And let me add to that. The two places you'd see that is probably some of the new venture things, because if gas price is low you don't need the new ventures as much. And then, also in some of the stuff we're doing in East Texas where most of that is HBP, so it's really as we've got the dollars we can invest there.

Scott Wilmoth: So impact to guidance would be minimal?

Steve Mueller: We haven't done the calculations, but that's probably right.

Scott Wilmoth: Okay. And then, just one other question. You mentioned in the release operational and weather related issues. Were all of those operational issues due to the weather or can you just give me a little more color on that?

Steve Mueller: It was all due to the weather. And when we say operational and weather, we had several snowstorms and if you look at that chart included with the press release on the production, you'll see some little bumps and glitches in January. We had some little bumps in February as well. But what happens is you get a bunch of snow and ice out there and you can't move the equipment. And if you can't move the equipment, you can't drill as fast. And that's the combination.

Scott Wilmoth: Okay. Thanks, guys.

Operator: Thank you. Our next question is from the line of Jeff Hayden of Rodman and Renshaw. Please go ahead with your question, sir.

Jeff Hayden: Good morning, guys. A couple questions, I guess starting with the Haynesville. Could you guys give any color on what you had in terms of reserve bookings from the Haynesville at year end, kind of number of locations, as well as kind of EURs you had on them?

Steve Mueller: Well, I can start by talking about the EUR. I believe the EUR is just over 5 Bcf on our wells. We're kind of looking at the numbers right now trying to figure out exactly what we had from a well count booked. It wasn't that many wells total that we had booked in the year. And again, if you think about our acreage position out there, we've got a middle block that we call Jebel acreage, if you look at any of our presentation material. We have now drilled all four corners of that block, so we're feeling comfortable about the acreage, but we certainly don't have that completely booked. What we had booked at the end of the year was a total of 30 Bcf to the Haynesville and that included seven proved locations and 10 PUDs for a total of 17 total locations.

Jeff Hayden: Okay, appreciate that. And then, jumping up to the Marcellus really quickly, I just wonder if you could give us an update kind of how you're looking at the drilling program for 2010 in terms of where you're going to spot the wells, whether it's Bradford, Susquehanna, Lycoming, et cetera. And then, kind of building on that, sort of an update on the takeaway capacity that you're looking at and how you're going to manage that.

Steve Mueller: Well, the rig that we're running, we'll drill between 20 and 24 wells this year. It is going to be all in

Bradford County. It's right on top of--I want to say right on top or within a mile or two of the Stagecoach Pipeline. And we have firm on that pipeline today of 20 million cubic foot and we're building that going forward. And that's the reason we're drilling where we're at, because we do have the capacity on that line to be able to do that. We'll participate probably in another 20 wells. Most of those will probably be--a little bit maybe in the Bradford, but most will be in Susquehanna. And we'll have a minority in those wells. And whatever the operator there is will have the takeaway, so we don't have to worry about that portion.

Over the next year, we'll keep one rig running, and then you'll see us build that activity into the future. We'll say the one area that will have the less drilling over the next couple of years will be in Lycoming County. That's more 2012 and beyond before you see much drilling there.

Jeff Hayden: All right. I appreciate it, guys.

Operator: Thank you. Our next question is from the line of Scott Hanold with RBC Capital Markets. Please go ahead with your question.

Scott Hanold: Thanks. Good morning.

Steve Mueller: Good morning.

Greg Kerley: Good morning.

Scott Hanold: When you look at the Fayetteville, were any of the prior PUDs in the Fayetteville let go from last year to this year because of low gas prices?

Steve Mueller: There were some that--there's a very small amount that did. I don't know. It's--.

Scott Hanold: --And is it fair to say then, I think it was a $3.87 price at the end of the--or that you had to use for the reserves--most of those Fayetteville held up economic yet?

Steve Mueller: Yes.

Scott Hanold: Okay. Very good. Okay. And when--you'd mentioned you have two years of PUDs currently booked at this point in time. How do we--I know it's not sort of perfect math, but when you look at how many offsets per PDP, what does that kind of look like?

Steve Mueller: We'll have to calculate that one for you, Scott. It's something around 0.8 per PDP.

Scott Hanold: Okay.

Steve Mueller: The total number of wells--1,150 that we have booked as PUDs right now.

Scott Hanold: Okay. And that 2.2 Bcf I guess EUR on your wells, is that--I mean, that seems pretty conservative relative to the performance you were seeing. Is there--been sort of a difference in some of these newer wells that you're putting online where you book them at a much higher rate? I know there's a range, but on average is it a pretty clear trend that your 2009 adds were significantly higher than prior years?

Steve Mueller: Let me explain how we do the reserves and I'll let you kind of figure out where you want to go with the question from there. What we do, we break the entire Fayetteville shale into several different areas. We look at the production from the wells in those individual areas and then we look at what we're going to drill in the future. And the wells that we drill in the future in those particular areas get the average from whatever you've done in the past. And that average that you've done in the past has to have enough production on it to count.

And so, if you think about any of these areas and break it up, we've got roughly 30 different areas we break it up into. You're only using wells that are eight months or older for the most part in that average. So any of the things that's going on today isn't even affected in our overall reserve numbers.

Scott Hanold: Okay. Now, I've got it. That makes it clear. And one last question, if I could. PV-10 value, I'm sorry if I missed that. What was your year end PV-10 value? And if you have that between the PDPs and the PUDs that would be great.

Steve Mueller: Yes. I don't have that sitting right here, Scott. We'll look it up and give--answer that one here in a little while.

Scott Hanold: All right. I appreciate it. Thanks.

Operator: Our next question is from the line of Mike Scialla with Thomas Weisel Partners. Please go ahead with your question.

Mike Scialla: Good morning, guys. Now, one of mine sounds like you're probably going to have to look up as well, if you have it. Kind of along the same lines as Scott's question, I was wondering if you ran a sensitivity at a higher price than the $3.87 on your proved reserves for a PV-10.

Steve Mueller: I can tell you we haven't.

Mike Scialla: Okay. The second one you mentioned the Pettet. Wondering how big that could be. And are any of the new ventures targeting more oily plays or are you sticking with the gas plays at this point?

Steve Mueller: As far as the Pettet goes, we're trying to figure out how big it could be. Right now, there's about six wells that Cabot has drilled. We are on our first well and are participating in these other two I talked about. And it looks like, if you've got $60 oil, it's going to be a pretty good play. And with that $60 type oil range--and we need probably four or five more wells to see--there may be 100 type wells--100 wells that you have to drill out there. But it's way early. It could be that we drill four or five more wells and it's six more wells you have to drill. So we've just got to figure that out from that standpoint.

And then, as far as targeting new ventures, and targeting oil or gas, if you think about any of these plays that are new - and we just talked about the fact that we're in our--it's been five years since we found the Fayetteville. From the time you come up with the idea to the time you really get significant production is going to be a three to five-year period. And I really can't guess what's going to be a better product, gas or oil, down the road. So what we're doing is looking for the best 1.3 PVI projects and if they happen to be oil, they'll be oil, and if they happen to be gas, they'll be gas.

Mike Scialla: Thanks, Steve.

Operator: Thank you. Our next question is from the line of Brian Singer with Goldman Sachs. Please go ahead with your question.

Brian Singer: Thank you. Good morning. Going back to your comments on capital allocation, given lower gas prices here, can you talk more about the decision to add the two rigs to make yourself whole on Fayetteville drilling? And then, if you could talk a little bit more about the midstream commitments and how that allows or does not allow for flexibility in the Fayetteville activity.

Steve Mueller: Let me start with the midstream first. Our guidance for the year in the midstream was actually a little bit higher capital program than we had last year in midstream. And we'll be drilling a large number of wells in kind of the eastern--towards the eastern central area to hold acreage. And we'll be building out our midstream there. Our midstream per well or per pad is going to be about 20% longer this year than it was last year as it builds out that program. And that will give us flexibility into the future. And we've still got probably at least two more years of that $250 to $280 million a year capital to really build out most of the program we have. So it's just continuing to do that. It's a little bit higher this year than last year.

As far as adding the rigs, just like we did in 2009, we're trying with about 30% of our wells just to hold acreage. The other wells are still trying to learn things. And as we down space and do closer spacing, we're learning that certain areas look like they're going to be a little tighter spacing and other areas are going to be a little wider spacing. And we need to get that learning done very quickly, so we can actually get to--get on to the pad drilling portion of it. So the 25 wells isn't so much a production type number that we're trying to do something with. It's that learning part of it.

We had the opportunity to add two rigs early this year on relatively short term contracts. Both of those rigs will expire before the end of the year. And we thought it was a good bet going back again. If the gas price is $4, you'll see us drop those rigs later in the year. If it's $6, we've got them working and in shape so that we can accelerate going into next year. So it gave us a good bet and it helped us learn at the speed we want to learn at.

Brian Singer: Thank you, that's really helpful. And then secondly, on the Haynesville, Bossier and Marcellus, do you think about those assets as keepers or would you consider a joint venture to either accelerate activity or improve the balance sheet, etc?

Steve Mueller: You know, if you think about joint ventures in general, it's just another way to provide some kind of capital and at this point, as we said, we can manage what we need to do with just moving rigs around or moving rigs up or down, so I don't think we're right now thinking about joint ventures anywhere, whether it's Haynesville or anything else. We have stated in the past and what we stated here again today, that if you rank kind of the quality of our projects, both I think what we have in Pennsylvania and Fayetteville worked with $4 numbers on the gas; when you get into East Texas you're going to need to have a 5 on most of what's going on there and that's why we said if it was $4 gas we'd adjust East Texas down.

Harold Korell: Steve, I think I would add to that. We do have a joint venture in the Haynesville and Bossier; we have a partner in that and I don't think it would be a smart thing to do to have another partner in that. And as a practical matter, because of the way the acreage is distributed in Marcellus, we also have quite a few partners in the Marcellus acreage that we have. And as Steve said, we have the ability to fund and hold this acreage and we don't find ourselves in a financial squeeze here, so we're not compelled to do any of those kind of things right now.

Operator: Your next question is from Bob Christensen , Buckingham Research Group.

Bob Christensen: How thick a section of rock are we working with in your latest Bossier and then some of your latest Haynesville?

Steve Mueller: Kind of average thickness for the Haynesville is just over 100 feet and if the Bossier works, its average thickness is very similar to that.

Operator: Your next question is from Rehan Rashid, FBR Capital Markets.

Rehan Rashid: Just a capital intensity related question. The latest numbers I guess are $3 million for a 4,300 feet lateral; does this include the impact of your own sand production?

Steve Mueller: Everything we told you is historical data. As we've talked about and we gave guidance on, sand plant is up and operational. That sand plant will save us between $130,000 and $150,000 per well that it's used on. And so we expect that with the same lateral lengths in 2010 our overall cost will be down. We did a press release at the end of the year that talked about a $2.75 million average.

Rehan Rashid: Got it. So to take it beyond that 2.75 outside of let's just say pad driven synergies, is there anything else kind of from a technological standpoint that could accelerate the spud to release or any other cost reduction?

Steve Mueller: Well, we're working on all kinds of things and two of the rigs that we're running right now are AC rigs that have some of the characteristics and one of them has most of the characteristics we want to use on pad drilling and we're learning what those might be able to do for us. So we're continuing to work on the drilling side of this. Completion side, we're averaging between 12 and 14 frac stages, but I can tell you we're playing with a mix of the water versus sand and even the mesh of the sand and depending on how that mix changes and if those stages would change, there's some cost savings in there. And as you mentioned, we're not to pad drilling yet.

In 2010 we'll actually drill fewer wells per pad than we did in 2009 and you won't see us really start ramping up until 2011 when we're doing pad drilling. There will be a lot of synergies on the pad drilling that will put downward pressure on that cost. So there are certainly things we're working on, but I don't think any one of them is as much as the $130,000 to $150,000 we have in the sand.

Rehan Rashid: Got it. A couple of miscellaneous questions. Going back to the 2.2 Bcf per well, any kind of thoughts on the average lateral length associated with that? I know you said eight months kind of lag.

Steve Mueller: The average lateral length of the PUDs that are in our reserve report is 3,700 feet.

Rehan Rashid: And the negative reserve revisions, what vintage wells would these be?

Steve Mueller: We had very few wells that were five years or above that we had to do anything with that direction. Most of the revisions were price related. The ones that were performance related for the most part were in the Overton field and those just weren't performing the way we had them booked, frankly. And that's not a really big number but that's where most of those revisions were at.

Rehan Rashid: Got it. From a downspacing standpoint, I know 20 pilots going on; is it too early to kind of quantify what percent of the area gets as close to 30-acre spacing and some higher?

Steve Mueller: Yes. Let me just tell you, we talked before about the fact and I think we released some information that we were doing somewhere around 12-13 at very tight spacings. We've now increased that, so this year we'll end up well over 20 at tighter spacing. And the reason for that is we're getting mixed results. We've had about half of the tighter spacing work very well and give us our 1.3 PVI and we've got about half that we've got question marks on. So we're going to have to expand that program. That goes back to Brian's questions earlier about wanting catch up on those 25 wells. Just giving the mix results tells you we must be getting close, but we've got to get some more information so we can learn more about it.

Let me jump in here. Scott Hanold had asked the question on what our PV10 was on our reserve report for the Fayetteville shale for both the PDP and PUD. The PDP and this is at the 3.87 NYMEX average that we had and then there's going to be a basis differential lower than that, but the PDP was $2.2 billion; the PUDs were $23 million. So you can see the PUDs are just around the PV10 mark at the $3.87 minus roughly $0.30 basis differential.

Operator: Your next question is from Jared Sturdivant of O-CAP Management.

Jared Sturdivant: Congratulations on another record setting year. Listening to several earnings calls I've noticed a trend in pricing pressure from the service industry, primarily within pressure pumping and a little pushback on the rig prices. Can you comment on how this will affect your F&D cost going forward or any color you might have on the issue? And secondly, can you comment on your base differential of $0.39 versus $1.80 in 2008, and 2010 expectations? Thanks.

Steve Mueller: I will talk a little bit about the cost and I'll let Greg talk about the differential, but as far as the costs go, one of the reasons we own our own rigs and I'll remind everyone that we own 11 of the bigger rigs that are running in the Fayetteville shale, one of the reasons we own our own sand mine is that was the only way you could really hedge those costs over a long period of time and both of those we'll use in Fayetteville shale, we don't have to use anywhere else, so that allows us to have a relatively constant cost from those angles. We are lengthening out the steel and what we buy. Normally we buy a quarter ahead; we're trying to lengthen that out significantly right now to kind of control those kinds of costs.

And on the pumping service side, it really just depends on what part of the country you're in how much pressure you're getting on the pumping service. Certainly you're seeing cost go up in the Haynesville. And in the Marcellus, just because the equipment is not there yet, you're seeing some upward pressure. The other side of that equation for us is we're continuing to learn and take cost out and if you think about what we've done over the last three years, in 2007 it cost us $3 million to drill a 2,700 foot lateral; today it's $2.9 to $3 million to drill a 4,300 foot lateral and we're working hard with whatever we do on the learning side that we can offset any of those kinds of costs with that going forward.

Jared Sturdivant: Is it a fair assumption to expect $100,000 per frac stage going forward?

Steve Mueller: We're a little bit less than that on our average frac stages.

Greg Kerley: Just to follow-up on the basis question, we've seen basis continue to tighten and our current guidance is that we expect somewhere between $0.10 to $0.20 of negative adjustment to get to our price, so that's down considerably from more than a year ago, for sure.

Steve Mueller: And let me jump in; we do have 140 Bcf hedged at that low number, so we know at least over the near-term we'll have that basis. And when you look at the basis across the United States, it has collapsed significantly. If you look back at 2008, there were wide swings in basis in various basins; today almost anywhere you're at, you can almost get the best prices selling in your local market as opposed to trying to get to the East Coast.

Operator: Your next question is from David Heikkinen with Tudor, Pickering & Company.

David Heikkinen: Just had a question on your 2009 proved reserves category summary of net acreage and undeveloped acreage, make sure I'm understanding it. The undeveloped acreage, is that just acreage that has no wells drilled on it?

Steve Mueller: It has no producing wells on it, correct.

David Heikkinen: And then the delta between those, that's not that that acreage is fully developed; basically we should just think about you booked 1,150 PUDs to the Fayetteville and then all the rest of the locations that we may come up with using spacing assumptions would be the difference between producing plus PUDs and then remaining inventory. Is that fair?

Steve Mueller: That is correct. I'll use the Fayetteville shale as an example. In the Fayetteville shale if you drill one well on a 640 acre spacing and put it on production, that holds the whole 640, that would make it developed acreage. Then you come back later and our 600-foot spacing we're talking about would be at least 10 wells total, so we'd have to drill nine other wells on that section, even though as an acreage it's counted as developed acreage.

David Heikkinen: Okay, just making sure. That's helpful. Then you answered the question of kind of the split of PDP for each of the areas; just curious, trying to get some sensitivity around the PUDs for East Texas or the Arkoma, do they go down to that same relatively low value, have the same ratio or is it less sensitive because there is future value?

Steve Mueller: For the most part the PUDs in East Texas and Arkoma need a little bit higher gas price but you put it in perspective, 99% of our PV value as a company comes from proved developed. So there's almost nothing in the proved and undeveloped, it's all 10%, 8% type discount numbers.

Operator: Your next question is from Joe Allman with JPMorgan.

Joe Allman: I think you answered this in a way, but when you talked about the PUDs being economic at $3.87, you booked your reserves based on PV0 as opposed to PV10 and at $3.87 most of your Fayetteville shale probably isn't economic on a full cycle basis, is that correct?

Steve Mueller: The 2.2 Bcf well is just about economic at $3.90, $3.87-$3.90 so I want to say economic, gives you a PV10. To get a 1.3 PVI we need it in the $4.30 range for that 2.2 Bcf average. Now again, that's the average of what we have out there; we've got some PUDs that are significantly higher than that, we've got some that are lower than that. Those lower ones obviously were booked at something PV0 or greater.

Joe Allman: Got you. And then when you gave the PDP PV10 of $2.2 billion, I think Steve you said that was just the Fayetteville?

Steve Mueller: That was just the Fayetteville.

Joe Allman: Okay. Do you have those numbers for the whole company?

Steve Mueller: I'm sorry, that was total. I'm sorry. The number I gave you before, the 2.2 is the total company.

The Fayetteville was $1.9 billion basically for the PDP and two -- yes, $1.9 for the PDP -- or proved, I'm sorry.

Joe Allman: Okay. And what about for the PUDs?

Steve Mueller: $39 million for the PUDs.

Joe Allman: Okay, got it. So that suggests that --

Steve Mueller: So the difference between the $39 and the $23 says there was -- whatever that is, $16 million of less than PV-10.

Joe Allman: Yes, I got it. Okay. Thank you very much.

Operator: Our next question is from the line of Nicholas Pope with Dahlman Rose. Please go ahead with your question.

Nicholas Pope: Good morning, guys.

Steve Mueller: Good morning.

Nicholas Pope: Just back to the spacing with the -- you said it was successful in 65 acres. Like are you all seeing much interference, whatever you all are looking to the 700-foot spaced wells or what's it look like at this point?

Steve Mueller: We're drilling everything today at least 600 feet or closer and we're seeing about 15%, between 12% and 15% interference with that spacing.

Nicholas Pope: And then like on the -- I guess for the rest of the year you talked a lot about, like that 300 to 500-foot a lot of tests that are going to be done. Have you all done many of those wells yet or is that --

Steve Mueller: Well, we've got information on eight. Now, some of that information doesn't have a lot production on it, but we've got information on eight and I can tell you that on those eight, there's four that give very good economics, well above our 1.3 PVI. There's a couple that are bouncing around and may make a 1.3 PVI and there's a couple that aren't good at all.

Nicholas Pope: Okay, great. That's helpful. And then just -- I was wondering with the press release you all put out and the filing you had on that rights agreement, the acceleration of the expiration on that rights agreement, is there anything to be read into the removal of that rights agreement?

Steve Mueller: There really isn't anything to be read into it anymore than companies are getting beat up for corporate governance-type things and this is one of those corporate governance issues. You'll see that we've done a couple of different things as a company.

One of them is we just decided it wasn't worth the effort to keep the rights agreement out there. We also put in a policy for what our executives and board should have for total stock to put that more in typical corporate governance. So we just reviewed our corporate governance things. We tweaked it a little bit and one of those tweaks was we decided we didn't need the rights plan.

Nicholas Pope: All right. That's very helpful. That's all I had.

Operator: Our next question is from the line of Brian Kuzma with Weiss Multiple Strategy. Please go ahead with your question.

Brian Kuzma: Yes, my questions have been answered. Thanks for the corporate governance changes.

Operator: Our next question is from the line of Dan McSpirit with BMO Capital Markets. Please go ahead with your question.

Dan McSpirit: Gentlemen, good morning, and thank you for taking my question. Certain operators in the Haynesville, at least on the North Louisiana side, have experimented with, and even reduced the choke size at which they flow the wells. Can you comment on the benefit of that from your view of the world and whether or not you'll need to do the same on your acreage in East Texas, depending of course on what size you're using today?

Steve Mueller: Well, we've only got seven wells worth of information, so I can tell you, we haven't been able to do much work with whether it's better to come and put it on production on one rate versus another rate as we go through. So that's something on our list to learn, but with only one year of production and seven wells, we just don't have enough information to really give you much thought there.

I can tell you our general philosophy, whenever you're doing these wells, you have to calculate what the draw-down is bottom hole and we're going to, on any well, wherever it's at, make sure that we don't have significant draw-down, so that you don't have some kind of effort or problems with that. So we're going to do that anyway with whatever we're doing on our wells and it certainly is possible you can drill wells too hard in almost any basin. And that may be what you see going on. There may be some other things, but we just don't have enough information.

Harold Korell: Yes, I mean, I would say also, we find it very interesting. I've found that very interesting for some time and we're interested in understanding more about the why and what the impacts are of doing that. So we'll hopefully be able to learn some of that from other people's experience.

Dan McSpirit: Very good. Thank you. That's all I have.

Operator: Our next question is a follow-up question from the line of Bob Christensen of Buckingham Research. Please go ahead with your question.

Bob Christensen: How should we think about the compression in your midstream? As you drill more wells, we need more compression out there, or can we run the compression a little harder and these low-pressure lines -- and where are we at on creating more reserves, I guess, and the compression story here?

Steve Mueller: Well, we are putting compression right now to basically run the entire system at about 90 pounds pressure, and I'm sure over time, as the field matures, that 90-pound pressure will go down from there. Over the short-term, I mean, the short-term meaning extra years, we do have to add significant compression as we build out the system. So you'll see us continue to invest in compressors, but basically, we're trying to do about 90 pounds across the field right now.

Bob Christensen: So you're at 90 pounds today generally in --

Steve Mueller: Generally, yes, that's our goal. Depending on how far you are from a compressor station, that might vary up to 30 pounds, but we don't have any that are several hundred pounds, let's put it that way.

Bob Christensen: And you said you'd likely add compression over the next several years?

Steve Mueller: Well, as we build out the system, we need to continue to add compression.

Harold Korell: Every new lateral has to have a --

Steve Mueller: Every new lateral is going to have compression with it and as I said before, we're going to invest a couple of hundred million dollars a year at least for the next two to three years. So part of that investment is compression and let me just also talk a little bit about our philosophy in compression.

Bob Christensen: Thank you.

Steve Mueller: We purchase part of our compression and that would be part of the capital and we lease part of our compression, so the idea being that as we get out longer in the life of the field, we're going to want to own some of that compression just to keep the wells on longer with our control of that compression. So part of what that capital will be is going to compressors and like I say, part of the other side of it, the leasing side, will be caught up in the expense part of it.

Bob Christensen: Thank you very much.

Operator: Our next question is from the line of Joe Allman at JP Morgan Chase. Please go ahead with your question.

Joe Allman: Yes, thank you. Hi again. Back to the economics question on the 2.2 Bcfe well. Steve, when you're talking about it being -- getting a PV-10 right around $3.90, I think you're probably just talking about the drilling and complete costs, but in thinking about the economics of this play, I think you need to factor in other costs. So what are your thoughts there?

Steve Mueller: It's hard to -- and I'll kind of give you two pieces of that. The two pieces -- the big pieces that you don't count and what I just said was the land cost. Land cost is about $400 an acre, so it's a few thousand dollars per well. It's not a huge number compared to some of the other plays where people have paid significant amounts of dollars for the acres.

And then on the midstream side, that's -- the allocation of your cost to a well today versus the allocation of cost to a well in the future is going to be completely different, but today, if you just said "What's it cost to hook up the wells we have producing today," it's probably in the order of about $150,000 per well. And remember, you're bringing that line to a pad with a single well or maybe two wells on it. And so in the future, you won't have any cost to hook that up because you'll just be tying that into a manifold. And so that'll change over time.

Greg Kerley: But the compression stuff is in our costs. In those economic costs is our LOE, so we are -- I mean, I don't know what we would be missing there that we wouldn't have in the future, except the land costs which Steve touched on.

Harold Korell: If you added a portion of the cost of the midstream to a well cost, you would have to also reduce the operating expenses in the economic run from where they are now because in the economic runs, one of the costs is the cost of compression as allocated to each well by what it has to pay the midstream company.

Joe Allman: I appreciate that, but yet, like shooting seismic, for example, seismic you've shot in the past would be a [sunk] cost, but any seismic you plan to shoot in the future, I guess we'd have to allocate that across wells and capitalized G&A as well.

Steve Mueller: Right.

Joe Allman: Things like that --

Steve Mueller: All of that would be correct.

Joe Allman: Okay, got you.

Steve Mueller: In a reserve report, you are going to have a G&A component. You are going to have the drill and complete costs, but you're not going to have seismic, you're not going to have land. And to the extent that you pay to lay pipe to something, in the Fayetteville Shale, as I said, the midstream that comes through on the expense side. In some of the other projects, for instance, some of the stuff we're doing in East Texas, we're laying to ourselves or laying to another person,that could come in as capital also that may not pick up completely in the reserve report.

Joe Allman: Got you. And then just a follow-up. On the 2.2 Bcfe, do you think that's a pretty good representation of the wells you've drilled so far in your PUDs? Is that a representation of what you think the EURs) will actually be?

Steve Mueller: I think it's a good representation of the SEC rules.

Joe Allman: Got it. Okay. Thank you very much.

Greg Kerley: And we've had reserve revision, upward revisions, based on performance each year that we've booked reserves to the Fayetteville Shale. And so those reserves at 2.2 Bcf were based upon a 3700-foot lateral. Today, we're targeting a 4300-foot lateral and expect that to potentially even increase over time. So we would hope and expect that we would continue to have positive performance revisions as we continue to have more production history on all these areas.

Operator: Thank you. Our next question is a follow-up from the line of Mike Scialla with Thomas Weisel Partners. Please go ahead with your question.

Mike Scialla: Yes, a couple on the Fayetteville -- obviously, the 4300-foot laterals look like they're doing at least 3 Bcf or better based on that lateral length. What kind of price do you need to reach your 1.3 PVI?

Steve Mueller: For a 1.3 PVI, we just need just around $4.

Mike Scialla: Okay, thanks. And then a couple of questions on the Haynesville. What were the costs on those most recent wells?

Steve Mueller: The most recent wells were averaging in the 2.95, something like that.

Mike Scialla: Oh I am talking about the Haynesville.

Steve Mueller: Oh, Haynesville, I'm sorry. The $10 million --

Mike Scialla: That would be good, by the way.

Steve Mueller: Yes, that would be good -- $10 million.

Mike Scialla: $10 million, okay. And the improvements you've seen there, has that primarily been just due to lateral length or is there anything geologically that you've learned that -- in areas that you want to focus there?

Steve Mueller: Well, as I said really, all we've tested is that central block and we've kind of drilled the four corners of that central block we have that's about 30,000 acres. So we haven't done much step-out. You'll see us step out in some of our other acreage in 2010. Stages, I would just say in general, drilling costs are very comparable to what you're going to see whether it's the Louisiana side, Texas side, that direction.

We are doing, I think, on average more stages, more in the 14-plus stage range in our wells and at least what we hear, some of the guys on the Louisiana side are eight to 10 stages. And I think that's the difference between -- somebody quoted an $8 million well and a $10 million well, but we really haven't -- except for just playing with the number stages and doing just some minor things with the fluid mix, we really haven't done much testing to try and make the wells optimized. Most of all we've done this year is just trying to figure out how big an area it could be good on, so then we could go back and do optimization.

Mike Scialla: Will you be operating in any of the 21 to 26 wells you're planning on drilling there this year?

Steve Mueller: We will. There's a -- our most eastern acreage block, it's about 10,000 acres. We have 100% of that block and we will be drilling three to -- somewhere between three and five Haynesville wells, Haynesville or Middle Bossier wells this year that we'll operate.

Mike Scialla: And how much cheaper do you expect the Middle Bossier to be? Is there much savings there?

Steve Mueller: It's 400 foot shallower. If you drill the same lateral, it's going to be the same price.

Mike Scialla: Yes, okay. Thank you.

Operator: The next question is from the line of Rehan Rashid of FBR Capital Markets.

Rehan Rashid: Apologies. Don't mean to beat a dead horse here, but the 2.2 Bcf, would the presumption be correct that it is the associated development cap ex in the PV-10 calculation is not reflective of future synergies, like pad drilling and savings from the sand that you'll have on your own?

Steve Mueller: What you have on the reserve report is just what you've done recently.

Rehan Rashid: Right.

Steve Mueller: There's nothing future put into that at all.

Rehan Rashid: Okay. Just wanted to confirm that. Thank you.

Operator: Our next question is from the line of Bob Christensen of Buckingham Research.

Bob Christensen: Just a follow-up on your midstream. Your EBITDA, is that money that is being made in the midstream off of your company or is it from third parties in the Fayetteville Shale? Just trying to understand the intra-company profits --

Steve Mueller: Today about that 1.3 Bcf a day that they're gathering, about 100 million a day is third party.

Bob Christensen: And of 100 million a day, you're making EBITDA –

Greg Kerley: Yes, that's -- that is the standalone for the Midstream using a gathering charge that is out there, a third-party gathering charge that everybody else is charging, whoever is gathering gas in the play. So if you stood it alongside by itself, that's what it is. Ultimately, we report the segments separately and ultimately eliminate, inter -company at the top.

So the majority of the EBITDA is related to our E&P segment. However, and the E&P segment fully bears the true LOE for that, just like we were a third-party gatherer and all the numbers that Steve is going over with you on the economics and everything else.

So if ultimately something is ever done with the Midstream, you end up with the exact same numbers that we're showing you right now in the E&P segment. It's the true operating expense, and that EBITDA that's generated by the Midstream you really should be looking at that as a multiple of what those things are trading out there, that that is an apples-and-apples type comparison with a third-party MLP type Midstream.

Harold Korell: Bob, the Midstream, another way of saying it, the Midstream is set-up as a separate entity. In other words, it has capital investments. And whose ever gas it gathers it charges for that, so it charges an operating -- okay, and it charges a cost per Mcf, for example. So if it's gathering Chesapeake gas, it charges them a rate. If it's gathering our own E&P gas then it charges the E&P company a rate.

And that is important to understand, and someone else's question back awhile ago about reserve calculations. So that cost to gather is a cost that the E&P wells have to bear X amount, X dollars per Mcf in calculating their reserves. And so the financials that we report are as a standalone company for what you're asking about on its EBITDA.

Bob Christensen: How much debt would we assign to that or do you internally assign to that operation?

Greg Kerley: Well, we -- I mean we don't assign specific debt to any specific entity. It's total corporate debt. We have in total about a billion dollars of debt. As you can see, we're -- and as we will get even at a little over $5 gas, you know, towards the end of this year we get pretty much cash flow neutral.

On the EBITDA basis we're getting closer to that in the Midstream and, but we still probably have a year or so before we'll actually be kind of at a neutral standpoint with Midstream, but we have at least, as Steve said, a couple more years that we'll have $200 million, $250 million type investments in Midstream, and this year I think it's actually $270 million.

Bob Christensen: One final, if I might? What's happening back up in the Overton Field? Let's go back and, you know, what's production there now, and it's way down from the past? I mean we, you know, it was such a--?

Steve Mueller: Well, I think the easy answer in Overton is we haven't drilled there in almost two years, and so you're just on a PDP decline. And that doesn't mean that there's a problem with Overton, other than the fact we haven't drilled. And the well cost there, we really need $6 gas to drill.

Bob Christensen: Right.

Steve Mueller: There is two horizontal wells we've drilled in some of the worst rock that's performing fairly well, and we drilled those a year-and-a-half ago. And so you'll see us go back into Overton and drill some more wells in the future, but really you're just seeing the decline.

Bob Christensen: How fast is the decline annually?

Steve Mueller: It's roughly 25% in Overton.

Bob Christensen: A year?

Steve Mueller: Yes.

Bob Christensen: Okay, so we're down 50% in two years?

Steve Mueller: Yes.

Bob Christensen: Okay, thank you.

Operator: Ladies and gentlemen, we have reached the end of our allotted time for questions. I would like to turn the floor back over to Mr. Mueller for closing comments.

Harold Korell: Mr. Korell I think.

Steve Mueller: Yes, Mr. Korell is going to do closing comments.

Harold Korell: Brad tells me I need to do a perfunctory personal note, closing here. So here's my attempt at that.

As you know, this will be the last one of these teleconferences for me, as I will be retiring as an employee of

Southwestern Energy at the end of March. I plan to remain on the Board and serve as a non-Executive Chairman, and have more flexibility with my personal time to pursue new ventures, or I should say adventures, possibly.

I want to say thank you for letting me live the American dream, really. Looking back at my career, I've been so fortunate to have had opportunities, opportunities for a great education, opportunities to use my knowledge, skills, and competitive spirit, and the opportunity to participate in an environment of free enterprise and American capitalism.

I've been able to be a part of something here at Southwestern that has truly been extraordinary, and I've loved almost every minute of it. I'm thankful for all the people here at Southwestern who have made all of this happen, and many of those will be friends for my life.

I also want to say thank you for the shareholders who have had faith in our Company, as we have lived through some tough times and who have been able to celebrate with us through the really good times, which are now.

And I want to thank the Board for giving me the opportunity to be at the helm of this fine ship.

That concludes our teleconference for today, and thanks for joining us.

Operator: You may now disconnect your lines at this time. Thank you for your participation.