

SWN - Southwestern Energy Company
Q2 2010 earnings conference call & webcast
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Officers

Steve Mueller; Southwestern Energy Company; President, CEO
Greg Kerley; Southwestern Energy Company; EVP, CFO

Analysts

Dave Kistler; Simmons & Company International; Analyst
Brian Singer; Goldman Sachs; Analyst
David Heikkinen; Tudor, Pickering, Holt & Co.; Analyst
Amir Arif; Stifel Nicolaus; Analyst
Scott Hanold; RBC Capital Markets; Analyst
Dan McSpirit; BMO Capital Markets; Analyst
Jack Aydin; KeyBanc Capital Markets; Analyst
Marshall Carver; Capital One Southcoast; Analyst

Presentation

Operator: Greetings, and welcome to the Southwestern Energy Company second 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. (Operator instructions) As a reminder, this conference is being recorded. It is now my pleasure to introduce your host, Steve Mueller, President and Chief Executive Officer for Southwestern Energy Company.

Steve Mueller: Thank you and good morning and thanks, all of you for joining us. With me today are Greg Kerley, our CFO, and Brad Sylvester, our Vice President of Investor Relations.

If you have not received a copy of yesterday's press release regarding our second 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 conference 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 sections 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.

To begin, we had a very good second quarter in 2010 and made progress on many fronts. Our operations in the Fayetteville shale are on track, as evidenced by the 32% growth in company production compared to last year and by 9% sequential growth.

The previously announced sale of a portion of our Haynesville and Middle Bossier properties in East Texas closed for approximately \$355 million and finally, because of our improving results in the

Fayetteville, our production guidance is unchanged for the third and fourth quarters of 2010 and our capital investment program also remains unchanged at approximately \$2.1 billion.

Now to talk about each of the operating areas, last week our gross operating productions in the Fayetteville shale exceeded 1.4 Bcf per day, up from about 990 million cubic foot per day a year ago. During the second quarter of 2010 our horizontal wells had an average completed well cost of \$3.1 million per well, average horizontal length of 4,532 feet and an average time to drill to total depth of 13 days from re-entry to re-entry. In the second quarter we had 22 wells with drill times of over 20 days, most of which were first wells in sections that were in the deeper southern areas of the play.

On the flip side, we placed 3 wells on production during the quarter with average times to drill to total depth of five days or less from re-entry to re-entry. In July of 2010 our average time to drill to total depth improved to 10 days from re-entry to re-entry and we set a new record by drilling a well with total footage of 6,600 feet in four days. Because of our recent faster drilling times, we are dropping a horizontal rig in August, reducing our horizontal rig count to 15 rigs in the Fayetteville shale.

Our Fayetteville shale wells placed on production during the second quarter of 2010 averaged initial production rates of 3.449 million cubic foot per day, up 8% compared to the first quarter. Results for the second quarter included 75 wells placed on production which were first wells in the section. We also placed 9 wells on production with initial rates over 6 million cubic feet per day.

We continue to test tighter well spacing and at June 30th had placed over 430 wells on production that have well spacing of 700 feet or less, representing approximately 65-acre spacing or less. Recent information from these larger group of wells indicates interference of 5 to 8% compared to earlier estimates of 10 to 15% from the smaller well set. As you'll recall from last quarter, our 2010 drilling program includes testing over 44 different pilots with well spacing that will range from 200 to 450 feet apart. Within these pilots, approximately 67% of the wells have been spud and 23% of those wells have been placed on production. Because of the small number of wells and the short time on production of the completed wells, no conclusions can be made yet about any new spacing.

Switching to East Texas, as I previously noted, on June 30th we closed the sale of certain oil and gas properties, leases and gathering equipment in Shelby and St. Augustine counties for \$355.8 million. The sale includes only the producing rights to the Haynesville and Middle Bossier shale intervals and approximately 20,000 net acres. We retained the drilling and producing rights covering all depths in the acreage, including our James Lime and Pettet drilling programs.

We still have approximately 10,500 net acres with Haynesville and Middle Bossier potential and drilled 2 wells on this acreage in the second quarter; the Timberstar Blackstone A-1H well targeting the Haynesville shale formation has been drilled and is currently being completed and the Harris B1H well targeting the Middle Bossier shale formation has been drilled and is scheduled to be completed later this year. A third well, the Crest C1H is currently drilling and will be completed in December.

Production from our East Texas properties was 19.2 Bcf during the first six months of 2010 compared to 15.6 Bcf during the same period last year. Approximately 2.1 Bcf of our 2010 production was related to the Haynesville and Middle Bossier properties that were sold in June. Initial production rates from the James Lime wells that were placed on production during the quarter averaged 7.2 Mcf per day and initial

production rates from our Pettet oil wells that were placed on during the quarter averaged 505 barrels of oil per day with less than 1 million a day associated gas.

In our conventional Arkoma Basin program, we participated in drilling three wells and production was 10 Bcf for the first six months of 2010 compared to 11.6 Bcf for the first six months of 2009. One of those wells was the SWN-operated Johns 2-4H3 well in our Midway Field area that was a 2,100-foot horizontal well in the Turner sand. It had initial production rate of 7.2 Mcf per day and we have a 60% interest in the well.

As reported in the first quarter we began drilling with one rig in Pennsylvania and have drilled 4 horizontal wells so far in 2010, all of which are currently scheduled to be completed later in this quarter. We plan to drill about 20 total wells during the year. In addition, the Greenzweig 1H well was placed on production on July 8th and is currently producing 3.3 Mcf a day without compression into the pipeline with just over 3,000 pounds flowing tubing pressure. The Greenzweig well was our first horizontal well and was drilled in late 2008, with a 2,945-foot horizontal lateral and was fracture stimulated with a slickwater frac in seven stages.

We are very encouraged by the early results of this well and look forward to our continued progress in the area as the year goes on. We also believe that Marcellus in Northeast Pennsylvania is rapidly developing into one of the best plays in the country. There are still many challenges from regulatory, logistics and environmental perspectives, but we fully expect those to be worked out over time.

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

Greg Kerley: Good morning. As Steve noted earlier, we had a very good second quarter, fueled by our strong production growth. We reported earnings for the second quarter of \$122 million or \$0.35 a share compared to \$121 million in the same period in 2009. We also reported discretionary cash flow of over \$345 million, up 6% from last year, as our strong production growth more than offset the impact of lower realized gas prices and increased operating costs and expenses.

Operating income for our E&P segment was \$162.5 million for the second quarter compared to \$174.4 million for the same period 2009. The decrease was primarily due to lower realized gas prices combined with increased operating costs and expenses which were only partially offset by our higher production volumes. We realized an average gas price of \$4.27 per Mcf in the second quarter of 2010, down 15% from the prior year period.

Our commodity hedge position increased our average realized gas price by approximately \$0.58 per Mcf in the second quarter and we currently have approximately 87 Bcf of our remaining 2010 projected natural gas production hedged through fixed price swaps or collars at a weighted average floor price of \$6.26 per Mcf. This represents a little over 40% of our expected production in the third and fourth quarters.

During the quarter we also increased our hedge position in 2011 and added some hedges in 2012. We currently have 92 Bcf of our 2011 forecasted gas production hedged at an average floor price of \$5.61 and approximately 80 Bcf of our 2012 forecasted gas production at a floor price \$5.50 per Mcf.

Our lease operating expenses per unit of production were \$0.85 per Mcf during the quarter, up from \$0.73 last year. The increase was primarily due to higher gathering costs and increased water disposal costs associated with our Fayetteville shale play. Higher water volumes, disposal rate increases and the use of more third-party disposal facilities all contributed to the increase during the quarter.

Our general and administrative expenses per unit of production declined to \$0.31 per Mcf in the second quarter, down from \$0.34 last year due to the impact of our increased production volumes. Taxes other than income taxes were \$0.09 in the quarter compared to \$0.08 in the prior year.

Our full cost pool amortization rate declined in the quarter, dropping to \$1.33 per Mcfe from \$1.46 in the prior year, primarily due to lower trending finding and development costs. Our total per unit operating costs and expenses including LOE, G&A, taxes and our full cost pool amortization was \$2.58 per Mcf in the second quarter, down from \$2.61 in the prior year period.

Operating income from our Midstream Services segment increased by 57% to over \$43 million in the second quarter. The increase was primarily due to increased gathering revenues and an increase in margin from our gas marketing activities, both related to our Fayetteville shale play, which were partially offset by increased operating costs and expenses. At July 30th, our Midstream segment was gathering over 1.6 Bcf of natural gas per day through 1,367 miles of gathering lines in the Fayetteville shale play, compared to approximately 1.1 Bcf per day a year ago. Included in our gathered volumes is approximately 170 Mcf per day of third-party gas, which has more than doubled since the beginning of the year.

To update you on the Fayetteville Express Pipeline, they are making very good progress and we currently expect interim service to NGPL as early as October of this year and full service commencing on or about January 1st, 2011. Our initial firm capacity on this pipeline will be 400 Mcf per day as of January 1, 2011, increasing to 1.2 Bcf a day by November of next year.

We invested approximately \$1 billion in the first six months of 2010 compared to \$959 million in the same period last year. At June 30th we had \$506 million borrowed on our billion-dollar credit facility at an average interest rate of 1.2% and had total debt outstanding of \$1.2 billion. This leaves us with a debt-to-book capital ratio of 31% and a debt-to-market capitalization ratio of only 9%. As Steve mentioned, during the second quarter we closed on the sale of a portion of our East Texas properties and have deposited the net proceeds of approximately \$355 million with a qualified intermediary to facilitate potential like-kind exchange transactions.

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

Questions and Answers

Operator: (Operator instructions) Our first question is from the line of Dave Kistler with Simmons & Company.

Dave Kistler: Real quickly, looking at the IP on the 24-hour, 30 and 60-day rates out of the Fayetteville, they up-tick nicely in Q2; can you guys delineate for us what portion of that was due to increases in drilling back in the core versus what portion might be due to just maturing green completions?

Steve Mueller: Well, there's really another component to that, Dave. When you look at our 30 and 60-days you've got to remember that you're not comparing the same wells all the way through there, so it's really not a second quarter issue on at least the 60-day part of it. But in general, compared to the first quarter, we drilled fewer wells on the north and east part of our section and kind of moved back more towards the middle and those were on the acreage capture wells and that's really what drove the increase in the IP portion of it. The drilling in the field, back in the field area, when you look at the IP of those wells quarter-over-quarter they look about the same. So it's really just on the acreage capture side. Now, let me mention, on the acreage capture side, the first half of the year we front-end loaded acreage capture and we'll have about two-thirds of the acreage capture that we're going to do this year in the first half. So you go towards the second half of the year it will look a little different also. And you didn't quite ask this question, but I'll just jump out and say it. As you go towards the second part of the year, third quarter we're doing a lot of what we were doing in the second quarter. As you get into the fourth quarter we're going to be moving back to the northeast and north of the lake. And so, you'll see us capturing some more acreage in the fourth quarter. So it's going to bounce around these next couple of quarters. But most of what you're seeing on the IP and really 30-day is acreage capture. 60 days is really looking more back, well into the second quarter, almost in the first quarter.

Dave Kistler: Great. Thank you. And then, just one quick one on costs. Looking at the LOE creeping a little higher due to increased costs for water disposal, are there any particular measures or things you can do to start bringing that number back to historical levels?

Steve Mueller: Well, let me start with we've actually guided higher than our costs were. So we're pretty happy about the costs where they're at. There is a little bit of cost creep. And when I say cost creep, we mentioned the transportation portion of that. Our midstream contract has a small escalator in it and it's about \$0.02 per Mcf. And so, on a company basis, the sum to the company cost hasn't changed. On the E&P side, there's about \$0.02 was going to our own midstream company. Then on the water handling gathering portion of it, we have a series of wells that we own that we use for injection when we can't reuse the water. Two of those wells this last quarter were giving us some trouble - one, significant issues, and the other one not quite as significant. We're working hard to bring both of those wells back on. If we can get them up and running, then you'll see those costs on the water go down.

Right now, I can't tell you that we can do that though. So as I'm looking out towards the future, I wouldn't assume that we can cut much back near term. Certainly, if these couple wells, we can't get them back, we may have to drill another salt water disposal well down the road. And then, you'll see the costs go down again.

Dave Kistler: Great. Thank you, guys, very much.

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

Brian Singer: Thanks, good morning.

Greg Kerley: Good morning.

Steve Mueller: Good morning, Brian.

Brian Singer: In the Marcellus, can you just talk a little bit more about the visibility of getting kind of frac work done and the timing and potential solutions as you go forward with your program?

Steve Mueller: Well, we had a couple of things that needed to get done before we could even get to the initial production. We had to get a pipeline put to our initial pad. And then, we will be drilling 20-plus wells this year. That's from three different pads and towards the end of the year we'll be in a fourth pad. Sometime during August, we'll have all of those various pads hooked up, so that we can put wells on production. So that was the first thing we needed to do. We've been working on that. We're very close to having that done.

Then on the fracs themselves and lining up fracs, fracing is tough in Pennsylvania. We've got some frac dates set up, so we can get the wells that we have done or we've completed now drilling. But that is a challenge and you're looking out something well past 60 days towards, in some cases, 90 days to catch those frac dates. And we're doing everything we can to pull that up. But that's kind of the way it is that direction.

The other thing that hasn't bothered us much, but could bother us going forward, is that they've had a very dry year in northeast Pennsylvania, and so water has been limited. Fortunately, for us, it started raining here before we've had to start to do some of these fracs going forward. But if it stays dry through the fall, you'll see the entire industry be slowed a little bit down just from the fact that there isn't enough water for all the fracs that the industry wants to do.

Brian Singer: Great. Thank you for the color. And then, secondly, on the midstream services segment, how are you thinking about the strategic nature of that? And is there a point at which as you move forward with the Fayetteville you see the midstream as a candidate for asset sale, or do you see it as a core piece?

Steve Mueller: Well, right now it's core. We've talked about in the past that the reason we have the midstream group is that it strategically lets us get the wells on faster, lets us set up our system the way we want, not just for today, but for long term. And we still have a lot of pipe to lay to actually get all of that done. And to just kind of give you a top side number, last year we laid 1.4 miles of pipe for every well we put on. This year, it was something like 1.8, 1.9 miles of pipe. So we're actually laying a little more pipe this year, because we're up in the northeast and we're pushing down to the south. We've got at least one more year and probably a little bit more than that of just laying in the basic infrastructure, so we can get to our major portions of our acreage. And then, once we get that backbone in we can start talking about whether the midstream is important or not to us. So it's farther out before we start talking about if we'd ever want to get rid of it.

Brian Singer: Great, thank you.

Operator: Thank you. The next question is coming from the line of David Heikkinen with Tudor, Pickering. Please proceed with your question.

David Heikkinen: Good morning, Steve. Just thinking about the Marcellus rig count you might need to keep a frac group committed, can you give us a thought around either number of wells or activity level as you look forward?

Steve Mueller: Well, if you wanted to keep a frac crew, just a single crew committed to your account full time, you need to have somewhere between four and five rigs running. And that's really Marcellus or Fayetteville, whichever. What we're planning to do, we'll keep one rig running this year, and then you'll start seeing us probably scale up, and again this depends on gas price and cash flow and those things, but you'll probably start seeing us scale up next year.

Ultimately, with the acreage the way we have it today, I think we're going to need five or six rigs running. So down the road, we'll certainly have enough rigs running to continue to have a crew working for us full-time. But for the next 18 to 24 months that's probably not going to be the case and we'll have to worry about frac windows. We are trying to use some of the leverage we have in the Fayetteville shale with some of our vendors and trying to put that under some contracts. Don't know if that will work or not, but we're trying to do whatever we can to make sure we've got the crews on time when we need them.

David Heikkinen: Okay. And then, just on the like-kind exchange, how do any acquisitions fit within your current CapEx budget? And thinking about, if you don't execute a like-kind exchange, what is the tax implication on the East Texas sale?

Greg Kerley: Well, David, this is Greg. If we don't have anything that qualifies in that bucket between now and the end of the year, which we will have some things, if you had nothing, we would have about \$45 million of current really alternative minimum tax that we would pay this year. That would be the worst case scenario. But things like acreage positions that we're acquiring in areas clearly qualify, and so we'll be able to mitigate that somewhat.

Steve Mueller: I think the other part of your question was how do acquisitions fit in. Again, we're not in the acquisition business per se. If the right thing would come along that had acreage and maybe had a little bit of production, we might look at that. But that 1031, the first thing we're looking at putting in there is the leases that we're acquiring between now and the end of the year. You've got 180 days to basically close that 1031 account. So anything we're doing in any of the areas that we've got, I can tell you that's going to be in there. And that's why Greg says we know we'll have some. And then, we'll just see what else might happen after that.

David Heikkinen: Yes. I was thinking about acreage acquisitions primarily.

Steve Mueller: Yes.

David Heikkinen: Just kind of how much you had in the back half of the year remaining.

Steve Mueller: We're working hard on putting the list together, not only in the back half of the year, but if we thought we were going to pick up something next year, if we could somehow accelerate that. So that's part of the reason for just keeping the capital budget where it's at. If you think about it, we had mentioned before that in selling the property, I'd say just over \$50 million in East Texas in what we're doing there. But if we can accelerate some of our acreage acquisition and take advantage of some tax things, we'll do that.

David Heikkinen: I was going to segue that into any updates on the new ventures program, but I'm probably not going to get much. But if you have anything that you can illuminate, that would be helpful.

Steve Mueller: We're still picking up acreage on several different plays. In New Brunswick, we have flown gravity magnetics, and we're in the process of going out in the field right now to do surface geo-chem work. All of that is to set us up so we can figure out where to shoot seismic. And we're in the process of permitting field tests where you go out and actually try to pick up a very small piece of seismic to see how easy it is to do the seismic and how you want to design your seismic. We'll be doing that later this year on the field test, and hopefully sometime next year start shooting some seismic early in the year. So we're on track on the New Brunswick portion of it.

David Heikkinen: Thanks, guys.

Operator: Our next question is from the line of Amir Arif with Stifel Nicolaus. Please proceed with your question.

Amir Arif: Thanks. Good morning, guys.

Steve Mueller: Good morning.

Amir Arif: My first question is just on the Marcellus. Can you just give us a sense of what you're thinking of in terms of laterals and number of frac stages on the remaining 15 to 20 wells that you're going to be drilling or completing up there this year?

Steve Mueller: On the four we've drilled, they're all over 4,000 foot. And I don't know where we'll ultimately end up. I know some people are pushing over 5,000 and towards 6,000 foot. But you hold, right now, on our acreage, you hold roughly 640 acres when you drill a well. So they'll be in the 4,000 to 5,000 foot range for wells as we're doing first wells in units. As far as frac stages, I think as we go to frac these you will see us have commensurate stages with what you have seen other people talk about. So it's going to be 10-plus stages. It won't be the seven that we had on the well we have now. So everything we're saying says that what the industry generally is doing is basically what we'll do as well.

Amir Arif: And Steve, just relative to any comments you made about the availability of water. How many of those 20 wells do you think you'll have completed by the end of this year? What are you guys thinking about?

Steve Mueller: Completed? I would say about half of those is what our target is.

Amir Arif: Okay.

Steve Mueller: It may be 12. It certainly won't be 20.

Amir Arif: Okay. And then, the second question just on the cost per well. I mean, it crept up this quarter. Can you just talk a bit about is that due to the 20 wells that just took longer to drill than this other portion, or is that ongoing cost pressures you're just seeing to drill and complete the wells?

Steve Mueller: It is simply those 20 wells. If you compare that to last quarter, we had nine wells that were greater than 20 days. If you factor out the wells greater than 20 days and the various reasons those were in there and just say, okay, take all wells less than 20 days, last quarter and this quarter were almost identical, both in the number of days and the cost of those wells. So it's just a factor that we were

to the southern end of the play with one of our rigs. We were drilling wells that vertical depth were over 6,000 feet, and then putting 5,000 foot laterals on those, and it just had a little bit of extra cost.

Amir Arif: Sounds good. Thanks, guys.

Operator: Thank you. (Operator Instructions.) Our next question is from the line of Scott Hanold with RBC Capital Markets. Please proceed with your question.

Scott Hanold: Thanks. Good morning, guys.

Steve Mueller: Good morning.

Scott Hanold: Can I ask a more direct question on the like-kind exchange? What type of things are you specifically looking at in terms of acreage acquisition? I mean, is there some stuff like in the Fayetteville, I know some of your partners up there are looking to potentially sell some of their stuff. Is that something that would interest you all or are you sort of looking at more of stuff in your new ventures program?

Steve Mueller: Yes. If you're specifically asking are we going to go to Petrohawk's data room, we're not. But what we're putting in there, for instance, in the Fayetteville shale, when we put our units together there is always a little bit of acreage that you have to put together. And if you look at our budget there I don't know what it is - we've got something like \$40 million this year in the Fayetteville shale just putting the acreage together to drill the wells we need to for first wells in section. As much as we can of that will be put in there. In Pennsylvania, any of the white area we have around our acreage that's open, even though they may be small blocks, any of that will go in there. And then, as I said, anything, to any extent that we can accelerate some of the new ventures things, which we're trying to figure out if we can, our new ventures will go in there as well..

Scott Hanold: Okay, good. I appreciate the direct answer on that. That made it pretty clear. And in the Marcellus, on that well that was producing at 3.3 million a day, I'm sorry if I missed it. Did you give what the 24-hour IP rate was on that well?

Steve Mueller: I did not. And I don't know if I've got that right now, to tell you the truth.

Scott Hanold: Okay, that's fine.

Steve Mueller: I mean, that would have been a 24-hour rate that we gave you. But I assume you're talking about a 30-day rate or some other rate.

Scott Hanold: Well, I think that you said it's currently producing 3.3 million a day. Is that right?

Steve Mueller: Well, it's been 3.3 million a day since day one because it went straight into 3,000 pounds.

Scott Hanold: Okay.

Steve Mueller: I mean, it's been between 3 and 3.3 million a day this entire time.

Scott Hanold: Okay.

Steve Mueller: And again, that 3,000 pounds is important. Most companies when they're giving you rates, maybe 1,000 pounds, but certainly it's usually even less than 1,000 pounds because you have compression. We'll have compression in a couple weeks, and that rate's actually going to go up then.

Scott Hanold: Okay. Okay. I appreciate that. And one last question. On the pace of completions in the Fayetteville, you guys, it looks like, I think set a record at 143 wells. What is the pace of completions going to look like in the back half of the year? What's sort of your backlog at this point relative to what it has been in the past?

Steve Mueller: Well, if you remember, at the end of the quarter we were trying to catch up and we put 50 wells on in April. But from here forward and today, we've got a backlog of about 30 wells. We'll have about a 30 well backlog and we'll be drilling 120 to 130 wells a quarter. So you'll just kind of see a roll. But I think we're back to what we were, around 30 wells any point in time backlog.

Scott Hanold: Got it. Appreciate it, guys. Thanks.

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

Dan McSpirit: Thank you, gentlemen. Good morning, and thank you for taking my questions. We've observed many of your peers chase the oil and liquids-rich stories. Some have been early. Most have been late. We haven't seen Southwestern pursue the same conversion, if you will.

I guess my question is why? Or does that non-natural gas potential or diversification lie within the Maritimes Basin or what you may be working on within the new ventures group?

Steve Mueller: Well, we're not opposed to oil. And to the extent that we had a play that had some kind of liquids with it, we're not opposed to that either. We just want to look for whatever's economic. And we haven't - whenever you think about it, you're always looking out on new plays three to five years. And we don't really know how to predict what the price of either product's going to be. So we just look for good plays.

I can tell you that some of our new ventures, and you mentioned New Brunswick, New Brunswick could have both an oil and gas window in it. So it certainly could have some liquids with it. Some of the other new ventures plays we're looking at are oily plays. But it wasn't because we said, go look for oily plays. It was just that some of them fall into that category. All of them are economic or should be economic under reasonable price scenarios.

The only thing that we do differently is today if you've got an oil play and a gas play that's in a new ventures group, for instance, and everything's equal on them, you're going to try and get to the oil play faster than the gas play. But that's the most we do as far as a strategic. We're just going to look for the best projects. We're going to make sure that we get a PVI that we want to get on those projects, and then we'll drill whatever we've got.

Dan McSpirit: Got it. Thank you. And one more, if I could. The regulatory pendulum has swung pretty far in one direction in the Marcellus, particularly in the state of Pennsylvania to the point where it's become maybe a bit of an overhang. Do you fear it becomes a hangover, a headache, if you will? And would that ever prompt you to monetize your position where you may recycle those proceeds into the Fayetteville or even a Maritimes Basin potential?

Steve Mueller: Well, you said is it going to get to be a headache. I can tell you it's a headache right now from that standpoint. But one of the things we've always said is if an area doesn't want us, we don't plan to be there. What we can tell from Pennsylvania is they want the industry, ultimately. They've got a lot of things they have to sort out. As long as we believe that they want us, we'll be happy to be there and we'll keep working that direction and go with it. If we come to the conclusion that they don't want us, then we're not going to be there as a company and we'll figure out a way, whether it's sale or bring in somebody that drills for us or something, where we don't have to operate there.

So right now we think it is going to get better rather than worse. We think that's going to take some time to do that. That's one of the reasons we're only running one rig besides just kind of working within our cash flow. But we don't want to jump out there and put a bunch of rigs to work and then have this thing crash around us either. So we're taking it cautious, being flexible with it. We'll watch it. If it gets worse, we'll respond. If it gets better, we'll respond that way as well.

Dan McSpirit: Thank you for your thoughts.

Operator: Our next question is from the line of Jack Aydin of KeyBanc Capital Markets. Please proceed with your question.

Jack Aydin: Hi, guys.

Steve Mueller: Hi, Jack.

Greg Kerley: How's it going, Jack?

Jack Aydin: Over the 120 to 150 wells you're drilling per quarter, how many of those to capture the acreage, to hold the acreage?

Steve Mueller: For the next couple of quarters, I would say in any quarter 30 to 40, roughly, a quarter.

Jack Aydin: Okay. Now

Steve Mueller: Give or take.

Jack Aydin: Go ahead.

Steve Mueller: No, that's it.

Jack Aydin: Okay. Now, looking forward for 2011, how many rigs do you need in order to maintain in a way keep your program going?

Steve Mueller: Well, I'm not sure exactly what keep your program going means, though.

Jack Aydin: Well, in a way to keep the - I know you haven't set the budget for 2011. I'm just trying to see what kind of budget you might be thinking about in 2011 and how many rigs you need to maintain, to carry that budget.

Steve Mueller: Let me kind of answer two pieces of that. As far as the budget for 2011, we're going to build a budget that has minimum borrowings on it, may have a little bit of borrowings, but basically try to stay within cash flow. That will probably be, without looking and having done a 2011 budget yet, it's probably going to be around what we've got this year, give or take, \$2 billion.

Then when you start talking about Fayetteville Shale exactly, and I think you're trying to get to growth rates in Fayetteville Shale, if you looked over the last three years, we've roughly drilled the same number of wells the last three years. Two years ago we had a 76% increase in production, 50 - I think it was 55 or something last year. We're talking about 32% this year. If you just keep that same number of wells per year out there, that number drops in the 26%, 27% range next year. And you can see from progression it just kind works its way about. About five years from now, you're in the 8% to 10% range, just keeping the same number of rigs running.

So if that's all we do, that's kind of the program for increase in production each year.

Jack Aydin: Thank you.

Operator: Thank you. Our next question is from the line of Marshall Carver of Capital One Southcoast. Please proceed with your question.

Marshall Carver: Yes. On the dry weather in northeast PA, are you thinking that it's just going to be more expensive to get water or that you wouldn't be able to frac wells at all because you couldn't get permits and things like that?

Steve Mueller: Well, the way it works, at least for us, and different companies, and it depends on where you're at in Pennsylvania, how you're getting your water. But we have permits to take the water out of certain streams and rivers in Pennsylvania.

With the dry weather, what they did was come in and say, okay, take your permit and cut it by this amount. And so they just cut how much you could take out of the various streams. Which we've built a couple of holding ponds, and the whole concept is we pull water out of the streams, filled the holding ponds, and those holding ponds would be used to frac wells, and we kind of get ahead of the game.

Well, to the extent that you've got holding ponds and you can stay up with the number of permits, it doesn't slow you down at all. But that's the trick. I mean, that's the game you're playing. In our case, we thought we had plenty of water that we wouldn't have to really even worry about the holding ponds. And now we're having to make sure we've got the holding ponds full before we go fracing the wells.

So I think each company's going to have a little bit different issue. But, in general, in at least the northeastern portion of Pennsylvania, they significantly restricted each permit, and it's just across the board. They'll tell this stream, everyone who's got a permit on this stream or everyone who's got a permit

on this river, take whatever number you had before and cut it by this percent, and that's how much you can take out a day or that's how much you can take out a week.

Marshall Carver: Okay. That's very helpful. And one follow-up on that. Is that just how widespread is that? Is that just Susquehanna or do you know?-

Steve Mueller: Well, I don't know. I really don't know. I know that in the Bradford Susquehanna areas that we're working it's there, but I really don't know about the weather in the rest of the other part of the state or how the various companies are getting their water.

Marshall Carver: Okay. Thank you very much.

Operator: Thank you. 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.

Steve Mueller: Thank you. We're excited and pleased about what's going on. We've made a lot of progress this quarter. And when you think about it, Fayetteville Shale continues to perform. We're continuing to learn there. We've still got a lot to learn. We've got our first production in Pennsylvania - we're excited about that.

And then when you look at the bigger picture, we just talked about the water, there are other issues out there. And we know we've got a lot of work to do, both on the technical side and then gas price is still a challenge and it continues to be volatile. We will take advantage of those hedging opportunities that we've already done in 2010 and done in 2011, 2012. We'll continue to try to find the right places for us to add more hedges so that we can get rid of some of that volatility and we can lock in better what we're doing in the future.

And then when you look at going forward, we've talked about the various areas. We talked a little bit about new ventures. But keep in mind; we'll continue to build Fayetteville. We'll use our east Texas and Pennsylvania as jumping points to continue to grow, but also to kind of fill in down the road two to three years. And then five years down the road we've got our new venture.

So we think we're on track on all three areas, immediate near term, the middle term, and then the longer term. And so we're just excited about what's going on in the quarter. We wish gas price was higher.

And with that, I thank you and look forward to a good third quarter.

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

Explanation and Reconciliation of Non-GAAP Financial Measures

We report our financial results in accordance with accounting principles generally accepted in the United States of America ("GAAP"). However, management believes certain non-GAAP performance measures may provide users of this financial information with additional meaningful comparisons between current results and the results of our peers and of prior periods.

One such non-GAAP financial measure is net cash provided by operating activities before changes in operating assets and liabilities. Management presents this measure because (i) it is accepted as an indicator of an oil and gas exploration and production company's ability to internally fund exploration and development activities and to service or incur additional debt, (ii) changes in operating assets and liabilities relate to the timing of cash receipts and disbursements which the company may not control and (iii) changes in operating assets and liabilities may not relate to the period in which the operating activities occurred. See the reconciliation below of GAAP net cash provided by operating activities to non-GAAP net cash provided by operating activities before changes in operating assets and liabilities for the three months ended June 30, 2010 and June 30, 2009.

Non-GAAP financial measures should not be considered in isolation or as a substitute for the Company's reported results prepared in accordance with GAAP.

	3 Months Ended June 30,	
	2010	2009
	(in thousands)	
Cash flow from operating activities:		
Net cash provided by operating activities	\$ 391,474	\$ 266,436
Add back (deduct):		
Change in operating assets and liabilities	<u>(45,744)</u>	<u>58,860</u>
Net cash provided by operating activities before changes in operating assets and liabilities	<u>\$ 345,730</u>	<u>\$ 325,296</u>