Southwestern Energy Q2 2005 Earnings Conference Call

C: Harold Korell; SWN; President, Chairman & CEO
C: Richard Lane; SWN; EVP of Exploration and Production
C: Greg Kerley; SWN; CFO
P: Joe Allman; RBC Capital Markets; Analyst
P: Michael Bodino; Sterne, Agee & Leach; Analyst
P: Ryan Zorn; Simmons & Company; Analyst
P: Travis Anderson; Gilbert, Gagnon & Howell; Analyst
P: Robert Christensen; Buckingham Research; Analyst
P: Kevin Kelley; J.M. Hartwell & Co.; Analyst
P: Amir Arif; Friedman, Billings, Ramsey; Analyst
P: Laurance Narbut; Passport Capital; Analyst
P: Van Levy; Dahlman Rose; Analyst

Operator: Good day, and welcome to the Southwestern Energy Company second quarter 2005 earnings conference. At this time I would like to turn the conference over to the President, Chairman and CEO, Mr. Harold Korell. Please go ahead.

Harold Korell: Good morning, and thank you for joining us. With me today are Richard Lane, our Executive VP of our E&P Company, and Greg Kerley, our Chief Financial Officer. If you have not received a copy of the press releases we announced yesterday, you can call Annie at 281-618-4784, and she will fax a copy to you.

Also, I would like to point out that many of the comments during this teleconference may be regarded as forward-looking statements that involve risk factors and uncertainties that are detailed in our Securities and Exchange Commission filings. We also would warn you that these forward-looking statements are subject to risks and uncertainties, many of which are beyond our control. Although we believe the expectations expressed are based on reasonable assumptions, they're not guarantees of future performance and actual results or developments may differ materially.

Well, to begin with, things have gone pretty well for us during the first six months of 2005. Yesterday we reported earnings for the second quarter, of a record $26.8 million, up 29% from the same period last year. Our cash flow for the second quarter was also up 29% from a year ago, to a record $65.1 million.

These results have been primarily driven by the current commodity price environment, and by the strong growth in our production volumes.

In our E&P program we continue to have excellent drilling results at our Overton Field in East Texas and the Ranger Anticline in the Arkoma Basin. In the Fayetteville Shale Play we have made progress in our understanding of horizontal wells, established production in six pilot areas, are now drilling in a 7th pilot and are completing a well in the 8th pilot area. In addition, we have obtained field rules for 3 fields in total and are now producing at a gross daily rate of approximately 10 million cubic feet per day.

As we announced yesterday, we are preparing to accelerate our drilling program in the Fayetteville Shale. In addition to the purchase of new drilling rigs for the Play, we have increased our capital program for the Fayetteville Shale from approximately $100 million to $127 million for 2005, to fund our growing program and to continue our leasing efforts.

We now plan to drill 80 to 90 wells in 2005 in the Fayetteville Shale Play, with approximately 50 of these wells being horizontal. We also plan to increase our drilling activity at Overton, our other East Texas areas, at the Ranger Anticline and in the Permian Basin.

Richard will talk more about the capital plan and give an update on our E&P operations in a moment.

Overall, I'm very pleased with what we've accomplished to date and look forward to what lies ahead for us in 2005 and beyond. I will now turn the teleconference over to Richard Lane, who will tell you more about our E&P results and then to Greg Kerley, to discuss our financial results and then we'll answer questions.

Richard Lane: Thank you, Harold, and good morning. Production for the second quarter was 15 Bcfe, up 19% from the 12.6 we produced in the second quarter of 2004 and up 7% from the 14 we produced in the first quarter of this year. Of the 15 Bcfe of second quarter production, 6.5 was from East Texas; 5.2 from our conventional Arkoma Basin properties; 1.8 from the Permian Basin; 1.1 from the Gulf Coast; and 0.4 from our Fayetteville Shale Play.

Production during the second quarter of 2005 included the continued effects of curtailment of production at our Overton field. This curtailment issue was resolved late in the quarter and current gross production from Overton is approximately 100 million cubic feet per day, as compared to about 80 to 90 million cubic feet per day while we were being curtailed.

We continue to be very active in East Texas and in the Arkoma Basin, particularly in our Ranger Anticline field and our Fayetteville Shale Play.

Year to date we have spudded a total of 119 wells, including 43 wells in East Texas; 22 wells at Ranger; and 30 wells in our Fayetteville Shale Play. We currently have 6 rigs running in East Texas; 4 at Ranger; and 3 in the Fayetteville Shale; and expect to increase our Fayetteville Shale rig count through the remainder of the year.

As a result of strong E&P revenues and our inventory of high PVI drilling projects, we have increased our E&P 2005 capital budget from $339 million to $425 million. This $86 million increase includes $27 million for additional drilling and land in the Fayetteville Shale Play; $15.5 million for East Texas drilling; $5.6 million for Ranger Anticline; and $4.2 million for the Permian Basin. The remaining $33.8 million is for the purchase of 5 new land drilling rigs plus associated equipment, that we announced at the beginning of July.

Moving to our Shale Play. In the first half of 2005, we invested approximately $55.3 million in the Play, including $33.3 million to drill 30 wells and $19.1 million for lease hold acquisitions.

As of June 30th, we held approximately 690,000 net acres in the undeveloped Play area. In addition, we control approximately 125,000 net developed acres in the traditional Fairway area of the Basin.

Since beginning our drilling program in the Fayetteville Shale in 2004, we have drilled a total of 50 wells and participated in one outside operated well. The wells are located in 8 separate pilot areas, located in Franklin, Conway, Van Buren, Cleburne and Faulkner Counties, in Arkansas.

In an East-West direction, we have drilled wells and established production approximately 40 miles apart and in a North-South direction, 15 miles apart.

Of the 51 wells; 41 are producing; 6 are in some stage of completion or waiting on pipeline hookup; and 4 are shut in due to marginal performance. To date, we have drilled 9 horizontal wells in four separate pilot areas. Of the 9 horizontal wells; 7 have been completed and 2 are waiting on completion.

Since our last press release on June 28th, the Koone #2-34 horizontal well, located in our Gravel Hill field, was placed on production at approximately 1.7 million cubic feet per day. In addition, the Hall #1-12 horizontal well, located in our Brookie pilot area, was production tested last week at 2.8 million cubic feet per day, and the Black #2-17 horizontal well in our Scotland field recently tested at 2.9 million cubic feet per day.

The initial test rates for the completed horizontal wells has ranged from 1.4 to 3.7 million cubic feet per day, excluding our Vaughan #4-22 well, where we encountered well bore problems and had a limited stimulation treatment.

Two of these wells, the Stobaugh #2-1 and the McNew #3-2, which have been on production for more than 30 days, have an average first month production rate of 2.2 million cubic feet per day. Based on these production histories and our modeling work, we believe the average ultimate production from these horizontal wells will be between 1.3 and 1.7 Bcfe per well. We expect our year-end reserve assessment for our horizontal wells to be composed of both proved and probable reserves, as we have limited production histories for these wells.

Our first 9 horizontal wells have, on average, taken 15 days to reach total depth and our most recent well costs have been between $1.4 and $1.8 million per well, excluding non-recurring costs.

In June of 2005, the Arkansas Oil and Gas Commission approved rules for our Gravel Hill and Scotland fields in our Fayetteville Shale Play area that provide for 560 feet minimum distance between completions in common sources of supply and up to a maximum of 25 wells per section.

To ensure adequate rig availability for our development plan here, we entered into a sales agreement in early July with a private company to build 5 new land rigs capable of drilling both vertical and horizontal wells in the Fayetteville Shale. These new rigs have design features that are optimal for drilling in our play.

The first rig is expected to be completed in November, with one additional rig delivered per month after that.

Our Fayetteville Shale activity in the third quarter will include drilling additional horizontal and vertical wells, some seismic acquisition and testing of additional new areas of our acreage. For all of 2005, we expect to drill 80 to 90 wells, with our remaining 2005 program, with approximately 50 being horizontal.

At the Ranger Anticline, as I have mentioned previously, we spudded 22 wells in the Ranger area in the first half of 2005. All of these wells are either productive or currently being tested. The Ranger Anticline, located in Yell and Logan Counties Arkansas, produces from the Borum sands, between 5,500 and 8,500 feet.

Of the 22 wells, 15 are located in the core producing area of the field; 4 are located in the Western expansion area we began developing last year; and 3 are in an Eastern expansion area, 9 miles from the proven productive part of the field.

The 3 wells we drilled in the Eastern expansion area have penetrated pay in the Basham and Turner sands at about 3,500 feet. We are currently obtaining rights of way and beginning construction of a pipeline to bring these wells on production.

Additionally, we participated in an outside-operated test between the core area and this Eastern expansion area and this well penetrated the Borum sands and is now being tested.

Due to our continued success here, we now plan to drill 50 wells in the Ranger Anticline area for 2005, up from the original forecast of 43 wells.

Moving to East Texas, in the first half of 2005, we invested approximately $81.7 million. We continue to be pleased with results of our development drilling program at our Overton field, located in Smith County, Texas.

In the first half of 2005, we spudded 36 wells at Overton and have maintained our 100% success rate. We have now drilled 209 wells since we acquired the field in 2000. As mentioned earlier, our production at Overton is no longer being curtailed. Gross production is approximately 100 million cubic feet per day, up from the 80 to 90 million cubic feet per day during the curtailment.

In addition to our Overton field, we continue to be active in other areas in East Texas. At our Angelina River Trend, we have acquired a total of 12,800 net undeveloped acres in 4 development areas, located primarily in southern Nacogdoches County. To date, in 2005, we have drilled 4 wells in this Trend and 2 of which have production tested over 4 million cubic feet per day. And we expect to drill 5 more by the end of the year. And we're hopeful that this area will continue to grow for us as well.

In summary, we are encouraged by our results at Overton, at Ranger Anticline and our Fayetteville Shale Play. We are well on track to achieve the 13 to 16% organically driven production growth for the year, by continuing to invest in our high PVI projects.

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

Greg Kerley: Thank you, Richard, and good morning. As Harold indicated, we reported strong results for the second quarter, primarily fueled by our production growth and higher realized commodity prices.

Earnings for the first quarter were a record $26.8 million, or $0.36 per share, up 29% from the second quarter of 2004. Cash flow provided by operating activities before changes in our operating assets and liabilities, also set a new record for the second quarter, at $65.1 million, up from $50.3 million for the prior year period.

The improved operating income of our Exploration and Production business drove our record results, as our natural gas distribution business generated a seasonal operating loss for the second quarter. Operating income for our E&P segment was $48.6 million for the second quarter, up 30%, from $37.5 million for the same period last year, primarily due to the general increase in natural gas and crude oil commodity prices and the growth in our production volumes.

We realized an average gas price of $5.71 per Mcf for the second quarter of 2005, up from $5.25 per Mcf for the same period last year. Our hedging activities decreased our average gas price realized during the quarter by $0.75 per Mcf, compared to a decrease of $0.57 per Mcf for the same period in 2004.

Disregarding the impact of hedges, the average price we see for our gas production during the second quarter was approximately $0.27 lower than average NYMEX spot prices, compared to approximately $0.17 lower in the second quarter of 2004. This change was due to widening locational market differentials that have occurred since the prior year period.

The Company currently estimates that its average realized market differentials for the third quarter of 2005 will range between $0.25 to $0.30 per Mcf. We have approximately 75% of our targeted gas production hedged in 2005, and our current hedge position is detailed in our Form 10-Q that we filed yesterday.

Leased operating expenses for per unit of production were $0.43 per Mcf in the second quarter of 2005, compared to $0.39 for the same period in 2004. The increase was due primarily to increased compression costs and higher oilfield service costs.

Our general and administrative expenses per unit of production were $0.39 in the second quarter of 2005, compared to $0.35 in the second quarter of 2004. And that increase was primarily due to increased compensation associated with our increased staffing levels.

Our full cost pool amortization rate rose to $1.38 per Mcf, compared to $1.18 a year ago, primarily due to increased finding and development costs. We currently expect our full cost pool amortization to average between $1.40 and $1.45 per Mcf equivalent for 2005.

Our utility systems realized a seasonal operating loss of $2.4 million in the second quarter of 2005, compared to a loss of $1.4 million for the same period last year. The decrease in operating income resulted primarily from higher operating costs and expenses. Operating income for our gas marketing activities was $900,000 during the second quarter, which was up slightly from the second quarter of 2004.

Our capital investments for the first six months of 2005, totaled $186.7 million, which included $181.5 million for our Exploration and Production business. As we announced yesterday, we've increased our capital program for 2005 from approximately $353 million, to $438.8 million, which includes the rig commitment that we announced earlier this month and approximately $52 million, primarily used to fund additional drilling in our core operating areas.

We are currently forecasting operating cash flow for 2005 of approximately $290 to $300 million, assuming that NYMEX gas prices were to average $7 per Mcf for the year. We expect to fund the balance of our capital investment program from borrowings under our revolving credit facility and/or proceeds from any debt or equity offerings we might pursue.

We filed a new shelf registration statement with the Securities and Exchange Commission yesterday which will allow the Company to sell up to an aggregate $600 million of debt securities or common stock. The new registration statement will replace a shelf that was filed approximately three years ago. The registration statement, combined with our revolving credit facility, which currently has approximately $400 million of available capacity, will provide us with a great deal of flexibility in funding our capital program going forward.

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

Joe Allman: I guess this is for Richard. Richard, could you comment on the Jackfork drilling you were doing in Arkansas and also the Rocky Mountain drilling if there's anything going on there? And then any comments on any new ventures you've got beyond what you've talked about?

And then the follow-up is, in the Fayetteville Shale, beyond the 5 rigs that you're having built, any other plans to increase the rig count there and can you describe those plans?

Richard Lane: Okay. On our Jackfork play, we have a pretty sizeable acreage block that we put together in Arkansas. And we've drilled one test well there, about an 11,000 foot well. We did encounter some--the short answer is--we didn't find what we were after there, but we did encounter some sands in the Jackfork and a little bit of pay in there. And so we're kind of encouraged that it's a large structure. It looks like maybe it had some gas in the system. But it's going to take some more drilling to prove up something commercial.

In the Rockies, probably the next thing in the queue there is our Round Mountain prospect. And we think we'll spud that in August or September. And that is primarily a Madison test, about 12,000 feet. And a good looking prospect. I think it has about 50 Bcf of potential.

On other new things, we certainly are working on some new things. We have a team of people dedicated to that. And probably don't want to comment yet on that, because it's not a good time to be doing that. But we are certainly working on new things.

For the rigs, for our Fayetteville Shale Play, just to kind of reiterate, we have 3 running right now. We're looking to add to that fleet as we go through the end of the year. And then of course, we have the 5 new ones coming. You heard the schedule for that, the first one in November and then one after that. So, the ultimate amount that we have for 2006 is kind of subject to the plan that we formalize, which is not formalized yet. So, I think we'll probably provide those details when we come out with our '06 plan, but we're pretty positive on what's happening out there.

Michael Bodino: Congratulations on a nice quarter, guys. A couple of quick questions to follow up. Joe hit a couple of them. But relative to the Ranger Anticline, could you expand your thoughts on how the inventory of locations has continued to grow there?

Richard Lane: If you think about what's happened there development wise and some of the more step-out tests, between what we've done to the West with a pretty big step-out and what we've done here with this newer Eastern area, which, as I said in my comments, is about 9 miles away from HBP and we have a significant amount of acreage there. We're over 50,000 acres total in the play. And so I think those activities to the West and the East are very encouraging for possibility of more drilling and then the down-spacing we're doing in the HBP area seems to be going okay.

We've talked about 130 to 140 other wells past our '05 plan and these activities are very positive towards that or maybe something better.

Harold Korell: I think that, a little bit of additive to that, you recall we started drilling at the Ranger Anticline about 6 years ago. It was an idea that we had that we went out and began testing. It was one of the seeds we planted then. And by the end of '04 we had drilled, I guess about 45, 43, 44 wells there. This year we'll drill another 50, so we're going to be sitting at about 90. And then, as Richard said, maybe there are another 130 or so that we could see. That number can vary a lot. It's totally dependent upon the results as we extend into new areas. But at this point, it's looking better, not poorer.

Michael Bodino: Okay. My follow-up question, relative to the Nacogdoches County drilling, could you expand on the play a little bit? Is this Travis Peak? Are you looking at other horizons? Can you give more details on it?

Richard Lane: It's Travis Peak and Cotton Valley, Mike. More of it I think is Travis Peak than Cotton Valley. We have a nice block there. It's not a contiguous block of 13,000 acres, but it's a pretty solid piece of acreage there. And the drilling we've done is pretty encouraging. We had our Reavley well that really started that right at the end of last year and it was about 4.4 million a day and we've offset that with a well we call the Isaacs and it tested real well, production holding up nicely. And a couple of other tests that are really designed to prove-up the Travis Peak and Cotton Valley.

Ryan Zorn: I wondered if you could give us an idea of which areas you might go to field rules and when that might be in terms of hearings?

Richard Lane: I believe our next hearing that will be for field rules will be in September. And I believe that's for our Brookie pilot area. And of course, we're in front of the Oil and Gas Commission monthly for the integrations and other things.

Ryan Zorn: Okay. And Harold, did I hear you correct--or maybe it was Richard that gave the stat, the 40 miles East and West and 15 miles North and South in the Fayetteville. Were those wells that you have initiated or is that where you've established production--established those end points?

Richard Lane: Those are areas where we are either producing or have tested gas. There's a little bit of difference between testing and actually flowing in the pipeline, but we would call it where we've established production. And that does not include--that geometry that we detailed there does not include wells a considerable distance to the West in our Fairway area, where we also have established production.

Ryan Zorn: Okay, but I guess for the 7th and 8th pilots, those would be inclusive in that area?

Richard Lane: Well, there's one pilot that we're currently drilling on that would be in the count of 8 that would not be in those mileage figures.

Harold Korell: In other words, the 8th one would be in a further extension.

Richard Lane: The 8th one is about another 10-mile extension from those numbers.

Ryan Zorn: Okay. So, can you say which way, East-West, North-South?

Richard Lane: Yes, it's East.

Travis Anderson: I was wondering if you could tell us, on the 41 horizontal wells you're planning to drill--.

Harold Korell: Travis, we can't hear you here.

Travis Anderson: Sorry. Is that better? Of the 41 wells you're planning to drill in the Fayetteville in the second half, the horizontal wells, how many of them are going to be in these 7 or 8 field areas, as opposed to new areas?

Richard Lane: Predominantly they will be in one of these 8 pilot areas that we've discussed. We start out new pilot areas with vertical wells. But I can't say for sure that we wouldn't be at the point where we're following up on new pilot areas late in the year with the horizontal wells.

The bulk of them would be in our existing pilots, but we would be looking to be opening up new pilots with vertical wells this year and then maybe getting to a couple of horizontals in those.

Travis Anderson: Okay. And if all these new rigs are additive, that implies that potentially on next year's plan you could be drilling north of 100 horizontal wells? [Inaudible]

Richard Lane: Well, we have the 3 existing rigs and the 5 coming are 8 rigs. We're not locked in that that is our plan. We're heading towards being able to do a horizontal well, say every 20 to 24-days, something like that. So you can kind of do the math on it. But we're not locked at those 8 rigs.

Robert Christensen: A couple of questions. The Stobaugh well came on at 3.7. The last update was 2.3, but that was back June 10th. What is the Stobaugh at right now, may I ask?

Richard Lane: Let's see, I think the current production on it is probably somewhere around 1.5 to 1.6 million a day, something like that.

Robert Christensen: And then the McNew, where is that at right now? That's the other one that you had put on for 30 days.

Richard Lane: I don't have that in front of me.

Robert Christensen: Okay. The extended reach capability of the new rigs, I mean, the older rigs without top drives only get you about 2,000 feet, as I understand it. What is the extended reach capability of the equipment you've ordered?

Richard Lane: Well, on paper, the design says they'll do 4,500 feet of lateral. So, we like that ability.

Kevin Kelley: You guys have shown some success in bringing down drilling costs in Fayetteville. What do you perceive, I guess going forward, your ability to continue to drive down cost there?

And I also wanted to get an understanding of your ability maybe to down-space within Fayetteville?

Richard Lane: If you look at the whole evolution of the drilling costs out there, and I think your question is focusing on the horizontals, we started out with a conservative design and had wells over $2 million. And then that has been coming down. Our current AFEs, if you look at them in the last couple of wells were more in the $1.4 to $1.8 range. We're still doing some science out there and we're still learning. And certainly, we would say that the equipment that we're using out there right now, we are not happy with the performance of it. And we think we could improve the cost pretty significantly just with better equipment. That's part of what the new rigs are for.

And then there's just the learning curve on the design and the performance ourselves. I don't want to tell you long-term where we'll get that number to. I will tell you that we have a history of driving them down when we have high well-count projects.

Harold Korell: I think the caveat to that has to do with the pricing we're seeing in the rig market today. So, for rigs that we are contracting that other people own, we're faced with upward pressure, obviously, upward pressure and rig companies also wanting to term-up equipment for longer periods of time. In some cases the equipment is inferior equipment and crews are not such a good thing. So, that impacts our ability within that cycle as well.

But engineering wise, I think we're going to be making improvements and we hope that these rigs that we're buying, which are designed for this kind of drilling, are going to give us an efficiency improvement also.

The other part of the cost of the wells, aside from drilling rigs, has to do with the frac'ing, stimulation, which is a big part of the cost. And we're continuing to learn and try to make improvements, cost savings relative to the time as required to carry on these multiple stage frac jobs and working with the vendors who provide that service. And we're making some progress there. So, I think that's another area that we hope to improve in.

Kevin Kelley: Great. And what do you see as your ability to down-space within Fayetteville?

Richard Lane: Well, the data that we've put out there and the modeling we've done and the performance of the wells and all those things rolled up, it's early in the play, but we're kind of looking at that we should be able to do something like about 8 horizontals within a 640. But that is preliminary. We have filed testimony that our vertical wells could be 20 acres or less and that our horizontal wells are 45 to 60 acres. And then you have, in the field rules, where we have offset requirements between wells, all that has to be taken into account. But right now, we're thinking 8 or 9 per 640 and then that can change based on how we situate the wells, using multiple pads or longer horizontals and things like that.

Harold Korell: And as well, the performance of these wells. I think that everyone should be aware, as we mentioned in the comments earlier, that the longest well that we have on production that's a horizontal well, what's the numbers? Probably in the 40--the horizontal, the longest one that we have on for 80 days now. So, we have 80 days worth of production history on the first horizontal that we drilled.

So, discussions about spacing, ultimately are discussions about what area does a well drain and what area a well drains is going to be dependent upon how the production curve looks and the cumulative production under that, relative to the gas in place. So, we don't have all the answers about that. So any answers we're giving and any testimony that we've made in the Commission is our best estimate, based on short production histories.

I know it's not a black line in the sand--black and white kind of answer, but you all need to understand that these are estimates and there are uncertainties involved in them.

Amir Arif: Based on your recent vertical drilling that you've released over the last couple of releases, it seems to indicate that you're trying to get some better rates as you go out East. I was wondering if you're doing anything to try to capture that productivity on the horizontals yet or are you waiting until the new horizontal rigs come in, in terms of larger fracs or longer lengths?

Richard Lane: I guess what you're alluding to is that you've seen some higher test rate verticals in the last couple of reporting periods. And I think we'll see that throughout the play, that there are some areas that are going to have higher deliverability. And then when you're talking about the total averages for all the verticals and comparing them to these newer higher tested verticals, you will recall that the Griffin Mountain area, where we had the greatest amount of verticals, is probably not our best area. So that pulls the average down some. And then when you contrast that just with a few higher rate verticals, that's giving you the contrast there.

Amir Arif: Yes, but what I was alluding to was, is the high vertical rates that you're seeing sort of indicate maybe potentially better reservoir characteristics, whether it's thickness or flow rates. So I was wondering whether you're trying to capture that right now with the horizontal wells or whether you're just limited in terms of the horizontal length you can drill right now with the size of the fracs that you're doing or you're just not changing those factors?

Richard Lane: I would say that the current rigs running out there are not a limiting factor in the context you put it. We're learning from both and we're using the same kind of technology in frac'ing a vertical. In a horizontal, the horizontal we just have a lot more stages of it. Certainly, from the very earliest vertical wells to these, we have refined our completion techniques.

Amir Arif: And then I guess just a final follow-up question on what the rates that you're--are you doing anything different on the horizontals, let me just put it that way? Or can you tell us what kind of techniques you're seeing out there, has that been changing?

Richard Lane: Is your question about doing anything different, you mean in regard to the frac job in the horizontals versus the verticals or are we doing--?

Amir Arif: I'm just trying to get a sense of whether the reservoir characteristics are improving, and whether it's the thickness or the flow rates. And then also, are you doing anything to try to capture that? Are you adjusting any of the perimeters on the horizontal completion techniques right now?

Harold Korell: Well, Amir, in general, within that what we have been calling unproven acreage, which is now some becoming proven, but out to the East where we'll be doing most of this drilling, in the non-Fairway area, in other words, most of that area, the gross thickness of the shale is kind of similar. It's above 200 feet. Maybe all that isn't contributing, but in terms of the shale thickness it's similar.

There is probably some difference in the rock characteristics, being either maybe some natural fracturing in areas, maybe differences in mineralogy in some of those areas, structural differences in areas, that Griffin Mountain area, where we really haven't had quite as good a wells, is faulted up more than some of the other areas. So, that could be a difference.

On the frac stimulations, generally speaking, as Richard said, the frac jobs we're doing on the horizontals are similar to the ones we're doing on the verticals, except for we're doing multiple stages. Because in a 2,000 foot lateral, we'll perforate, frac, set a plug, back up the hole, perforate, frac, set a plug, and so we're doing multiple stimulations. But the mix of what we're pumping in there is pretty much similar to what we're using in vertical wells.

But are we making improvements and changes and are we trying to take advantage? Certainly. As we can get through the integrations that we're doing to be able to drill in areas where we've had good results. We're drilling horizontal wells where we are comfortable with understanding the geology. So yes, we're trying to exploit that.

And yes, we're continuing to make changes in the frac design and some of them might seem rather small. And I don't think this is the forum to get into the details of it. But in how we perforate, how we break down sand concentrations, a lot of that is our guys are very busy on it and Schlumberger's been very helpful to us in experimenting with things. And we think we're making progress there, both in cost and maybe that's reflected ultimately in performance as well.

Laurance Narbut: Just a quick question also related to the fracturing. I know that you all had used--you tried--slick water on your vertical wells. Have you done so yet on your horizontal wells and more generally, are there any sort of non-nitrogen based techniques that you think might still hold promise on your horizontals?

Harold Korell: We have not done anything but the nitrogen foam fracs in the horizontals. At some point we need to go back and try a slick water frac. The slick water fracs generally would be less expensive. We only have done, I think two slick water fracs, kind of early on, on the vertical wells. And yes, we're talking about that. I think yes, we do need to do that and we will. I don't know when that will be scheduled, but we've been talking internally about that.

Van Levy: Harold, I was hoping to understand the cost advantage from owning your own rigs. Also, you talked about the service companies. They talk about how difficult it is to get and maintain qualified crews. Can you address this?

I was also interested that it appears to take five or six months to build these things, so from my perspective it seems to have a pretty interesting impact on the service side and what service companies can do to jack up rates. It seems like the E&P companies have a response if the rates get too far out of hand. Could you discuss this?

Harold Korell: Well, it's very clear, when you sit down and look at the economics or when you guys talk to the service sector on the drilling side, that current day rates are in excess of replacement costs. And in addition to that, rigs are very tight and the quality of what you get incrementally when you try to add rigs, both in the iron and in the quality of the crews generally, is kind of marginal. In fact, in some cases, unacceptable.

So, for a play like this and how we've viewed this, when we look at the economics of it, the economics themselves are compelling, just based upon--if you could get the rigs you want--based upon the rig rates, versus the cost of owning these things and operating them yourselves.

Now, realize that if you're going to do that, which we've made a decision to do, then we're faced with some of the same issues that the drilling companies are, relative to crews, training crews and all of that.

We went through a pretty heavy soul-searching before we made the decision that we made. The first driver in it is availability and the design of the rig that we need to do this type of activity. And so specifically what we're buying, we think is directly suitable to this. We know that we're going to be faced with the same challenges, relative to crews and so on. But, what we can do is we have enough margin between the cost of operating that rig and where current rig rates certainly are, to share some of that in a motivational way, with the crews that we have and with our ability to recruit and retain and manage a quality workforce.

One of the things we've done in Southwestern Energy is we struggle sometimes, we work hard to make our decisions, but once we've made them, we're going to work really hard to make it work. And that's what our commitment is regarding the rigs that we're buying here. And if you think about overall the driving force for our Company has been to create a present value of at least $1.3 or better per dollar invested in our business. And so, if we're saving that increment between the cost to operate those rigs and where day rates are, that's a further enhancement for the economics of our project. And that's what's driven that decision.

Van Levy: That was kind of the thread of my question also. In the Barnett Shale and some of the areas, people are talking about IP rates essentially equaling reserves, so if you get a 3 million a day well, it translates into 3 Bcf sort of ultimate recovery. Your rates were 1.4 to 3.7 IPs on the horizontals and the reserves you're talking about are, I guess 1.3 to 1.7.

It was interesting also, in following the Barnett, a big company like EOG was pretty aggressive in outlining some significant reserve upside. I guess what I'm asking is with the cost advantage you have in the rigs, and if there is some conservatism in the way you cast the reserves to date, you had given some numbers earlier I think on gas prices and rates of returns. Have those changed as you're getting more results? Are you feeling the bias of those numbers moving up or down or are they still at the same level that you last released?

Harold Korell: The first thing is, I guess, it's going to wind us back to something I said just a minute ago. We have 80 days of production on the oldest horizontal well. And then the other thing, just to clarify this, since you used the term reserves, I think most of what we've put out has things on it like estimated ultimate recoveries, which are easy to translate over into the word reserves. We all need to understand also that in today's world, reserves have a certain set of characteristics. They must meet hurdles and criteria they must meet to be called reserves. So when we talk about estimated ultimate recoveries, that's our best guess at what we think something's going to produce, with the data we have. Again, the horizontal wells, the oldest one's 80-days. So we're using that in that terminology.

The only reason I bring up reserves versus ultimate recoveries is also there may be a difference in what we can actually and do book in reserves. The difference between what we think the ultimate recoveries might be and the actual reserve bookings. And that has to do with the certainty at a given point in time.

Now, I just lay all that out, because it might be important in understanding how we talk about this. Now, one could call some amount of whatever you might think the ultimate recovery is, you can call that probables.

Our numbers that we put out to this point on estimated ultimate recoveries are our best guess estimate of what these wells will produce. And within 80 days, that won't change a lot. The early declines on these things are pretty steep and the real open question is when will they flatten or will they flatten or do they flatten at all?

Van Levy: Okay. So the numbers that are out there are still your best educated guess at this juncture?

Harold Korell: That's right.

Joe Allman: In terms of the development of the Fayetteville Shale, I'm just trying to get my arms around kind of what you folks are thinking about just beyond, say, 2005, in terms of number of rigs you might have working at the peak of the development of this play. And also, what might some other constraints be, pipeline capacity, people constraints, can you kind of help us go through what you're thinking about in terms of the development of this play?

Harold Korell: Yes. I think that we're not prepared today to talk about the ultimate program. As Richard mentioned earlier, we do our planning cycle, really heavy-duty planning cycle, we're getting into it right now. And particularly the question about the peak. Let's just think in the bigger picture and broad picture about this whole thing--690,000 acres plus another whatever.

The real question here is--two real questions here. One is, we planted a seed here a long time ago and now you can think of 8 pilots as seedlings that we're watering. And the real question is, how large. And just visualize this. Our annual report had a seedling and a great big tree behind it. The question is, how big is that seedling going to grow as an individual tree? And the second question is how large is the forest? And we don't know the answer to how large the forest is. We've tested it now over a pretty big area and we have a short production history on each individual horizontal well.

Now, the ultimate number of rigs that are going to run out here, the peak question, is dependent upon how big the forest is and what the economics and the ultimate reserves are for each one of those horizontals. So, the peak number of rigs could be a lot of rigs. I mean it's just obvious, because of the acreage position and doing the math.

I think probably your question is you'd like to get a little tighter on what '06 is going to look like. And we had an earlier question there, if we have 8 rigs up and running at the beginning of the year, then you can sort of go through the math. I haven't done it in my head. But you'd get a lot more wells than we've drilled this year, it could be double that number.

But that's about as far as probably I want to go today in trying to answer that.

Joe Allman: Okay, appreciate that. And then, over to the Ranger Anticline, you've had some good test rates on some recent wells and how do those compare to previous wells? Are they better than what you've been doing before or similar? And I know there's been some variability amongst the recent wells too. And also, the 130 or so contingent wells that you've got beyond this year, what's included in that? I know you touched on it. Is there a lot of, say, Eastern development included in that 130 or so? Is it a lot of Western? Can you kind of describe that for us?

Richard Lane: We see a lot of variability in the test rates out there. And what we've seen the first half of this year is not out of the boundaries of what we normally see. So I think we're kind of doing our average well out there. Last year we had some real high-rate wells moving to the West. And I think we'll see some more variability there. Our kind of base average well though is providing real good economics.

In terms of the contingent locations, certainly they would involve acreage to get to those kind of numbers, proving up acreage, as we have been, to the West. And then this Eastern expansion is kind of a newer thing and I think that's where maybe some of the upside would be.

Harold Korell: Joe, I wanted to come back to your question. I don't think I went as far in answering that as probably part of your question. That is, what will be the critical elements that might be roadblocks to the ultimate plan. If you think of this as an academic question, a business is a unit that does a transformation of some inputs to some outputs. And our output is gas and our input is ideas and that requires rigs--it requires resources--which means rigs, vendors, capital, people and all of those things. And this project, by the nature of it, is going to change every day. It's size has the potential of changing every day and so we are going to need to react to that. And I think we will have a different constraint at different points in time.

One clear restraint we had is we couldn't see the ability to go on the market and find drilling rigs that we needed to use and wanted to use to do this work. So now we've taken a step to deal with that. In the last eight months we've hired about 65 people here. We're still recruiting people. So, the people resource, we have to keep that matched up. And then the capital resource is another element of it. So all of those things, we have our eye on the ball and we're working hard to manage them and bring them up.

But I think at any given point in time, one or the other of those inputs is going to be a constraint if you had to put your finger on it. Your takeaway capacity, you probably noticed that we recruited a really experienced high quality guy, Gene Hammonds, and announced that recently and formed the Southwestern Energy Midstream Company, which he'll be heading up our marketing operation and our Desoto gas gathering project. There are lots of alternatives there.

We don't have a constraint on gas moving out of here now, but there's a chance that that could happen one day. So, we want to be prepared on all the fronts.

Joe Allman: Got you. And then just quickly, on the CapEx increase, how much of that deals with cost inflation?

Richard Lane: There is a piece of that, especially where we're drilling lots of wells. But I think if you take about the $50 million piece, that does not include the rigs, maybe about 10% of that we would allocate towards rising costs kind of on a well basis.

Ryan Zorn: Harold and Greg, on the shelf, I know you've got some term debt to probably refinance here in December, but I also noticed that the shelf just says either debt or equity and no converts or anything like that named. Is that intentional or how are you thinking about future financing?

Greg Kerley Well, the shelf actually covers debt, convertibles and equity. So it's in there for all those kind of things. But our current shelf is almost three years old now, so it's stale, really, by industry standards. Then we had about $190 million of remaining capacity and then we have the $125 million of public debt that matures this December. So, the shelf filing, really combined with our revolving credit capacity, which on our revolver right now we have about $400 million of additional capacity. You take those things combined, it just gives us a great deal of flexibility in funding our capital program as we go forward.

Harold Korell: I think the key point is as this all ties together, as we go through our process here and firming up our plans for '06, capital is one piece of that.

Ryan Zorn: Okay. Any change to your historical thinking on optimal debt to capital levels, given the evolution of the Fayetteville?

Greg Kerley: Well, that's a moving target too. It really is a function of the same point that Harold has, is what's our plan going to look like over the next few years and as we've indicated, we do expect our program to be increasing next year in our drilling in the shale. And when we get that plan really developed, it'll help drive what that capital structure should be going forward.

Robert Christensen: Coming back to constraints, the pressure pumping business, you're using Schlumberger and just with the commitment to the rigs and all the future holds, is it a "build it and they will come" for Schlumberger to expand or to perhaps draw other pressure pumping companies into the play? Is that in your strategy? That's point one.

And point two, if it's not a "build it and they will come," are you offering any inducements to Schlumberger or others to get involved in it?

And I guess the third would be, maybe you ought to enter the pressure pumping business. If you entered the rig business, why not the pressure pumping business? So, it's sort of a three part question just to update us on the expansion possibilities for that bottleneck. Thanks.

Richard Lane: I think for the pumping services, stimulation, cementing, that kind of package of services that we need, the strategy is definitely not start drilling lots of wells and hope they come, because we've got much bigger plans than that.

We have engaged folks that are providing those services right from the beginning and sharing with them where we're trying to get to. And we have vendors that are making significant capital commitments right now, to kind of be in lockstep with us, related to those services. So, no, we can't just build the rigs and hope the other stuff happens, Bob, but we're working it all simultaneously.

Certainly we are looking at the whole picture and Harold has encouraged us to look at the whole supply chain and value chain, if you will, on this thing. And we are kind of stepping out of the box and looking at that whole thing. When you have the potential for the number of wells and the years of a program that we hope this will be, I think it's smart to do that. And when you're needing goods and services that are highly repeatable, it's smart to do that.

So, we're looking at that whole picture in terms of supply and service. The pumping service is probably one of the harder ones and maybe not one of the wiser ones to do that with. But there are a lot of other things in that chain that we are looking at.

Robert Christensen: Again, on capacity, when you bought the 5 drilling rigs, in that contract was there an option, any money towards an option to buy more from that supplier?

Richard Lane: Yes, there is.

Robert Christensen: Any sort of preferential right to move yourself up in the queue in terms of-- I don't know what their manufacturing capacity is. Anything along those lines?

Richard Lane: Well, I just would stop it there. We got a firm contract. Those rigs are going to come, we think as we laid out the schedule. And we do have an option to do some other things.

Robert Christensen: Okay. And then, I'd like to ask a Ranger question. You had a little red dot on the map to the South. It looked like a mile to the South. Was that well drilled in sort of the middle of all your activity, you were going to step a little further South? Have you drilled that well?

Richard Lane: No, we have not drilled that well yet. It is designated as a well for this year. We drilled the outside-operated well that we've talked about, between the HBP area and the Eastern expansion would be in our block of acreage kind of half-way between those areas.

Robert Christensen: I see. Shifting around now to Fayetteville, you had a well that was permitted, oh, it looked to me about 12 miles further East of the Sneed well, which was about a 14-mile step out. The Carter well, has that been drilled?

Richard Lane: It's drilling right now.

Robert Christensen: Beautiful. And I just wanted to--I don't know that I wrote it down--.

Harold Korell: How many questions are you going to ask here, Bob?

Robert Christensen: Oh, I don't know. Maybe I'm last in queue. I can get off and you can give it to others. I just wanted one more clarification on the Stobaugh. I don't know if I wrote it down. Started out life at 3.7. The 30-day update was 2.3 and you said what is it flowing at right now? I'm trying to get a sense is the rate of decline slowing? I think you said 1.5, but I want to be a little more clear on it.

Richard Lane: Yesterday's rate was about 1.5 million cubic feet per day. And while we're talking about those wells, the one that was the Eastern one I think you were trying to pin down there, Bob, is actually the Martin. You said the Carter.

Robert Christensen: They labeled it wrong on the map.

Operator: There appears to be no further questions at this time.

Harold Korell: Well, thank you for joining us today and asking all the good questions. And that concludes our teleconference.