Southwestern Energy Company First Quarter 2005 Earnings Teleconference Call
Monday, May 2, 2005

C: Harold Korell; SWN; Chairman and CEO
C: Richard Lane; SWN; EVP of Exploration and Production
C: Greg Kerley; SWN; CFO
P: Joe Allman; RBC Capital Markets; Analyst
P: Amir Arif; Friedman, Billings, Ramsey; Analyst
P: David Heikkinen; Hibernia Southcoast Capital; Analyst
P: Ryan Zorn; Simmons & Company; Analyst
P: Ken Beer; Johnson Rice & Company; Analyst
P: Michael Bodino; Sterne, Agee & Leach; Analyst
P: Mike Bradley; Millennium; Analyst
P: Stu Wagner; Petrie Parkman; Analyst
P: Robert Christensen; Buckingham Research; Analyst

Operator: Please stand by. Good day, everyone. And welcome to the Southwestern Energy Company first quarter 2005 earnings. Just as a reminder, today's call is being recorded.

At this time, I would like to turn the conference over to the President, Chairman, and CEO, Mr. Harold Korell. Please go ahead, sir.

Harold Korell: Good morning, and thank you for joining us. With me today are Richard Lane, our Executive Vice President of Exploration and Production and Greg Kerley, our Chief Financial Officer.

If you have not received a copy of the press release we announced on Friday regarding our first quarter financial results, you can call Annie at (281) 618-4784 and she'll 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 are not guarantees of future performance and actual results or developments may differ materially.

We are off to a great start in 2005. Our first quarter financial results were the best in the company's history, as we set new records for earnings and cash flow due to our production growth and higher commodity prices. We continue to have excellent results in our drilling programs at the Overton Field in East Texas and the Ranger Anticline in the Arkoma Basin.

In addition, we continue to make progress in our Fayetteville Shale play. By the end of the quarter, we had drilled 39 wells in six pilot areas in four separate counties in the play. We have begun testing horizontal wells with encouraging results, which Richard will discuss.

On the land front, we are continuing to lease new acreage, and to date we have leased approximately 630,000 net acres in the undeveloped play area and we control an additional 125,000 net developed acres in the traditional "Fairway" area of the basin. We have also seen increasing competition for leases over the last few months.

Overall, we continue to be excited about the potential of the Fayetteville Shale play. Our drilling program will remain flexible throughout the year and will continue to be impacted by a number of factors, including the results of our drilling efforts, our progress in determining the most effective fracture stimulation treatment, the performance of wells we drill in new pilot areas, prevailing costs for services and materials and the gas commodity price environment.

We have had an excellent start to what I believe will be a very exciting year for Southwestern Energy. I'll now turn the teleconference over to Richard Lane, who will tell you more about our E&P results, then to Greg Kerley to discuss our financial results, and then answer your questions.

Richard Lane: Thank you Harold, and good morning.

During the 1st quarter of 2005, we continued with an active drilling program in East Texas and the Ranger Anticline Field in the Arkoma Basin. In addition, we have been evaluating fracture stimulation techniques and testing horizontal technology in our Fayetteville Shale play. We currently have 6 rigs running in East Texas, 3 at Ranger and 3 in the Fayetteville Shale. In the 1st quarter, we spudded a total of 64 wells including 21 wells in East Texas, 13 wells at Ranger, and 18 wells in the Fayetteville Shale play.

Our production volumes for the 1st quarter were 14.0 Bcfe, up 22% from the 1st quarter of 2004 despite the curtailment of a portion of our production at our Overton Field in East Texas. Due to continued curtailments at Overton into the 2nd quarter, we are revising our 2nd quarter production guidance down slightly from a range of 15.0 Bcfe to 15.4 Bcfe to a new range of 14.8 Bcfe to 15.2 Bcfe. We are continuing to hold our full year guidance at 61.0 to 63.0 Bcfe. At this time, we expect all curtailment issues at Overton to be resolved by the end of the 2nd quarter. Of the 14.0 Bcfe of 1st quarter 2005 production, 5.9 was from East Texas, 4.9 from our conventional Arkoma Basin properties, 1.8 from the Permian Basin, 1.2 from the Gulf Coast Region, and 0.2 from our Fayetteville Shale play.

In the first quarter of 2005, we invested approximately $20.1 million in our Fayetteville Shale play, including $11.9 million to drill 18 wells and $6.9 million for leasehold acquisitions. As of March 31st, we held approximately 630,000 net acres in the undeveloped play area. In addition, we control approximately 125,000 net developed acres in the traditional "Fairway" area of the Arkoma Basin that is held by production.

Since beginning our drilling program in the Fayetteville Shale in 2004, we have drilled a total of 38 wells and participated in one outside-operated well. The wells are located in six separate pilot areas located in Franklin, Conway, Van Buren and Faulkner counties in Arkansas. Of the 39 wells, 27 are producing, eight are in some stage of completion or waiting on pipeline hook-up, and four are shut-in due to marginal performance.

To date, we have drilled three horizontal wells in three separate pilot areas. Of the three horizontal wells, two have been completed and tested and one is waiting on completion. The first horizontal well was drilled in the company's Griffin Mountain field area with a 1,857' lateral and required 32 days to reach total depth. We initially planned to perforate and stimulate four different intervals along the length of the horizontal section. However, problems with wellbore isolation limited the potential stimulation of the well to effectively only one stage at the tail of the horizontal section. This well had a final test rate of approximately 580 Mcf per day. The second horizontal well, completed in the company's Rainbow pilot area had a 2,264' lateral and required 11 days to drill. This well was successfully fracture-stimulated in four separate stages, tested at a rate of approximately 3.7 MMcf per day and will be put on production later this week. The third horizontal well, located in our Brookie pilot area, took 19 days to drill and had a 2,170' lateral. We expect to be completing this well over the next few weeks. We are currently drilling our fourth horizontal well which is located in our Rainbow pilot area.

The average drill and complete cost for the first three horizontal wells was approximately $2.1 million per well. Excluding extraordinary and non-recurring costs, we estimate that our horizontal well costs during the second quarter will range between $1.5 to $2.0 million per well.

We also recently placed a new vertical well on production at a rate of approximately 1,300 Mcf per day with a flowing tubing pressure of approximately 1,100 psi in our Brookie pilot area and tested another vertical well at a rate of 1,283 Mcf per day with a flowing casing pressure of 490 psi in our Rainbow pilot area. The costs to drill and complete our vertical wells range from $440 thousand to $650 thousand per well, with the higher cost wells predominately in our Griffin Mountain Field area.

We are continuing to get more history on our producing wells. As was expected, we have begun seeing some variance in the Fayetteville Shale's productivity between the different pilot areas. Initial potentials of the vertical wells have ranged from 300 Mcfpd to 1,500 Mcfpd. The first 30-day average producing rate from the 13 wells which have been on production more than one month is 375 Mcfpd. The second 30-day average rate from the 8 wells producing this long is 214 Mcfpd. Assuming a first year average exponential decline rate of 75%, a second year decline rate of 45%, a third year decline rate of 20% with further flattening in the out-years, we currently estimate that the ultimate recoveries from our existing vertical wells will be between 300 and 750 Mmcfe per well. The wells in the Griffin Mountain area, which represent over half of the producing wells, are expected to average approximately 300 Mmcf. No estimates have currently been made for the completed horizontal wells.

Our activity for the remaining part of the year will include continued efforts in improving the fracture stimulations on vertical wells, drilling additional horizontal wells, some seismic acquisition, and testing of additional new areas of our acreage. The key word here is flexibility to pursue the best path forward for value creation.

As I mentioned previously, we spudded 13 wells in the Ranger Anticline Area in the 1st quarter of 2005. All of these wells are either on production now or are currently being tested. The Ranger Anticline, located in Yell and Logan Counties, Arkansas, produces from the Borum sands between 5,500' and 8,500'. Of the 13 wells, 10 are located in the core producing area of the field, 2 are located in the western expansion area we began developing last year, and one, the Standridge #1-10 well, was drilled as a nine mile eastern step-out of the core producing area. As mentioned last time, the Borum sands were tight in the Standridge well, however, the well did penetrate 150 feet of gas pay in the Basham and Turner sands at 3,550'. This well is currently waiting on pipeline connection. We plan to drill offsetting wells in 2005 to determine the extent of these shallower pay sands as well as to continue testing the deeper Borum sands.

The success of our Ranger Anticline drilling program is reflected in the field's increasing production. We are currently producing 25 Mmcfpd gross from the field, up from 8 MMcf per day at year-end 2003.

We continue to be very pleased with the results of our development drilling program at our Overton Field, located in Smith County, Texas. In the first quarter, we spudded 18 wells at Overton and have maintained a 100% success rate. We have now drilled 191 wells since we acquired the field in 2000. The average estimated ultimate recovery for our 1st quarter 2005 wells is approximately 1.6 gross Bcfe per well. The combination of our cost controls and continuing good well performance is allowing us to continue to exceed our economic hurdle rates at Overton.

As mentioned earlier, our production at Overton is still being curtailed due to the failure of a transmission line into which a large part of Overton Field's gas sales are made. The operator of the line is continuing to seek regulatory approval to return the line to its normal operating pressure. To partially offset the curtailment caused by the line failure, additional compression was recently added to a second transmission line serving the Overton Field. Plans also call for "looping" this line to further increase take-away capacity. We expect all curtailment issues at Overton to be resolved by the end of the 2nd quarter.

In addition to our Overton Field, we continue to be active in other areas in East Texas. The Reavley #1 well, located in our Black Bayou Prospect located in Nacogdoches County, is currently producing 1.3 MMcfpd from the Travis Peak formation at approximately 11,000; We are currently staking two offsets to this well which we operate with a 40% working interest.

At our Doyle Creek prospect in Cherokee County, we are currently completing our Session Heirs #1 well. This well encountered 94 feet of pay in the Travis Peak formation at 10,900'. We expect this well to be on production in late May.

Also in East Texas, we plan to spud two of our exploration tests in the second quarter. The Watts #1 well in our Pines prospect in Marion County, will test the Lower Cotton Valley and Boosier sands at 11,350'. This well is currently drilling. We also plan to drill a test of our Ginger Quill prospect, located southeast of our Black Bayou discovery in Nacogdoches County, late in the second quarter.

Moving on briefly to the Permian Basin, at our No Bluff project in Eddy County, New Mexico, we are developing a shallow oil play in the Glorieta/Yeso formations at 3,700'. To date in 2005, we have drilled two wells producing 144 Bopd and 93 Bopd, respectively. Although fairly small, at these shallow depths and at $50+ oil pricing, this project yields an excellent PVI. We plan to drill an additional 2 to 5 wells here by the end of 2005.

In summary, we continue to be encouraged by our results at Overton, at Ranger Anticline, and particularly at our Fayetteville Shale Play. We are looking forward to strong results for the remainder of the year.

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, our results for the first quarter were excellent, primarily fueled by our strong production growth and higher realized commodity prices. Earnings for the first quarter were a record $32.6 million, or $0.87 per diluted share, up 33% from the first quarter of 2004. Cash flow provided by operating activities before changes in operating assets and liabilities also set a new record for the first quarter at $73.6 million, up 30% from the same period in 2004.

Operating income for our E&P segment was $47.7 million for the first quarter of 2005, compared to $33.4 million for the same period last year. The improved results were primarily due to a 22% increase in our production volumes combined with a 16% increase in our average gas price.

We realized an average gas price of $5.71 per Mcf for the first quarter of 2005, up from $4.92 per Mcf for the same period last year. The company's hedging activities had minimal impact on the average gas price realized during the first three months of the year, compared to our hedges in place during the first quarter of 2004 which lowered our average price by $0.42 per Mcf. Locational differences in market prices for natural gas have continued to be wider than historically experienced. Disregarding the impact of hedges, our average realized gas price during the first quarter of 2005 was approximately $0.55 per Mcf lower than average NYMEX spot prices. This was in line with our previous guidance and about $0.20 wider than our average for the prior year period. We currently estimate that our average realized market differentials for the second quarter will range between $0.40 to $0.50 per Mcf lower than average NYMEX spot market prices, excluding any impact from our commodity hedges. We have approximately 70% – 80% of our targeted gas production hedged in 2005 and our current hedge position is detailed in our Form 10-Q that was filed Friday.

Our E&P segment continues to be one of the lowest-cost producers in the industry. Lease operating expenses per unit of production were $0.45 per Mcfe in the first quarter of 2005, compared to $0.38 per Mcfe for the same period in 2004. The increase in our unit operating expenses was primarily due to increased compression costs and higher oil field service costs. General and administrative expenses per Mcfe were $0.39 during both the first quarters of 2005 and 2004. Our full cost pool amortization rate rose to $1.29 per Mcfe, compared to $1.18 per Mcfe a year ago, primarily due to increased finding and development costs.

Operating income for our utility segment was $7.4 million in the first quarter, down from $8.8 million in the same period in 2004. The decrease in operating income resulted primarily from decreased deliveries due to warmer weather in the utility's service territory during the first quarter, and higher general and administrative expenses. On December 29, 2004, our utility filed a rate increase request of $9.7 million annually with the Arkansas Public Service Commission. The scheduled hearing date for the rate increase request is in September, and any increase allowed would likely be implemented in the fourth quarter of 2005.

Operating income from our gas marketing activities was $1.0 million during the quarter, up slightly from the first quarter of 2004.

Our capital investments for the first three months of 2005 totaled $80.9 million (including $78.5 million for our E&P operations), up from $58.6 million during the first quarter of 2004. Our strong cash flow enabled us to fund our increased capital expenditures and also pay down $27 million of debt during the quarter. As a result, our total debt-to-capitalization ratio improved to 40% at March 31, 2005, down from 42% at year-end.

Our outlook for the balance of 2005 is very positive. As Richard indicated, we are targeting total oil and gas production of 61 to 63 Bcfe for the year, and if you assume NYMEX commodity prices of $7.00 per Mcf of gas and $50.00 per barrel of oil, we are targeting net income of $120 to $130 million, and net cash provided by operating activities (before changes in operating assets and liabilities) of $290 - $300 million. Our current planned capital investments for 2005 of $352.7 million are expected to be funded by our cash flow from operations and borrowings under our revolving credit agreement. We currently have $427 million of available capacity under our credit facility.

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

QUESTIONS AND ANSWERS

Joe Allman: Harold, in the Fayetteville Shale, what might be constraints in developing that as fast as you would want to; people, equipment, anything?

Harold Korell: Well, I guess, Joe, we really haven't gotten to the "as fast to" question. I mean, at this point in time we are progressing at the pace we would like to. It's kind of a hypothetical question. I suppose there could be various answers to that. Richard, maybe you would want to take a shot at that.

Richard Lane: Well, I think, you know, we have people in place to execute the kind of plan that we've talked about. We have equipment, in reasonable anticipation for equipment and resources to do it. And I think, as we've talked about it as a group, that if you want to call it a constraint, is we want to move quickly and realize the value of it, but we don't want to outpace our understanding of it and have waste.

So, I think right now we're not really constrained by resources or people and we want to move down the path of understanding it the best way and not have waste along the way by doing operations that aren't the most optimal.

Joe Allman: Okay. I know it's still fairly early on in the play, but can you just talk about any surprises that you've had, either positive or negative with what you've seen so far?

Richard Lane: Well, there are some things in my comments and in the press release and in the past we've talked about, that we're seeing variability in the play. I wouldn't know if I would call that a surprise. We've kind of said that all along. And the variability can be within the individual pilot areas even.

So, we're still working to try to understand what drives that, yet we're seeing some pretty good things happen also.

Amir Arif: Congratulations on a great quarter. Just a follow-up question on that variability here. Richard, can you talk a bit more in terms of what variability you're seeing, whether it's just thickness or if it's the frac that you're seeing in the formation? Can you just go into a little more detail if possible?

Richard Lane: Yes, sure, Amir. You know, the thickness that we're seeing in the shale, I think we're getting fairly good at predicting that before we drill. There is variability in it, as we've understood it from the beginning and from the well control. You know, everywhere we drill we're seeing gas in the shale and a good gas resource.

I would say probably the main variability is how they are reacting to the stimulations and where the stimulations are going, the best way that we can understand them and try to visualize them, and then how the wells are flowing back and performing.

Amir Arif: Okay, great. And just a second question. In terms of your horizontal development program going forward, can you just summarize what you have in the queue right now in terms of you're stimulating one and then you have two more growing and do you have anything else lined up after that?

Richard Lane: Well, as we've talked about in the past, this idea of wanting to be flexible, and the plan is just for this kind of thing. And Harold's talked about it a good bit also, that as we see good things happen with horizontal wells, obviously, we'll want to do more of those. So, we do, for just the facts right now, we do have one waiting on completion. We have another one drilling. And then as we look into the second quarter, probably best guess there would be that we would have a higher ratio of horizontals to verticals than in the first quarter.

David Heikkinen: Just again, congratulations on a good quarter. The rates from the horizontal and the Fayetteville are pretty encouraging. Can you talk about the finding and development costs in the Griffin Mountain field and your PVI for that? It looks like if you're coming at the low end of reserves and high end of cost, that you're above $2.16 kind of average F&D costs. How does that qualify and then what are your thoughts as far as are you going to keep that development up or go to other areas more likely?

Richard Lane: I think we're, you know, we started at Griffin Mountain in this vast acreage block. We had to pick a place to start and we had some thesis on where to start. I think kind of a little bit ironically, it doesn't look like it's the best of the areas that we've started to develop.

So, it is also where the higher costs have been on the vertical, so that, in conjunction with the slightly EURs makes it not as promising as the other areas. But, when we're talking about the ultimate production there, we're looking at what we think these ultimately might produce. When you talk about finding costs, you're talking about proved reserves, and we're not to the point there where we know what those are or what they will be at the end of the year.

So, the pressures are there that the performance is slightly lower and the costs are more, so the finding costs will be a little higher, but it really represents just one small area in the acreage.

David Heikkinen: Kind of thinking about each one of the areas; the Rainbow Project, the Brookie Project, what are your average net revenue interests in each one of the projects?

Richard Lane: We're probably around 87.5 NRI to the 100%, and for the most part we have right at or near 100% working interest.

David Heikkinen: Okay. In each one, so it's pretty contiguous across the acreage.

Richard Lane: Right.

Ryan Zorn: Let me ask this first. The variability in your drilling days on the horizontals, what'd you see in your Brookie well, in terms of number of days to drill?

Richard Lane: The Brookie well, I believe was 19 days. And you have to kind of equalize these for depth. The first well took 32 days to td, the second well 11. If you kind of normalize those to depth, it's more like a comparison of about 26 or 27 days to 11 days. And then the last one 19, with a little bit more measured section there.

I think the key though that we saw in number 1 and number 2 was some of the design changes in the drilling part of it. Where we kicked off, how we built our angle and all that, was more efficient.

Ryan Zorn: And so your plan for the upcoming horizontals would be towards the better end of that range?

Richard Lane: You know, we've only done a few of them here, but we're learning pretty quickly on them. We've talked about, looking forward, that we'd be in 1.5 to 2 million per well. That's on a completed basis, during the second quarter.

Ryan Zorn: Okay. The recent land that you've taken, can you give it roughly the same terms that you've had before? It sounds like your net revenue interests have been holding up, but I wondered what the last segment of land acquired, what the terms were there?

Harold Korell: Well specifically--I don't think we're going to tell you what our specific terms are that we're leasing at right now, as far as royalties and so on. So maybe we'll just leave that with that.

Ryan Zorn: Okay. Can you give us a hint on what percentage might be non-operated at this point?

Richard Lane: Well, it's kind of a forward-looking thing to try to predict that. We have places that we're still adding lease hold and--.

Harold Korell: Is the question, what percentage of wells that we might drill would be non-operating?

Ryan Zorn: Well, what percentage of your land position right now might be non-operated?

Harold Korell: I don't think it's possible to answer that question. It won't be operated until a well would be planned to be drilled there, and since we don't know when that would be, it'd be hard to answer that question.

Ken Beer: Just sticking with the Fayetteville, a couple of other questions. I may have missed this. How many rigs do you have running in the Fayetteville?

Richard Lane: We have 3, it's kind of been our average in current. And we've moved one in and out a few times. Kind of our nominal rate there is 3 rigs.

Ken Beer: And your thought is let's go ahead and just stay with 3, let's call it through the end of this year, is that a good thought or would you look to slowly, but surely, ramp that to 4 or 5 or 10? I guess I'm trying to get a sense as to when and how the ramp might occur.

Richard Lane: I think our best look at it now is still kind of the capital number that we've put out there, the up to $100 million. I think we can see our way to investing that amount at a prudent pace. And that would require us to start to ramp up our rig count in this next quarter, late in the quarter. And depending on the mix of wells, you know, I hate to keep beating on that, but depending on the mix of horizontals and verticals, we could build up to 5 to 10 rigs late in the year.

Harold Korell: And the other factor in it is depending upon getting acreage concluded and integration hearings and so on that would allow us to drill at new pilot areas.

Ken Beer: Fair enough. Just one more, Harold or Richard. In terms of variability or tinkering with the frac technique, are you happy with that? Is that something where kind of for the last, let's call it 5 or 6 or 7 wells, you've been happy with your technique and you're not tinkering so much with that, going forward? Or is there still work to be done in that area?

Richard Lane: We've not set on a procedure and there will be plenty more tinkering, I think. And some of them will be very subtle things. But we're starting to see some reaction to fairly subtle changes and we just need a bigger data set to make that conclusion. But I think you'll see us working on that procedure in both verticals and horizontals throughout the year.

Michael Bodino: I guess my couple of quick questions I'll make real simple. First of all, given the limited amount of data we have out of the Fayetteville, could you venture to guess whether there's been any changes to the spacing on vertical and horizontal wells and what you would anticipate going forward?

Richard Lane: Just to kind of go back to where we started from there, our initial filings where we had to get field rules at Griffin Mountain, the data there concluded about 30-acre spacing or less for the verticals. From what we've seen, I think that would be kind of the top of the range. It could be lower than that.

On the horizontals, it would logically be a multiple of that. But until we get to where we can start projecting some reserves off of those, it would be hard to say. Certainly the well bore is out there over a bigger area and we're stimulating all along that horizontal. There'd be some geometry that defines that--that will go into that drainage calculation. But it's really too early to say on the horizontals.

Michael Bodino: Okay. The second question I had is on the Standridge well, the step-out and the Ranger Anticline, was this a situation where the Borum was tight because you were too close to the overthrust or was it properly placed for the Borum and it was just tight?

Richard Lane: Oh, it's hard to say it was properly placed, because it doesn't look too good. But the variability that we saw in that well relative to, say, offset wells out on the eastern end of the field is not very different than what we see throughout the structure. Even in our core production area we'll--we can have a poor well and the Borum right next to really good wells. So we're not too flabbergasted by the fact that that one was tight in the Borum and then I think we'll see variability as we continue to drill out there in the hopes that we'll find some more good Borum. But the shallow section looks very promising and we'll be offsetting that to try to prove it up. I don't think there was a big structural component to what happened with the Borum, Mike.

Michael Bodino: Okay. Thank you. Great quarter. I'll get back in the queue.

Robert Christensen: Yes, good morning. Could you conceivably do dual laterals or is it not worth it because the vertical portion is so small? Because dual laterals would allow for a lot fewer wells and I could make the case of getting to a lot of this acreage pretty quick. That's question one. And then, question two, on the borum well where you have the mechanical difficulty of completing it, could you give us a little more insight as to what you think went wrong there in sort of layman's terms? Thank you.

Richard Lane: Well, question one as to dual laterals, is it feasible? I think certainly it's feasible. It's done in other areas and the engineering technology is there to do it. And we're just starting to scratch on that and try to think about it. It's certainly something that will be evaluated as far as the overall pursuit of this play. And I think it's really a question of economics to me on whether you do those, Bob. You know, if you have some savings and the performance--cost savings and the performance outweighs doing two separate laterals, then we'd look real hard at that. And the other thing is the help you get there on the surface, part of the cost savings is mostly one surface instead of two. And then, also, the impact to the surface if we end up doing lots and lots of wells it's a good thing. So it's really economics.

Robert Christensen: Yes, because if you drill down and you go 2,000 feet one-way and 2,000 feet another way, there's almost a square mile. And if you stepped out within that square mile to the--oh, I don't know, east a couple thousand feet, and drilled down to the same thing, you'd have that square mile covered in effect by two surface locations. And you've got 1,000 square miles, or 1,200 square miles you get--then it's 2,400 locations. It would seem to be something. It's probably way down the road for you, but--.

Richard Lane: We'll certainly look at the technology and see if it makes better sense and the PVI would drive it. The borum well, maybe to elaborate a little bit more there, we had about 1,850 feet of lateral, all of it in the shale. And then, looked at segmenting that lateral section into four intervals with the idea we wanted to try one of these nitrogen foam stimulations on each interval. We pumped the first job, which isolated the most toward section--or the end of the horizontal section. And then, after that, we really had a lot of mechanical problems. And I think when I talk about well bore isolation, I think basically after that we weren't able to get good isolation in the individual intervals that we wanted to stimulate, and we saw some things happen that indicated we were seeing some pressure in places that shouldn't have been, perhaps related to some poor cement bonding. And that is not definitive that that was the cause of it, but certainly we weren't containing the fractures in the individual intervals. So the result is we spent quite a bit of money on the completion, and really, we just have the one interval, which is acting like a vertical and that's kind of what you'd think it would do.

Robert Christensen: So it sounds almost totally mechanical.

Richard Lane: Yes, absolutely.

Robert Christensen: And was the Stobaugh well done with nitrogen? Was it where you did get a good cement job off? I mean, what kind of frac was done on that lateral leg on your second one? Are you staying with this nitrogen?

Richard Lane: Yes, staying with that. And then, tweaking some little things on what we're pumping and quantity of sand and quantity of nitrogen and those kind of things. I think the difference there is the individual stages went away pretty well and individually. And then, accumulating to something a lot better.

Mike Bradley: Yes, hi. Everyone seems to be getting exciting about this drilling, which is understandable. My question is more operational. It seems to me, if I could get some clarity, looking at your press release and your guidance for 2005 compared to--.

Harold Korell: --Sir, is there some--could you get closer to the phone or something? We're having a hard time hearing you at this--. Hello?

Mike Bradley: Can you hear me now?

Harold Korell: Yes, we can hear you now. Thanks.

Mike Bradley: Okay. I'm just looking at some of your presentations from recent investor conferences and I just want to get a little bit of clarity here. It looks like you're assuming the same production guidance here. And--but you're assuming now $4 higher in oil price assumption and you're giving lower EBITDA cash on operating results. Just trying to get an idea why that is. Is it an expense issue or what are--am I looking at that right?

Greg Kerley: Yes, this is Greg Kerley. We had given $5 and $6 guidance, and we've put out $7 guidance also this quarter. In the $6 guidance, our earnings comparison was down somewhat due to really just the increase in, primarily in our higher DD&A rate. So the cash flow effect was about -- the range is $260 to $270. The upper end of our range before was to $270 on our cash flow, also. The lower-end range may be about $5 million more, just wider range, just -- and that was driven by a combination of a couple of different things, one of which was their utility having a poor first quarter due to warmer weather, which affected us a couple million for the year there. And then there's just a combination of a little bit lower production numbers originally in the quarter where we're expecting prices and a little bit higher leased operating expenses.

So, I think there is about a $5 million effect in our net cash flow range. And the earnings were a little bit more than $5 million, probably about twice that, but as far as the range goes, and driven by the combination of those same things that effect cash flow plus the DD&A.

Mike Bradley: Yes, because your presentation you have $6 gas here and $40 oil, and in the last presentation you were assuming $6 gas and $36 oil, and the ranges were lower based on what you just gave in this presentation. I just wanted to get an understanding why you would have a higher price tick but lower assumption?

Greg Kerley: Well, we only changed oil by about $4, and about 8 percent of our production is oil. Part of the difference, too, is just the basis differentials that we've seen, as we talked about, both in the first quarter and the second quarter.

Stu Wagner: A couple of quick questions. Correct me if I'm wrong, but it seems, in the past, your EURs, you more or less give an average, I think it was a little over 400 million per location. Is the reason for the range that you've upped the range, the upper end of the range, but you don't have enough confidence to up the average yet? Is that fair? Am I interpreting that right?

Greg Kerley: I think we gave an average of about 430 gross.

Stu Wagner: Right.

Richard Lane: And the Griffin Mountain is more like about 300, so it would be pulling that down some. And the more of the wells are weighted in the Griffin Mountain area. I still think kind of -- and then the wells that look like they are higher EURs, we don't have a lot of production on those. So, yes, there is some uncertainty there, but I think the averages still would be somewhere around 400 million cubic feet per well.

Stu Wagner: Okay. Nothing from you guys further. I get you. Second question, obviously, the reason you're looking at horizontal wells is to see if they're more economic and you can drill through wells, etc., but is there also an issue of maybe, I haven't determined it yet, but is there maybe a vertical thickness, or the thickness of the shale, is there a cutoff point of, say, 40 feet or 30 feet or something where the verticals don't work but you're hopeful that a horizontal might go into that section and actually turn it into an economic well, because you'll come in contact with more of the shale, even if it's a thinner bed? I mean I don't know if you've determined a cutoff point of thickness yet, but is that one of the hopes where the horizontals might add some value?

Harold Korell: Well, Stu, the primary job of the stimulation, as we viewed it here, and we've talked about this all along, is that the name of the game here is going to be to get in contact with the most rock you can per dollar invested. We got a question earlier from one of the -- I think Bob Christensen, about drilling dual laterals, which also gets to that point. We think that, logic would tell us, that we'll get in contact with more of the rock if we drill a horizontal well and do multiple-stage fracking along that than we would if we drill vertically through that same section.

Stu Wagner: Right.

Harold Korell: And then attempt to do just a fracture of stimulation there. So what's guiding us is to get the most contact with the rock. And that's why we're doing the horizontals. I mean an offshoot of that could be that back over in the Fairway, where the shale tends to be thinner, horizontal wells might make that more economic. But out here where we're drilling where we're 200 feet or so at least of shale, still the main job is to try to get the most contact, which we -- and we're encouraged by what we've seen to this point in the horizontal wells.

Joe Allman: Just in terms of the Fairway section, I noticed that you co-mingled a well, I guess with the Wedington sands. Are you going to try some more of those, or might you switch over to the horizontals up there in the Fairway section as well?

Richard Lane: Joe, this is Richard. One of the wells over there, I believe the co-mingled zone is a Hale sand, which is the typical producing interval in the Fairway. So the kind of connection with the Wedington that we've talked about before, I don't think that's what we have completed there. But in the Fairway, we hold a lot of acreage, followed by production. Those wells, we are kind of encouraged by what we're seeing there. We could do some re-completions there or deepenings. We can have secondary zones, like that well indeed is. And like Harold said, the ability to maybe go in there where it's 50, 60-feet thick and do some horizontal work may be potential also. So a lot of good things that we can try there and we hold a big piece of it, as you know.

Joe Allman: Okay. And then away from the Fayetteville for a second, in East Texas, at this point, how much acreage do you have, outside of Overton, in East Texas?

Richard Lane: I believe the number is about 20,000 acres gross and our net is way up there, probably 18,000 or 19,000 of that and in the separate 4 or 5 projects areas that we're talking about.

Joe Allman: And then lastly in Ranger, if I heard you correctly, Richard, I mean just the fact that you drilled this one well to the Borum and it was tight. I mean did you see some of those same kinds of tight forms, sands in the core area or to the west, so that kind of doesn't necessarily discourage you from further development in the Borum out there in the east?

Richard Lane: Definitely. I mean I think that's a correct statement. I think I said earlier, we might set up in the core area and offset a good well and find it Borum section tight and not very good, but overall, if you look at the performance of the field, we have some variability there, but our success there is something like 50 out of 57 wells, I think. So, yes, there is variability, but our average is very good and the economics are excellent.

Also, in this trend, we're on the southern part of the basin where you have big rollover anticlines and thrust faulted anticlines. Other fields along trend, it's not uncommon to have the shallow sands present in a significant part of the accumulations of those fields. So I think certainly we've got good hopes for finding more Borum out there and the shallow stuff is promising.

David Heikkinen: Just had a few questions outside of the Fayetteville. First, on the Permian, what's your net revenue interest and should we expect some oil production growth a little in your guidance? What is the percent oil for third and fourth quarter?

Richard Lane: David, I think we're talking about maybe for the year we might do 6 or 7 wells total, and they're not huge-rate wells. Our net revenue interest is high. Can't tell you an exact number, but certainly I don't see that project alone driving our oil guidance for the year. We've got other areas affecting all of that. But it's a good solid little project that we're trying to pursue.

David Heikkinen: Okay. And then, Harold, go back a couple years, you had a couple of exploratory plays before you really got into the Fayetteville. You're still pursuing some new ventures. Any outlook as far as when you can start talking about some of the new venture plays?

Harold Korell: I think we could -- Richard might want to comment on one of our new venture plays that we planted a seedling in that a pine beetle got into in the first quarter. I'll let him address that. But aside from that, we do have some other new ventures, things that we're not ready to talk about. We also have some exploration wells that will probably come about later in the year, and we'll talk about those a little bit later.

Richard Lane: Yes, the pine beetle got to us on the thing we call our road-crossing project. We had put an acreage block together there with another operator. It's Fort Union Coal is there and the Green River Basin. We had a nice thick coal, really looked good, measured good gas content, but we had a very high concentration of C02 in it when we did the analysis, so looks like that will not work.

David Heikkinen: Okay.

Richard Lane: Other kinds of things we have in the works are we've talked about our block acreage we have with Encana in that similar area there. We had a Madison prospect that we're trying to get spud this summer that's on the order of 50 Bcf gross potential. We had a large Jackfork prospect in Arkansas that we control a big acreage block that we're trying to get spud maybe in June or July. And then our unconventional team is working on some other areas that we really don't want to talk about right now.

Michael Bodino: My follow-up has been answered. Thank you.

Robert Christensen: Yes, if I look at the Fayetteville and take away what's out to the west, I guess, in Franklin County, just drew a line around the wells, 35 wells that you have, make a perimeter line around –-

Harold Korell: Bob, we're having trouble hearing you.

Robert Christensen: Sorry, can you hear me now?

Harold Korell: Yes.

Robert Christensen: Okay. If I threw away Franklin County and I'm making sort of a preliminary map on this Fayetteville shale here, and if I just did sort of a perimeter line around the wells that you've drilled, I'd come up with about 225 square miles having been tested, again exclusive of Franklin County. That would imply about 22 percent of your acreage or 20 percent of your acreage has been tested. Is that a reasonable calculation to do right now?

Richard Lane: Well, I don't think it is, Bob, because there is going to be vast areas in between those pilots that are undrilled. I think we look at a number here recently that -- the actual sections that we have drilled the well in, whether it's one or more than one, sections that we have tested relative to the total acreage block is less than 2 percent. I think something like 1.5 percent. I think we are starting to get some decent spatial sampling of the clay, because the pilots are of some significant distance away from each other. And so that's good, but then they'll just wrap them all, coral them, and say that whole thing is how you described it, it might be kind of early to do that.

Robert Christensen: Okay. Second question, this shale is sedimentary and probably pretty extensive. How much acreage is remaining out there when you kind of look into your maps? I mean I know everything has a different cost associated with it as the play gets levels of interest from others, but I mean how much acreage could still be leased?

Harold Korell: That's a good question that some people would certainly like to know the answer to and we might not have found the edges of it. What we're doing on our leasing is we're continuing to fill in leases where we have been working all along and we're stretching into some areas additionally. We're also seeing competition along the edges of where we've been leasing up to this point in time. So we're not going to address the total prospective acreage here. We may have our idea of it, but we also may not be [technical difficulty – no sound].

Operator: Mr. Korell, it appears we have no further questions at this time. I will turn the conference back over to you.

Harold Korell: Thank you, Operator. Well, we're off to a great start this year with the drilling that we've done at Overton and Ranger. We're also making progress, as we've discussed here, in understanding and pushing forward with the Fayetteville shale play and we think we're looking at a very bright year for the Company overall. I want to thank you, each of you, for the interest and being on the call today. That concludes our conference.