

Second-quarter 2006 teleconference script

QUESTAR CORPORATION

Moderator: Steve Parks
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8:30 am CT

Operator: Good morning. My name is Michael and I will be your conference operator today.

At this time I would like to welcome everyone to the Questar Corporation second-quarter 2006 earnings conference call.

All lines have been placed on mute to prevent any background noise. After the speaker's remarks there will be a question-and-answer session. If you would like to ask a question during this time, simply press star then the number 1 on your telephone keypad. If you would like to withdraw your question, press the pound key.

Thank you.

It is now my pleasure to turn the call over to Mr. Steve Parks, senior vice president and chief financial officer. Mr. Parks, you may begin sir.

Steve Parks: Thank you, Michael.

Good morning and welcome to Questar Corporation second-quarter 2006 conference call.

Yesterday we reported that Questar's second quarter 2006 net income rose 49%, driven by a 16% increase in natural gas and oil equivalent production and higher realized prices for natural gas, oil and natural gas liquids. You can access our earnings release at our Web site at www.questar.com.

Following my remarks this morning, Keith Rattie, our chairman and CEO, will comment on operations and update our guidance for 2006 earnings and production. After Keith's comments, we'll take your questions.

We have with us today other members of Questar's senior management including Chuck Stanley, president and CEO of Questar Market Resources, Allan Bradley, president and CEO of Questar Pipeline, and Alan Allred, president and CEO of Questar Gas.

Our remarks this morning will contain forward-looking statements about the future operations and expectations at Questar. These statements are made in good faith and we believe are reasonable representation of the company's expected performance at this time. Actual results may vary from our stated expectations and projection due to a variety of factors that are described in our Form 10-K and 10-Q filings with the SEC.

Now let me briefly recap our financial results for the first half of 2006.

Questar first-half 2006 net income was up 46% to \$227.5 million or \$2.60 per diluted share. There were 87 1/2 million diluted average common shares outstanding on June 30 this year compared to 86.9 million a year ago.

Our Market Resources subsidiary led the way for the first half of 2006 with net income of \$173.9 million, up 56% compared to a year ago. Market Resources engages in gas and oil exploration, development and production,

gas gathering and processing, wholesale gas and oil marketing and gas storage. All four Market Resources subsidiaries — Questar E&P, Wexpro, Gas Management and Energy Trading — had double-digit increases in earnings.

Questar E&P net income was up 79%, driven by a 19% increase in natural gas and oil equivalent production and higher realized prices for natural gas, oil and NGL.

Wexpro net income was up 15%, driven by a 17% increase in its investment base over the past 12 months.

Gas Management net income was up 12% due to higher processing volumes and margin.

Energy Trading net income was up 59% due to higher marketing fees and interest income.

Questar Pipeline, our interstate pipeline and storage business, earned \$21.3 million in the first half of 2006, up 34% over 2005. This increase was driven by new transportation contracts and higher NGL volumes and prices. The new contracts included the November 2005 completion of an expansion of our southern system and the December 2005 completion of a new interconnection between Overthrust Pipeline and Kern River Pipeline.

Questar Gas, our retail gas distribution utility, reported first half 2006 earnings of \$28.7 million, 13% higher than a year ago. The improved results were from higher margin, from customer growth and a recovery of gas-processing costs in 2006 that were not recognized in 2005 results until the fourth quarter pursuant to a regulatory order.

Now I'll turn the microphone over to Keith Rattie, Questar chairman and CEO.

Keith Rattie: Good morning everyone.

The bottom line on our second quarter and first half is the bottom line. All Questar operating units posted double-digit net income growth in the first half of '06 but it's the operational results from Questar and E&P that stand out. We grew natural gas and oil equivalent production 19% in the first half, 17% excluding one-time adjustments.

Questar E&P has now delivered 15% or higher production growth for four straight quarters. Our veteran E&P team's getting the job done with the drill bit and that's allowing us to raise Questar E&P production guidance for the second time this year. We now expect '06 production to range from 126 to 128 billion cubic feet equivalent. That's compared to our previous guidance of 124 to 126 and '05 actual production of 114.2 Bcf equivalent.

Note in our release that we also trimmed a dime off the top end of our EPS guidance. That's entirely due to the lower forward price curve for natural gas for the remainder of the year. We put a table in our release to reconcile our current and previous guidance. We now estimate that '06 EPS could range from \$4.50 to \$4.70 per diluted share and that's compared to our previous guidance of \$4.50 to \$4.80.

Our revised guidance, as we noted, assumes an average NYMEX natural gas price range of \$7.00 to \$8.00 per million Btu for the second half of the year. And I should note that, at the close of the market yesterday, the market was

actually at the top end of that range. That's a dollar per million Btu less than the \$8.00 to \$9.00 per million Btu that we assumed in our earlier guidance.

Note that we haven't changed our basis assumptions. Our revised guidance assumes that Rockies and Midcontinent basis differentials to NYMEX will average \$2.25 per million Btu and \$1.50 per million Btu respectively for the remainder of the year. As you'll note, that's well above the current Rockies basis of about \$1.30 per million Btu and current Midcontinent basis of about 90 cents per million Btu. Now as always, our EPS guidance excludes one-time items.

Note that we've now hedged 70% of forecast second half '06 natural gas production. We've taken commodity risk mostly out of the equation for Questar and its shareholders in '06. A dollar change in the average NYMEX gas price over the rest of the year moves EPS by just 7 cents.

Also note that we've added fixed-price swaps on '07, '08 and '09 equity production and note the upwards slope of our new hedges. The average net-to-the-well price of hedged volumes in each of the next three years is higher than in the preceding year.

Also, as you'll note, we've begun using basis-only swaps to hedge Rockies basis. Between now and the end of '08 we think the probability that Rockies basis will widen is greater than the probability that it will narrow from current levels. Now so far we've been wrong. Unrealized mark-to-market losses on natural gas basis hedges reduce second quarter EPS by 4 cents per share. The 2006 Rockies basis differential thus far has been tighter than we expected and I think tighter than anyone predicted. The reality here is it's been scorching hot here in the West this summer so far, so the gas burn for electricity is way up.

Let me focus your attention on our update of probable and possible reserves. We think this is the key part of our release yesterday. These estimates were reviewed by the same independent reservoir engineers that prepare Questar E&P proved reserves.

Note that our last updates were in our March 8, 2005, and August 9, 2005, press releases and we put a link to our Web site in our earnings release yesterday. We encourage you to refer to those previous releases.

The three numbers are — there's good symmetry here and they're pretty easy to remember — 1.5 trillion cubic feet equivalent proved, 2.5 trillion cubic feet equivalent probable and 3.5 trillion cubic feet equivalent feet possible. At year-end 2005 we reported proved reserves of nearly 1.5 trillion cubic feet equivalent. The revised estimate of probable reserves, 2.5 trillion cubic feet equivalent, is up 83% since our March '05 report and possible reserves of 3.5 Tcf equivalent are up 103%.

I'm going to comment on what's in and what's not in these estimates as I go through our major plays here in a moment, but let me make four points about our reserves estimates.

First, we don't report non-proved reserves estimates in our SEC filings.

Second, in accord with SEC rules, we don't book proved results on undrilled locations that are more than one direct offset from a developed well. Now at Pinedale, because we have very good control on the distribution of reserves across the structure, the quality of our probable reserves approaches that of the reserves we've booked as proved/undeveloped.

Third and possibly most important, reserves estimates are a snapshot in time. They're going to change as we develop, produce and evaluate well performance and incorporate new data.

Fourth, we want to remind investors not to sum the proved, probable and possible estimates without first considering the differences in the risk of potential recovery with each classification.

Now reserves are important information, but you ring the cash register with production, so let me just briefly comment on our production results. Steve hit some of this.

Questar E&P produced 31.3 billion cubic feet equivalent in the second quarter. That's up 16% from the year-ago quarter. Note that Pinedale production was up 26% compared to the year-ago quarter. Pinedale in the second quarter comprised about 1/4 of Questar E&P's production but, as we've discussed, that share will grow. We're still in the very early stages of our Pinedale development play.

Note that Rockies Legacy production was up 20% or 12% excluding the one-time adjustment in the second quarter. Increased volumes from the Vermillion play and Wedge and Wamsutter areas offset normal declines from mature properties.

And our Midcontinent team shot the lights out again. Production was up 28% and that's driven by our Elm Grove play in northwest Louisiana and a high-volume well in the Arkoma Basin of eastern Oklahoma.

Let me talk about Uinta Basin production, which was down 10% from a year ago. That's a bit misleading because volumes in the year-ago quarter included

production from a backlog of wells drilled in the first quarter of '05 that we couldn't complete until the second quarter for reasons related to weather that we talked about at the time.

A compressor failure and gathering-related delays also hurt our volumes in the second quarter, but the primary issue here is that our core Wasatch/Upper Mesaverde play is maturing and the average working interest in our remaining inventory is declining. What that means is we're going to need a new play in the Uinta Basin to overcome decline and turn production back up. Our potential Mancos play may be the key and I'm going to talk about that in a moment.

Let me walk through the major plays now and give you a little more color starting with Pinedale. We came out — as you know — of the winter drilling season with 33 new Pinedale wells drilled and cased, ready to complete. We couldn't frac most of these wells until we got the drilling rigs out of the way so only five of the 33 were flowing to sales at the end of the quarter. We should have them all on by mid-September and that should help drive Pinedale volumes in the second half.

Now if you're a Questar shareholder, you've got to tip your hat to our Pinedale team. Over the past couple years they've found ways to offset the soaring cost of rigs, completion services, steel, wellheads and other related costs. Today a typical Pinedale well costs about \$5.5 million to drill and complete and that's about the same as it was two years ago before the big inflation in those costs.

With pad drilling, once we drill and case the well, we skid the rig a few feet and spud the next well. That cuts some cost. Slick-water fracs have cut a lot of costs — a lot of completion costs — out without any apparent adverse impact

on well performance, and there's other items on the list. Chuck can elaborate in Q&A but the key point is that this focus on cost continues because it matters. We have a lot more wells to drill at Pinedale.

You'll recall that we reported 780 billion cubic feet equivalent of proved reserves at Pinedale at year-end 2005. Questar E&P now estimates that its Lance Pool probable reserves are 819 billion cubic feet equivalent and possible reserves are 715 billion cubic feet equivalent.

The big jump in the third category, the possible reserves category, compared to our August 2005 estimate is tied to potential 5-acre development on part of our Pinedale acreage. As you'll remember, our reservoir model suggest that with 10-acre density, our current development plan, we'll recover less than half the gas in place at Pinedale. We're going to start evaluating 5-acre density later this year.

Also, please note that the deep potential in the Rock Springs and Hilliard formations is not included in our Pinedale probable and possible estimates and this is a good time to bring you up to date on the Pinedale deep test.

As we've said in the past, we know there's a lot of gas in the Rock Springs and Hilliard formations at depths down to about 19,500 feet. What we don't know is whether we can produce that gas at rates necessary to justify the high incremental cost to drill and complete wells at these depths, and on that count the news so far is not encouraging.

Let me catch you up on what's happened since our April call. We got back on the Stewart Point #15-29 location in May. We quickly cleared the obstruction that we've talked about — the obstruction at 6,800 feet — and cleaned the wellbore down to about 19,050 feet. That's the middle of the Hilliard, where

we found another obstruction, and we're not sure what that obstruction is. It might be another frac plug that's moved up hole and lodged in the pipe; it might be collapsed casing. We tried but we couldn't drill it out and, given the risk and the cost, we decided to resume the test on just the upper part of the Hilliard only.

This time we bailed the Hilliard by choking back on it to avoid pulling shale and proppant into the wellbore and the upper Hilliard flowed at fairly stable rates of about 1 to 1.5 million cubic feet a day for about six days. Then we set a plug over the Hilliard and moved back up hole to test our primary target, the Rock Springs, and that's where we are today.

We're still testing the Rock Springs. We are producing gas but the rates are disappointing, though frankly not surprising, given the generally poor rock quality at these depths. We still have several more zones to test in the Upper Rock Springs. Once we do that we'll decide what to do next. Chuck can give you a little more color in Q&A.

Let me turn to the Vermillion Basin. Our confidence in this play is growing and that's reflected in our updated estimates of probable and possible reserves, which now include 341 billion cubic feet equivalent of probable and 836 billion cubic feet equivalent of possible reserves for the Baxter/Frontier/Dakota play.

The Vermillion probable-reserves estimate is based on 210 80-acre locations above the lowest known gas accumulation defined by drilling to date, mostly covering the Canyon Creek and Trail structures. And if you look at Slide Number 17 in our IR presentation, this will probably make a little more sense.

The possible estimate for Vermillion adds the 40-acre infill locations next to the probable locations, plus the acreage within the greater structural limits of the play defined from regional 3-D seismic.

Note also that both our probable and possible estimates assume an average EUR — Estimated Ultimate Recovery — of 2.5 billion cubic feet equivalent per well.

I should also add that our technical team believes that this play could expand beyond the areas included in our 3P estimates. We're going to drill several wells later this year to test that thesis.

Let me move next to the Uinta Basin, where our reserves estimates now include 450 billion cubic feet equivalent of probable and 955 billion cubic feet equivalent of possible reserves. As we've been saying, our core Wasatch, Upper Mesaverde tight-sand gas play is maturing. We're down to about a one-year inventory of undrilled 40-acre locations. We're going to do some pilot work on 20-acre density in the field and we should have some data by the end of the year. But, as I said earlier, we're going to need success in our new plays in the Basin to arrest decline and turn production up and, towards that end, we're continuing to evaluate Uinta Basin deep potential. The targets, you'll recall, are unconventional reservoirs in the lower Mesaverde, Blackhawk, Mancos and Dakota formation.

We've now drilled and tested our second Mancos and Dakota well down to about 16,000 feet. The Mancos, you'll recall, is a thick over-pressured shale section, the age-equivalent of the Baxter shale in the Vermillion Basin and the Hilliard shale at Pinedale.

The Mancos and Dakota are present and, more important, over-pressured across most of our Uinta Basin acreage. Well performance in these first two wells has thus far been similar to what we've seen in the Vermillion Basin and we still have the shallower Mancos B, Blackhawk and Mesaverde formation behind pipe to test later. We're also close to planned total depth on our third well which we're going to test shortly.

Now, unlike the Vermillion Baxter play, the economics of a possible Uinta Basin deep play might be boosted by developing the shallower Wasatch and Upper Mesaverde formation tight sand on 20-acre density. Our Uinta Basin reserve estimates include 290 billion cubic feet equivalent of probable and 364 billion cubic feet equivalent of possible reserves for the deep Mancos play.

Let me turn quickly to the Midcontinent. As I noted, our Tulsa and Oklahoma City team are doing a great job replacing decline and growing volumes. At Elm Grove in northwest Louisiana our inventory of undrilled locations is now up to about 250; two thirds of those are Questar operated. We recently added a second rig at Elm Grove. We now expect to drill about 50 wells a year with two rigs.

Our Oklahoma City team also continues to stave off decline. Chuck and I were down there just recently reviewing their activities and I came away very impressed with the great job our folks are doing generating attractive drilling opportunities in the Texas Panhandle and western Oklahoma with a variety of targets that include the Granite Wash, Atoka and Morrow formation.

Briefly a comment on Wexpro: The Wexpro investment base, as Steve noted, has grown 17% over the past 12 months and Wexpro still has about \$700 million of identified undrilled investment opportunities — good news for our

customers, the customers of Questar Gas, and good news for our shareholders. That should drive further growth in the investment base and therefore net income while helping to keep rates for Questar Gas customers among the lowest in the country. Note that Wexpro produced about 10 billion cubic feet equivalent in the second quarter on behalf of the utility.

Gas Management, our gathering and processing-services business, had another good quarter as gathering and processing margins remain strong. They're going to be very busy this summer. We're building a 20-inch pipeline from our Blacks Fork plant to Kern River Pipeline near Opal, Wyoming. We're also expanding the Blacks Fork processing plant. We're building new facilities to handle growing volumes from Pinedale.

Also note we're expanding our Uinta Basin gathering and processing hub. With the Northern Ute tribe and another industry player as partners we're building 64 miles of 12-inch pipeline from a tap on Questar Pipeline in northeastern Utah down to the southern part of the Uinta Basin to pick up gas in new plays that would otherwise be stranded including Questar E&P's Gar Mesa/Flat Rock play plus some third party gas.

Please note that we're also planning another Rockies hub in the Vermillion Basin. We intend once more to piggyback on Questar E&P's investment in the area.

Let me move on to our regulated businesses, starting with Questar Pipeline. I hope you all saw that the pipeline net income was up 34% in the first half, 30% in the second quarter. As we've said in the past, we've given Questar Pipeline a simple mandate and that's to identify and eliminate pipeline bottlenecks in Questar E&P's core Rockies producing basin and they're getting after it. We're going to invest \$50 million to extend Overthrust

Pipeline west to Kern River Pipeline at Opal. This expansion should be in service early next year.

Also next year we're going to extend Overthrust 77 miles east to the Wamsutter hub in central Wyoming to an interconnect with the Rockies Express Pipeline.

Questar Pipeline also recently announced a binding open season for a notional 540 million cubic-foot-a-day expansion east from the Uinta Basin to the Meeker/Greasewood hub and Allan Bradley can give you more details on that in Q&A.

Finally, our utility, Questar Gas, earned its allowed return in the first half of 2006 for three reasons.

First, new customers added about \$4.7 million in non-gas margin compared to the first half of '05.

Second, we're now recovering part of our gas-processing costs which, of course, we were not recovering in the first half of '05.

And third, temperature-adjusted usage per customer declined less than we expected and that's despite high natural gas prices.

To summarize, all major Questar operating units posted double-digit earnings growth in the first half, but it's our E&P business that's driving value for Questar shareholders today. Questar E&P's updated reserves estimates, we hope, tell a pretty compelling story: This company has significant organic growth potential. Our E&P team is turning that potential into reality. For the second time this year we've raised our production guidance for '06. With

hedging we've taken commodity-price volatility mostly out of the equation for the rest of this year. We're gaining confidence in our Vermillion Basin shale play. With the initial results from our first two Mancos wells in the Uinta Basin we think we might be onto something good there.

And with that we'll now be glad to take your questions.

Operator: Thank you.

At this time I would like to remind everyone if you would like to ask a question press star and then the number 1 on your telephone keypad.

Your first question comes from Carl Brown of Cramer Rosenthal.

Carl Brown: Hi guys. Congratulations on a great quarter once again.

Keith Rattie: Good morning, Carl.

Carl Brown: A quick question on the reserve update. When you look at the Pinedale reserves of about 1.5 Tcf between probable and possible and divide by the locations that you've laid out for that, I'm coming up with about 1.2 Bcf per location which, even after you gross up for something like a 45% net revenue interest, that works out to about 2.7 Bcf per location. That just seems a little bit low relative to previous Pinedale wells. Can you just comment on that or whether or not I'm making a mistake in how I'm thinking about that?

Keith Rattie: I'm going to let Chuck field that one.

Chuck Stanley: Morning, Carl.

Without checking your math here, the average of the 10- and 20-acre probables is 5.6 Bcf and, you know, the average working interest is about 57% and the NRI's about 77%, and then all of those are in the probable category. So, basically, the unbooked 10- and 20-acre locations that aren't currently booked as proved are averaging about 5.6 Bcfe and there's 575 of those. And then the remaining 5-acre locations are averaging 3.77 Bcfe, same working interest in NRI, and there should be about 665 or so 5-acre locations. So when you go through that math I think you'll come up with the probable and possible reserves we reported there.

Carl Brown: OK. I'll double-check that and then I'll circle back if I have any more ...

Chuck Stanley: Yes, if you have any other questions, give us a holler. We'll help you work through the numbers.

Keith Rattie: And Carl, I don't know if it was part of your question or not, but please keep in mind on the proved side we've got about 585 of the locations that we've talked about on 10-acre densities that have not yet been booked.

Carl Brown: OK, great, and then on the Vermillion location, it seems like, between probable and possible, it's a little over 600 locations. It seems kind of right in line with the locations that you had listed out on your slide for the May analyst meeting.

I was just wondering, for the other 3,000 potential locations that you laid out in resource potential for Vermillion in the May analyst meeting, can you just talk about conceptually what needs to happen to move those from resource potential to a 2P, 3P number? Is part of that delineation wells that we're going to be drilling in the back half of the year or are there other factors involved?

Chuck Stanley: Sure, Carl. You basically answered the question for yourself. We need more spatial sampling, obviously, and if you think about it, as Keith described it, the reported probable reserves are simply the crestal area above the lowest known gas based on today's drilling and based on 80-acre density. As we collect more well data we'll get more confident as to the drainage area. And then, as we move down dip on the structures, we'll push out the known limits of gas, which is necessary in order for our reserve auditors to get comfortable with the classification of those areas as probable or possible. So that requires these additional delineation wells that you mentioned to push the limits of gas down dip.

In addition to that, we just need more time and well performance. So we wanted to get this update out because there's obviously some changes in our thinking on Pinedale and other places. But we also wanted to remind investors that this is a continuum and, as we collect more data, we'll modify the estimates. And, obviously, important wells haven't been drilled yet in Vermillion and those are those delineation wells. They'll come later this year. But, frankly, by the time we get those wells down, produce them long enough to get a meaningful production data set from them, it will probably be early next year at the earliest before we have a meaningful data set to update our estimates in the Vermillion.

Keith Rattie: I would just add — and I'll refer the others on the call to Slide Number 17 in our IR presentation which you can get on our Web site. The three key delineation wells that are yet to be drilled that we plan to drill later this year are shown there as the Sparks Ridge Unit Number 1, the Alkali Gulch Unit Number 3 well shown in turquoise, and another well in the West Hiawatha structure.

Chuck Stanley: Wild Hare.

Keith Rattie: Yes.

Carl Brown: OK, so after those wells get drilled, we would expect an update. We don't need to bring Netherland & Sewell back in to have them kind of redo the whole process?

Chuck Stanley: Ryder Scott does reserves in the Rockies, Carl. They will review this because we rely on them to sort of vet our reasoning and our assumptions. So we will obviously review it with them again, but it's incremental work, just like it was this time: OK, here's the latest information that we've developed, this is how we think it fits into our analysis, do you agree or disagree?

Carl Brown: Great. And lastly, Chuck, could you just give me an update on your thinking or progress on rigs in the Vermillion Basin and where we stand today, or where we expect to be towards the end of the year?

Chuck Stanley: Well, it goes hand in glove with this work that we're doing on delineating the field, Carl. Currently we're using older rigs which are sub-optimal for moving. They move in a lot of truckloads. And so, as we become more confident with the scope and scale of this play, we'll be talking to drilling contractors about specific custom-built rigs for this program. That will be happening hopefully by the end of this year.

Carl Brown: OK great. Thanks a lot and again, great quarter.

Chuck Stanley: Thanks Carl.

Operator: Your next question comes from Faisal Khan of Citigroup.

Faisal Khan: Good morning.

I just wanted to see, Chuck, if you could elaborate a little bit more on your last comment in terms of being able to drill up all these probable and possible reserves at a faster rate. So you're saying the data point in Vermillion is by the end of this year before you decide whether to take contracts for additional drilling rigs. How about for the other plays? How is that going to work?

Chuck Stanley: Well they're all in a continuum, Faisal. If you'll look at our previous IR presentation, our current IR presentation, in addition to the slides on the Vermillion, we have what I would call an E&P life-cycle curve. And these projects all sit somewhere on the curve as to our level of certainty and the key point where a project moves from the testing and validation phase into a sanctioned commercial development project. Obviously Pinedale was well into it.

The Vermillion is on the cusp and, as we gather more data, our confidence goes up there and our ability and comfort with committing to large-scale development in the form of long-term rig contracts, because we're still talking about having to sign significant-term contracts in order to have new built rigs available for these projects. It grows with every well we drill and with more of a spatial sampling.

Uinta Basin is a little earlier in the process. Obviously we have two wells down, as Keith mentioned. They're both very similar in characteristic to our results from the Baxter in the Vermillion Basin. As we see more performance from those wells and get additional wells down, that project will move along the curve into the realm of commercial sanctioning. We'll have to work with drilling contractors to pick up additional rigs.

So we try to give you that slide to help you see sort of graphically how we visualize these various projects and where they are in the continuum of certainty and maturity for commercial development.

Faisal Khan: How about the pilot wells — on 5-acre spacing at Pinedale. What do those look like now? How much data ...

Chuck Stanley: Well, first of all, we haven't drilled them yet. We'll drill them this summer with one of the rigs that's moving around to do some delineation work. After we get the data, there's two things that we look at from these 5-acre pilot wells: The first will be real-time information where we will collect pressure data in individual sands to determine whether or not they've been drained or partially drained by the nearby well.

Basically what we'll do is we'll offset some of the oldest wells that have been producing the longest on our property. And theoretically those wells would have drained a larger area because they've been on longer so, by offsetting about 5 acres, if there's going to be drainage or interference, hopefully we'll see it in these 5-acre pilots in the form of pressures that are below virgin discovery pressure. So that data will be real-time and important.

And then, after we correct the pressure data, we'll go on and complete the wells normally like we would any development well at Pinedale and then monitor the production performance to see whether or not the offset wells perform as the parent well was performing or if there's a lesser performance. From that production data we can then validate our assumption on reserves or degradation in reserves or interference between the 5-acre well and the parent wells.

Faisel Khan: OK, I got you. Can you just talk about the 500-million-cubic-feet-a-day expansion you're looking at on the pipeline system? What exactly is that? Is that the binding open season you're holding on that system?

Keith Rattie: I'm going to let Allan Bradley handle that.

Allan Bradley: That's correct, Faisel. What we're looking at is a expansion of our system from Fidlar, which is sort of in the core of the Uinta Basin, over to the Greasewood/Meeker hubs which are the receipt points into the WIC and Rockies Express-Piceance laterals.

We're also looking at an expansion of our Rifle line east to west coming up from northwest Colorado. Obviously we have, as Keith said, looked at a notional 540 million a day, which will be a culmination of flows moving west to east from the Uinta Basin over to the Greasewood/Meeker hub, and then basically Colorado east and north up to the Greasewood/Meeker hub.

So we're looking at basically a pretty flexible service. We're looking for binding bids. We're asking customers would they like that service done incrementally or would they like to have Questar Pipeline integrated with this existing system which gives them access to Clay Basin? We're a couple weeks away from finalizing or from the open season closing. There's a lot of competition in these corridors, but hopeful we'll get a sufficient interest that would allow us to go ahead and build in that corridor.

Also in the background, we're talking with Northwest Pipeline about a joint venture expansion for some of their volumes which would move basically Williams E&P production from the Greasewood area over to Sand Springs and their connect with the Northwest pipeline systems. So there's a lot of activity in that corridor right now sort of driven by the big Rockies and WIC

expansion projects moving east and we see a potential to help de-bottleneck that corridor.

Faisal Khan: And what's the cost of the 540 million cubic feet a day?

Allan Bradley: On the upside it's between \$150 and \$200 million.

Faisal Khan: OK. Thank you for your time.

Operator: Your next question comes from Shneur Gershuni of UBS.

Shneur Gershuni: Hi, guys. Congratulations on a blowout quarter.

Just had a couple quick questions. Some of the previous callers actually asked most of my questions. That said, I was wondering if it was possible to break out the deeds that are associated with the deep play in the Mancos and so forth that were booked in reserves.

Chuck Stanley: For the Uinta Basin — this is Chuck Stanley, Shneur.

Shneur Gershuni: Hi, Chuck.

Chuck Stanley: Are you talking about individual wells or the total number?

Shneur Gershuni: Yes, basically, Bcf per well, if that was possible.

Chuck Stanley: For the...?

Shneur Gershuni: For the lower...

Chuck Stanley: We assumed about 3 Bcf per well.

Shneur Gershuni: Three Bcf per well.

Chuck Stanley: That's on a gross basis, Shneur.

Shneur Gershuni: OK.

Keith Rattie: And Chuck, just to be clear, that's for the entire section?

Chuck Stanley: That would be for the Baxter to Dakota section so that would include the — I'm sorry the Mancos section and Dakota section only, the deeper section only.

Keith Rattie: Right.

Shneur Gershuni: The deeper section, OK.

My next question is, I'm wondering if we could switch gears to the deep test at Pinedale and so far understand completely a science project at this point right now. I guess the comments were it wasn't currently viewed as economically viable, or there wasn't enough data and so forth.

What is the next step that you guys would do? Is there any interest in drilling another one, and do you have flow data that you would be able to release at this point right now?

Chuck Stanley: Well, Shneur, Keith gave you a little bit of flow data. We started testing of this well last fall by testing the Hilliard shale. We had a very short duration test, as you'll recall, blocked off. We went back in, we cleaned it up. What we

found during the cleanout was really not as bad as we had feared. We had some concerns that perhaps the Hilliard had flowed into the wellbore and completely plugged it. The upper obstruction was only about 30 feet and it was mostly frac plug and proppant with a little bit of shale debris.

We didn't encounter any other obstruction in the wellbore until we got down to about 19,050 feet where we hit a second obstruction and we're not sure if it was a frac plug. We had two frac plugs in the well when we frac'ed the Hilliard in three stages. One of them was the one that was up at 6,000 feet. The second obstruction, the deeper obstruction, down at 19,000 feet, may have been a frac plug that moved a few hundred feet up the hole which was set above the first stage of the Hilliard. We couldn't get through it.

Now the other alternative interpretation is that the casing collapsed in the bottom half of the Hilliard. That's certainly a possibility given the bottom-hole pressures, although the mechanical calculations for casing strength would argue against that. It could have been the damage during the casing, damaged threads on one of the joints that collapsed. We just don't know.

Given the pressures, we determined that it was uneconomic and very risky to continue with the snubbing unit to try to clean the well out, so we tested the lower interval. And, as Keith mentioned, during last fall's test we opened the well up to see what it would do and we'd never experienced any mechanical failure ... so we reported initial rates of 10-1/2 million a day or so last fall.

This time we decided to basically hold back pressure on the well and not let the flowing pressure drop too much. And we saw with back pressure on the well that we could stabilize the well and flow it at a million to a million and a half a day from the Hilliard. And, yes, sure it might do more than that, but we risk mechanical integrity of the wellbore and we just didn't want to do that.

After seeing the Hilliard rates, which were about what we were expecting from the half interval or so that we tested, we thought we'd gathered all the information we needed there. As you'll recall, the primary objective was the Rock Springs, so we moved up hole.

We pumped a total of six stages in the Rock Springs formation. The bottom one was at a depth of a little over 18,000 feet — 18,200 feet. And the top stage — the top of the top stage — was about 16,330 feet: six separate stages, all frac'd and pumped and frac'd at the same time — multi-stage frac stimulation.

And then we drilled out all of those frac plugs and co-mingled those six stages — Hilliard, remember, is behind the plug — and we flowed the row and what we saw was, you know, initial rates of 2 or 3 million cubic feet a day sort of stabilizing in the 1 to 1-1/2 million cubic feet a day (range). But interestingly, in this interval — it's a very coal-y interval, especially at one of the frac stages — we also are seeing a lot of water and this water's coming from the coals and it's not surprising because, typically, coals have water in them.

We don't know if they'll do water or not, but it presents all kinds of interesting problems for dealing with water at this depth, both just the volume of water for a water-gathering system and the challenges for disposal. But it also created some additional problems because the water — the fluid compatibility issue — creates a minimal scale inside the casing which we had not seen in any of the other Pinedale wells and it's clearly related to the chemistry of the waters associated with the coal.

So we're still producing that coal-y interval. In fact we think most of the gas in this Rock Springs is coming from the coals; very little's coming from the

sand. That's due to the low permeability of the sands. We want to produce it a while longer to see if we see any meaningful change in the water-to-gas ratio that would indicate that these coals are de-watering. We think they probably would de-water over time. The question is, at these rates, is it really economic to spend a lot of time trying to de-water them because it is, as you said, a science project, probably not an economic project.

There are some additional sands up hole in the Upper Rock Springs that we need to frac and flow back to determine whether or not they will produce at commercial rates. Logs are notoriously difficult to interpret in these tight gas sands so we just have to wait and see whether those sands are any better than what we've seen so far. They're not markedly different than the sands that we've already tested so it would surprise me if the result was much different.

Shneur Gershuni: So I guess would it be fair to say it's too early to figure out whether you want to do another science project?

Chuck Stanley: Well, science projects are interesting for scientists and I'm a scientist, so I would tell you that I'm interested in the science. But as a businessman it's pretty difficult to justify drilling another well based on what we've seen in our area today, I mean, it's clear there's a lot of gas in the rock, (but) when our technical team sits around and discusses this thing, we can't come up with anything different to do in another well as far as completion technology and frac design that we think would yield any different result. It's just tight rock that, as we said at the outset, is not giving up gas at commercial rates.

We were actually frankly surprised at how easy it was to frac. We had mustered a lot of horsepower especially for the Hilliard to pump these large fracs and the fracs went very easily. In fact they didn't look that different from a Lance Pool frac as far as the ease of pumping the frac jobs. So we think we

got the well properly stimulated and it's just not giving up gas at rates that would be commercial at this depth and for these well comps.

Shneur Gershuni: OK. I'm sure there's lots of people with many more questions after me, but I must say that we're definitely glad to see both the Mancos and the Vermillion additions and reserves. I guess that's it for now.

Chuck Stanley: Thanks, Shneur.

Operator: Your next question comes from Sam Brothwell of Wachovia Securities.

Sam Brothwell: Hi — good morning.

Keith Rattie: Morning, Sam.

Sam Brothwell: Hey, Keith, I don't want to beat this deep test to death, but from your vantage point, let's say that that it looks like it's not going to work out as originally possibly thought. But as you look at the whole scene, how does a loss of that deep potential, if that's what happens, how does that affect your view of the overall potential for what you're doing? It seems to me that maybe it's gotten a little bit overblown in the market.

Keith Rattie: Well, Sam, we think it probably has. From my vantage point, I'm much more interested in execution with respect to the Lance Pool development. We are early in the second inning of what may be the most profitable natural gas play in the U.S. Lower 48 today. We've got over 932 locations total with over 750 of those yet to drill on 10-acre density.

If I had to rate the things that I think about today in terms of possible future growth potential, I'm very focused on the results we're going to get from the

5-acre density evaluation that Chuck talked about that we mentioned in our earlier remarks. I'm very focused on these next few delineation wells in the Vermillion Basin because they have the potential to extend the play significantly, and I'm very focused on the Mancos development as well.

A final concern, as we focus on returns on invested capital, as we focus on cost and keeping our cost structure very competitive so we remain one of the last ones standing if there is a significant pullback in gas prices some day, I'm concerned about the impact that the dedication of rigs and people, time and capital to a deep play would have on our ability to execute on the rest of the stuff. I hope that kind of helps you calibrate where I've seen this from the get go.

Sam Brothwell: Yes, and I think it's also important to think about that there were maybe 200 deep locations out of thousands of potential drilling locations.

The other thing I wanted to ask you, Keith, as obviously the E&P story I think is continuing to clock along well, is there any update to your thinking on how to ultimately properly structure the company?

Keith Rattie: There's a lot of thought being given to that question as there has in the past and there continues to be a lot of thought given to it. When you talk about structuring, what you're talking about are any number of ways to unlock value and close what we see as the value gap in the company today.

The industry obviously is talking about the potential for putting pipeline and midstream assets into an MLP. There's pretty crowded array of offerings coming to the market right now. That gives us some concern.

Our other issue there is that we've got several projects in the pipeline business that are going to require some capital that, if we execute the cash flows from that business, will be significantly higher and that will give us the more flexibility to — and probably enhance — the consideration of an MLP.

What we see — a trend emerging today is that MLPs are launched on a much smaller scale, EBITDAs in the \$40 to \$50 million range typically, with visibility to future growth mostly organic and much of that resulting from the drop down of assets from a parent and that's a model that we're looking at very closely.

We get a lot of questions about the utility and whether or not, in the current industry environment, remaining in integrated natural gas play is still the best strategy for the long term. The answer to that question depends a lot on what you mean by the long term and your view of commodity prices going forward.

Our thesis has been, and continues to be, that we can offer investors a lower risk play on the fundamentals of gas with this mix of businesses but, as you noted, the reality is that the utility this year will generate only about 8% of our corporate net income. It's been significantly marginalized as far as shareholder value is concerned.

This is a topic that we talk with our board about in every board meeting. We're going to have another conversation in August. We are a team that is going to do the right thing for the shareholders over the long term.

Sam Brothwell: OK. Thank you very much.

Operator: Your next question comes from Carl Kirst, Credit Suisse.

Carl Kirst: Hey, good morning, guys.

Just very quickly, Keith, Chuck: From an economic standpoint on the 3P reserve report, was there any specific price deck that was assumed? And also, Chuck, do you have a rough estimate of what the development capital associated with the non-proved reserves are or should we basically be just using the development costs of the PUD which was, I think, around \$1.30 an M(cf) when we run our net asset values?

Chuck Stanley: Carl, I'll answer the last question first.

Obviously the development cost on this stuff — the way the logic on probable/possibles work is you use now current cost. And basically we looked at that and we see on average that these are \$1.75 finding and development cost numbers across all categories, on average. Some are higher, some are lower, but it's in that ballpark.

And the second question, or the first question you asked, by nature of probable and possible reserves, you don't look at a particular price deck when looking at these things. They're looked at on a technical-certainty basis and, of course, if you go back and look at our earlier — our first probable and possible release last year — you will see some definitions and we've adhered to those definitions, which are generally accepted, I think, by the reservoir engineering firms — reserve auditing firms — as the definitions for probable and possible reserves, and they do not include a price-deck assumption.

Carl Kirst: Yes, that was my understanding. I just wanted to make sure of that ...

Chuck Stanley: So, in other words, Carl, in plain English, they're unrisksed and by categorizing them as probable or as possible there's an implicit risk embedded

in the categorization rather than reducing the absolute number for risk or for price sensitivity.

Carl Kirst: Now fair enough.

Two other quick questions if I could: Just delineation wells that are going to be drilled in the Vermillion later this year. So again, just to kind of confirm from a timing standpoint, we hopefully will be in a position that, by the end of the year, not only will we have completed but we'll also have comfort with the test data out of those three wells?

Chuck Stanley: No.

Carl Kirst: No?

Chuck Stanley: In fact, probably not. We're drilling these wells not necessarily in the order that you would — you as an investor or we as a management would like to drill them — but we've been driven in part by when the permits are popping out of the BLM.

And secondly, we're forming federal units and we're drilling these wells strategically to preserve as much leasehold as we can out here by unitizing and so, to a certain extent, leasehold and expiring leases are driving our strategy of which wells we drill first. And it's not necessarily the ones that you're the most interested in, and that I'm the most interested in, that are getting drilled first.

Probably it will be late year before we get the key delineation wells down and maybe even into the first quarter, and then we'll need enough production history from them to get comfortable. So it's a first-quarter, second-quarter

'07 event before we really have a full comfort level on these off structure wells.

Carl Kirst: No, that's great color. I appreciate that.

And then just a last question: As we look at the total production guidance for the full year '06, it would seem to imply a relative growth rate that's a little bit lower here for the second half. I don't believe you guys have given official guidance for 2007 but I guess is it safe to say that, with everything that's going on, you guys are still encouraged, hopeful of certainly seeing sustained double-digit production growth in '07?

Chuck Stanley: I think so Carl. I mean, there's a lot of moving parts here. As Keith mentioned, we've been pleased and frankly a little surprised at the delivery from our Midcontinent team, not only from the western Midcontinent folks, Oklahoma City, who have continued to amaze us with their ability to harvest this rather mature set of assets to replace decline, and that the eastern Midcontinent team, who's charged with developing the Arkoma properties and also northwest Louisiana, has been able to deliver astounding growth from the Elm Grove area. They've recently picked up a second rig. But as that production volume grows, it's a bigger and bigger snowball that you have to push uphill and it's unrealistic for us to expect them to continue to deliver the production growth rate that they have.

They've certainly bolstered this year's early period, first and second quarter growth, that's going to slow down some as we go into the third and fourth quarter and into next year. We're fighting a fairly mature set of assets in the Uinta Basin that we hope this Mancos play that's evolving will help breathe new life into.

So those are the variables and, of course, the big delta comes from Pinedale and this year we'll complete somewhere between 45 and 48 total wells. We think we can do a few more next year. Again, that snowball gets bigger and bigger.

The big step change, Carl, in our ability to grow production organically is a process that's under way right now to submit to the BLM a supplemental EIS at Pinedale which will allow us to go to areas of concentrated development — one for each of the three operators on the Anticline, but would allow for year-round drilling, which we already have but we have it on a limited basis.

You'll recall we can drill with six rigs from three pads through the winter but we can't complete any wells until after May of each year and then we have to be done with their completions by the 15th of November. With this supplemental EIS, which we anticipate will hopefully be approved in the middle of next year or by the middle of next year, we'll be able to go to a more or less conventional level of activity where we can drill, complete and move rigs around.

We'll still be concentrating our activity on pads to reduce surface disturbance, but we won't be constrained as we are now by only being able to complete half of the year. That could result in a step change in our ability to drive production out of Pinedale, potentially doubling the number of wells we can drill and complete in a given year.

So that's a big catalyst out there, but it won't happen until 2007, and even if it's approved it won't have an immediate impact because we'll have to move additional rigs into the area in order to achieve the full level of activity.

Carl Kirst: Great. No, that's excellent kudos and good luck.

Chuck Stanley: Thank you.

Operator: Your next question comes from David Thickens of Deephaven.

David Thickens: Good morning, gentlemen.

Most of my questions have been answered, but going back to the revisions that you made today in your probable and possible: In the May analyst meeting you had 680 3P wells in Vermillion and then another 3,100 in resource potential. How many of those 3,000 wells in resource potential — of 3,100 in resource potential — were moved into the 3P category with today's update?

Chuck Stanley: Give me a second. The number of probable and possible wells included in today's number — I think, Keith, you have that number in your script there, don't you?

Keith Rattie: Two hundred and ten — was included in the probable estimate and 478 in possible. If you add those two they add up to the 680. I believe the answer is zero.

Chuck Stanley: That's what I was thinking. I wanted to make sure that was correct. That's the number that I have as well so...

David Thickens: But you didn't add anything that was — that was nothing — OK. So we've still got over 3,000 potential Vermillion wells that are not included in the 3P numbers...

Chuck Stanley: In the ...

David Thickens: ...the revised 3P number you put out today?

Chuck Stanley: That's correct.

Keith Rattie: That's correct. And if you go to Slide Number 21 in our presentation, the numbers we gave you today are consistent with the Vermillion numbers in that slide.

David Thickens: OK and...

Chuck Stanley: And the reason for that, of course, is we haven't drilled any new wells outside of that limit of lowest known gas that we talked about in our analyst presentation in May.

David Thickens: OK. So kind of the negative focus we're seeing on — maybe the disappointment that we're seeing from what you've mentioned in the — about the relative lack of success so far in the deep test really seems to me to be missing the forest for the trees.

Chuck Stanley: That's certainly an interesting way to interpret it.

David Thickens: OK — fair enough.

The other thing I'd love you to touch on a little bit is can you talk about the supplemental EIS in the Pinedale a little bit more?

Chuck Stanley: Sure.

David Thickens: Where we are in terms of timing and, if that comes through as hoped, what is that going to do for your ability to accelerate development in that play?

Chuck Stanley: OK, well, I just talked about it with Carl Kirst's question ...

David Thickens: OK. I'm sorry. I missed that then.

Chuck Stanley: But just, very quickly, we believe that timing on that is likely second half of '07 for certainty. And as I mentioned in detailing my answer to Carl, the key is that it's not a switch, that when we get approval, the next day we can immediately go to the rate change or step change and the pace of development to double the number of wells we can drill. It will take time to build a good quality inventory of rigs out there to effect the step change, so it won't be an instantaneous event, but it's an event that is very meaningful for Questar shareholders.

As to the process, it's the same process that any Environmental Impact Statement goes through except, because it's a supplement to the existing EIS, it's narrower in scope. But it still goes through a process of consultative meetings with various stakeholders, formal public input session, and then, ultimately, a full study of all of the various scenarios by the BLM and ultimately a decision by the BLM.

David Thickens: Am I correct, though, in that, if it's passed, you would have to be kind of at the minimum spacing or have the minimum spacing figured out, because once you're in an area and move out of that area you can't go back in. If you developed it on tens...

Chuck Stanley: Absolutely.

David Thickens: ... for example, and then later decide that, you know, fives are going to work.

Chuck Stanley: You're absolutely correct, David. I mean, one of the tradeoffs in this supplemental EIS will be that we will concentrate our development activity in an area, drill it up and then move north or south through the field. And as we move out of an area we will reclaim the surface disturbance that is larger of necessity for drilling because you have to accommodate the drilling rigs and the associated equipment.

Once the drilling is complete, we can reclaim those surface disturbances down to probably about, oh, half or less than half of the disturbance during the drilling phase. Once we do that, we're done. We will commit not to come back, which is why we are going to do 5-acre pilot studies this summer to determine what portions of the field are amenable to 5-acre development and answer that question so that we know the answer before we start into this concentrated development plan.

David Thickens: OK.

Keith Rattie: David, this is Keith Rattie. I'm going to cycle back to your earlier question on the Vermillion Basin and add a couple of key points that maybe we've overlooked and will help with the understanding of what we've done on reserves.

We've mentioned in the Vermillion Basin that there are 680 gross unrisksed locations in the 3P estimates, 210 of those are in the probable and about the rest are in the possible. The probables are based on 80-acre development. The possibles pick up 40-acre development.

The point I wanted to add is that well performance to date suggests — it's early, but it suggests — that these wells are draining a lot less than 40 acres. And if you look at the resource in the rock, I think you could see the potential for an increased density down the road as well.

David Thickens: And what are — the resource potential wells are based on — is that a — in the core area — you've got it broken down 1,400 in the core and 1,800 in the expanded area. I'm assuming that the difference between the 680 and the 1,400 or the incremental 1,400 in the core is down-spacing, or is that a greater extent in the core area as well?

Chuck Stanley: It's down-spacing to densities below 40 — into 20-acre density and then the expanded area pushes the limits of the play off of the structures and into the synclines.

David Thickens: OK. All right, well thank you very much.

Chuck Stanley: You're welcome. Thanks David.

Operator: Your next question comes from John Mansfield of SAC Capital.

John Mansfield: Yes, good morning. Great quarter, guys. Just wanted to ask the question about, with the number of undeveloped locations you guys have now, in the thousands, do you see any value in bringing in a partner doing some drill-to-earns or doing anything to accelerate the drilling in some of these fields to not only increase the actual proved but also just to increase the production?

Chuck Stanley: John, that's a good question. I'll take it, Keith, and you can bat it back and forth.

The first thing that we want to do is delineate these plays. So, for instance, the Vermillion, we'd like to know what we have and have a good handle on its ultimate value before we consider taking a partner. I'm not going to foreclose the possibility of taking a partner, but frankly the limitation right now is not capital. It's the natural caution and a sort of progression that you go through as you pilot, validate and then start a commercial development project. So even if we had a partner, our conversion rate from probable/possible to proved and from proved to production wouldn't be materially different.

I think we have plenty of access to capital to, in essence, develop these assets at whatever pace we deem prudent. The other obvious constraint is the ability to obtain good drilling rigs and use those drilling rigs efficiently to develop these fields and, as you know, in places like Pinedale we have further constraints on the pace of development like seasonal access restriction.

John Mansfield: Sure. Also, as you alluded to the possible MLPing of the midstream assets, I mean, what would be the reason for not doing that. Doesn't it just make so much sense to do that?

Keith Rattie: Right now our thinking on it's more of a timing issue. Clearly an MLP structure has a big advantage from a cost-to-capital standpoint and we're very focused on that. MLP valuations today are better on a per-unit EBITDA and other metric basis than what we think is implicit in the ownership of assets in a C Corp type structure.

It's a crowded field of current and potential new entrants. First law of stampedes is someone always gets trampled, but beyond that we're looking down the road to the completion of these projects that we've talked about and then more flexibility in how you execute an MLP — a transfer of pipeline and, potentially, midstream assets to an MLP-type structure.

John Mansfield: OK, and then I guess the last piece would just be on the deep Uinta. What is the spacing on the two wells that you have down in there now?

Chuck Stanley: They're 160 acres apart from each other in the same section, John, and the third well is in the same section as well — or actually it's a section away, but it's in the same area.

John Mansfield: OK, and you haven't actually flowed from the third well?

Chuck Stanley: No it's still drilling.

John Mansfield: OK.

Chuck Stanley: It's nearing total depth. It's below 14,000 feet. We've had, frankly, some tough drilling problems with the well because of high pressures in the shale, but it's a learning curve that we're on in drilling these wells as well. Our plan is to drill some more and obviously get some spatial sampling away from this area. This, again, happened to be the permits that we had in hand at the time.

John Mansfield: OK. All right. Well, once again, great quarter, guys. Thank you.

Chuck Stanley: Thank you.

Operator: Your next question comes from Rick Gross of Lehman Brothers.

Rick Gross: Keith, I finally made the queue. I've got I guess just scraps left.

Keith Rattie: Rick, we were not trying to exclude you.

Rick Gross: I know. I took it personally.

My assumption is on the supplemental EIS, with the deep test coming in the way that it has, and you've got 5-acre pilots at the end of the year, that you'll probably go about a program that emphasizes the Lance Pool and that you won't spend a whole lot of time and attention to figuring out how you would want to optimally develop the deeper horizons at this juncture.

Chuck Stanley: That's a reasonable assumption, Rick. I mean, frankly, developing the deep and the Lance Pool simultaneously presented a whole host of challenges that involve different size rigs, potentially two separate gathering systems because of pressures, et cetera, et cetera.

Rick Gross: Right. OK.

Chuck Stanley: So this profoundly simplifies it.

Rick Gross: Right. From a standpoint, you alluded to it any number of times, one of the things that I've wondered is that you've done a very, very good job of monitoring your costs, riding the rig operators, working all the various types of science experiments into improved techniques and complete wells, et cetera. As you move from Pinedale — accelerate Pinedale a little bit, move to Vermillion, if you have success in the Mancos, do you have enough internal capacity? I mean, is all the people, your drilling engineers, et cetera, et cetera, scaleable to handle — we'll call it attacks across multiple fronts or is that also an issue aside from just getting good rigs, et cetera?

Chuck Stanley: Well, obviously, manpower's always an issue. In this environment it's a huge challenge for us, Rick.

I think the interesting thing is, a lot of the techniques and basically efficiency gains that we have been able to accomplish at Pinedale are transferable technology — not the specific well design but the techniques, the focus on certain things that really matter in driving down cost. And what we have now is a cadre of people on the rigs who are doing this stuff themselves and are looking for ways themselves to make improvements.

So Pinedale, while I'm never satisfied with the results and will always drive for lower number of days to drill and complete wells and lower cost, it's pretty much on auto pilot. We've got a great group of people who are doing good things and making improvements every day out there.

We can now take the core team of people who have driven that efficiency and turn their attention to another manufacturing process like Uinta or like Vermillion, use the same techniques, the same basic tools that we used at Pinedale, and I think that's something we're really good at and we've got a good — a great — group of people that do it. Trust me, it's not me that does it. It's these folks that are focused on this 24 hours a day, seven days a week and I have no doubt that, given time, that they will come up with ways to do the same thing that they did at Pinedale in the Uinta in the Vermillion Basin.

I think we have the people to do it. Most of the people that we have are obviously working very hard but, given their capability, we feel pretty comfortable that they can expand to take on the additional work.

Rick Gross: OK.

Keith Rattie: Rick, from where I sit, one of the most important things that Chuck and his team have done in the last couple of years is, we've recruited a lot of new talent to the company and some bench strength and some youth in the

organization. And it's pretty impressive to watch the younger folks learn from the old pros and not too much emphasis on the old part of that.

This industry though is, I mean, this is a critical issue. I think it could be the Achilles heel for the industry if we don't continue to attract young, talented technical professionals to the industry. We are doing our best to build this part of the organization and I'm pretty pleased with what we've done to date, but we've got some more to do.

Rick Gross: OK. I'm going to ask a question on the Midcontinent.

It seems like over in Oklahoma, you know, you mentioned the Granite Wash, you mentioned Atoka. I assume you've got a considerable amount of HVP that a lot of these things are developing plays that, whether it's completion technology or it's interpretation, technology would seem to set up a reasonably long duration inventory given — and you haven't talked so much about, we'll call it, the inventory that you may have built there as far as well locations the way you've described it in other areas. Can you actually do that given the nature of how some of these plays are developing?

Chuck Stanley: Well, they have now — they've developed kind of like amoebas. A lot of these plays started on structures and they've migrated off the structures and into the holes between the known structures. The Granite Wash play's a great example. You look at a Granite Wash well log, it looks like a Pinedale log. It's got just a huge pile of sand.

And it used to be, back when I started out as a geologist and looked at the Midcontinent, you only completed the things that really met a specific pay criteria on your log analysis. And today you frac the entire section and it gives up gas and people go, oh wow, that's all reservoir!

Our Western Midcontinent position, unlike Pinedale, the Uinta Basin, Elm Grove even, is a typical fragmented leasehold position where we have in many instances less than 50% working interest in sections and those sections are by and large not contiguous.

So what we see is activity over a broad area and not a lot of concentration with just a handful of exceptions — one being the Granite Wash play where we've identified 30 or 40 development locations to chase so we're able to secure a rig and drill a program there. But that's the exception rather than the rule in the Midcontinent, and the technical team there and the land team, more importantly, start the year with no proved undeveloped locations and continue to drive production and reserve replacement with basically no inventory. And it's an amazing accomplishment and one that they have continued to be able to do.

And it's a strong testament to their capability and it's also a testament to the resilience of that basin as plays have evolved in these different intervals, as tight-gas-sand technology has taken off not only in the Rockies but also in the Midcontinent region.

Rick Gross: OK. One last question: I'm surprised that I haven't heard a revival of the storage project out of the Rockies given the build-out of your network, given the flexibility that you articulated earlier that you're trying to provide people access to multiple pricing points and given what I look as huge seasonality. I mean, if you look at the forward curve and you look at how gas is being priced in summer versus winter. Is there a particular reason why we haven't seen a revival in the storage projects you've talked about?

Keith Rattie: It isn't exactly dead, Rick, and I'll let Allan Bradley add to my comments. I assume you're talking about the salt-cavern storage development.

Rick Gross: Well, salt cavern, or just any project at all?

Keith Rattie: One of the major — one of the big hurdles today and then I'll let Allan — we are active on a parallel path with the salt-cavern project but the big challenge today is the high cost, the big investment associated with cushion gas for storage. There's a lot of capital that's tied up just in filling up the cavern to the level where you can add working gas and operate it. So cost, and therefore the economic value of storage, is an issue.

The other problem from a developer's point of view is regulatory policy, I mean, you're absolutely on the mark. We need a lot more storage in this country and I think we're going to see evidence of that over the next couple of quarters.

The U.S. market today would benefit a lot if we had over 4 Tcf of gas in storage at the end of the injection season but that's not going to happen due to capacity limitation. The regulated returns that are allowed for storage aren't keeping up with the market value of storage and the cost and risk associated with storage development. It's a problem that we think needs some attention.

Rick Gross: Thank you.

Operator: Your next question comes from Monroe Helm of CM Energy Partners.

Monroe Helm: This is really for Rick Gross. I just figured out that they're going through the queue by age since I just came in behind him. But actually, my questions have been answered.

But while it's disappointing, I'm sure, that the deep test didn't work out, it's probably good from the stock-market standpoint that the focus would go off that and back onto trying to improve the present value, you know, moving the present value, the 3P reserves, forward. And I think you're doing a great job going back to the Wyoming commission to try to accelerate Pinedale.

So great results and just keep it up.

Keith Rattie: Thank you.

Operator: Your next question comes from Joe Magner of Petrie Parkman.

Joe Magner: All right. I think I might have a couple more scraps to follow up on.

Any update on the Hiawatha EIS and where that stands?

Chuck Stanley: Joe, the Hiawatha EIS, as everyone or maybe not everyone realizes, is the Environmental Impact Statement associated with the Vermillion Basin development activity.

Joe, it's moving along through the process. As we've stated, these things take 18 to 24 months to go from inception to final approval. No surprises so far, as far as anything that we didn't anticipate.

Joe Magner: OK. And there were, I believe, a couple more wells in the Vermillion completed in the second quarter. Any update on those wells or just general comments on how, now that you've got three more months of production data in the Vermillion, how wells have been tracking to your model?

Chuck Stanley: You're correct. We had a couple more wells added. These wells were basically sort of inside the known limits of gas so it didn't add anything materially as to the aerial extent of the gas.

The well performance on the two new wells falls right on to the type curve that we've developed and we continue to see from the older wells. These wells are tracking along pretty good on our type curve. We still see 2-to-4-Bcf range per well and everything seems to be holding together pretty good.

So we're — as Keith said in his comments — gaining confidence in the repeatability of the play. Obviously we're anxiously anticipating drilling some of these off-structure wells to see if we see a fundamental change in the rock properties or well performance relative to structural position.

Joe Magner: OK. Great. And, then, just one other follow-up question on one of the first questions. Specifically, the 2P and 3P potential based on the number of locations you lined out and then the per-well reserves that you talked about and the net revenue interest. Was there any sort of risk factor taken into consideration on the probable and possible on the Pinedale?

It seems like, if you walked through the math, locations, per-well reserves, and then your 49% roughly net-revenue interest, you come up with something much higher than what you put in the table. Just curious about risk and how that was taken into account.

Chuck Stanley: No, there's no risk other than the implicit risk in the characterization of the reserves. Probable reserves carry a higher probability than possibles. But the numbers that are included — the way we build this is, we start with gross unrisks per-well reserves and then adjust, you know, obviously count the locations and then adjust for average working interest and average NRI.

Keep in mind that we do, in our 10-acre and 5-acre wells and in the 20-acre locations, reduce the average EUR to take into account potential interference between wells drilled on denser spacing. So, as we've stated in the past, we impact the reserve assignment for an individual 10-acre well at roughly 60% of the EUR of a 40-acre parent well within that 40-acre spacing unit.

So if that's what you mean by risking, yes, there is a reduction. But we believe based on reservoir modeling that there will be some sands that will cover greater than 20 acres and greater than 10 acres and therefore be drained by more than one well and that we need to account for that in our reserve assignments.

Joe Magner: OK. Maybe we can follow up off line and just go through the math.

Chuck Stanley: Sure. Be happy to.

Joe Magner: OK. Great. And then, just shifting gears on the regulated side: There were some hearings planned for June to discuss the issue of decoupling revenues from usage. Was there any update on that front?

Keith Rattie: I'll let Alan Allred handle that.

Alan Allred: Joe, those hearings that were scheduled for June have now been moved to the first week of September. Testimony's coming in. We still have support for the decoupling from the Division of Public Utilities, from some — from Utah Clean Energy and from a southwest energy-efficiency group along with the Natural Resources Defense Council. It is being opposed by our consumer advocate in the state and we'll just have to wait and go through the hearings and see where we end up.

Keith Rattie: As you know, Joe, other states have embraced decoupling. It eliminates the disincentive that a utility has to work aggressively to promote conservation. For Questar Gas, about 70% of our revenues are tied to volumes. We do promote conservation, mindful of the fact that when we're successful it hurts us.

Decoupling would basically result, if customer usage declined through conservation efforts, the utility wouldn't be hurt by it. We think that's a win-win for our customers, for Questar Gas and for the state, but as Alan mentioned, the state-funded agency is opposing it. Others are opposing it unless we offer some kind of a rate reduction and so the outcome on this is uncertain.

Joe Magner: OK. Thanks. That's all I've got.

Operator: Your next question comes from Brian Singer of Goldman Sachs.

Brian Singer: Thanks. This may have already been asked, but I just wanted to check what current finding and development cost assumptions are in the Uinta Basin, especially as it relates to the incremental probable and possible reserves that you added. What gas price do you feel like that works at and what would be the finding and development cost associated with that resource?

Chuck Stanley: OK, Brian. Give me a second here while I find the numbers for you on the Uinta.

As I mentioned in one of the questions — answered in one of the questions earlier — we did not screen these reserves based on price. We did it strictly on a technical assessment so these are price-independent reserves.

The question on finding and development cost — I'm having trouble finding that right sheet here. Hang on for a second. For the Uinta, the average probable finding cost is \$2.05 and the possible finding cost is \$1.90.

Brian Singer: Great. That is helpful and is it safe to say that that's — I guess between that and relative to Pinedale or relative to Vermillion that you went to — on the high end?

Chuck Stanley: Yes that's right.

Brian Singer: Yes.

Chuck Stanley: And let me point out, Brian, that these are unrisks reserves and unrisks costs and they're cost-based on our current experience, not on any assumptions of future well-cost savings through economies of scale like we're enjoying at Pinedale.

Brian Singer: Based on your current price outlook and the drilling results that you've seen so far in the Uinta, is that something that you'd think about accelerating drilling, or what would be necessary for that to happen?

Chuck Stanley: Well, we see more than just the Mancos as potential in the Uinta. We see the lower Mesaverde, the Blackhawk, a silt in the upper part of the Mancos which used to be as deep as we drilled called the Mancos B always adding incremental reserves to just this — to add to the economics of the Mancos play.

We're also intrigued by the possibility of infilling our existing Wasatch well development program on 20-acre density. We were concerned about that on

the stand-alone basis because of potential interference. It probably wouldn't work, but with the addition of upper and lower Mesaverde, Blackhawk, Mancos B and Mancos shale reserves, we get up into the 4- or 5-Bcf-per-well range. That makes an economic play, and if we can get a repeatable result out of this deeper section as we drill some more delineation wells in the play across our acreage, certainly we'll look at accelerating it.

But the limitation will be, a) correcting the data to get comfortable and then, b) getting the deeper rigs out there to drill it because, remember, we're drilling down to almost 16,000 feet in these Mancos wells and the current fleet that we have out there, except for this one rig that we're doing the deep drilling with, is incapable of drilling wells to that depth.

Keith Rattie: Brian, just an added comment from my vantage point. Where we see the U.S. today, at least the lower 48 onshore scene, is that threshold economics imply that producers are going to need Henry Hub prices north of 6 bucks, possibly in the 6.50 range, to earn acceptable returns on capital.

So we are going to run this business so that we earn acceptable returns at prices below those levels — hopefully well below those levels. We're going to try to take advantage of opportunities to hedge when the market is above those levels to protect our investments against possible downturns. But that's our current thinking.

We think the marginal cost producer in a resource play today ultimately sets the long run price for natural gas in the U.S. market. Our intent and hopefully our execution will keep us well below that.

Chuck Stanley: And, Brian, let me add something that maybe wasn't clear to you when I had spit out those numbers to you. Those numbers don't include the sort of incremental reserve adds above the deep section in the Uinta.

So if we go in and we are successful and we think that we should get decent incremental reserves out of the Wasatch, that's not in the numbers yet. It's only reserves and well cost to drill the deeper section, so the finding and development cost could come down obviously two ways: one, by getting additional incremental reserves in the shallow section and two, by reducing well cost through economies of scale.

Brian Singer: Great — very, very helpful. Thank you.

Operator: Your next question is from Marshall Carver of Pickering Energy.

Marshall Carver: Quick question: This may have been asked, but any plans for a follow-up well, follow-up deep test, in the Pinedale?

Chuck Stanley: Marshall, Chuck Stanley. We don't have any plans at this point to drill another deep well. We understand that other operators are going to drill one further south. We'll obviously watch with great interest the results from that well to see if they learn anything that changes our view. And if they do, of course, then we'll incorporate that information into our decision-making process. But no, we don't — we haven't permitted another deep well and we have no plans at this point.

Marshall Carver: OK, thank you.

Chuck Stanley: Sure.

Operator: We have a follow-up question from Carl Brown, Cramer Rosenthal.

Carl Brown: Hi guys — just a couple of quick loose ends.

I was wondering if you could tell me where in the queue for Vermillion wells would be Alkali Gulch Number 3 and its planned horizontal well be?

Chuck Stanley: Carl, I think Alkali Gulch Number 3 will be drilled after the currently drilling Alkali Gulch Number 2, and the horizontal well will probably be drilled late this year, early next year.

Carl Brown: OK — yes, thanks, and Chuck, on the 2- to 4-Bcf range that you're using for Vermillion, I believe you said in the past that the biggest variable in where you are in that range is the decline rate — the terminal decline rate and whether or not that's something like 6 or 8%. I was just wondering if you could update us on your latest insights into where some of those other wells are tracking along the terminal decline rate.

Chuck Stanley: Well, they're showing less decline that we currently have them booked at, which I think is at 6%, because we're seeing reserve growth at every quarter. As we look out in time, we hope that that sustains itself but we just have another 90 days worth of information. They're looking — they're very flat declines and that's not surprising given the massive thickness of shale we have open in these wellbores.

Carl Brown: OK, great, and last question: I'm sorry I missed the comment on the second deep Uinta well. Did you guys say that it's basically performing right in line with what the first was doing?

Chuck Stanley: It is. It is.

Carl Brown: OK, great. Thanks a lot.

Chuck Stanley: You bet.

Operator: We have no further questions at this time. Are there any closing remarks?

Keith Rattie: We want to — we've kept you on the call a long time. Thanks for listening in, everybody. You know how to get hold of us. Also, you can have access to our Web site for copies of slides and other information. And again, thanks for listening in today.

Operator: Thank you for participating in today's Questar second quarter earnings conference call.

This call will be available for replay beginning at 1:30 Eastern time today. The ID number for the replay is 4211295. Again, the ID number 4211295 and you may access the replay by dialing 800-642-1687.

Thank you for participating.

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