

**RESOLUTE ENERGY CORP**

**Moderator: Nick Sutton**  
**3Q 2010 - November 15, 2010**

Operator: Good day. Welcome to today's conference call discussing Resolute Energy Corporation's 2010 third quarter results. Today's conference call is being recorded.

This investor conference call includes forward-looking statements within the meaning of the safe harbor provisions of the United States Private Securities Litigation Reform Act of 1995. Words such as "expect," "estimate," "project," "budget," "forecast," "anticipate," "intend," "plan," "may," "will," "could," "should," "poised," "believe," "predict," "potential," "continue" and similar expressions are intended to identify such forward-looking statements.

Forward-looking statements in this presentation include matters that involve known and unknown risks, uncertainties and other factors that may cause actual results, levels of activity, performance or achievements to differ materially from results expressed or implied by this investor conference call. You are cautioned not to place undue reliance on these forward-looking statements which speak only as the date of this investor conference call.

As a reminder, today's conference call is being recorded and will be available in full two hours from the completion of this call through November 29. Please see our Web site at [ResoluteEnergy.com](http://ResoluteEnergy.com) for more details.

At this time, I would like to turn the call over to Nick Sutton, the Chairman and CEO of Resolute.

Please go ahead, sir.

Nick Sutton: Thank you.

Good afternoon, and welcome. For the benefit of those of you on the call who may be relatively new to the Resolute story, I will give a brief overview of the company, and then I will provide an operations update. After that, Ted Gazulis will review our financial results.

As a preface, a quick reminder that until our merger with Hicks in September of 2009, that entity did not generate any revenues other than interest income earned on the proceeds of this initial public offering. The pro forma results we provided eliminates certain activities with Hicks, as well as certain other non-recurring items, in order to present what we believe is representative of our underlying business.

In the press release issued this afternoon, we've made available to you a reconciliation of these items through the GAAP presentation. Because we closed the Hicks transaction at the very end of September last year, this is our final quarter in which the quarterly pro forma numbers won't line up with the GAAP numbers. Unfortunately, annual comparisons will be non-standard for a little while longer.

Resolute is a liquids-focused E&P company with stable and long-lived assets at the Paradox Basin in Utah and the Powder River Basin in Wyoming. We also own exploration properties in the Bakken trend of North Dakota, the Big Horn Basin in Wyoming and the Black Warrior Basin in Alabama.

Resolute has a solid balance sheet, thus we are well positioned to make strategic and tactical acquisitions, which we intend to do as the right opportunities become available. We also have a strong hedging strategy in place that provides us with a dependable stream of cash flow to effectively manage our operations regardless of commodity pricing.

The Aneth Field in southeast Utah is our largest-producing asset. There, our operational efforts are focused on tertiary recovery, CO2 flood, techniques to increase production from oily long-lived assets that have a long history of production and that have responded well to such recovery efforts in the past.

The nature of this complex CO<sub>2</sub> project requires Resolute to take a long-term approach to our activities. These are large-scale industrial projects that do not turn overnight, and as such, we have a long-term plan that we follow in a very disciplined manner.

Again focusing on Aneth Field, as we have said in the past, we have viewed the early part of 2010 as an inflection point for Resolute CO<sub>2</sub> flood efforts, as we have invested significant capital dollars in the infrastructure required to advance that project.

As you will see, this quarter's results continue to show increases in production as our operational activities are moving along as we expected. We have seen a strong production response from our wells at the phases 1, 2 and 3 of the CO<sub>2</sub> project, and we have put in place a number of additional expansion programs that we believe will provide solid incremental growth opportunities for us, the results of which are already coming to fruition.

Let me turn to some overall company production metrics, not just those from the Aneth Field, although I will touch on those in a moment.

Net production in the third quarter totaled 72,000 BOE, or 7,628 BOE per day, an increase of 18,000 BOE versus third quarter of 2009. Year-to-date production levels totaled 1,999 mBOE, or basically 2 million barrels, as compared to 2,055 mBOE in the first nine months of 2009.

Despite the modest decline in production year to date, our overall production was in line with our expectations. If we look at sequential production results, we produced 7,062 BOE per day in the first quarter of 2010, 7,266 per day in the second quarter and 7,628 BOE per day in the third quarter, increases of 2.9 percent from Q1 to Q2 and 5 percent from Q2 to Q3.

As you know, much of our activity this year has been geared toward ramping up work on projects that we expect will contribute to overall production levels in the rest of 2010 and beyond.

Two final comments on the nine-month production comparison. First, as you will recall, we elected to shut in uneconomic coal bed methane production in Hilight Field, representing about 29 mBOE of production in the nine months.

Second, in the Hilight Field area, the compression and processing facility, which is owned by Western Gas Resources, suffered a compression failure in November of 2009, thus curtailing just under 30,000 BOE of gas during the first nine months of the year. The plant came back online in September, but that was too late to have significant impact on our volumes this quarter.

Based on our current and expected activities in the final quarter of 2010, we expect to be within our production guidance estimates provided at the beginning of the year.

Production from Aneth Field is essentially on plan and up sequentially, and the field continues to show encouraging response from our CO2 flood expansion. The first three phases of the Aneth unit CO2 flood are substantially complete, and we have increased CO2 injection in those phases of the program.

Looking forward, we've moved into the phase four area, and the plan is to begin infrastructure work in that area by the end of the year.

Now, we have previously described to you the Desert Creek IIC project in the McElmo Creek unit. We now can report that we have successfully deepened or recompleted eight producing wells and one injection well. Those producing wells have resulted in production results that are higher than we had originally projected.

Six of the eight wells have been in production for one to six months, and they have an average production of 130 BOE per day higher than the rates prior to recompletion. Building on this, we anticipate recompleting another two producing wells and seven injection wells before the end of the year.

Based on our current thinking, we believe that an additional 50 wells could be deepened or recompleted at the McElmo Creek unit. The cost to recomplete producing wells in the Desert Creek IIC has averaged approximately \$450,000

per well, so the economics are extremely attractive. And obviously we are excited about the continued development of the D.C. IIC and the McElmo Creek unit.

Turning next to activities in the Hilight Field, I'd like to report that the field was producing substantially as planned, except for the previously explained curtailment of the uneconomic CBM wells and the impact of the Western Gas Resources processing plant failure. With the gas plant coming back online in September, we do not expect further production constraints.

We have moved forward with our Hilight Field refrac program with five refracs completed so far this year. The program will continue, and we are targeting three additional refracs during the remainder of 2010. At the end of the year, we will evaluate the effectiveness of the program and, like all other projects, the refrac program will compete for capital in our 2011 plan, with capital being allocated to the most economically attractive opportunities.

We have moved forward with plans to test additional formations within Hilight Field. This includes the potential to develop the Mowry Oil Shale on our nearly 45,000 net acre position. We commenced our first Mowry test in October. It is far too early to expand our plans beyond our original program to perforate and apply a two-stage frac on three wells in the Mowry by year end. Unlike many companies looking at the Mowry, we have the advantage of knowing that the Mowry is oil-bearing and it exists in Hilight Field; the Mowry formation sits above the field's primary-producing formation, the Muddy. Many of the 400 wells drilled to the Muddy formation logged the Mowry, and in some cases, we have cores. We're building a strong technological understanding of the Mowry in Hilight Field, and we look forward to continuing our work.

While we're talking about the Mowry formation, let me also take a moment to update you on the activity around our 70,000 net acres in the Big Horn Basin in northwestern Wyoming. We acquired our acreage there starting in 2005 on mostly federal leases that have 10-year terms. Recently, well permitting activity in the area has picked up with companies like Plains and Cirque involved and we could see several Mowry tests near our acreage. We hope to

apply the knowledge we will gain in our Hilight Mowry program to this exploratory acreage, and we believe that industry activity will lead to more interest in the Big Horn Mowry potential.

Moving now to the Bakken, we have come a long way since our second quarter call, and we are excited to update you on our near-term potential. In our joint venture with GeoResources, we have drilled one well to TD and are currently drilling a second well.

The first well was drilled to a total depth of 15,900 feet with a 5,700-foot horizontal leg, and it is designed to test the 640-acre unit. The well is scheduled to be fracked later this month.

The second well is drilling, and it will test the 1,280-acre spacing unit with a horizontal section of about 9,600 feet. This well is expected to be fracked in December. We expect to start drilling on the third GeoResources venture well shortly after finishing the drilling of the second well.

As we have previously said, once these three wells are drilled, we anticipate that we will move off location and expect that the rig will return to continue drilling sometime in the second quarter. Depending on results, we may look to stand a second rig during the second or third quarter of 2011.

Our second major Bakken area is a farm-out from Marathon that covers approximately 19,000 gross and 8,425 dead acres. The first well has been drilled and is waiting on frac equipment, which we will expect will arrive in December.

The second well has experienced a brief permitting delay that we expect to be resolved in December, at which time a Marathon-operated rig will become available. These wells are designed for 1,280-acre spacing units.

In addition to these larger joint ventures, we have additional Bakken acreage, and we have several small interest non-operated wells that are producing, drilling or in planning stages. All of our Bakken wells are targeting the middle Bakken formation, and if successful, they should add production in the first quarter of next year.

We have a large acreage position in the Bakken of approximately 90,000 gross acres and 33,000 net acres with potential to participate in the drilling of more than 90 gross or 25 wells net to our interest, assuming 1,280-acre spacing. All the wells target a very highly prospective area of the Bakken formation, and we believe that both areas have substantial production and reserve growth potential.

In addition, we believe that these areas are prospective in the Three Forks formation, and it seems likely that the down-spacing will also be attractive. Certain other operators are talking about six wells per 1,280-acre unit, three targeting the Bakken formation, and three targeting Three Forks. If that's an area that plays out, Resolute could have more than 540 gross wells and 150 net wells.

In summary, then, we are very pleased with our operational results. We believe that our activities in the Aneth Field are progressing well. We remain very excited with the potential in the Bakken. And we think the Mowry gives us some very interesting upside, both in Hilight and in the Big Horn Basin.

With that, I'll turn the call over to Ted Gazulis who will provide details on the financials.

Ted?

Ted Gazulis: Thanks, Nick.

First, let me just note that our 10-Q was filed this morning, and it's available on the SEC Web site as well as at [ResoluteEnergy.com](http://ResoluteEnergy.com).

Let's start with revenue. For the third quarter, we had total adjusted revenue of \$41 million, including the effect of realized losses on derivatives of \$800,000. For the same period in 2009, we had total pro forma adjusted revenue of \$35.5 million, including the effect of realized gains on derivatives of \$400,000. The 15 percent increase in adjusted revenue for the quarter resulted from increased production and product pricing.

Year to date, we had total adjusted revenue of \$119.2 million, including the effect of realized losses on derivatives of \$4.4 million. In 2009, we had total pro forma adjusted revenue of \$102.1 million, including the effect of realized gains on derivatives of \$14.4 million. The 16.8 percent increase in adjusted revenue resulted from increased product pricing that more than offset the 2.7 percent production decline.

Moving to operating expenses, third quarter lease operating expense was \$13.1 million, or \$18.73 per equivalent barrel of oil, before production taxes and overhead. That compares to total LOE for the corresponding period in 2009 of \$10.4 million, or \$15.21 per BOE.

For the year-to-date period, LOE increased \$3.9 million, so \$38.6 million, compared to the \$34.7 million of comparable prior year period. Though the current year totals are higher, in absolute terms, lease operating expense is right on plan.

For the quarter, total production taxes decreases by \$300,000 to \$5.8 million, or \$8.27 per BOE, equal to about 14 percent of revenue. In the 2009 period, total production taxes were \$6.1 million, or \$8.95 a BOE, equal to a tax rate of about 17 percent of revenue.

Through the first nine months, total production taxes increased \$17.9 million, compared to the 2009 period amount of \$13.5 million. While the increase in taxes seems large, it's really a function of increased product prices and increased revenues. The actual tax rate, however, remained essentially flat at about 15 percent of revenue.

Turning to G&A expense, in the third quarter, we incurred total G&A expense of \$5.2 million, or \$7.47 a BOE of production. For the prior year period, we incurred G&A expense of \$3 million, or \$4.38 a BOE. The majority of the difference between 2009 and 2010 resulted from costs associated with new employees to support our continued growth and share-based compensation expense related to our long-term incentive plan.

Adjusting for the non-cash share-based compensation amounts, G&A was \$4.26 a BOE in the 2010 period versus \$1.88 per BOE for 2009.

It's worthwhile noting that, in 2009, Resolute was a smaller, privately held company, and as a result we had not yet staffed up to take advantage of opportunities available to us, and of course we didn't incur the costs associated with being a public company.

For the first nine months of 2010, our G&A expense increased to \$11.7 million, or \$5.87 a BOE, compared to pro forma G&A expense of \$7.5 million, or \$3.63 a BOE, for the prior year period.

Similar to the year-over-year increase in the third quarter, the increases between year to date 2009 and 2010 resulted principally from higher head count, thus employee compensation costs, and the cost of being a public company. And after adjusting for non-cash share-based compensation, G&A for the 2010 period was \$3.97 a BOE versus \$1.92 per BOE for the 2009 period.

Next we'll look at EBITDA. During the third quarter, we generated \$19.2 million of EBITDA, or \$27.33 a BOE, as compared to the prior year period in which we generated \$5.2 million of adjusted pro forma EBITDA, or \$7.56 a BOE.

For the nine-month period, we had \$55.1 million of EBITDA, \$27.55 a BOE. And during the comparable period in 2009, we generated \$37.6 million of adjusted pro forma EBITDA, or \$18.31 a BOE.

Let's turn to capital expenditures. For the third quarter, we incurred about \$15.6 million in CAPEX. Of this amount, \$2.4 million was related to the acquisition of CO<sub>2</sub> to support our ongoing tertiary recovery project. An additional \$9.1 million was spent on various facilities-related projects, including phases 1, 2 and 3 of the Aneth unit CO<sub>2</sub> expansion project and other compression-related items. Finally, we incurred \$4.1 million related to our activities in the Bakken trend.

For the year-to-date period, we incurred approximately \$47.1 million in total CAPEX, of which \$9.4 million was related to the acquisition of CO<sub>2</sub>, \$15.6

million was incurred in facilities-related projects, and \$22.1 million was spent in the Bakken.

Because of the previously discussed delays in implementing certain compression projects in Aneth field, we have not incurred as much CAPEX to date as we had initially anticipated. However, after adjusting our internal estimates to reflect those delays, we believe that our capital spending is where we would have expected it to be at this point in the year.

Let me conclude with two final points. First, we continue to have good liquidity in our senior secured credit facility. Our facility has a borrowing base of \$260 million, and we generally have between \$120 million and \$140 million of availability at any given time. That gives us great flexibility to adjust our spending as appropriate and to take advantage of opportunities as they arise.

Second, as you probably noticed, our plan transaction with Pine River and its affiliates to exchange shares and warrants has lapsed. Without getting into detail, the NYSE would not grant regulatory approval to accomplish the transaction, and we are extremely disappointed in that outcome.

With that, I think it's time to open the call to questions.

Operator: Thank you.

At this time, I would like to remind everyone, in order to ask a question, please press star, then the number one, on your telephone keypad.

Your first question comes from the line of John Freeman with Raymond James.

John Freeman: Good afternoon, guys.

Male: Hey, John.

John Freeman: The first question, and I know Ted, you don't really want to elaborate much on it, but in the Q it just said that the SEC said it was violating the listing rule? Can you at least just give me their perspective on why they denied it?

Ted Gazulis: I'm going to actually let our general counsel, Michael Stefanoudakis, answer the question. Because I'll just get grumpy.

Michael Stefanoudakis: Sure. first, I want to say that it was a completely unexpected and non-intuitive interpretation of the listing rule that we referenced in the 10-Q that took all of us by surprise.

The NYSE's position was appealed, I guess you might say, by us and Pine River, working with our respective outside securities counsel, to the highest regulatory authority within the NYSE. And we even went so far as proposing alternative transaction structures. But unfortunately, they just would not grant the approval for the transaction.

And the rule that they cited was [703.12]. It had to do with the warrant listing rules. And so the agreement expired by its terms today. And, as Ted mentioned, we are very disappointed. But we really had no other option other than to let the agreement expire.

John Freeman: OK, thanks.

On the operations side, looking at the McElmo Creek recompletions, which continue to do extremely well, it would appear, just based on how much those are costing and the response that you're getting that that's arguably the highest-return dollars that you all are spending, possibly.

If I'm trying to look out to 2011, you know some sort of an idea maybe how you all are thinking about how much capital you want to shift to that area just given the success you've had. I would imagine, you know as you mentioned, there's a lot of room – running room there.

And then also, just kind of a second part of that question, if I could, is there anything just from a – you know from a geology perspective that makes McElmo Creek unique in its response to these recompletions? Or could you do the same thing at other parts of the Aneth unit, Ratherford, et cetera?

Nick Sutton: OK, let me take them one at a time here. In terms of looking forward to 2011 and beyond, as I noted, John, we've got approximately 50 opportunities within the McElmo Creek unit. And you're absolutely right, and the economics are absolutely superb.

In an unconstrained world, we would obviously run out there and do all of those as fast as we possibly could. But we do have some constraints. I mean, it's welcome to the real world. That's usually the case.

We have constraints in terms of equipment, but more importantly, each of these wells being a high-producing well really generates a significant volume of liquids and gas that has to be reprocessed. And as you will recall, we are right now, in the middle of reconfiguring our entire compression system in the field, and therefore there are limits as to how much fluid and gas that we can recycle and effectively sort of maximize the overall balance of the field.

Another thing that comes into play is that we have to be following along behind these producing well recompletions with injection well recompletions, because we need to maintain pressure in the reservoir.

A couple of reasons – first of all, you'll obviously enhance the production just as it – the reservoir as it is by maintaining pressure. But a second consideration is that our plan is to go in and eventually be injecting CO<sub>2</sub> into the Desert Creek IIC. And the miscibility pressure in the formation in this area is about 2,200, 2,300 pounds. And if we get too far ahead of ourselves in terms of following up with injection support, we will draw down on the reservoir pressure, impacting both current production as a water flood, in effect, and also the potential for the CO<sub>2</sub> flood.

So we're going to get at this as fast as – as fast as we possibly can. We're in the early stages of our 2011 planning process. We're – all of our capital activities have to stack up and compete for capital. This certainly will rise to the top, and we'll evaluate it in terms of – in terms of just what kind of physical and processing constraints that we have in the area.

In terms of the second part of your question, the McElmo Creek unit certainly – and the Desert Creek IIC – is an excellent quality reservoir. It's located elsewhere in the field. It's located in the Aneth unit and in the Rutherford unit.

I would say, and I would defer to the geologists who have worked this area so very hard. But my takeaway is that the formation is there. It's likely to – meaning there in Aneth unit and Rutherford unit. It's likely to not be quite as good. But we think it's got some real potential. And we have started doing some recompletions up in the Aneth unit just on the edges of where the phases 1, 2 and 3 project is in place.

And the results are encouraging, but that's really early-stage activity compared to the work we're doing in the McElmo Creek unit.

(Long-short) takeaway, we're going to be going after McElmo Creek as quickly as we can subject to all the other considerations. We're moving forward with evaluation of Aneth and Rutherford. It's likely to have some significant potential. I can't tell you that it'll be as good as we're getting in McElmo Creek.

John Freeman: I appreciate that. Thanks, guys, I'll turn it over to somebody else.

Operator: Your next question comes from the line of Noel Parks with Ladenburg Thalmann.

Noel Parks: (Afternoon). All right, just a couple things. At Aneth, the CO2 production for the quarter, in case I just missed it, what's the current production rate right now? (Just straight) production?

Nick Sutton: Let me see if I can understand the question you're asking, because if we look at Aneth unit, we have phases 1, 2 and 3 ...

Noel Parks: Right.

Nick Sutton: And we've got you know additional area in the Aneth unit that isn't under CO2, and then we've got Rutherford. You know so Aneth Field versus Aneth unit, really looking at phases 1, 2 and 3.

And, Ted, do you have that?

Ted Gazulis: I'm actually ...

Nick Sutton: What I can – while he's looking for that, what I can tell you, which is, to me, the most telling thing, is that the production in Aneth Field has been very, very good. Part of that is the D.C. IIC that we just talked about, but also that we're getting ongoing response from phases 1, 2 and 3.

And you know if we look at our September production, as an example – I don't think it's appropriate to give you specific numbers for September, but I can tell you that we had a very nice September, and we look forward to that continuing on through the rest of the year.

Noel Parks: OK.

Ted Gazulis: I mean, essentially, Aneth is currently providing about, oh, 75 or 76 percent of the total production, 533 mBOE in the third quarter versus 490 in the second quarter. So a fairly meaningful step-up.

Nick Sutton: Yes, that's in the Aneth Field.

Ted Gazulis: That's the total field.

Nick Sutton: Versus just limiting phases ...

Ted Gazulis: I don't have any – I don't have any good production data by unit with me, unfortunately.

Nick Sutton: Simply because we've gone to tank batteries.

Ted Gazulis: Well, it's in the tank batteries that come from mixed locations, some with CO<sub>2</sub>, some without, and then unit by unit, it's hard to break down the increment just by CO<sub>2</sub>.

Noel Parks: That's fine. I think what I was trying to get a feel for was, since of course there's a certain lumpiness in how – or, often, how you see response from the CO<sub>2</sub> injection, I was just looking for some rough characterization, you know

maybe through now where we are, more or less mid-quarter, as far as just how the – how the production ramp has gone from the CO2 injection.

Nick Sutton: Rough characterization is that it's going quite well.

Noel Parks: OK, I guess I'd just say steady or you know barely visible or ...

Nick Sutton: Increasing in a noticeable, visible way.

Noel Parks: OK, great. And in the Desert Creek IIC recompletes, from your comments, it sounded like you were saying that you were now pretty confident about having 50 recompletion opportunities there. And I believe the – before I more often heard you say a 30 to 50 well range. But is the upper end of that now feeling pretty good?

Nick Sutton: The upper end of that is now feeling good. It's partly a – I would say a result of what we have accomplished so far, the results that we have achieved and the team continuing to work the area.

Noel Parks: Great, and in the Mowry, the timeframe now being talked about for getting those recompletions done in those existing well, now talking about happening over the next six months. Just a sense of when you might be ready to begin the first one?

Nick Sutton: Well, the Mowry in the – in the Hilight Field ...

Noel Parks: Yes.

Nick Sutton: ... We have – we have already commenced work on the first Mowry recompletion. And a little bit of background, you'll remember that the Hilight Field is a muddy unit, and so part of what we've got to do is, for wells that we want to test the Mowry, we have to remove them from the – from the unit so that we can then get access to the well bores.

Noel Parks: Right.

Nick Sutton: On the first well, we went in, we isolated the Mowry, perfed it and fracked one of two subzones in the Mowry. And we're testing that subzone right now.

After we get what we feel is enough information out of that particular activity, we'll go up hole and frac a second subzone of the Mowry and test that. Now, our plan is to move on to two additional Mowry recompleted, hopefully before the end of this year, and again move these things along in a very considerate, deliberate way.

And then we'll – then we'll take a look at our evaluation of the results and move forward from that point.

Noel Parks: Right, and I realize of course it is early with the completions there. Your first couple tries at it there, do you feel like you're onto something as far as what the – you know what a good completion method would be? Or do you think you still have a lot of experimentation ahead of you there?

Nick Sutton: I think we have some learning to do, but I would emphasize that we are really in a – I would say, a unique position in that we've got 45,000 acres, all HVP. It's not going anywhere. We have 400 well bores that – you know certainly we can't mess around with all of them, but we've got a lot of different ways to go in that field.

And so we are going to take a very considerate approach and – considered approach and move forward. I would say that you know we're at the early stage. We've done a lot of work. We've got a scientific team that has been working this pretty hard. But it's – you know it's just a matter of getting in these well bores and actually testing various things – testing for the formation response, pressure buildup, things of that nature. Not to mention, then, as you – as you touch on, all the completion techniques.

Noel Parks: OK, great, and my last one is, talking about the different priorities you have for allocating CAPEX for next year, do we have a fairly wide set of outcomes as far as where you might put capital? Or do you have a sense of where most of it's going, and with only you know some of the smaller projects around the fringes still to be decided as far as how they'll be funded?

Nick Sutton: I think based on where we are in our planning sequence, we have a pretty good idea where capital will go in – let's put it this way, in terms of the larger buckets, how much will go to Aneth, how much will go to Bakken, et cetera.

And then subdividing from there, we have some additional work to do, but I think we have a pretty good sense of where the capital is going to go, excluding consideration of some acquisition transaction, as you know. And as Ted mentioned, you know we've got a great balance sheet. We've got the ability to move forward with acquisitions, and we have a very active team, and that team has evaluated, oh, I'd say somewhere between 60 and 70 different possibilities just so far this year.

And so when we talk about capital allocation, let's just say that it's – that's based on sort of status quo existing properties. You know it may well be that we wind up expanding outward from there in the normal course of our business.

Noel Parks: Great, thanks a lot.

Nick Sutton: Thank you, Noel.

Operator: Once again, if you would like to ask a question, please press star, then the number one, on your telephone keypad.

Your next question comes from the line of Richard Tullis with Capital One South.

Richard Tullis: Thank you, good afternoon.

Nick Sutton: Hi, Richard.

Richard Tullis: Just a couple questions. A lot of the items have already been touched on. But Nick, what are the Bakken well costs running? I know you have some shorter laterals for the first couple of wells, but what about the plans for the next couple wells?

Nick Sutton: Good question. We have the 640-acre well that's down and is waiting to be fracked, but the other wells that are on the schedule are all 1280s. And I'll

give you a rough average. We are targeting about \$6-1/2 million to drill and complete the 1280s.

Richard Tullis: OK.

Nick Sutton: The extended laterals.

Richard Tullis: OK, what about on the acquisitions front going forward? I mean, I know some oily assets pricing's been running up a little bit. I mean, you could see the deal Williams announced today in the Bakken. I mean, what's your outlook on that today? Any thoughts on maybe shifting some focus to natural gas assets? You know how are you looking at it today?

Nick Sutton: I will admit that I look at the environment out there, and I think several things. One, I think, thanks goodness we were prescient enough or fortunate enough, I'm not sure which – you know I won't claim we were smart enough – to target oil assets as early as we did. And you know the fact that you see a lot of the companies running from gas to oil certainly has run up the value of oil-related assets, including our own. And so that's a good thing.

But the – sort of the dark side of the picture that you kind of allude to in your comment about Williams or any number of other transactions out there, is it's getting really pricey. And you know we certainly have talked in the past about the pressure on service and supplies in this environment. We also are seeing the pressure on land prices and other things.

And we think that it, while we continue to be an oil-oriented producer, we do feel that it takes a great deal of organizational discipline to not just follow the crowd and to push the economics to the point where you know what may have been a formally good project turns uneconomic. So we have to monitor that on a day-to-day basis.

And you know one of the other questions we ask ourselves that's sort of a follow-on to yours is, you know at what point do you become a seller instead of a buyer in this environment? You know I'm not saying we're doing – you know looking at that actively, but it just – it is a very interesting dynamic on the oil side.

And that forces the question, at what point is it appropriate to start looking at gas? And my personal view is that gas is going to be penalized, punished, whatever, for a period of time here. Perhaps when the HVP drilling on the – on the gas shales starts to roll over, we'll see some changes.

But you know we have had strategic discussions where we say, at some point, it may make sense to look at some gas assets, because as the oil side gets overvalued, the gas side, arguably, is going to get undervalued. We don't see it right now, but it could happen, and we're very much attuned to that potential change in the macro environment.

Richard Tullis: OK, well, thank you. I appreciate that. And that's all I had for today, thanks.

Nick Sutton: Thank you, Richard.

Operator: Your next question comes from the line of Phillip Jungwirth with BMO Capital Markets.

Phillip Jungwirth: Hi, good afternoon, guys.

Male: Hi.

Male: Hi, Phillip.

Phillip Jungwirth: On the Western contract, I think it went to 90-day termination notice at the end of the August. Are there any plans to extend that and make it longer-term? And then I guess you probably can't comment on the 625 differential that's currently in there?

Nick Sutton: I think the answer to your question is that we have had some back-and-forth with Western. It's been very constructive discussion. We have a meeting scheduled for later this month. And you know we have passed some possible alterations to the contract back and forth – nothing major at this point.

But as I say, it's sort of on the to-do list, and the conversations back and forth thus far have been very constructive. And we're optimistic that we're going to get an appropriate redo on the contract in the not-too-distant future.

Phillip Jungwirth: OK, and then, let's see. Some Bakken operators, they've talked about service availability possibly having peaked. I know it's pretty early for you guys, but would you tend to agree with this view? Or is it still pretty tough, or getting harder, to get a frac date?

Nick Sutton: It's certainly – getting the date isn't necessarily the hard part. It's keeping ourselves calm while we see that the date is you know 30, 45 days out. And certainly certain service providers are more scheduled, or overscheduled, than others.

So I would say, based on at least the feedback I'm getting, is if – it is doable but time-consuming, it's expensive and not necessarily hugely more expensive than not too long ago, although I think some operators are offering premiums to see if they can't bump their way up on a schedule, which is, in effect, a de facto price increase.

But I also see that nothing stays still forever. And the service and supply companies are certainly talking and seem to be actively moving to bringing additional equipment to the situation. And that may – that may cause some easing. But I wouldn't expect a big fall-off in cost as much as maybe a slight easing of timing and scheduling.

Phillip Jungwirth: Right, and then would you guys – I see you picked up acreage in Williams and McKenzie county. Would you consider acquiring Bakken acreage over in Montana?

Nick Sutton: It's something that we have – we have considered, and we haven't moved on anything yet, and at some point we may or may not move on it. But certainly it's a little bit more uncertain the farther away you get from the core.

And on the other hand, we've seen how the Bakken core has expanded to include acreage that, not all that long ago, would have considered to be – would have been considered fringe acreage, so it's a very interesting play. And we'll see how far it can run. And we are looking at the full play, not just you know our existing acreage.

Phillip Jungwirth: Right, and then do you have an indication of the planned activity for the 19,000 gross acres covered under the Marathon agreement, what the activity would look like next year? And then can you comment on the completion design for the two – the two wells?

Nick Sutton: On the Marathon wells? First of all, what we anticipate is we'll get a couple of these wells done with Marathon, maybe take a breather and then work with Marathon to move through the acreage on a – basically I'm thinking a one-well basis.

On the completions, you know the two wells are designed to be, in one case, a 9,500-foot lateral, and the other case a 9,600-foot lateral. Both of them are set up, at least in the planning stage, to be 24-stage fracs with sliding sleeve. And so you know the Watson, while we're further along with the design, that's almost 3 million pounds of sand, and it's going to be pumped by (B.J.).

Phillip Jungwirth: OK, great, and then last, the sequential growth at Aneth, pretty strong in the quarter, was that driven more by the CO2 response or the D.C. IIC recompletions?

Nick Sutton: Off the top of my head, and I would emphasize that this is really off the top of my head, I would say roughly 50-50.

Phillip Jungwirth: OK, that's it for me. Thanks, guys.

Nick Sutton: Thanks, Phillip.

Operator: Your next question comes from the line of Todd Cohen with MTC Advisors.

Todd Cohen: Afternoon.

Male: Hi, Todd.

Male: Todd.

Todd Cohen: Hi. You know on the injection wells you referenced, those are in the Desert Creek area?

Male: Yes.

Todd Cohen: OK, and how many wells can those impact?

Nick Sutton: Think of it this way. Think of – think of it like a die, you know when you place dice? Think of it – think of the five-spot. The four on the corners would be injection, and the one in the middle would be producing.

Todd Cohen: OK.

Nick Sutton: This is – I'm saying this generally. But now you put – take that first die and put fives all the way around it, and you can see that it's not four to one you start to impact. And so you know you go through the patterns that way, and as you expand out, it's – it gets to be more like one-to-one, two-to-one.

Todd Cohen: Are those mostly being done for the – for the wells you just kind of recompleted that are – or in the process of completing?

Nick Sutton: Certainly the initial focus is on injection support in the area where – in the vicinities of our existing producers. But as we broaden out from there, we're going to be doing injection wells to support the full scope of the D.C. IIC producer recompletions.

Todd Cohen: Great, thank you.

Nick Sutton: Thanks, Todd.

Operator: At this time, we have no further questions. I would now like to turn the call back over to Mr. Sutton for any closing remarks.

Nick Sutton: The only closing remark that I would have is, I think the quarter was a strong quarter. We had positive movement on a number of fronts – positive responses on the Aneth, our compression reconfiguration, which is a major project, is on time and on schedule. The team there is working incredibly efficiently, and things are moving forward in the Aneth Field, as we would have expected.

We add to that you know stable production in the Hilight, and moving forward with the refrac program and the Mowry recompletion program.

And we look at the Bakken, and you know we spent the early part of the year compiling acreage positions and whatnot. Now we have wells drilling. We have wells down. We have wells waiting on completion. We're going to start to see that production in 2011, which I think is going to be a real positive increment to our already positive movement in our preexisting properties.

And in the meantime, we have our exploration acreage that we are moving forward with plans on some of those things. So good quarter all the way around. I think it sets up the rest of the year and 2011 to be – to be even better.

And with that, again, thank you for your time and for your interest in our company. And don't hesitate to call if you have any questions. Thank you again.

Operator: Thank you.

This concludes today's conference call. You may now disconnect.

END