Valeura Energy Inc.

2019 Annual General Meeting

TRANSCRIPT

Calgary, May 9, 2019: The following is a transcript of the Valeura Energy Inc. Annual General Meeting, held on May 9, 2019. An audio replay of the meeting webcast is available with the link:

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Corporate Speakers:
Tim Marchant, Chairman of the Board of Directors
Sean Guest, President & Chief Executive Officer
Lyle Martinson, Chief Operating Officer

Tim Marchant — Chairman of the Board of Directors, Valeura Energy Inc.

Good morning, everyone. It's just shortly after 9:00 a.m. and I'll ask that this meeting come to order. My name is Tim Marchant, I'm the Chairman of the Board of Directors of Valeura, and I also chair the Governance and Compensation Committee.

I will act as the chair for today's meeting. So on behalf of Valeura, I'd like to welcome you to today's meeting, and I'd also like to welcome those shareholders and others who are listening via our live audio webcast.

Before we proceed with the formal business of today's meeting, I'd like to introduce the directors of Valeura who have come to join us today. I'd ask each director to stand momentarily while I call his name. Sean Guest, our President and CEO; Ron Royal, who chairs our Reserves, Health, Safety, Security, Environment and Community Relations Committee; Russel Hiscock, the chair of our Audit Committee; and Jim McFarland, anybody that knows Valeura knows Jim McFarland. Kimberly Wood, our newest director, sends her apologies. She was in Calgary earlier this week for meetings and for an introduction to the Company, but she was unable to attend the AGM today because of a previous conflicting meeting.

Some members of our management team are also here today, and I'd like to introduce them as well, and ask them to stand when I call their name. Steve Bjornson, our CFO; Lyle Martinson, our Chief Operating Officer.

Lyle Martinson — Chief Operating Officer, Valeura Energy Inc.

Good morning.

Tim Marchant

Gordon Begg, Vice President, Commercial; Rob Sadownyk, our Vice President of Exploration; Heather Campbell, our Financial Controller; Robin Martin, who's our Investor Relations Manager; and the newest member of the management team, Peter Sider, who's our country manager in Turkey.

In accordance with the bylaws of Valeura, Stephanie Stimpson, our Corporate Secretary and a partner of Torys LLP, will act as the secretary for today's meeting. And I appoint a representative of Computershare Trust Company of Canada to act as the scrutineers.

The notice calling this meeting, the Information Circular, the Form of Proxy, and the Mailing Request Form, were mailed to all registered shareholders on April 5, 2019. The Declaration of Mailing is available for inspection by any shareholder, and I would ask the secretary to file a copy of such with the minutes.

I've been advised by the scrutineers that the quorum has been met for this meeting. The scrutineers' report is available for inspection by any shareholder, and I ask the secretary to file a copy of this with the minutes.

With that said, I declare this meeting to be called and properly constituted for the transaction of business. For convenience, we'll divide the meeting into two parts. The first part will deal with the formal business of the meeting, and the second part will consist of a presentation by Sean Guest, our President and CEO, on the operations of Valeura, which will be followed by questions from registered shareholders and proxy holders.

To facilitate the timely completion of the formal business, arrangements have been made with certain shareholders to move and second the resolutions to be considered.

First item of business is the presentation of the 2018 audited financial statements of Valeura and the auditor's report thereof. The financial statements are available on SEDAR, and have been sent to those shareholders who have requested copies.

The next item of business is the appointment of the auditors. May I please have a motion for such business?

Steve Bjornson

Chair, I move that KPMG LLP [off mic].

Tim Marchant

Is there a seconder?

Shareholder

[off mic]

Tim Marchant

Any discussion? All those in favour of this resolutions, please signify by raising your hand. Any contrary?

The motion is carried.

The next item of business is the election of the directors. Valeura has nominated six directors for election and did not receive any nominations from shareholders in accordance with our bylaws. Accordingly, I will now receive the Corporation's director nominations.

Shareholder

Chair, I nominate [off mic].

Tim Marchant

May I have a motion for such business?

Shareholder

Chair, I move that the Corporation's director nominees [off mic].

Tim Marchant

Is there a seconder? In accordance with Valeura's majority voting policy, the directors will be elected individually by way of ballot. For a nominee to be elected as a director, she or he must receive a majority of votes cast in favour of his or her election. If you have not received a ballot, please identify yourself to the scrutineers.

I am advised by the scrutineers that each director nominee has received greater than 50 percent of the votes cast in favour of his or her election. Accordingly, this motion is carried and each nominee is elected as a director.

That concludes the formal business of this meeting. I declare the formal part of the meeting terminated, and thank you all for attending.

Now that formalities are completed, Sean Guest, our President and CEO, will provide an update on Valeura's operations. If you have any questions at the end of our presentation, we ask that you raise your hand, wait to be acknowledged and to be handed a microphone because we have people on the online webcast, and then begin your question by identifying yourself and indicating whether you're a registered shareholder or a proxy holder.

Sean?

Sean Guest — President and Chief Executive Officer, Valeura Energy Inc.

Thank you very much, Tim. Thank you all for coming today. It's a pleasure to be here and I look forward to giving you a bit of an update.

Now, we have a corporate presentation that sits on our website, it has a number of slides there. I'm not going to go through that fully today. What I really want to do today is really talk to you a bit about how have things progressed in the past 12 months since the last time that we actually met here, what information has changed, both operationally and in the macro environment. I then really want to go through, what are we going to do in the near term, what's our program, and how is that going to help us understand the potential of the play that we have here. Then give a bit of a reminder as to what is the potential of the play here, and give a very clear position as to, where are we today, where do we see ourself going, and to recognize that right now, we have the money, we have the partner, and we have the program that's really going to take us in that position. So that's really what I'm going to focus on as we kind of step through the program here. And then again, to Tim's point, we'll go to Q&A.

So first of all, just a reminder of where we're working in the map. We are solely dedicated to Turkey. Our area of operations is in the very west of Turkey, so really, about an hour from Istanbul, and close to the Greek and Bulgarian border. All of our operations in that area we call the Thrace Basin.

On here, another point I want to really make when I talk about what's happened in the past year is, we currently have just over 56 million in working capital. Over a year ago, we raised between 56 million, 57 million net. So we have that money all in the bank at this point in time. We're very well-capitalized for what we need to be doing.

Why do we still have that money in the bank? We have received higher netbacks in the past year so we're getting more cash flow into the Company, and we've actually been able to deliver the operations generally on budget, so that we still have more money than we would have anticipated having when we look back a year from now. So we're in a very good position. And we also expect, after we've gone through our whole program this year, is still have on the order of $40 million left in the bank after that.

The last thing I would just point out, one of the key things we did in the past quarter is we have now completed a listing on London. We trade under VLU on the London Stock Exchange, which we believe will be very important for the Company as we go forward to try and attract more institutional investors there. As well as, should a capital rise be required at some point in the future, there is significant capital being raised in London for international E&P, and unfortunately, we've seen really that deteriorate more in Toronto. So that's really the reason that we've moved over there. And just over a week ago, we started trading.

Gas prices. Key point. Now this slide goes back to when we actually entered in the country. The black line is about the price that we receive in US dollars, referred to as the BOTAS price, and the red line is the EU gas price. Now what we've seen historically is that the gas price we receive behaves in line with that EU gas price. And then when I look back at 2018, this was emphasized even more, because the government introduced the policy that, on the first of every month, they were adjusting that gas price up.

So what we saw last year was real nervousness, the Turkish lira takes a drop, our share price follows it down. But in actual fact, what we've seen is, our gas price in US dollar terms went up about 30 percent last year when the Turkish lira went down 30 percent. This is very important, not just from that near-term value we're getting, but it gives us confidence that the government is behaving in a commercial way related to pricing. So it's good for our near-term cash flows, but more importantly, it gives us confidence that if we look at a major project going forward, the price that we're going to realize is going to be in line with what you get in the EU in that period.

This is a map of our operational area, our blocks being in yellow. The red dots that you kind of see around that are our gas fields. There's been decades of oil and gas production from this area. What I wanted to point out here, though, were the two red lines that come in from the north. That's the existing import lines from Russia into the whole domestic Turkish grid, does about a 1.5 BCF a day of production, and that's right on the edge of our block.

But again, what's changed in the past year? Well, the blue line in the south is TANAP, it's running from Azerbaijan and will run into Europe. Last summer, they commissioned that pipeline and it now runs from Azerbaijan right to the Turkey-Greek border, just to the south for a block. On July 1 this year, they're due to open the part through Greece and Albania, and are currently constructing the link into Italy, so that by early next year, we will have a major pipeline to the south of us that is actually accessing into Europe. One last one I'll point to there, the brown one is actually TurkStream, a new Russian line. It's completed across the Black Sea and is to connect into Europe.

So as a Canadian here in Alberta kind of looking at this, I get a new major pipeline right next to me every year. So it's a great position to be for access to infrastructure—sorry—access to gas infrastructure, whether we're going into Europe or whether we're accessing the Turkish market.

Technically now, what's happened in the past year. The map I'm kind of showing there is just a depth map of about our target horizon there. The red dots are the wells, and we've shown this in many of our presentations. So we now have about 11 wells that have been drilled all into this basin that have all intersected high-pressure gas and have evidence for that.

The Yamalik well located in the south there was our discovery well. And what we've now got to the point in the past year, we've now completed the drilling of two additional wells, which are in Inanli, which you can see just to the east of Yamalik and slightly deeper, and then we move 20 kilometres away over to Devepinar.

The first point I'll make is that those were very high-pressure, very high-temperature wells. We were able to drill both of them under the budget that was planned, and we drilled both of those wells without any HSE incidents or any accidents on site. So very pleasing considering the pressures, temperatures, and everything that we were dealing with in those operations.

But when we told you we were starting into this program, the objectives of it were, let's see if we can get down to 5,000 metres, how deep does the gas in the reservoir go. Let's then move to the west and prove that you find the same gas and the reservoir over in the West. And also, what we wanted to do is demonstrate, with the new seismic that we had, that we could actually predict areas that were more naturally fractured, which we believe might help us in production as we go forward. So with those two wells, one went to 4,900 metres, the other to 4,800 metres, both of them had gas influxes right down to the bottom of those wells. We ended up with about a mile of column that we're interested in in Inanli, and just over 1 kilometre of vertical column when we look at Devepinar.

So where it's kind of brought us to now is that, we've drilled these wells, we've demonstrated that we can actually predict what we're going to find in this basin, and we have much more confidence in the actual gas in place. That's where we're at. And that's really why, when we talked about drilling a third well, we couldn't see the value in this without that testing information. And the markets were actually very clear on this, too, is that, great, you've drilled a mile of vertical gas, not really interested, let's see how it flows. And that's the point that we're at now. We have very varied geology, we have different porosities, we have different fracturing, we've moved 20 kilometres away, it's about going into the wells now and testing these zones to prove how this is going to flow. And that's the critical step that we're at now.

So looking at the program now, as I said, the wells have been drilled and we're starting into this testing program. So we're getting the equipment in site, we hope to have it all there by the end of this month to really start going back and testing Yamalik, Inanli, and Devepinar. And again, I'll emphasize this, is that we are not testing one zone and seeing how it flows and then extrapolating; we have quite varied geology in these wells and it's about testing all of these zones individually to try and identify how it flows, that you are sustaining a gas flow, what are the condensate properties in the fluids that you're flowing from each zone to identify the best zones. We need to come through this with definitive information on actually where you move to next, and that's really what this program is about. We're not shooting for an IP rate that you can take away and compare it to the Montney. This is about them showing that any one of these zones will sustain a gas flow with condensate and that's where the value jump is going to come from, in doing that.

Just on the capital program there, just again, to emphasize, including all of the work that we would do on Yamalik, on Inanli, on Devepinar, and even we may go back to Hayrabolu (as we've maintained it as contingent in the budget), we still expect to exit the year with on order of $40 million. So I emphasize again, we have the partner, we have the capital, we have the program that's going to run for probably the next three to six months of continual testing of all these different zones. So it's a very exciting period for us right now, as we try and take this from gas in place to recoverable gas, and hence, commerciality.

Just to really emphasize the scale of the project, and we've shown these numbers before. But using the risk numbers from our auditor, D&M, we're talking about—with our partner, Equinor, another partner—about 12.5 TCF recoverable gas risked. To give you a scale of that, you're going to need a project that's on plateau for about 20 years, doing about 1.5 BCF a day of production. So it is a very significant world-class type of project.

Another point I'd like to make is on the fiscal terms are excellent in Turkey. It's a very simple Texas tax royalty system; 12.5 percent royalty and just a corporate tax of 22 percent. And what this yields when combined with our high gas prices is very good returns. And you can see a well-based economics approach there on the bottom-right, which is, what's the return for a single well in Turkey compared to Texas and Alberta, with the current prices that we have. So this looks great. You can have a project that delivers massive value.

The other way you should look at it is, we're in the phase now of trying to demonstrate to you that we have a commercial project here. So in Turkey, we can actually have wells that are some of the poorer wells that you get from analogs over here, and that still delivers a commercial return. And this is very critical as we look at it, because what we're trying to do now is prove commerciality, because that's where we achieve that large bump.

So when you look at the value that would then be attributed to Valeura on this, and the different analysts and the different banks have kind of worked through this, but the numbers come out on the order of a couple of billion dollars, some of them are north of that. That's also using a discount rate that normally is above the 10 percent that's normal in our industry. And for this type of project, discount rate is extremely important. Because when you take a value—a cash flow and look at it 20 or 30 years out, whether you say it's 12.5 percent or 10 percent discount rate, can end up being billions of dollars. So but we have significant value here, and just different views of the analysts, different view on risking, but the prize is pretty well-understood.

So just to kind of summarize that now, and kind of these are all in US dollar terms, but the top table is really looking at, what's our current market cap, what's our working capital that we have. We still have production, we have 2P resources which are delivering a cash flow right now. And it kind of says that you've got about $50 million in value, so that you've got 10 TCF potential, 5 TCF risk from D&M, and that the market has added $50 million value.

When you then look at that as how that works on a BOE basis, the risk numbers come out at about $0.06 a BOE. And you can look at the comps of other companies, you can look at the transaction comps related to gas, and we are at a significant discount to that.

We've also presented before, acreage value. And again, this is data that's provided by GMP FirstEnergy. It's all of the unconventional deals done in North America, so we're not pointing at one. And there is a huge value differential on a dollars per acre. But what we do know, it's not saying we're going to get that dollar value; it's really pointing out we are just so far away from that potential value that the upside here is significant.

So, again, where are we at today? We've done the drilling, we've shown we can drill very long columns of gas; it's now about flowing all those different zones to find exactly where the reservoir floor is, to find the zones that flow well, to then determine the next phase. Where would you put a horizontal well to really try and prove this up. But we have the money, the program to really prove this up and add this value, and that's why we're really coming into a very exciting time for the Company and for all of our shareholders.

So thank you very much for your time this morning. And at this point, I believe we'll open up to any questions.

Q&A

Justin Snelling - Audience Member

My name is Justin Snelling . I'm an independent geological consultant, and I have a presence, as probably many know, on some investment bullboards. I'm here today representing two shareholders that cumulatively add up to about 400,000 shares in Valeura, and they've entrusted me with asking a few questions on their behalf. So I'll be asking some technical questions; some I fully expect won't be perhaps easy to answer or, the answers aren't available right now. First question I had for one of the investors was, he had some confusion over the number of potential tests that would be coming up on the two wells that were recently drilled, on Inanli and Devepinar. He is on the understanding that there might be 8 to 12 fracs or test zones on each well. My understanding might be that it would be a—in total on the two wells, it could be 8 to 12 tests. Is that reasonable?

Sean Guest

Yes. Justin, thank you very much for showing up and asking the question. And you're correct, that's what was in the press release this morning, is the test that we had. And a lot of it is related to, we're actually uncertain as to the level of flow you get. When you get down at around 5,000 metres, the rock is very tight. So as we kind of test that, it'll be about, how does that rock behave, how does it flow. And actually, if it flows well, it's quite likely we'll flow it for longer periods.

We've also, with Equinor, come up with a program that has flexibility in it. So if we move up, we start to see better results from these flow, then, actually, we would maintain the ability to do some more work within there and possibly test more zones. So that's why there's uncertainty. One, we're maintaining flexibility as we go into Inanli; two, Devepinar just finished the results a week ago so we're actually just starting with our partner to review the zones that you would test in that well; and the third thing is, we are going to go back to Yamalik and look at the work there. So whether we just do one zone there or whether we actually look at several zones will really be defined by the results that we're getting. But again, the key thing is here to find the zones that sustain a gas flow, because we know, with horizontal wells, we can always up that flow significantly by learning how you can stimulate and frac your rocks, you can increase that number. So it's about sustained gas flow.

Justin Snelling

Okay. Yes. Thanks. Yeah. I have some other questions here, and basically, it goes to address some of the points in trying to get that commercial unsustainable flow. Because I think the thing that has concerned a lot of shareholders is the, with the Yamalik fracture, fracs and testing, there was a little disappointment about how rapidly the gas flows seemed to have dropped away, and what perhaps the reason for that might be. And obviously, part of that could be just fluid loading for various reasons. But the questions I was going to ask here on behalf of these fellows is, there was the suggestion that the porosity at Devepinar, because of the faster draw rates, the porosity values were expected to be higher than seen at Yamalik. Now with all the log data, can you confirm that the porosities are in fact higher? Or was it just—did it just drill faster?

Sean Guest

Definitely, we can confirm the porosities are higher there, and this is based on different porosity tools verse the sonic tool yields a higher result. Density neutron yields a higher result. We ran NMR in this as well, which yields a higher result. So all of the different data sources are suggesting higher porosities over in that location there.

Justin Snelling

And that's very encouraging. But, yeah, the other question I had was, log resistivity values at Inanli and Devepinar, just are they comparable to the equivalent zones at Yamalik? And perhaps at Hayrabolu?

Sean Guest

Yeah. It's a good question. And as a geologist, I've worked all around the world in different areas and different geological settings, and it's really to understand that different rocks behave in different ways. And I noticed I remember seeing some of the notices put out there in the investor sites saying that those resistivities would never flow. What I can tell you is, I was surprised, too, when I came into the area and looked at how low the resistivities were. But what I'm talking about is our convention production. So we look at the rocks, which is the same reservoir section, and we flow dry gas from those reservoirs at those resistivities. So to me, it was kind of like, really, how can people make that call? It's about looking at the evidence we have, and there are papers out there that I think TransAtlantic published that show the resistivity date in the shallow. That resistivity flows dry gas. That's the key thing there. Now we see variations down in the deep. But again, we have that correlation to fall back on, which is, our rocks in our basin and flowing dry gas.

Justin Snelling

Okay. That's good. Third question I had to bring here. Any of the log sections at Devepinar, do they appear to be highly fractured, as you mentioned, at Inanli, and mineralized, perhaps? Or no sign of any mineralized fracturing? It's more suspected to be open fracturing?

Sean Guest

No, it's a good question, because we're very clear. But when we chose the Inanli location, one of the key drivers for that was, the seismic data was suggesting you would get higher fractures there, and we did. We actually found that. And actually, to my surprise, even they were actually, you could even get it down to certain zones as being more fractured.

At Devepinar, we hadn't expected it to be as fractured as Inanli. We had expected it to be, I think a bit better than Yamalik, but not on that level of Inanli. And that is kind of what we got. And I know if Rob was to stand up, he would have told you that he wanted to go another a couple of hundred metres on that well because there was some more prediction of fractures down at that level. But, no, we got fairly good correlation.

But again, when you talk about how these fractures are behaving geologically, we do have fractures in there that are actually healed up, but we're getting fractures that are actually quite open, where you actually can see the crystallization on the faces of these fractures, which are quite clear then that these are open fractures. And the seismic technique that we're using is actually going to respond more to the open fractures, and not so much to the healed-up fractures. But we have a very good understanding of the stress field, ability to predict the fractures, and which ones seem to be behaving more open or more healed up.

Justin Snelling

Okay. No, I think that answers that perfectly. Thanks. And can the Company at this time confirm where the water issues, if there are water issues, at Yamalik? There was the production logging operation that was conducted there, is the Company able to confirm where any water or where the gas flows are coming from?

Sean Guest

Yeah. And a lot of people—again, a good question. Because what we saw last year was the mention of water in Yamalik was viewed extremely critical by people. Whereas, we don't see it at the same level; we saw it as a bit of negative evidence. But what we do know is, at the end of last year, we had our reserves auditor come in, who reviewed that data and really said, okay, you've actually got some water coming into the well but you don't know where it's coming from, but you've been able to achieve sustained gas flow from this, which is very important. So there was no adjustment made at that time to adjust to over a 50 percent pause.

So when we now look at Yamalik, it's like, as we said, we went back and did a PLT log. But a lot of times, people expect that the data that we're interpreting gives you a clear-cut answer that you say, oh, there it is, it's there, we've got to do this. Yamalik is still quite a complex flow from what we've seen with the very high-pressure differentials

Complex flow from what we've seen with the very high-pressure differentials from the top and the bottom fracs. And what we're actually seeing from the flow is very complicated on the PLT because there are fluids that are moving down in cases, and moving up. So it took us a while to really work with Equinor and come to an answer that we said, yes, this is what we believe these data are telling us and it's now time we've got a plan to go in there and try and see whether we can now prove that up. So we'll look to do that as we kind of go through this quarter, and we hope for results on that.

But again, we do expect that you will get some water flow in these wells. It's very natural. And I know, I get e-mails from people wanting me to invest in water disposal companies in Alberta and in the US. It's part of our business to manage that water. It's just a matter of understanding where is it coming from, can we block that off and actually produce just dry gas to get the most value, or do we need to actually work in a plan to manage that.

Justin Snelling

Okay. And with all the coring that was conducted at Inanli, I presume most of the main zone that's of interest would have been cored, or a lot of them captured, anyway. Can you comment on average water saturations from that core data?

Sean Guest

They do vary throughout the zone and that's what we've seen in all cases, that you have variations in saturation. But again, again, I've seen people post things about saturation and say, oh, I hear or I hear from someone or I talked to so-and-so that water saturations are very high in those. But you need to look through that data critically first, because when we take those cores, you need understand whether you're looking at the formation water or whether you're looking at the drilling fluids. So a lot of those cores that had higher water saturations in them, when we tested them, would actually be a KCl, which is not a natural salt, it's a salt that we use to drill the well with, and it indicates you've had invasion during your drilling fluid. Or putting tracers in there to understand. So you can't just take a number from that data without first assessing it.

The other thing you need to consider is to whether you're looking at a total porosity or an effective porosity. Because we know from the minerology of these zones that there is quite a bit of shale minerology in there, which has a lot of bound water. That doesn't affect your production at all, but it is poor space, and it's water that's measured. And that water, when you do a core analysis, comes off. So you have to be just very carefully about how you use it. But with the saturations we're seeing, we're working in a range right now but it's in that order on average, about 50 percent for effective porosity. But we need to actually benchmark that now with flow data. That's the key thing. We're working in an unconventional reservoir, we're working in a very tight rock, you can't just take the numbers that come out of a core and blindly apply them. You test it, you flow it, and then you use that to calibrate your core data.

Justin Snelling

Okay. I think that explains everything very well. Yeah. As a little guy, I didn't really understand my ability to move markets. It seems I did have a little bit of an effect on the share price through March. The last question I have is really just, is—and I think you discussed this—is Hayrabolu still a re-entry candidate for the testing? And maybe fracture-stimulating? Because there was some interesting gas shows there.

Sean Guest

There were, and there was gas, so we're able to talk about the gas that was recovered there. But you're right, it's appeared on our chart for a while as a contingent testing operation. Initially, we were looking at where we were going to drill our wells. And once we decided we would drill Devepinar over in the west, we decided to defer anything on Hayrabolu. Now that we have the results of Devepinar, we have our own well bore that's in great shape with great casing, and that's the one that we want to test.

The problem with Hayrabolu is, even though you know it's a well you have and you got gas out of it, they left a fish in the hole, so the whole bottom section of the hole is blocked with a bit of pipe that they dumped cement on. So we can go in there and work on it, but it's one of these risked operations—is it going to cost $1.5 million? Is it going to cost $5 million? So we'd rather work with our clean well bore and then determine whether we think there's additional information we might be able to get out of Hayrabolu. So that's kind of why it's been maintained in our budget and sat there as contingent.

Justin Snelling

Okay. No, I understand that. I've been involved in a lot of re-entry drilling projects where people thought they'd sort of go cheap and reenter an existing well bore and discovered the well from hell and ran into all kinds of problems that way. So, no, that's good. Yeah. One final thing, sorry, is, just looking at the published mud density mud weights while drilling curves against depth which show the nice transition into the overpressured zone, it looks like within the overpressured zone itself, there are different compartments with different pressures. There are some zones that are even more, if you like, super-overpressured than others, so there are discontinuities there. So would those be related to major faulting? Or just temperate reservoir zones?

Sean Guest

Yeah. A good question. Right now, we don't see that there is actually a difference in pressure there. And again, as we continue to test here, we're going to get really the information that is going to validate that concern. And even some of the testing we've just done down in Inanli now, even though it looks like very—it could be different fault blocks down there, the pressure is very continuous across those two. So we're not seeing that data but it is something we'll progress as we go forward. We believe at this point, it's about the same gradient overpressure, and may increasing down further in the depth, but we'll get the data to validate that as we go forward.

But the other thing being an unconventional reservoir, we all know a lot of wells are required with this, so that compartmentalization concern is a little bit less because you know you're going to need a lot of wells to recover this. So generally, you're going to have wells in the different areas to try and do that. But information that hopefully we get to is we come and we frac and we test and we do all this work, we should gain that understanding.

Mark Wayne - Audience Member

I was a bit surprised today when I read in the press release—sorry? My name is Mark. Mark Wayne. I'm just a shareholder.

Sean Guest

Hi, Mark.

Mark Wayne

Hi. So I was surprised today to read that you're going back into Yamalik—given the lower porosity, lack of fracking that you did initially. So what is it you're hoping to learn or achieve from going back in there?

Sean Guest

Well, the first thing is—and just to be clear—we really are in an information-gathering phase. You'd almost say, as a small company right now, what do we want to do? We want to go see the best zone and how it looks, and we want to go over and we want to frack that, and we want to flow that and talk to people about that. But a bit of the anomaly we have is, we have such a long column here, and we're working—this basin is almost 0.5 million acres and we're working the things ourselves with our partner, Equinor. So we are in data gathering, and we are going to start the testing down at the bottom of the wells as you have to do, and work up. So the initial results are likely to be poor. But we do want to get that information from Yamalik, because again, it's a very important piece of information to help us then say, where do we go next.

And when we talk about the porosities here, yeah, the porosities are a bit better in Devepinar, but it doesn't mean the porosities actually over in Yamalik or Inanli are bad; it's about understanding how those rocks behave with flow now. So we do want to get that information to try and help us decide the way forward.

Mark Wayne

Has this become an issue of just how effective the fracking is, in order to get this flow? And if that's the case, was there an issue as to what type of fracking to?

Sean Guest

Yeah. We don't believe we have the optimal fracking solution right now, and that's because you have to learn how to frack your rock. So there's been so much fracking stimulation over here in North American that we have all those learnings to build on. But these are the first fracks that have been done in these rocks, so we really have to learn how they behave. So definitely, we don't think we had the best fracking approach in Yamalik, and that—and it's one of these things that, once you get doing the horizontal wells, once you get multistage fracking, you're going to see how it behaves and then kind of work from there to adjust your fracking as you go forward.

It's also learning, once you frack it, how do you flow it back, what's the optimal way for the rocks to behave. And a lot of the experts we've talked to in Denver have said, you want to make sure you flow the gas out and you don't reflood these zones. Well, that's one of the problems we are going to have in Yamalik, it's been reflooded a number of times. So we don't expect the optimal flow results from these, but we just want to demonstrate sustainable flow from these zones.

Sean Guest

Any more questions?

George Reynolds

George Reynolds, private investor. Question I've got. I've seen so many scenarios where it says it's really overpressured. What's your pressure differentials between where you first touch it to the bottom? Number one. Number two, how much water can you lift with those high-pressure reservoirs?

Sean Guest

So the first question is, so we know we're on the order of hydrostatic generally at 2,500 metres, so what 0.4 PSI per foot, 2,500 metres, let's say 8,000 feet. So what am I at, 4,000 PSI. Any technical guys going to challenge that? So let's say 4,000 PSI, it's that 2,500 type of level. Down at the bottom—near the bottom of Inanli, where we did the deepest test, we were at about 12,500 PSI. So 8,500 PSI differential over that difference of about 2,000 metres in that, so it is a large step up in it.

Now the second question was related to liftability? I'm going to go to an engineer on that one. I did really well on the geology questions from Justin, but I'm going to hand over to the engineer on this … Lyle?

Lyle Martinson

Yeah. I guess I would say that it's no different than any vertical well here. You need so much gas and so much gas velocity to lift your liquid and it's all a matter of gas-water ratio, is how we do it, so. In Yamalik, we were not—I mean, that was a proof of concept well and so we only could do so many things to get ready, because we just still didn't know whether the reservoir would flow. If we could redo the Yamalik completion, we'd like to do it like we're doing the ones now, which is going to be really step by step, and making sure that we're ready to clean the fracs up as we go along. And to do that, we're going to use some gas lift technology and stuff this time so that we'll make sure that we get a load up. Because as we're testing these little zones, little by the standard of one or two fracs versus here where you're doing a horizontal where you've got 15 to 50, we don't expect enough gas rate out of those to effectively lift the water so we have to assist it by using gas lift. So that's our plan.

George Reynolds

Yeah. The only other question I've got associated, once you start sticking other pipe down the hole, I don't know what your diameter is at the bottom, but once you start sticking other pipe down the hole, you restrict your annular space. So, can you lift all that water from the bottom? You're telling me, probably not, but I don't know how far up you've got to go to lift it.

Lyle Martinson

[off mic] We're going to go clean those plugs up and snub in 2 3/8" tubing and then we'll use gas lift to help us unload them. Now they're going to come back right away, obviously, with the frac water initially, but we want to make sure that we're ability to clean them up. And we don't expect each one of these individual reservoirs to have enough gas to lift water out from those depths, so that's why we need to go with.

George Reynolds

[off mic] with respect to that is, you have more of a tendency to lose stuff down the hole. And I just don't want you to start fishing at 5,000 metres. I mean, you've lost a hole if you have to go down there and try and fish something out, period.

Lyle Martinson

I assure you, no more than I don't want to be fishing. Yeah. No, I think we have a pretty robust plan, and I think we're trying to do it in as simple a fashion as we can. But if I just say, where are we today versus what we did to design for Yamalik. Maybe in Yamalik, we, because of the proof of concept well, and we were just focused on what we can get out of the well. Now we want to try to correlate individual zones or individual sections of the hole to our logs, and the only way to do that is get flow data from those small sections of the well. And so that's why it's a lot more onus in this case.

Vertical wells, we used to think that the horizontal wells were tough, but right now, when you go about doing one of these in a vertical well, it's much tougher than the horizontal well because your formation's not all at the same pressure. And so any—you've got all these dynamics within the vertical well section, so. I think 2 3/8" tubing, we're going to be set up so we can at least do gas lift at 1 million, 1.5 million a day, and so that should be able to lift any water that comes out.

Sean Guest

If I could bring it back, one of the key points, this is about information gathering at this. A vertical well and the type of testing we're doing is not an optimal production approach, and that's why you really look, you're going to be going horizontal when it comes to that. The ability to produce from a zone that's largely all at the same pressure, at the same rock properties, at the same condensate properties is what's going to be very important, and we'll get the designs for that. And that's why some of the results we're going to release, if you compare it to the Montney or to the basins in the US, it's very unexciting. But the information that we look to acquire here is stuff that the reservoir engineer, the engineers can go through this and make a call, when I drill this horizontal well, this is the rate I'm now going to get out of it. So we'll put that information out publicly, you guys would be unexcited, but if we have a sustained flow, you get an IP of a couple of hundred thousand a day from those deep zones, that's going to be brilliant.

Any other questions?

Pat Maguire – Audience Member

Yeah. So Pat Maguire, I'm a shareholder. Just for clarity, the water that the engineer was speaking of was, it was frac water, not formation water. Is that reasonable?

Sean Guest

Yeah. That's correct. I mean, what he's talking about is trying to just clean out the zone to bring it back.

Pat Maguire

Just the fluid that's fracked into the formation.

Sean Guest

And obviously then see what comes up.

Pat Maguire

And then dry gas after.

Sean Guest

That's right.

Pat Maguire

Second question I had was, you had talked about sort of $0.06 a share was the value that presently the market was giving, and that there were other companies out there that had sold with a basic gas accumulation. And what kind of value they got for their equivalent. I was just—can you give us a sense as to what analogs you have for that, is to value of this when this becomes what you believe it to be?

Sean Guest

Yeah. So first of all, the number on the $0.06 was actually a value for risked BOES, in other words—the volume of gas. And then what you can really do, a lot of it is looking at whether it's global transactions, on-shore transactions for gas. You can narrow it down to the European area and that, but then, obviously, you start to limit the data set. Or the other one you could look at even companies reporting, what do they have for their risk resource base, and therefore, what's kind of an enterprise value for that and that. So that's kind of the comps you can dig around from in the different areas to look at those numbers. And again, you're going to see variations there, and there's quite a large range, but it's a matter of just trying to recognize that where is it at today, what are trading metrics on this stuff. And so it's not about whether it's 5 or 6 on our number or $0.50 or $1.50, there's a big gap.

Pat Maguire

Got it. Thank you.

Mark Wayne

Just one more question. On previous presentations, you've given, I think people asked you what kind of flow rates you needed to make this work and you said something like 3 million to 5 million cubic feet a day. What I think I just heard you say now, though, is on these tests, if you get a couple of hundred thousand, just a few hundred thousand, that's going to be great. Did I hear that right?

Sean Guest

Yeah. Especially from the deepest zones. And again, when you look at what would be a, let's say a well-based economics is to make a horizontal well actually deliver a 10 percent rate of return. We know, given our fiscal terms in gas prices, is that number is, I think when I looked at it last year was on the order of three. Now again, you're still modelling analogs so we're cautious on that. We need to then go out and find what is a type curve for our basin. But that was kind of the IP rates we were looking at, was about three at the time, I believe, worked out to give you about an economic return. So then again, when we frac a zone in a vertical well, that's just that one frac. And now you want to put that well out 6,000 feet and put, as Lyle said, 15 50 fracs whatever, and scale up that amount of production that you can get.

Mark Wayne

So just to be clear, on these results coming out, we shouldn't be looking for 3 million cubic feet a day?

Sean Guest

No. If we do, we'll be very happy.

Mark Wayne

Yeah. But it can be as low as a few hundred thousand and you'd still be very happy.

Sean Guest

I believe that's correct. That's just it's more about sustained flow. Because give us time with horizontals, give us time with fracking improvements, and you see how it notches up, how you get better recoveries per well, increased IP per well. And that's the curves you can look at, from how basins here have gone from their initial exploration wells to actual development wells, even whether it's three, five years later, and maybe those initial wells are only doing 5 percent to at 20 percent of the actual IP rates of production you get from the wells a few years later in development.

Mark Wayne

Thanks.

George Reynolds

One other question. It relates to, you talk about horizontal wells. All we've seen so far is something that's $X million for a vertical. How much—and you're talking 6,000 feet out—how much is that horizontal well costing?

Sean Guest

The horizontal well in development phase, we estimate—and this is having our drillers work through this, drillers who are working in our area in Thrace with our contractors and have also worked here in Canada—and they estimated the cost of those $9 million, horizontal well from a pad, drilled 6,000-foot horizontal and fracked and completed. That's the estimated cost we've got for those. And really, to give you a case, we've drilled wells in this area five, six years ago, we were drilling down 4,100 metres, drilled, cased, and just perforated and tested for less than 5 million. So we believe the costs are quite reasonable. But your first horizontal well is not going to be 9 million.

Sean Guest

Any further questions? If not, at this time, I'd really like to thank you again for coming. I would like to thank the guys who asked questions for very good detailed questions, and we're happy for any follow-ups. So thank you very much.