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# FINAL TRANSCRIPT

## Enerplus Corporation

## Investor Day

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## PRESENTATION

**Jo-Anne Caza** — Vice President, Corporate and Investor Relations, Enerplus Corporation

My name is Jo-Anne Caza. I'm Vice President, Corporate and Investor Relations for those of you that I don't know.

I would like to introduce our presenters this morning. So we have Ian Dundas, our President and Chief Executive Officer, and he'll give an introduction to the webcast and an overview of what you'll be hearing today. Next to him is Ray Daniels, our Senior Vice President of Operations, and he will be giving you the detail on our new assessment of our Fort Berthold asset. Next to him we have Eric Le Dain, who's our Senior Vice President, Business Development, Commercial, and he will be discussing transportation and the marketing of our crude oil and natural gas out of that region.

I'd also like to introduce a couple members from our Denver office. We have Ed McLaughlin, who's our President of our US operation, as well as Nate Fisher—there he is—and he's our Manager of Geology and Geophysics. And our Denver office manages the day-to-day operations of our Fort Berthold asset.

We expect the presentation will last about an hour or so, and we'd like you to hold questions to the end and then we'll open it up for any questions that you may have.

So with that, I'm going to turn it over to Ian. Thanks very much.

**Ian Dundas** — President and Chief Executive Officer, Enerplus Corporation

Thanks, Jo-Anne. Good morning. Appreciate very much everyone's time today. As Jo-Anne said, we'll spend the next hour or so taking you through one of the most significant projects in our company, a Bakken Three Forks play that we have in North Dakota.

You may have seen, we put out a press release this morning on the project. The main message we'd like to leave with you is we see more value in this project. It comes from two key factors: we see a larger opportunity set and we see improved individual well economics.

The highlights of the release: our unbooked contingent resource estimates have increased substantially. Estimates have increased by almost 100 million barrels and now stand—our contingent resource estimates now stand at 136 million barrels of equivalent, which is about 1.3 times our current booked reserve estimates in the field.

We also see this increase ties to a deeper drilling inventory. The inventory has almost doubled from where we were. At the current pace of drilling we see a 16-year inventory in front of us based on these revised estimates.

We've also revised our individual well type curves. Now overall we're keeping effectively the same average per well recovery, but we are seeing our new completion design is enhancing quite meaningfully individual early time well performance, which is leading to substantially improved well economics.

Just to give you a flavour for that, we have an inventory, contingent resource inventory of over 300 locations. So let's say 60 percent of those are long lateral wells, 200-ish long lateral wells.

An average well would recover somewhere in the 600,000 barrel range, 650,000 barrels of equivalent. That well has a PV 10 at $95 flat oil of about $11 million. That's up 15 to 20 percent from where it would have been before based on the changed shape of the curve and adjusting for spending a little bit more money to make that happen.

The final point that we'd like you to take away is this increased opportunity obviously supports a greater growth potential in the field. When we originally got into the field it wasn't producing effectively, and we saw a potential upside between 20,000 and 25,000 BOE a day. Now we see upside potentially close to 50,000 barrels a day. And the pace is going to depend upon drilling rigs and the well count and the development plan we settle into, but that potential for more than a double from where we are now is quite meaningful.

Fort Berthold, one of the biggest projects in our company. It's clearly the largest oil field in the Company; just under a quarter of our production, quarter of our reserves. It will attract about 40 percent of our capital this year. It's clearly been a meaningful driver of growth and value creation for the Company.

As I said, we acquired this position late '09 and then into 2010. Wasn't really producing; in the first quarter we had taken that to 18,000 BOE a day while seeing significant reserve growth.

On the value creation side, as at the end of the year if you look at our acquisition cost and then our net investment, net capital investment, we'd be into the play for about $1 billion. That would compare with a PV 10 reserve value as at the end of the year of 1.5 billion, plus whatever value you want to ascribe to the 136 million barrels of contingent resource. So it's been a really significant win for us and has been a key driver of value of the Company.

So with that, I'm going to turn this over to Ray Daniels and he'll start to take you through some of the details that fit in behind what I just told you.

**Ray Daniels** — Senior Vice President, Operations, Enerplus Corporation

Thank you, Ian. I would also like to welcome you to the presentation today, whether you're in the room here or on the webcast.

The famous Scottish Formula 1 driving legend Jackie Stewart once said, "It's a great day for motorcar racing." Well, it's a great day for Enerplus today and it's a great opportunity. I thought I'd try my Scottish accent here.

And it's a great opportunity for me to have a chance to share with you the work that we've done around this play, enabling this increase—or significant increase in value. I'll spend about 30 minutes going through five topics. Ian's mentioned them, really: the increase in resource that were found; the resulting increase in inventory; the improvement we've made in our operational execution; how that plays into better economics; and then the opportunities it provides and various development options going forward.

A recent industry research report that I read identified lands that were centred on that Missouri River with parts of Dunn, McKenzie, Mountrail, and Williams counties being Tier 1 land. Our land lands neatly within their identified Tier 1 lands. So we feel good about that. And Ian's already shared with you the value that the Fort Berthold play has already brought to our organization.

At the end of 2013 the key numbers here I pointed to are that we had 145 future drilling locations and 39 million barrels of oil equivalent contingent resource. These are the numbers that I'm going to be talking—the big improvements I'm going to be talking about really are reflected in these—or will be—come out with these numbers.

Over the last six months we have completed a thorough technical evaluation that's enabled a significant increase in oil in place. We correlated detail analysis of 50 cores with 155 well locks in and around our acreage and remapped our oil in place.

It was painstaking work. It was done in half-foot increments over the total package, which is about 300, 350 feet, and it was done DSU by DSU.

The major influence in the increase in oil in place was primarily the oil saturation in the Three Forks and in the—Three Forks first bench and in the Bakken. There was some contribution from thicker rock and from more pour volume, but primarily it was oil saturation.

However, oil that was included in the in-place calculation was only the oil that was considered to be accessible from our drilling programs. So we did not include all of the contribution, or all of the oil that we see in the second bench of the Three Forks.

We did not include any oil from the third or fourth benches of the Three Forks, or from the Upper Bakken and Lower Bakken shales. So could we see contributions from these zones in the future? Maybe, but at this stage of development we've not included any of that upside in our plans.

This has led to a significant increase in oil in place in each of our DSUs ranging from between 4 million and 20 million barrels. That then adds up to a total increase of oil in place to about—well, not about. It's 500 million barrels, so a 50 percent increase in oil in place.

I will be talking a bit later about some of the work we did around adding drilling locations, but suffice to say that with our technical work that we've carried out it's enabled an increase in contingent resource of 250 percent. This work was sent to McDaniel, our independent evaluators, and received audit confirmation earlier this month. And so under NI 51-101 we've increased our best estimate contingent resource from 97 million barrels—by 97 million barrels to 136 million barrels. And I'll give you a moment to digest these numbers because they're dramatic.

So on to our drilling inventory. In addition to the oil in place work, we continued to understand our reservoir. We continued to work on our reservoir modelling looking at current performance and looking at analogous reservoirs. And we're still pointing to a recovery factor of 15 percent, which we feel comfortable with.

Could we see a higher recovery than 15 percent? Maybe, but at this stage we are planning on a 15 percent recovery of oil in place.

So with respect to our drilling inventory, we've capped recovery to 15 percent of the oil in place in each DSU, and then we calculated the number of wells that we could economically drill within that DSU to provide our updated drilling inventory number.

What this means is that we have a different well pattern across our acreage. The first diagram here on the right shows a six or seven well density pattern where we'll get four wells in the Bakken and two or three wells in the Three Forks, depending on oil saturation.

If we know that we've got land with oil down in the second bench, then the middle schematic shows our eight well density pattern: four in the Bakken, two in the Three Forks first bench, two in the Three Forks second bench. And these are the patterns that we've got in our plan right now.

The last schematic there shows a possibility of higher drilling density if we find additional oil in the third bench, or if we create what we call super units where we add lease line wells to our plan. And no upside is baked into our current go-forward plans.

We have and we will continue to monitor industry downspacing activity, and we'll learn as much as we can from other operators before we commit our own capital. Other operators are proposing and testing higher density drilling than we are proposing, but with our view on the 15 percent recovery factor and a belief that the well patterns that we are proposing will actually recovery that 15 percent, we feel comfortable where we are just now in that we will not over capitalize.

Is there a chance that we might increase our density further than that? There is, and we will continue to monitor what's going on in industry carefully to make sure we understand the value that can be added from increasing the density.

What we did observe was that there was no decrease in initial production from seven-well patterns; that's four in the Bakken and three in the Three Forks. And so that offered us a lot of support and confidence as we advanced our plans for a couple of tests that we have carried out on our lands. And you can see them; they are the Snakes and the Furbearers downspacing tests.

To minimize capital and to save time we just drilled part of these higher-density patterns. On the Furbearers, we drilled three wells of the seven-well pattern; that was two in the Bakken and one in the Three Forks. These wells in the Bakken are 1,400 feet apart with the Three Forks well drilled in between them, but about 80 feet below.

And then in the Snakes pad we drilled two wells of an eight-well pattern. These wells are about 1,200 feet apart horizontally, but with it being in the Three Forks second bench, so that was an additional reason for drilling this well. We actually tested out the second bench of the Three Forks; it sits about 130 feet below our Bakken well.

The tests, the reason for carrying out the tests, we're looking for communication interference between the wells. And we're looking to see what and if there was any impact on initial production.

We have carried out an interference test on both these pads. The results are in. We're evaluating what that means to us as I speak today.

In terms of the impact on initial production, the graph on the right shows that, and so there was absolutely no degradation on initial production. In fact, these are the best wells that we've drilled to date.

The shorter red line and shorter green line should be broken. They are actually the Three Forks lines, not the Bakken wells. I think in your handout they look okay, but technology's not working with us on this particular slide.

But the longer Furbearers Bakken wells, they produced about 45,000 barrels each in the first 30 days. And then on the Snakes Pad, where we've got the Three Forks second bench and the Bakken wells, they produced about 70,000 barrels each in the first month. So really, really fantastic wells and have a major impact on improving our economics; certainly support our view that we can economically downspace our acreage.

So with our new view on oil in place and downspacing, we then have mapped these well patterns across our acreage. We previously were working on four wells a DSU. Now we're going to an average of seven wells a DSU.

You can see that the patterns vary through our lands here down in this central/south area there. We have four wells in the Bakken and two or three wells in the Three Forks, depending on oil in place. In that corridor that runs northeast to southwest we will have six, seven, or eight wells, depending on what we see in the second bench and third bench of the Three Forks.

And now that we've completed our test up in the Snakes Pad, we know that we've got good second bench productivity, and so up in that northwest corner we have planned for eight well densities.

Will we increase our densities? Maybe. There's a test that will be carried out in that central area. You can see it noted there. One of our competitors is drilling down into the third bench there, and we'll get information from them that we'll apply to our learnings going forward.

This all adds up to 127 percent increase in drilling inventory from 144 to 329 wells, so a significant increase in the amount of wells that we see ahead of us. I think Ian's already mentioned this, but the average long we see are around 625,000 barrels and the average short being 320,000 barrels.

If you look at our current two-rig program that we're running our base case, this would add about nine years of reserve life index to our plan.

So moving on to operational execution. Over the last few years we have been making many changes to our completion design.

What this is showing is the evolution from about 2012 to 2014, starting from the left-hand side of the table there on the grey box through to the green and red boxes on the right-hand side. You can see on the graph that our initial production continues to improve through that period.

We moved from—we wanted to put more proppant downhole. It was cost prohibitive to stay with ceramic, so we changed from ceramic to sand. And we're putting down about 4 times as much proppant as we were a few years ago.

We also wanted to increase the number of frac stages that we put in the ground, so we've gone from about 28 stages to 40 stages. And then within these stages we've increased the number of clusters from one to three. So we've made some real changes to our completions design over the last few years that have had a major impact on initial production.

Of course we can't do that without looking at our costs. And you can see on this slide here that we've actually—whilst we've been increasing the frac side is we've been bringing our costs per stage down over the years. The last two orange bars there show an increase of about 13 percent from 195,000 a stage to $221,000 a stage.

That was a conscious decision because you can see at the bottom there the blue and the gold-coloured bars are our Bakken and our Three Forks wells, and you can see that we've had a 30 to 40 percent increase in initial production as a result of that additional cost. So it was a very economic decision to make.

In turn, we've seen improving capital efficiencies as a result of the work that we've been doing. And we've not stopped trying to influence both sides of the capital efficiency equation.

We are monitoring all of the work that’s gone on in industry around completions, especially what’s happening close by in Fort Berthold. There’s some great slickwater completions that have been carried out recently in our area, and the results are competing to some extent with the results that we are seeing from our own design.

We're finding the slickwater very interesting. It takes about twice the amount of water to do a slickwater frac than our current design, and water costs are significant down in Fort Berthold. So we're looking at different ways to try and reduce the costs of the water to see if we can actually test out some slickwater, and I wouldn't be surprised if we find ways to carry out a slickwater test down in the southern area of our Fort Berthold land.

We're also monitoring coiled tubing fracking. It's at the edge of operational capability for our depth. The cost of the jewelry (phon) to put down hole is expensive, especially for the number of entry points we would be looking for. The costs are coming down quickly, and so we'll continue to monitor what's going on in that area to see if it's something that we could use at a future date.

We are looking at using a divergent agent in an upcoming completion. A divergent agent, basically once you've initiated one frac you put up a pillar (phon); divert this divergent agent down. It clogs up the frac and causes the frac fluid to go and create more fracs; then it biodegrades and you get flow from all of the fracs that you have initiated.

Depending on the results of that work—and the reason that we're doing it is actually for operational reasons—but depending on the results of that work, we may find some application for that in our current design that will help ensure some consistent fracking in each of the clusters. But again, we need to go through that technical work to see if that's something that will add value because it certainly adds costs.

On the cost side we look at every line item of our AFE. Two of the areas that we're spending a lot of time on, the flowback is about 6 percent of our costs. We're working hard to plan properly so we have flowback crews on for the minimal amount of time.

The problem with that, though, is that when you bring wells on that are much bigger than you expect you end up having to have these flowback crews on for longer, so it's a bit unfortunate, but we're happy to see these higher wells come in.

And then I mentioned water before. Water makes up about 7 percent of our completion costs. We've been carrying out tests of bringing water in by temporary line in our last frac, and we can see significant—potential of significant cost reductions in that. If we can bring frac water in just in time it means we don't have to store it, it means that we're not hiring tanks and paying rental costs on tanks, and it means we're not trying to keep that water warm and get up to temperature that we want for injecting down the hole because we've got much less water on site.

And if we can get confidence around that it might even allow us to get the point where we can reduce the size of our leases, which has a lot of knock-on effect in terms of costs. So we're really focusing hard and working hard on finding ways to bring our costs down.

When we look at our performance relative to the industry, it's difficult to compare capital efficiencies. So this is information that we do know as fact—it's from NDIC—where we can compare peak calendar month production.

This is—this database has over 6,000 wells in it. All of the vertical lines in there are our wells. The blue ones are the older designs, the red ones are more recent designs, and you can see as we have progressed with our completion design that many of our red—many of the red lines up there are more recent wells—are actually within the P10 performance of production, and in fact our last few wells that were brought on are some of the best that have ever been drilled in that basin according to the data that we've got here.

So these changes to the initial production have a great knock-on effect to the economics. We really understand our acreage now and actually developed 16 different type curves. These type curves are split between the Bakken and the Three Forks, between our different areas, and between short, long, and extra-long wells. And that will allow us to more accurately forecast our production going forward.

The other thing that we've done is we've looked at the actual production, old completions to the new completions, so what this is showing here is a couple of areas in our central/south area. And what this is showing is a dramatic increase between the old design and the new design. And that's allowed us—and played into the ability to actually create new type curves for different areas.

On this first slide here you can see somewhere between a 70 percent and 90 percent increase in cumulative production after 180 days, and in these particular wells that equates to about 50,000 to 70,000 barrels, so a significant increase in additional production.

On this one here we're moving up into the more northerly and west side of our land. Again, these are showing Bakken wells. We're showing a 90 percent increase in cumulative production, but this time after 110 days—we just don't have the run time for these wells—and that equates to about 60,000 barrels. So a real impact in this advancing the initial production, a real impact on our economics.

And here just showing the information on two type curves. The information's shown slightly differently here. This is a rate versus time plot. The solid lines are our new type curve lines; the broken lines are the previous ones.

The blue lines show our higher IP Bakken wells with 800,000 barrels of recoverable, and the red lines are our lower IP Bakken wells that have about a 530,000 barrels of recovery. The reason for showing these plots is that you can see the lines cross over after about a year. And so although we've got higher initial production we see the EUR of our wells being the same.

It does increase the decline rate, so the decline rate here that we're showing is about 80 percent, but well offset by the increase in economics that we see as a result. And this is the same type curves, the economics of the same type curve. You can see a significant improvement in net present value and rates of return, and clearly the payback periods are much quicker as well. And again, I'll give you a moment to digest this slide.

So what does all that mean in terms of our development planning? What this shows you is our base case. The red bars show our capital spend on a two-rig program, which is our base case, and then the blue bars show our net operating income. And you see there, 2013/2014, that's where we made the switch and we now get a lot of free cash flow coming from Fort Berthold.

The sold black line is our base production that takes us up to 30,000, 32,000 barrels a day and holding flat, and then the two sensitivities over on here are a three-rig and a four-rig program that takes us up to 40,000, 45,000 barrels a day.

We're currently in the middle of our development planning process that leads into our budget process, and we will look at all of the different options that we've got for this play and all of our other assets within our portfolio to decide how we take this—how we decide to take this play forward. And this information we'll be sharing with you later in the year.

I have spoken about upside as I've gone through the presentation, so I won't go through them again, but I just want to leave you with the fact that we do have upside potential on top of what we're showing you today; that we are committed to continually—to continue working hard at in order to continually improve the value of this asset to Enerplus.

And with that, Eric, I'll hand over to you.

**Eric Le Dain** — Senior Vice President, Corporate Development, Commercial, Enerplus Corporation

I'll be covering the gathering, transport, and differentials that we've realized to date on our forecast going forward.

So when you look at this region, the growth, as you know, for industry as a whole has been significant. Is transport or egress capacity an issue? Not at all. And it's a—that is a significant factor as we look at how we're managing our commitments to rail and to pipeline; how we manage the diversification of our pricing and realized netback.

There's about 500,000, 550,000 barrels a day of pipeline capacity in place today with the plans in place now to grow that for about another 400,000 barrels a day after a couple years from now.

Rail, the growth in loading capacity has been very significant. A year ago if we'd had this slide we would have had 800,000 barrels a day there of loading capacity. It's now grown to 1.2 million barrels a day of capacity.

Now the natural question that would follow to that is, okay, you can load it, but are we seeing restrictions on the physical rail itself, logistical restrictions? And to date we haven't seen that.

Now keep in mind we're not using all of that capacity on any given day. As you all know probably, we're producing as an industry about 1.1 million barrels a day; just cleared the 1 million barrel a day mark in North Dakota. But for North Dakota and Montana that would access this capacity we're about 1.1 million barrels a day, so not all that rail capacity's being used, but it is available to us and no logistical issues to date.

So what this does for us is it provides significant optionality. It doesn't require us to commit to kind of those 10 to 15-year terms for all our production at this point. We can use the flexibility in these egress options to adjust where and how we ship on any given month.

Notwithstanding that, there's still a prudent level of commitment that we feel it was appropriate to take, and we've done that and have that strategy consistently from early days. And remember, we've been operating in this region with our Montana production for close to 10 years now.

So we have about 8,500 barrels a day of firm commitment on pipeline going to the east and to the south and west accessing markets. We have committed to an additional 5,000 barrels a day of pipeline going east that is part of the Sandpiper project that Enbridge is a proponent of that will come online in 2016.

And on the rail side we have made commitments—and we're on our second phase of those—commitments to term rail capacity. Now probably for the majority of the people in the room you're aware of how we use that. These are commitments we make with a party that is the marketer and the shipper of record. So we are delivering and transferring ownership and title at the—it could be a truck loading or at the rail loading point. We are not the shipper of record, and therefore we do not make the testing or the labelling commitment what the shipper needs to do on the rail.

What's interesting about the chart on the bottom here is it shows the kind of variability, the flexibility we have in terms of our transport and rail options in terms of touching the market. So what it shows is January through June, the light blue—you can see it more in June—is rail to the West Coast, the purple is rail to the Gulf Coast and rail to the East Coast, and finally our pipe going to the south and west towards Guernsey and the PADD IV markets and then pipe to Clearbrook, which of course touches PADD II and down to Cushing and ultimately PADD III.

But look at the variability in that where we're shipping and how we're touching the market. What our rail deal allows us to do is it allows us on a month's notice the flexibility to identify which coast, which market we want to be priced off and we want the ultimate sale to be made to.

As we optimize the netback what we're looking at are the pricing relationships across the US. We're looking at where the West Coast is pricing. Sometimes it prices off Alaska crude; sometimes it's a WTI-based price; sometimes it's a Brent-based price.

The Gulf Coast, of course, historically is priced off of Louisiana Light Sweet, which had a relationship with WTI. It's actually with the build out from Cushing to St. James it's now evolved to be more of a WTI plus 3 to $4 market, and that's actually disengaging from—that Louisiana Light price is still there, of course—but it's disengaging a little bit from the Brent price, which used to drive its value.

The East Coast is still a Brent price market. We would hope it would be Brent plus transport to the East Coast to the US, but the refiners there are aware of supply and demand, and they are now pricing actually at below Brent, a couple dollars below Brent the last little while as they look at buying crude coming from the Bakken or other parts of the US.

On the pipe side we can flow on those blue lines east to Clearbrook, touching markets in PADD II, and then you can see some of the blue lines going to the south and west that again touches that PADD IV market.

So what it means is that each month we are making these decisions on how and where we flow and working with a number of partners on the downstream side and the midstream side/marketer side as we move our product.

Realized differentials, this chart shows where we've been in the recent past. In first quarter we published a differential—and this is realized to us at the field—of just over $14 negative below WTI. We're forecasting to be around the minus 13 level, which is kind of where the market's been playing. Again, for our realized based on our share of pipe and rail and trucking to the point of sale in the field we're forecasting about minus 13 going forward. And again, that's based on our assessment of how we're using pipe and rail.

One interesting thing on the pipe, it's not a given that the pipe is always filled, and you saw that a bit on that slide earlier. In fact, some of our pipe capacity on the Enbridge expansion has not been filled a portion thereof some months because it has been more economic for us to use rail.

The rail netbacks, and you can see it in the competition that's out there now to feed these loading—this loading capacity, the rail netbacks have come down. The cost of moving rail to the Gulf Coast, which were about $20 a barrel a year and a half, two years ago are now down to about 16, and this is all-in: load, unload, shipping, any marketing fee. To the East Coast we're at about $14 and the West Coast around $11, and then we have roughly a $3 cost in the field to feed those railhead facilities.

Natural gas and natural gas liquids, they're about—our share is about 20 percent. There's roughly a 6 percent or so shrinkage in the field. On a revenue side versus crude oil, our gas and NGLs come out to somewhere in the 5 to 7 percent share of overall revenue stream. So it's not a significant item, but it is significant and it has been significant from day one in terms of how we've run the field and how we've worked with Targa Badlands LLC, who's our gatherer on the gas and crude side.

So the structure in the field is that we pipeline from each of our pads the crude and the natural gas liquids and natural gas—those two are combined, but the two sets of line are separate—run through a processing facility where the natural gas liquids are separated from the gas, and then Targa sells on our behalf the natural gas liquid and a fairly rich natural gas stream. We take out as much as possible, but it's still somewhere in the 1,200 heat rate for that exit stream. It comes in at about 1,500 heat rate.

The gas is significant in terms of its gathering because, of course, there is the environmental element of this, and it's again been a driver of ours from the beginning to gather as much, or all if possible, of our natural gas and avoid the flaring. We currently are connected at about the 80 percent level of our wells into the gas gathering system.

Now that doesn't mean on a given day that 80 percent is the level of gas recovered because, of course, you could have a recently drilled well that as Ray spoke to is still on flowback and is flaring at site until we run into the connections. But in general it's in that range.

Industry as a whole is currently recovering about 70 percent of physical gas. As many of you will no doubt know, the North Dakota Industrial Commission has recently set out requirements seeking a 95 percent capture of natural gas by 2020 from the region. And they are targeting a soft target of 75 percent capture by the end of 2014, and that definitely is the path we are on to achieve that.

As a fallback, and it does matter, but as a fallback when we do need to flare, whether there's an upset in the gathering system or otherwise, we are installing high-efficiency flares at each of our pad sites. And these can improve combustion efficiency from kind of a standard 90 percent to closer to 98 percent.

And that's all I had on the crude natural gas and natural gas liquids flows.

**Ian Dundas**

Thanks, Eric. And so we'll turn it over to questions in just a moment. Again, really appreciate everyone's time this morning.

We're pretty excited about where we are with this project right now and how it fits into the Company. Generally I think our belief is this field has got consistently better over time.

The resource keeps increasing, and we've made pretty meaningful strides in enhancing the economics over the last several years through that combination of cost control and productivity enhancement.

The upside's significant for the Company. We see over 200 million barrels of oil and associated gas through our reserve bookings and our contingent resource opportunity, of which less than half of it is on the books for reserves right now.

Long drilling inventory: 16 years at the current pace. Q1 production was 18,000 BOE a day, and we see opportunity for sort of 2.5 times that level as we move forward on the project. So it's an exciting time for us in this project, and we wanted to share that with you.

So now I think we're open to some questions after you've read our advisory in detail. I think Jo-Anne will tell people how to do that now.

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## Q&A

**Jo-Anne Caza**

Sure. So if anybody has a question we would pass the mic over to you, and then we'll also take some questions from the webcast as they come in.

**Unidentified Speaker**

Thanks very much. Just wondering when you're looking at some of your neighbours that are looking at higher drilling density if you've got a sense of what kind of recovery rates they're using? And could there be an indication there for what we could be looking at in the future?

**Ian Dundas**

Yeah. That's a great question. Ray talked about that quite a bit. We've built up our analysis extremely detailed. All of these assumptions, all of our views are anchored on our oil in place. Then we look at our performance and then we look at industry offset performance. So we know what's going into our thinking right now.

Even when you look at some of the other numbers out there, people aren't typically very specific with their recovery factors. And there is some variation here, particularly as you think about the lower benches of the Three Forks and what might contribute. And even some of the assumptions into the net versus gross that factor into what we'll contribute over time.

That being said, it seems to imply higher recovery factors than we're talking about right now. So we'll see where it goes. We're pretty comfortable with where we are. We're 51-101, best estimate, and some of those other numbers out there, I think, use a different resource standard, typically SEC US-based.

So I think we're comfortable with where we are. And we're not saying it can't go higher, but we'd like to see some run time around that and some more data.

**Jo-Anne Caza**

Ian, we'll take one from the webcast. So it says both infill tests occurred north of your larger, more contiguous acreage block. Was this due to historical density? Or are expectations different for the southern acreage?

**Ian Dundas**

So there are two tests that we're talking about. The most northerly one tested the lower bench, the second bench of the Three Forks. And that's an area where we saw—throughout that activity we felt pretty comfortable that the oil sat there. So it was one of the reasons we tested it. It's clearly an area that also has higher oil in place, in part because of that increasing stack that you're dealing with.

The second one further down was chosen for a series of reasons, but we thought it would be a good area, but not the best. I think we've been—we've tried to be pretty clear with people that as you move further south in the acreage block the Bakken still looks really good; the first bench of the Three Forks look good. We think you lose the deeper benches. And so we don't have any plans today to test the second bench further on, and we've tried to capture that in our analysis.

**Unidentified Speaker**

Thanks. I just wanted to see if we can go through just some of the stats as we go back and revise our outlook. Could you talk just a little bit about what the total well cost is going to be, D&C, for the long laterals and then for the short laterals? And if I missed this, shame on me, but the other question is just in terms of the type curves that we're looking at for, should we be thinking of Bakken first bench and the Three Forks as ubiquitous? And then how should we be thinking about the type curve and just EOR then as we get into the second bench? Or are you now thinking about all three as being fairly consistent?

**Ian Dundas**

So on the cost side we're for a long well talking about $12 million. We would have been a little baby bit higher than that in the first quarter through weather-related things, but 12 is a good number to think about. And that's what our economics are hanging on.

And that is a median what's happening to us with problems into that and everything we can think about this should be included in that capital cost. For a short well, which we're not doing very many, 9 million is a good number to think about. But we're not doing very many of those right now.

In terms of type curves and areas, Ray talked about 16 different type curves. What we've chosen to show you were sort of high end, the high-end range and the low-end range: 800,000 barrels to 530,000 barrels was the low-end range. And barrels, so we have a gas gross up on top of that.

Most of our activity now is focused on longs—and I'm sorry, for the longs, okay? Most of our activity right now is focused on the longs. Two-thirds of our inventory are focused on longs. So I'll talk about that for a little bit. That is a pretty good range to think about, and then the—for wells down to the densities that we're talking about.

So let's talk about an area where you don't have the deeper bench for a second because we don't have a lot of deeper bench, so an area where you don't have the deeper bench we're talking about four wells in the Bakken and three wells in the Three Forks. And then depending exactly where that is, all of those wells should fall into that category. And I think averages are your friend here. They're representative. Averages are your friend.

So that average well, 625,000 barrels is a long well; it's a Bakken well, but it might be a Three Forks well, depending where it is. If you're sort of in the middle to northern areas it looks a little bit better, but the southern areas look pretty good as well. As you move to the sides it falls off a little bit, but that's sort of all captured within our data set.

The deeper bench of the Three Forks, so the second; when I say deeper it's the second bench of the Three Forks. If you look at our map that Ray set out there, we have a fair amount of data to that northern area where we say we've got that there. And then you've got this middle area where it's not quite as clear. We've gone up and we mapped it all, and so a portion of the increase in the oil in place and a portion of the increase in the contingent resource was based on that second bench contribution, but it was a pretty small piece of it, 10 percent to 15 percent, something along those lines where we've got it in areas where it looks like Tier 1 plus prime. So that Hognose well we talk about is a deep bench well that looks like the best Bakken well in the basin, almost. Almost; it's quite spectacular, and so a well like that in that area I wouldn't differentiate between Bakken or Three Forks.

**Unidentified Speaker**

Thanks.

**Jo-Anne Caza**

I'm going to take another one from the webcast here. Sorry, I'm just going to go back and forth. Notice that we have some longer lateral wells that we're drilling on the northern acreage and there's three 3-mile laterals that we've drilled. What impact does lateral length have on performance versus proppant volumes? Is there any risk to toe contribution to recovery?

**Ian Dundas**

Most of our data are long wells, at least that's what the last couple years have been, and on long, not super extra-long, long—we got some super extra-long as well—but long wells, that's the last couple years of drilling, but prior to that it was actually shorter ones. It's difficult to compare the shorter to the longer because the completion has changed so much.

So internally we have a rule of thumb that a short on a per foot basis might be a little bit better, and that Hall well that showed up that—and it's been sitting in the data—looks like one of the better wells we've ever drilled, which is a short. So that's interesting as we think about that. So we don't think there's a meaningful risk toe versus heel on a 9,600 foot well.

We've just completed a few—it won't be a big part of our world—but we've completed a few 3-mile wells, 15,000, 16,000 foot of lateral length. Not quite as comfortable saying that. We're trying to analyze that right now, and we actually would think you'd see a little bit of a deterioration as you went into a toe of that well, but we don't know.

So—and then completion, completion change is everything. It's everything that's going on here, and different completion design will make a far bigger change than if you're talking 45,000 feet or 9,600 feet.

Did I capture all that, John (phon)?

**Unidentified Speaker**

Ian, in the areas where you decide to drill into the lower of the three bench, into the lower areas, will you be able to utilize existing surface infrastructure or any wellbores to reduce those drilling costs?

**Ian Dundas**

That’s a good question. Ray, do you want to chat about that?

**Ray Daniels**

Yeah. We'll certainly use surface facilities, the same surface facilities; unlikely that we use the same wellbore. I mean once we've got a well in there it's going to be there for a number of years, and so it's unlikely that we'll use the same wellbores as we'd be planning it right now.

**Jeremy Kaliel** — Scotia Capital

Thanks. At a higher level we understand that your—the cold weather delayed a lot of your activity at Fort Berthold in Q1. So I wanted to ask, have you caught up? And is it possible for you to give us a sense of current production levels at Fort Berthold and even better corporately?

**Ian Dundas**

Yes. It's possible.

**Jeremy Kaliel**

Go for it.

**Ian Dundas**

I think we're on track. So Q1, cold weather impacted us bit, but not a ton. It did impact us a little bit. It impacted delay on the oil side a bit, and it also actually dealt with we had downtime, specific downtime on the oil side.

So we're catching up. Yeah. We're catching up. Corporately we've guided to 100,000 BOE today. I guess it's 96 to 100, and we've guided to the high end of that range. We're comfortable with that guidance. A bit of a wild card in there is Marcellus outperformance, which continues to do quite well.

On the liquids side the single biggest project is the Bakken. That project we're saying will average 22,000 BOE a day. I think we're on track for that, and so I would anticipate, Jeremy, that we will see oil growth in the second quarter, which is part of our plan.

Corporately that ties to 44 percent, or 44,000 BOE a day of oil; comfortable with that guidance.

**Jo-Anne Caza**

I have another question from the webcast, and it kind of comes back to the completion and how that is evolving. And the question is, is there anything to be gained from going back to the older wells? And could they be re-fracked with the newer completion?

**Ian Dundas**

The short answer is maybe. Yeah, maybe. I mean we're not at a stage today where we're doing that. We have a lot of activity in front of us, but I know there's—the team's been thinking about that a bit. It would be sort of the 2012; that'd be sort of the vintage that you'd be thinking about.

**Unidentified Speaker**

Thanks. So you effectively more than doubled your inventory, and you've got 16 years of work in front of you. So going forward, how are you going to be looking at your pace of development and balancing your decline rates and your opportunities in front of you?

**Ian Dundas**

Yeah. I mean we're, as you obviously know, there's a series of multiples that we consider and that are important. It's having a financial plan that makes sense that grows the Company economically. So it balances today versus the future.

So we weren't in a position to increase the pace of spend, at least we didn't think that was appropriate a year ago because we didn't have a strong enough grounding on the inventory, and it would have involved spend that we didn't think made sense. We would have been borrowing past a level we were comfortable with. And we didn't think we needed to in terms of the project, the field, our understanding of the field, or growth that we needed to deliver to the market.

So today we've taken that inventory constraint off the table. We're very purposeful in not—to give you a vision of that future, but not saying tomorrow we're going to three rigs. So we're not going to three rigs tomorrow. We might for next year, and so that is a budget conversation.

The key variables that play in our minds right now on that would be tell me the price of oil. I don't believe $88, and we're a little better than that now for next year, but the market's saying it's coming off. And so we've got some hedging in place. I'd like more. I'd certainly like more if we're going to spend more money, but you can't actually effect that in the market. So we'll roll this out fall—I suppose it'll be probably a little bit later than the fall, and we'll put a plan together that's going to make sense for people on the what can we afford side.

We've also got competing opportunity. And we've done, I think, quite an admirable job of increasing the opportunity in the Company. And we spent a lot of time on this project because it was important to the Company, but a lot of other things going on too.

We're just—we just completed two wells in the Duvernay. Are we going to spend money there or not is a question. Those could be quite significant for us, but we've got other opportunities as well in Canada on the oil side at various levels of advancement, and the amount that we want to put into those will factor into the mix.

So is there a reasonable possibility that we run three rigs? That's a reasonable possibility that might happen, but we'll be pretty clear and specific and rule something out that people understand later in the year.

**Jo-Anne Caza**

I have another question from the webcast, and this one kind of goes back to the completion design and the evolution, again, that we've seen there. It's a question around what does the number of entry points mean and how important is that in terms of the completion evolution?

**Ian Dundas**

The short answer is we think it means a fair amount. Ray, do you want to expand on that?

**Ray Daniels**

Yeah. What we've—we just—the distance between the facts stages, so we've gone down to about 200, 220 feet, and then within that 220 feet we'll get three clusters of areas where we inject—or where we frac.

And so what we're seeing or what we believe is happening is more a realization around the wellbore, and we're seeing increased that initial—as you saw that first year of production really comes on quite strongly with that—with the increased number of entry points into the rock.

**Jo-Anne Caza**

Thanks.

**Unidentified Speaker**

Hi. Just a question again relating to commodity prices; I'm just curious at what commodity price would you slow your pace of activity in the Bakken?

**Ian Dundas**

I guess, Dean (phon), there's two variables. One is affordability and the other is economics, so where do you start pushing breakeven supply, 10 percent kind of stuff? Which we're not targeting 10 percent, but you've got room to go there. If you're at the high end your breakeven supply number for a 10 percent return could be $50 oil. At the low end of the curve it would be $7 oil, so that's the kind of you've got room to go there. And sorry, that's WTI with a shrinking discount to the net. So we've got room to go there. I think the bigger question's going to be one of affordability.

It is—and a critical part of our plan is to having a financial plan that makes sense to investors where we're not just randomly borrowing without a plan. So we've got a lot of room in terms of credit capacity, but we're not going to artificially borrow to juice a little more growth.

So we think about the world, and a lot of these cases are 90 to $95; 90 to $95, in fact 90; our planning world is $90 TI. I sort of believe a $0.90 dollar and $4 NYMEX, 3.50 AECO.

AECO maybe feel we could be a little better than that, but I think it's pretty reasonable. And that's how we think it ties. I think we feel maybe a little bit better about gas, but 90, $95 oil feels okay for us, and so we plan in the context of that. And then if we want to add a rig in North Dakota I would have an inkling to want to hedge a bit more of that so we could understand what happens if we have a little bit of a price shock.

If we sit in the 80s what does it mean to us? We run low-case scenarios, so our—as you well know, we've done a—we've grown our gas points pretty meaningful and it's mostly in the Marcellus outperformance that just keeps bringing this gas to bear, and that's giving us some more cash flow, but not a lot. It's really about the oil side.

So Enerplus in an $80 world looks different than Enerplus in a $95 world, and that $10 matters to us, so we're not going to do something where if we get a price shock we're going to get caught short. If we really think we're in an $80 kind of world, that's probably a pretty interesting place where you'd start to see some pressure on slowing activity down.

**Unidentified Speaker**

(unintelligible)

**Ian Dundas**

I'm not sure it would. Would it be in the Bakken? I don't know, I don't know. Because we'd make a lot of money and it'd be economic still and we'd be looking at every single project.

**Jo-Anne Caza**

I have another one from the webcast, and it's particularly about Fort Berthold, as well as the Sleeping Giant project over in Montana and what's the EOR potential? Or is there EOR potential in either of those areas?

**Ian Dundas**

For sure there is. So we have 200 million—2 billion barrels of oil in place between those fields, just under 2 billion, I guess. Sleeping Giant we would be booked to 14 percent recovery factor and would have cum'd 8 percent of that oil. And so the team this year is going to do something there.

Gas, I think, is delin'ing, maybe water. I think gas is delin'ing, so there's something there. We have a lot of expertise in the Company both sides of the border. I guess we would have spent more time on the Canadian projects, and so just based on where those US projects are, so then that's today in Sleeping Giant and so little changes in recovery factor can add a lot of light oil to the mix.

In North Dakota, just based on where—based upon where development is in North Dakota, there's not a lot of people who are doing a lot yet. EOG has probably talked the most about it, or people have talked the most about EOG and what they're doing. They're—it's very early, and we don't have a lot of information on that.

So I think the opportunity is real, there's a huge option, and it's a several year out thing. I think we're very well positioned as a company to be able to bring that into our plans from an expertise perspective. But it's several years out, but the thinking has to start quite quickly relative to thinking about long-term planning and the decisions you have today about your development plan, well orientation, infrastructure, all of that how might that affect secondary.

There aren't a lot of analogs out there, though, that look like this where you can say this for sure works. I'm relatively optimistic that the price of oil stays up because Ray talked a lot about 15 percent recovery factor. That is a very reasonable number to think about for rock like this in primary development, but it's still 15 percent, so there's a lot of oil in the system.

**Unidentified Speaker**

Ian, how much in the way of pad drilling are you doing right now? And are the well costs that we've talked about before, are those essentially the single wells that you're drilling? Or is it one or two?

**Ian Dundas**

Those numbers tie exactly to what's happening to us this year, and most of our drilling—maybe all—almost all of our drilling has at least some form of pad. Not much that you would call absolute most efficient first well to fourth well in a continuous operation, so it's here's the second well or here's the first and second well or here's, I guess, some second and thirds.

But it's what's happening to us right now. So if you fast forward two years, two to three years, depending upon what rig scenario we're using, you'll see—clearly you'll see some efficiencies coming with that.

I mean some of the work that—I apologize if Ray already said this—but those most recent completions we just did we actually were playing around with simul ops and working through what all that could look like right now, which would be important for us if we get into a bigger development a couple years out.

**Unidentified Speaker**

What's Enerplus' A&D strategy in North Dakota in the Williston Basin right now? And are you open to pro consolidation?

**Ian Dundas**

Absolutely. We would—I'd love to have more. We've got a great team. We're leading industry in cost performance, and so with a core area all of that says build around your core areas; that'd be great. The problem has been it's a pretty coveted area, and when you look at the limited number of transactions that have occurred and then you work backwards into what people paid for, they paid for a lot.

And so for the first time in our corporate history—we're not alone in this—but for the first time in our history we have a deep inventory in front of us where we can grow organically for years. And so that's great.

It makes life harder for the acquisition strategy because you bring something in it needs to displace something else that has decent economics. And so it would fit like a glove from a portfolio perspective, it would fit like a glove from an operational perspective, and then it'll have to be a question of opportunistic does it make sense, does the math make sense. No interest in buying something with a single-digit rate of return based on every idea we have for the future.

And somebody asked the question earlier around—Dirk asked the question around others. We're moving our way through this. I don't think it's hyper conservative; I don't believe that. I think we're moving through this prudently, but clearly there's many in industry who are—who believe this is completely proven what we've just talked about, and they're already believing a doubling of inventory. Not everyone's there and that's not necessarily the market, but there's more of that than there is a disbelief in the density that we're talking about.

**Unidentified Speaker**

Just another question; with these new completion techniques you're taking up your IP rates. You're also taking up your decline rates. So if you go from two rigs to three or four, I mean at some point does it have an overall impact on your corporate declines? And where would you like those corporate declines to ultimately settle out?

**Ian Dundas**

Yeah. I think, Dirk, you asked that too and I don't think I addressed it. The decline is huge. Thinking about decline relative to netback relative to sustainability and growth rate, that's the third factor in the equation. So we're 25 percent corporate decline.

If we added a rig it might move it by a point, somewhere along those lines. And not forever, but it would move it a little bit. So I like 25. I don't think you have to stay at 25, but you got to be really careful, and as you get closer to 30 it's a problem, I think.

And so I think we have a little bit of room in connection with that, and I think we could manage it, but it clearly would be sitting right in front of us as we're making that decision.

**Jo-Anne Caza**

And I think the last question that we have from the webcast relates to the dividend, and would there be any plan to increase the dividend?

**Ian Dundas**

There are no plans today to increase it. I think it would be awesome if the dividend went up because when the dividend goes up that's going to mean that we have been successful in our plan to grow our cash flow and to grow our capital base. And we are very focused on a total return proposition for people.

We have now, I believe, grown into our dividend, but there's not a tremendous amount of excess in the system. It depends on your commodity prices, but you certainly can't look to the forward market for guidance that we're going to have a higher oil price next year.

And so our plan is total return, growth, and then dividend increase will be an outcome of being successful in that. And so when will that happen? Don't know. Commodity price is going to be dramatically important to that, as will how successful we are in our growth plans.

We're in a great place right now with great people asking that question because I think it proves the math is very different than people thought it would be, but we're not there today.

**Jo-Anne Caza**

I think that's all.

**Ian Dundas**

Great. Well, thank you very much; appreciate everyone's time, and hope everyone has a great day.

Thank you.

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