FINAL TRANSCRIPT

Enerplus Corporation

Year-End 2014 Results

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PRESENTATION

Operator

Good morning, ladies and gentlemen. Thank you, and welcome to the Enerplus Corporation Year-End 2014 Results Call. All lines are currently in a listen-only mode.

After the speakers' remarks, there will be an opportunity for questions and answers. If you would like to ask a question at that time simply press *, and the number 1 on your telephone keypad.

I would like to now turn the call over to Jo-Anne Caza, Vice President, Corporate & Investor Relations. Please go ahead.

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

Thank you, Operator, and good morning, everyone. Thanks for joining us this morning. Ian Dundas, our President and Chief Executive Officer, will be providing an overview of our year-end operational, financial, and reserves results this morning. He'll also discuss our revised outlook for 2015, given the significant drop in commodity prices since our guidance release in mid-December.

Also with us on the call this morning is Ray Daniels, Senior Vice President of Operations, who will give some additional detail on our capital spending and operational performance in 2014 and the outlook in 2015; Eric Le Bain, Senior Vice President of Corporate Development, Commercial, who will provide some additional colour on curtailment in the Marcellus; and Rob Waters, our Senior Vice President and Chief Financial Officer.

Our financials have been prepared in accordance with United States generally accepted accounting principles. All discussion of production volumes today are on a gross company working interest basis, and all financial figures are in Canadian dollars, unless otherwise specified.

All reserve information that we'll talk about today has been prepared under Canadian Standard National Instrument 51-101, and are on a gross working interest basis using forecast prices and costs as provided by our independent reserve evaluator. Conversions of natural gas to barrels of oil equivalent are done on a 6:1 energy equivalent conversion ratio, which does not represent the current value equivalent.

The information we're discussing today contains forward-looking information. We ask listeners to please review our advisory on forward-looking information to better understand the risks and limitations of this type of information. This advisory can be found at the end of our news release issued this morning and included within our MD&A and financial statements filed on SEDAR and EDGAR and also available on our website at enerplus.com.

Following our discussion we'll open up the phone lines and answer questions you may have, and we'll also have a replay of this call available later today on our website.

And with that, I'll turn the call over to Ian.

Ian Dundas — President and Chief Executive Officer, Enerplus Corporation

Thanks, Jo-Anne. Good morning, everyone. Thank you for calling in. We appreciate your time this morning. I would like to leave you with two messages today.

First, we delivered another impactful year of operational and financial performance in 2014. This included a strong Q4 and exceptionally strong reserve performance. Second, as we navigate through the current market we are taking proactive actions to ensure we maintain our financial strength and enhance value for our shareholders.

So let's start with a recap of 2014. Production grew by 15 percent, or 13 percent per share, driven by strong performance once again in the Bakken and the Marcellus.

We met our upwardly revised production targets, averaging just over 103,000 BOE a day, despite selling 3,500 BOE a day of noncore assets and despite voluntarily curtailing production in the Marcellus that averaged approximately 5,000 BOE a day in the second half of the year.

Funds flow grew by 14 percent, or 12 percent per share, due to the growth in production and the strength of our hedging program. Capital spending came in under guidance at $811 million, as we slowed down activity in the fourth quarter in response to the drop in commodity prices.

We ended the year in a very strong financial position with a debt to trailing 12-month funds flow ratio of 1.3 times, and less than 10 percent of our $1 billion credit facility drawn.

We achieved another year of strong organic reserve replacement at very competitive costs. 2P reserves grew by 7 percent, 6 percent per share, representing 175 percent production replacement. Proved reserves increased by 9 percent and now represent two-thirds of our reserve base. Proved producing reserves also increased, up by 11 percent, and now represent about half of our total reserves.

The majority of our reserves growth came from Fort Berthold and the Marcellus. Strong well performance throughout 2014 drove significant positive technical revisions in both plays. We added 75 million BOE of 2P reserves through our development activities. This will add to F&D costs of $9.80 per BOE, including future development capital, for a recycle ratio of 2.7. FD&A costs were also attractive at $8.62 per BOE.

Strategically we continued to high grade our portfolio throughout the year with the divestment of noncore gas assets at attractive prices. Our 2014 divestment program realized net proceeds of $204 million at a metric of $19.65 per BOE. We also increased our contingent resource estimates by 86 million BOE, bringing our total to 449 million barrels of equivalent. This increase was largely from our oil assets in North Dakota.

Finally, in addition to our strong operational financial performance we also established a very healthy hedge position for 2014—sorry, for 2015—so a large percentage of both our oil and gas production is currently hedged at prices well above current market.

Okay. So now let's look forward to 2015. This strong performance in 2014 has put us in a position of strength as we entered this year, but as we continue to experience significant commodity price weakness, we are adjusting our plans to preserve value in the near term and ensure the financial strength of the company.

First, we are further reducing our capital spending. We are now forecasting $480 million of capital spending, which represents a 40 percent reduction from 2014 levels and is $150 million lower than our current guidance. Although a portion of the reduction relates to cost savings that we are now seeing, the large majority of the reduction is based on lower activity in the Marcellus and in the Bakken.

Secondly, we have entered into agreements to sell two noncore properties producing approximately 1,900 BOE a day of primarily oil production for proceeds of $182 million before closing adjustments and transaction costs. We expect these transactions to close early in the second quarter.

Third, we are planning for high levels of production curtailment in the Marcellus in this low natural gas price environment. We believe dialling back our production when prices are lower allows us to retain the value of our assets, and provides us with the flexibility to increase production quickly as gas prices strengthen.

And finally, we are reducing our monthly dividend to a more appropriate level. Effective with the April payment we are reducing our dividend to $0.05 per share from the current level of $0.09 per share.

We know that the dividend is important to our investors, and it will continue to play a role in our strategy to deliver value to our shareholders. We did not take the dividend reduction lightly, but believe the new level of $0.05 per month is a more sustainable and appropriate level in the current commodity price environment.

As a result of these proactive steps, we are revising our 2015 annual average production guidance range to 93,000 to 100,000 BOE a day, with oil and liquids representing between 42 percent and 44 percent. Our year-over-year production volumes would actually be effectively flat, excluding the impact of the voluntary production curtailment in the Marcellus.

These actions have clearly improved our financial flexibility. Including the proceeds from divestments, our capital program and dividend are effectively funded this year under forward prices with an adjusted payout ratio of below 100 percent.

We expect our debt level at year-end 2015 to be essentially unchanged from year-end 2014, although with lower cash flows we expect a higher ratio of debt to funds flow. We forecast our debt to trailing 12-month funds flow ratio will be about 2.2 times at year-end 2015, assuming a WTI price of $55 per barrel, a NYMEX gas price of $2.75 per Mcf, and a US to Canadian dollar exchange rate of 1.25.

And now I'll pass the call over to Ray to provide some details on our operating activities in 2014 and our plans for 2015.

Ray Daniels — Senior Vice President, Operations, Enerplus Corporation

Thanks, Ian, and good morning, everybody. What I would like to leave you with today is that one, we continued to deliver improved operational execution in 2014; and two, our organization is focused on spend discipline in 2015 in both our capital programs and our operating activities.

In 2014, we drilled 88 net wells during the year, 65 percent of which were directed to crude oil drilling. As a result, our average liquids production increased 5 percent to 43,800 barrels a day, and at the end of 2014 liquids represented 42 percent of our annual average production.

In North Dakota, where we spent 42 percent of our capital, we continued to deliver industry-leading well performance at Fort Berthold. This was achieved by advancing our completion design, optimizing our drilling density design, and testing the lower benches of the Three Forks.

Both our 30- and 60-day initial production rates were 20 percent higher on average than our high-case type curve, and our total Fort Berthold production increased by almost 30 percent year over year, averaging 21,700 barrels of oil equivalent per day.

Well costs did initially trend higher as a result of increasing the number of frac stages and volume of proppant pumped, but we saw meaningful reductions in the order of 8 percent in the latter part of the year. These savings were primarily driven by the efficiencies of pad drilling. In fact, the five wells we drilled and completed on the Turtles/Butterflies pad at the end of 2014 averaged US $12.1 million US.

The combination of increasing initial production and reducing capital costs drove a 25 percent improvement in capital efficiencies year over year, and by the end of 2014 we drilled 27.2 net wells and brought 18.4 net wells on stream at Fort Berthold.

We also completed a rigorous Fort Berthold resource assessment early in 2014, resulting in a significant increase in our estimate of discovered original oil in place by 500 million barrels to 1.5

billion barrels. With an estimated recovery factor of 15 percent, this enabled us to increase well density, and therefore meaningfully increase the number of drilling locations by around 127 percent.

With the revised resource assessment and improved well performance we added approximately 25 million barrels of oil equivalent of proved plus probable reserves inclusive of extensions and technical revisions at the end of 2014. This equates to replacing 2014 production by over 300 percent with an average F&D cost of $16.87 per BOE, including future development capital.

In addition, we added 76 million barrels of oil equivalent of economic best estimate contingent resource, an increase of almost 200 percent versus December 31, 2013, bringing our new best estimate of contingent resource to 115 million barrels of oil equivalent.

Turning to our operations in the Marcellus. Wells continue to outperform in this core area as well. Tighter frac spacing and increased proppant resulted in a positive impact on well performance. Thirty-day initial production rates averaged 11 million cubic feet per day in 2014 compared to 10 million cubic feet per day in 2013. And despite the increase in frac stages and proppant, on average total well costs in 2014 were roughly $1 million lower per well than in 2013.

With the additional working interest acquired in December of 2013 as a result of our drilling program, production doubled year over year from about 15,000 barrels of oil equivalent per day to over 30,000 barrels of oil equivalent per day, despite average curtailment of 5,000 barrels of oil equivalent per day in the last half of 2014.

We currently have a total of 13.7 net nonoperated wells waiting to be tied in. Proved plus probable reserve additions and revisions in the Marcellus were over 300 Bcf at the end of 2014, replacing nearly 450 percent of production at a low F&D cost of just under $0.50 per Mcf, including future development capital.

And despite the decline in natural gas prices, our best estimate of economic contingent resource increased from 1.3 Tcf to 1.4 Tcf at year-end, driven by strong well performance and higher expected ultimate recoveries.

In addition, although we experienced wide basis differentials, which reduced our netback, our recycle ratio was a very attractive 3.6 times.

In Canada, we continued to invest in our crude oil waterflood portfolio during 2014. At Brooks, we drilled 14 wells targeting the Lower Mannville sands as part of a 55-well development program. Early production performance has been positive, with average results in line with our expectations.

At Medicine Hat, we continued to develop the Glauc C waterflood, where we drilled seven injection wells and seven producing wells as part of our waterflood expansion project. Results from this drilling activity, as well as our polymer project, continue to exceed expectations.

Our Canadian gas activities were directed at the Wilrich and the Duvernay. We drilled 3.2 net wells in the Ansell area targeting the Wilrich, and in the Willesden Green area we drilled two horizontal wells targeting the Duvernay.

Turning to our 2015 plans. As I mentioned, we are focused on spend discipline. First, we have been very strict on our capital allocation; and secondly, we are working to maximize savings in all areas of spend. The result is that we have reduced our capital spending program significantly in 2015 to $480 million, a 40 percent reduction from 2014. The $480 million has some cost savings factored in, but the majority of the reduction from our current guidance is deferral of activity.

With respect to our operated activities at Fort Berthold, we will be dropping a rig at the end of Q1, and we will continue with only a one-rig program for the remainder of 2015. We have also reduced the number of completions primarily to those deemed essential. This minimizes spend, and also fills an inventory of about 16 wells by the end of 2015 that we can bring on stream expeditiously when market conditions improve.

In the Marcellus, we are reducing activity significantly, resulting in approximately a 75 percent reduction from our 2014 spend. With current gas prices, our plan also includes a continuation of production curtailment averaging between 6,000 and 7,000 barrels of oil equivalent per day in 2015, and Eric will talk a little about that later. The curtailment will moderate our decline rates and enable us to ramp up production quickly when natural gas prices improve.

Canadian activity in 2015 has also been minimized with, effectively, only two operated drilling programs planned. We have a three-well program at Ansell in our top-tier area in the Wilrich that will be completed by the end of Q1. The second program is at Brooks, targeting the Lower Mannville. This program will continue into Q3 and is primarily driven by lease expiries.

In addition to these programs we have some funds allocated to new facility construction, facility maintenance, and well optimization within our waterflood portfolio.

With respect to cost savings in 2015, our supply chain organization is very active working with our vendors exploring ways to save costs. This has included direct negotiations with key contractors bidding or rebidding work and written communications with lower-spend contractors.

We had a very positive response from our vendors, and have secured savings across the board ranging to as much as 40 percent on a contractor-by-contractor basis. Currently, we're seeing bottom line savings in the order of 10 to 15 percent but anticipate savings could rise to as much as 15 or 20 percent if the current business environment persists.

In addition to cost savings we are also targeting technology to help our cost structures, and some examples in our Fort Berthold operations include using insulating tank covers on our frac jobs, using natural gas instead of propane for water heating, and special frac plugs that don't require drilling out. These three modifications alone could reduce our completion costs by as much as $300,000 per well.

Suffice to say, our staff across operations are focused on driving costs out without compromising economics or safety.

With that, I'll now turn it over to Eric.

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

Thanks, Ray. I'll just say a few brief words concerning the Marcellus curtailment. As both Ian and Ray have mentioned, we foresee curtailing production at the levels of 6,000, 7,000 barrels of oil equivalent per day of Marcellus production on average in 2015. We just are not prepared to produce all of our capability into this low-price market.

Therefore, we see production on average somewhere between 170 million and 190 million cubic feet a day. The 6,000 to 7,000 barrel of oil equivalent per day level of curtailment is based on our December and January experience and our view that NYMEX and Marcellus prices will remain soft through 2015 due to the oversupply in the northeast and across the wider continent.

Our projected net level of production provides about $40 million of net operating income from our Marcellus production at current forwards, roughly that US 2.75 an MMbtu NYMEX we quote and roughly $1.25 basis differential. This level of spend is enough to roughly offset the decline in the Marcellus for projected production on an annual average basis. We're spending about—projecting spending in the low $40 million range. It doesn't quite balance decline on an exit-to-exit basis.

Do we foresee curtailing production into 2016? At the moment we do. Infrastructure, as you know, continues to be built to take gas away from the northeast. So there's no question the industry can absorb some level of growth year over year.

In the end, though, it comes down to whether competitors act as we and our partners are doing to limit production into this market environment. Indeed, we are seeing similar behaviour and announced reductions and spend across the competitive world there.

And with that, I will turn it back to Ian.

Ian Dundas

Thanks, Eric. Before I turn it over to questions I'll just wrap up. We believe that our primary job in the current environment is to ensure our financial strength and to focus on maximizing shareholder returns.

We believe that the steps we are taking have positioned Enerplus to withstand a low oil and gas price environment which could potentially continue past 2015. Although our plan, with a modest implications to near-term cash flow, we believe we are taking the right steps to position Enerplus to not only weather this downturn, but to potentially capitalize on opportunities as we see them.

We retain significant flexibility and are well positioned to reestablish production and dividend growth as market conditions improve. Although this may be seen as conservative, we view it as prudent.

And with that, I will turn the call over to the Operator, and we are here to answer any questions you may have.

Q&A

Operator

At this time, I would like to remind everyone in order to ask a question, press *, and the number 1 on your telephone keypad.

Your first question comes from the line of Greg Pardy with RBC Capital Markets. Your line is open.

Greg Pardy — RBC Capital Markets

Thanks. Thanks. Good morning. Just a number of nitty questions but, Ian, I'm wondering could you lay out what you think your spending trajectory looks like just over the course of '15, I mean on a quarterly basis? Rough numbers are fine.

Ian Dundas

Sure. We will have 90 percent—60 percent done—sorry, how about I use real numbers here? We will be more than half done as we move into the second quarter, and a good 70 to 90 percent done as we move through the summer.

Greg Pardy

Okay.

Ian Dundas

Very limited spend in the fourth quarter.

Greg Pardy

Okay. Okay. Which kind of brings me to my next question. I think the Marcellus speaks for itself in terms of that you can bring on additional volumes kind of as and when you want to. With the one-rig program now in the Bakken, what does that mean in terms of an exit rate? Approximate exit rate? And I guess to balance that, what Ray was saying, where you've got a number of wells that you'll—I think it's 15 or 16 wells you'll be able to bring on quickly, but just trying to understand those dynamics a bit better.

Ian Dundas

Yeah. So we don't talk exit to exit too much, but down a bit. I think the key message we would want people to retain is one of flexibility here. And so we will have—we already have a bit of an inventory. We're going to have a bigger inventory of holes in the ground as we move to the end of the year. Ray talked about 16 wells. Those aren't instantaneous completions, but that could come on really quite quickly.

And so is it a possibility we will adjust again this year? Absolutely that's a possibility if we see price response. We're already seeing costs come down. A completion last year—in that $12.1 million number Ray referenced, the completion was $8 million of that approximately. Now that's probably 6.5, and the longer we stay in this price environment the more that we see potential improvement coming there.

So I'd say it's not the same as literally dialling up currently producing wells in the Marcellus, but there is a lot of flexibility to bring more than 10 wells on. Our expectation is—well, I don't know. We're going to see how the market responds, but we can move pretty quickly there.

And when you think about 2016, which we're not really talking about explicitly, but obviously this is a plan that positions us much better for 2016 if this continues. So in a modest price environment in 2016, what'll happen there? Low spend will happen there as well, obviously, and so as we think about a two-rig program versus a one-rig program in a lower-spend area that one-rig program, we think, gives us enough inventory in 2016 as well.

Greg Pardy

Okay. Great. No. Thanks for that. The waterflood you sold or the assets you sold today, about a 7 percent decline on that. Can you just remind us what your corporate decline would sit at now approximately?

Ian Dundas

We still talk 25 percent, and that's not a bad number to think about. Selling 1,900 barrels a day of low decline—I don't think we said 7 percent, but in any event—low decline assets moves it a little bit; I think 0.3 percent or something along those lines.

Greg Pardy

Okay.

Ian Dundas

And then as Eric talked about, this curtailment in the Marcellus is a tricky thing to think your way through, so at the upper levels of curtailment you actually have quite a modifying effect on decline. But again, that changes on a—could change on a monthly basis as we bring it back on, but net net I would say 25 is a good number to be thinking about still.

Greg Pardy

Okay. And then maybe just to define curtailments right now. So essentially those are wells that you've drilled, completed, and they're essentially just awaiting connection? Or would they be further back in the process? I'm just trying to understand how you define curtailment.

Ian Dundas

Curtailment as we define it are wells that have produced that we are producing at a level other than their productive capacity, not their theoretic productive capacity, but their actual productive capacity. Think about just choking it back.

Greg Pardy

Yeah.

Ian Dundas

And so on a day basis we could see 10,000 BOE a day of swing, and you saw a fair amount of volatility in the fourth quarter. And there was a lot of stuff that was going on in the fourth quarter in terms of, first, pipe expansion, and then some really weak day prices that were happening in December. But over average in the fourth quarter we saw that 6,000 to 7,000 BOE a day.

So today, production's reasonably high as we're seeing a weather event in the east, but in January it was down a bit as it wasn't there.

Greg Pardy

Okay. And that's 100 percent—the 6,000 to 7,000, that's 100 percent gas?

Ian Dundas

Yes.

Greg Pardy

Okay. And two last quick ones for me. Just the production guidance you've got out now. Is that—that's inclusive of the 1,900 BOE a day that you're selling?

Ian Dundas

Yes.

Greg Pardy

Okay.

Ian Dundas

And it assumes an early Q2 close.

Greg Pardy

Okay. Perfect. And the last thing, just with respect to liquidity. I mean your balance sheet has actually been in good shape all along, even better now, but can you just remind us on your liquidity and then just what your covenants are around that?

Ian Dundas

Sure. I'll turn that over to Rob Waters.

Rob Waters — Senior Vice President and Chief Financial Officer, Enerplus Corporation

Okay. And, Greg, actually in our MD&A this time we actually laid out what the covenants are and where we were with respect to the covenants at the end of 2014, so that material's in there. I think it's around page—under Liquidity and Capital Resource section.

So the covenants on our senior bank facility, which is a $1 billion facility, we can take our senior debt to EBITDA, which is earnings before interest, taxes, and depreciation and what not to 3.5 times. But we can only do that for six months and then it has to come down to 3 times, and at the end of the year we were running at 1.3 times. And that's sort of the most—that's the covenant we watch the most. The other covenants wouldn't cause us much trouble at this time.

We also have a total debt to capitalization covenant, and the maximum ratio there is 50 percent, and we're running at 26 percent right now. And on our senior notes we have fairly similar covenants of that 3 to 3.5 times on senior debt to EBITDA, but we also have a maximum debt to consolidated net present value of total proved reserves, and that ratio is at 60 percent, and we're currently running at 37 percent at the end of the year.

And then there's an interest coverage ratio, EBITDA to interest, and the minimum ratio—minimum there—is 4 times, and we're running at 14.4. So really we're not worried about our covenants at this stage. Our balance sheet's in good shape. We ended the year at a 1.3 times debt to funds flow, and that was pretty close to what you'd call a debt to EBITDA at that time as well.

Greg Pardy

Yeah. That's great. Thanks, all.

Ian Dundas

Thanks, Greg.

Operator

Again, if you would like to ask a question, press *, and the number 1 on your telephone keypad.

There are no further questions. I will now turn the call back over to Mr. Ian Dundas, President and CEO.

Ian Dundas

All right. Well, appreciate everyone's time today, and hope you have a great weekend. Thank you for paying attention.

Cheers, bye.

Operator

Ladies and gentlemen, this concludes today's conference call. You may now disconnect.

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