Southwestern Energy Company

Fourth Quarter 2016 Earnings Teleconference
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Craig Owen; SVP, CFO
Jack Bergeron; SVP, E&P Operations
Randy Curry; SVP, Midstream

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Tim Rezvan; Mizuho
Arun Jayaram; J.P. Morgan
Jeffrey Campbell; Tuohy Brothers
Brian Singer; Goldman Sachs
Kashy Harrison; Simmons Piper Jaffray
Dan McSpirit; BMO Capital Markets

Presentation

Operator: Greetings, and welcome to the Southwestern Energy Company fourth quarter 2016 earnings and 2017 guidance teleconference call. (Operator Instructions)

As a reminder, this conference is being recorded.

It is now my pleasure to introduce Michael Hancock, Director of Investor Relations for Southwestern Energy Company.

Michael Hancock: Thank you, Melissa. Good morning, and thank you for joining us today. With me today are Bill Way, our President and Chief Executive Officer, Craig Owen, our Chief Financial Officer, Randy Curry, our Senior Vice President of Midstream, Jack Bergeron, our Senior Vice President of Operations, and Paul Geiger, Senior Vice President of Corporate Development.

If you have not received a copy of last night's press release regarding our fourth quarter 2016 financial and operating results and 2017 guidance, you can find a copy on our website at SWN.com.

Also, I'd like to point out that many of the comments during this teleconference are forward-looking statements that involve risks and uncertainties affecting outcomes. Many of these are beyond our control and are discussed in more detail in the Risk Factors and Forward-Looking

Statement sections of our annual and quarterly filings with the Securities and Exchange Commission.

Although we believe the expectations expressed are based on reasonable assumptions, they are not guarantees of future performance and actual results or developments may differ materially.

We may also refer to some non-GAAP financial measures, which help facilitate comparisons across periods and with peers. For any non-GAAP measures we use, a reconciliation to the nearest corresponding GAAP measure can be found in our earnings release available on our website.

I'll now turn the call over to Bill Way to discuss our recent activity and our plans for 2017.

Bill Way: Hello, everyone. We appreciate all of you joining us on the call this morning. I want to begin by sincerely thanking all of our employees across the country who came together and pivoted from some extremely difficult times and drove improvement in every aspect of our Company, to deliver on the commitments that we're going to talk about today for 2016, and set the Company up for greater success in 2017, and beyond.

I'm excited to be joined in the room by members of Southwestern's leadership team as we discuss our latest results and the growing momentum we have built through 2016 to capture the opportunities ahead that are all around us this year and beyond.

We made some bold decision and took some decisive actions in 2016, which allowed us to deliver on each of the commitments we made during the year, including the key priorities of capital discipline and a stronger balance sheet.

Now, as you saw in last night's release, the commitments are enduring and form the foundation of how we are moving forward. Our 2017 capital plan is again aligned and within expected cash flow, which includes the remaining $200 million of equity raise raised in 2016.

We have arrested our production decline and have pivoted to a trajectory of value-adding growth in 2017, with further opportunity, including the potential for economically driven double-digit production growth in 2018.

Given our lucrative vertically integrated business model, we are agile enough to flex our capital in response to market changes, while capturing the best economic contributions from our portfolio.

Our capital plan for 2017 is expected to be in the $1.175 billion to $1.275 billion range, again to be invested within cash flow and in accordance with our strict economic parameters.

This plan of economic growth opportunities is expected to deliver strong growth of approximately 17% in our Appalachia assets and 3% total Company growth, using the midpoint of production guidance, an exciting turn from last year's decline due to significantly reduced activity.

This growth includes an exit-to-exit production rate increase of approximately 20% for the Company. Looking beyond 2017, the portfolio is expected to deliver double-digit growth in 2018, assuming a capital plan based on strip pricing and again investing within cash flow.

This substantial growth, when factoring in our position as one of the nation's largest producers and the size of our base volume from our vast core assets, is a terrific path forward.

Capital allocation is based on individual project economics and prioritized based on returns against strip prices.

In Northeast Appalachia, we expect to run two rigs, with the majority of the activity centered on our core Susquehanna County acreage, with additional delineation testing throughout other portions of our acreage.

In Southwest Appalachia, we anticipate running two rigs throughout the year, primarily drilling in the rich gas window of the panhandle of West Virginia, targeting highly economic wells from our enhanced operational results and increased liquids pricing.

Additionally, in this area, we are very encouraged by the early results of our first Utica well, and, as a result, have accelerated the timing for our second test well located in Washington County, Pennsylvania, which was spud earlier this month.

And you will recall that we had originally planned to begin our Utica testing in 2018, but results from wells encircling our position and our first well provided us with the confidence to accelerate this activity.

In the Fayetteville, we are focused on several emerging opportunities within our acreage, and our activity in 2017 will advance our learnings on a number of fronts, including additional benches in the play.

Part of this plan will be to further our understanding of the high potential Moorefield and its ability to drive margin expansion in our asset.

We also are testing additional promising Fayetteville intervals. Success here and any other improvements in economics would only add to the economic and strategic benefit that the Fayetteville provides to the Company today, with its cash flow generation capability and the optionality the core asset provides within the portfolio to allocate capital based on market dynamics.

To capture these learnings, the capital program includes one rig running throughout the year in the Fayetteville.

As we execute this plan, our laser focus on margin expansion will continue to be a key priority, as we identify additional operating efficiencies and improve well productivity to enhance returns.

We are working to build on the realized savings in 2016, as we successfully adjusted the Company to excel in a lower-for-longer commodity price environment. Many of these savings are sustainable, and each team continues to add even more to the bottom line for 2017.

These reduced costs, coupled with improved commodity prices and a full year of uninterrupted drilling and completion activity in 2017, is expected to have a material impact on future reserve bookings.

As reserves utilize a 12-month look-back on pricing, the average NYMEX used for our 2016 reserves was $2.48 per an MMbtu. Given the current price environment and assuming strip pricing at December 31, 2016, we estimate we would have the ability to book approximately twice as many reserves and add an incremental PV10 value of $3 billion to $4 billion.

In addition to our E&P assets, our marketing portfolio is also driving value, taking advantage of its optionality and maximizing price realizations based off of market dynamics.

Our view of basis is improving with the addition planned activity and the capacity that's being built, and that view is solidifying as we expect differentials to improve over the next two years as pipeline capacity is placed in service.

So as you can see, we have tremendous opportunity ahead of us in 2017, and a plan that captures those opportunities.

Now let me turn it over to Craig to discuss some of our financial highlights.

Craig Owen: Thanks, Bill, and good morning, everyone.

As you saw in last night's release, thanks to the hard work and dedication of the entire SWN team, we ended 2016 in very good shape financially. At year-end, we had a cash balance of $1.4 billion and revolving credit facility capacity of $800 million, of which $174 million was utilized for letters of credit.

Our efforts throughout the year resulted in our net debt balance being reduced by approximately $1.5 billion from the end of 2015, exiting the year with only $316 million of debt due prior to 2020.

With our commitment to realizing expected returns on our investment program, we achieved our targeted hedging levels as we entered 2017. We currently have 560 Bcf of our 2017 gas production hedged, with almost half of these positions being callers, providing upside exposure to improving prices. We also have 272 Bcf of our 2018 gas production hedged, predominantly with callers, and a smaller hedge position with 2019 gas volumes.

Consistent with our strategy, we expect to continue adding to these hedge positions as we move throughout the year. These hedging activities will help us achieve our expected returns, providing downside protection, while also retaining upside potential as prices improve.

As Bill mentioned earlier, our relentless focus on margin expansion was a key driver to value creation in 2016, with our lease operating costs decreasing $0.05 per Mcfe when compared to 2015, which includes a 24% reduction in Southwest Appalachia.

We also achieved well cost savings, particularly in our Appalachian assets, while driving increased well productivity. We expect minimal service cost inflation in 2017, largely as a result of our vertical integration.

I will now turn it over to Jack to discuss some of the details of our operational update.

Jack Bergeron: Thanks, Craig. Good morning, everyone. We ended 2016 in a very strong position, achieving the top end of our production guidance, while making strong progress on a number of our testing initiatives.

First, in Northeast Appalachia, we continued testing our tighter stage spacing, increased sand loading, and optimized flow techniques. This work added significant value with material improvement over prior wells.

One example is our Cramer pad in Susquehanna County, where five wells were placed online with a total initial production rate of 92 million cubic feet per day. We are positive these actions are bringing value forward and improving economics and capital efficiency of our investment program. We also feel they will increase the EURs, although at this time it's too early to quantify the increase.

We also expanded our testing footprint on our core assets. We progressed our delineation efforts in Northeast Appalachia, testing our acreage in Tioga County. Initial infrastructure was installed and first production commenced there in early January. The well results confirm the productivity of this acreage, and we'll have additional activity in this area throughout 2017.

In Southwest Appalachia, the high proppant completion test discussed on the last call were successfully completed, with one well being completed utilizing 5,000 pounds of sand per foot and the others utilizing 3,500 pounds per foot. This compares to our standard completion design of approximately 2,000 pounds per foot.

These high proppant completions were successfully carried out by our operations team.

We continue to test the technical limits of getting sand put away. These wells were just recently placed online, and, as we have said before, we don't have enough flow history to provide clear conclusions at this time. We should be in a position to discuss the results of these on our next call.

Testing also continued in our Fayetteville area where we tested increased proppant completions throughout the fourth quarter. Early data suggests there is an average uplift in production volumes from these wells of approximately 30% over their offsets. The team will continue to monitor additional well data as they determine the optimal level of sand to use in order to maximize our well result and our economics.

Delineation efforts also continued in the Moorefield, where eight wells were drilled in the fourth quarter. Seven of these wells are scheduled to be put online in early March, and we expect to be able to share the results of these wells on our next call as well.

The potential of the Moorefield has encouraged us about our ability to deliver enhanced economics and compete with capital within our portfolio.

We would now like to get your questions. So we'll be able to turn it back over to the operator, who will explain the procedure for asking questions.

Questions and Answers

Operator: Thank you. (Operator Instructions) As a reminder, we ask you that you please ask two questions and invite you to rejoin the queue. Charles Meade with Johnson Rice.

Charles Meade: Bill, if I could go to the comments I think you made in the press release about the double-digit production growth in 2018, are there other important variables in that outlook beyond the natural gas price that we should be thinking about?

Bill Way: Not really. I mean, I think what we do is we take our hedging strategy, you take strip pricing, we combine those together and put them through our model to generate cash flow.

Depending on where that actual strip pricing is, we look at two things, our economic model for the whole enterprise and our individual investment criteria for individual projects, because you'll know that we force rank our projects highest PVI down, and then we invest within the cash flow that is generated from that model.

I think if there's a variable to 2018, it's the same variable that has existed since we entered into West Virginia, is where you drill.

We've seen a very strong improvement in NGL pricing. Our flow regime and flow practices on wells in West Virginia optimize around both production and the generation of NGLs and liquids. And so we take that into account as well.

But our basic thesis of investing within cash flow and assuring ourselves through our hedging program that our economics of the enterprise and our economics of individual projects drives those.

We are able to be very flexible because of our vertical integration. We're able to be very flexible because we have those items of financial discipline in front of us and it's about economic value generation, not just production growth to grow production.

Charles Meade: That makes sense, Bill. And so are we right to interpret that as the strip -- the 2018 strip, as we sit here this morning is right around $2.92. So it's valid at, call it mid-$2.90s?

Bill Way: That is correct. That is correct. As you would know, our hedging strategy and hedging program is a rolling three-year strategy and implementation plan.

And so as we work through this year, we've already begun doing a bit of hedging, limited as it is at this point, into 2018 and 2019, again for two reasons, or many reasons. A couple of which are we will assure ourselves that the returns that we're projecting we're going to get, and we will manage the volatility in some of those issues by putting on the appropriate level of hedges.

Charles Meade: Got it. And if I could just sneak one more in. I'm guessing on the Utica test if you guys had wanted to give us a rate, you would have.

So since you didn't, is there anything else you can talk about on that well and what gave you the encouragement to accelerate your spud and when you might be in the position to want to share what you guys think the potential there is?

Bill Way: Yes. And Jack may have some specific comments he wants to make. But let me say up front, and I've said this since I got here, is that we can bring wells on, especially wells like this that are heavily laden with different testing protocols, and trying to figure out exactly what we have. And we can surge flow wells and it all looks really great. We don't do that.

We want to have enough credible information from having ramped the well up, getting the data from all of the technical or technology-related investment we made so we can give you a solid picture. The initial flow rates and that we modeled in our AFE are being met or exceeded, and that gives us the confidence to continue to press forward.

The other piece of that is that we've got a lot of activity going on around us. And so studying that, learning from that, we're able to take that further step.

And as you watch and look and listen to the program over the course of the year, we're going to take a determined, but measured approach to this. We have the opportunity to put one or two more tests on throughout the year. But we are in that mode of testing, learning, and then trying to be as clear and transparent as we can with you all around when we put the data out there.

You can take some confidence in the fact that we're going to go do another one. But I really want to have the facts as we know them out clearly before we go from there. Hope that helps.

Operator: Tim Rezvan with Mizuho.

Tim Rezvan: My first question is on the guidance that you put out for 2017, as well as the initial comments about 2018.

Should we take it as guidance -- I'm trying to put that to the scenarios you put out last fall in the slide deck about multi-year production growth CAGRs. Should we sort of think of that as probably the middle scenario there that 8% to 12% production growth CAGR that you discussed last fall?

Craig Owen: Yes. Tim, this is Craig. And I think that's fair. I think that middle tier for 2018 was a $1.25 billion capital program.

So again, as Bill mentioned earlier, our capital investment will be dictated by cash flow levels. So it's a model that we kind of tried to put out there to provide some guidance. We'll invest it at levels of cash flow. No harm to the balance sheet.

But maybe one way to look at it as well, assuming we invest exactly as we've guided, our cash flow comes in to the penny, 2017 as we've guided, will be a low production. Most of that production will come flush into 2018, which will make the maintenance capital level in 2018 much lower than I think -- we've talked about in the past of 2017 and 2018 maintenance levels, with 2017 being roughly $700 million and then 2018 stepping up from there. But with the 2017 program as we've guided, the 2018 maintenance level really steps down to $500 million to $600 million for 2018.

So probably giving you ranges around growth, from maintenance level to growth. But that middle rung of that slide in our IR deck is about right. It may be, on today's pricing, a little high from what cash flow would provide at a kind of flat production level. But somewhere in there is going to be dictated by cash flow.

Bill Way: And just to underscore again, whatever number's on there it will flex with our gas price and our ability to hedge according to our hedging strategy. So we will maintain that rigor through time.

Tim Rezvan: Okay. That's helpful color. Thank you. And so my second question, if I could hop on the Utica again. I believe you said your second test was going to be in Washington County. You don't have a lot of acreage in Pennsylvania.

Is that stepping out to the east or is that a delineation-driven decision or can you kind of talk about how you're thinking about the first few wells and where you spud them?

Bill Way: I think we look across our acreage and look for ways to triangulate a testing program that can give us the best picture of the expanse of our acreage, and look at geological and subsurface characteristics and our estimation of those same things in adjacent acreage to ours.

And so we also have to take into account, obviously, that we have a dry gas outlet at that place. And so drilling a well in an area where there isn't any dry gas outlet means that either you've got to flare it to test it or you don't flow it at all.

And we're all about margin and about economics. So the sooner we can get it going, the better.

And I would imagine there may be some, as there always is, there's no message in this other than sometimes you have lease holding opportunities to capture as well. So that's what drives that.

But even the current Utica well we have, we're very mindful of every piece of this economic driver puzzle. And we were able to negotiate a gathering agreement on that one well, actually through a wet gas system but at a dry gas rate to let us test that.

So it's a very integrated, comprehensive view and both the subsurface, our acreage position, the triangulation of all of those plus our midstream and marketing side comes into play to maximize the potential for that.

Tim Rezvan: Okay. Appreciate the color.

Bill Way: And we'll continue to do a handful more. We've got quite an acreage expanse and we've got quite a bit of Utica under that acreage. And so we'll continue to place those where we can eventually get to the place where we can go into more of a development mode.

And as one would expect, the other piece of that equation is you got your cost down, and so we'll continue to work that, too.

Tim Rezvan: Thank you.

Operator: Thank you. Arun Jayaram with J.P. Morgan.

Arun Jayaram: Bill, I want to start a little bit with the CapEx and just philosophically just talk about the decision last year, you have to make some tough decisions and went down to zero rigs operating. And now, the capital program contemplates about $200 million of outspend versus CFO, understanding you do have some cash on the balance sheet.

So just wanted to get around that philosophical view as you approach 2017 and 2018.

Bill Way: Absolutely. So let me start with the last year question. We walked into the year, gas prices were south and heading further south. When we ran our economics on our individual wells anywhere, when you end up with $1.70 gas, there are no economic well locations to be going after.

And where you don't have a hedging position or any certainty about the next couple of years, which is the gas price that helps those economics become reality, the prudent and right thing to do is to stop, and so we did.

And as we progressed through the year, as prices recovered from a, as you would well know, a very significant abrupt halt by the industry in investment and prices and the strip began to rise and our hedging program that we instituted in a formal way in early 2016 began to come together, we were able to restart those.

And as I said earlier, we look at the Company model and we look at the individual well-by-well model. They both have to get a green light before we'll go and do that.

Even with our vertical integration, again, you go down into the depths of where gas prices went, it just didn't make sense to do that.

Now, you'll recall when we restarted our drilling and completions, that activity was funded by a $500 million equity raise capital allocation to this activity.

We invested about $300 million of that and then carried forward in projects that are ongoing and other activity carried forward of that into 2017.

And so that all the teams are very clear, we keep all this allocation and capital in very clear buckets, so nobody's going to the balance sheet and looking on the balance sheet and saying, oh, there's cash flow there, what about using that, because it's not for that purpose.

We had capital allocated for drilling and completions, $500 million, we brought $200 million in. So what appears to be a $200 million outspend is not that at all. It is the carry in from last year, and then the cash flow, based off of our projections of gas price supported by our hedge program, and that activity is supported by the next three years' view, really, of gas price because, remember, it takes more than one year for investments to pay out. So we watch that.

Just to be clearer, we've been working on the budget now for several weeks and probably our finance guys maybe several months, and we made a change just recently and pulled back a bit because we saw the trend for gas prices were coming down versus the model that we had produced. And so we'll continue to watch that.

Our ability to flex is present, obviously, because of our vertical integration. And so really, if you take a look at our budget or what we put out there and the range you put out there and you take the forward curve and you look at that and you combine that, especially with our 2017 hedge position, then that generates a level of cash flow.

And then you take the allocated capital from the equity raise and add that to that, and that's how we got to the numbers.

I'm sorry if it's not clear on -- we are not going to deficit spend and we are not going to go onto the balance sheet and take the money that is there under our financing that we did where we had to draw on our various lines of credit or whatever, that is not for that purpose. That is liquidity. That is part of running the Company.

We will use the cash flow in a very prudent way. And if we see a change, we will amend that up to where it is today.

So somebody can ask me later, what happens if gas goes to $4? Well, we don't just keep raising the capital. Where it is today is the upper end of that, and then we have other decisions to make following that. The capital --

Arun Jayaram: Thanks for the answer. And just the second question I had regarding your commentary around your expectations that the differentials would narrow for you in 2018, wondered if you could give us some thoughts on what that could do versus your 2017 guide? And how important is Rover? I think you have a couple hundred million on that line. How important is that as you think about the 2018 differentials guidance?

Bill Way: Sure. Let me ask Randy to step up here and give you a chat about that.

Randy Curry: Yes, Arun, if you'll notice, we put a pretty wide differential forecast out there, and you kind of zeroed in on it, hit the nail on the head.

Rover's going to have a material impact not just on us, but on the basin. And there's quite a bit of variability in the assumptions on the timing. If it comes on mid-June, as the company has professed, that will have a very positive impact middle of the year. If it's somewhat later, we'll receive less than that.

So Rover is a key to the 2017 outlook and the differential, and because it does have the potential to have such a material impact, that's really what's behind the wider range out there.

Arun Jayaram: Okay. Thanks a lot.

Bill Way: I'll comment for the crowd, we also have a basis hedging program that attempts to mitigate that volatility, and we can talk about that later, if you want.

But every one of these kind of risks, we've got a plan to look at how do we mitigate those, and it's very methodical through each of these.

Operator: Thank you. Jeffrey Campbell with Tuohy Brothers.

Jeffrey Campbell: Since it's important to the 2017/2018 story, I was just wondering if you're contemplating beginning to hedge NGLs.

Randy Curry: Yes. Jeffrey, this is Randy. Yes, and we have entered into that, particularly around ethane and we'll definitely be considering that as we go forward.

There has been some uptick in the liquidity in ethane and propane as the market's gotten deeper and the export capacity has increased. And so we will want to take advantage of that.

Jeffrey Campbell: Okay, great. Thank you. And the other question I wanted to ask, so I was just wondering if you're moving toward a stacked pay test with the Moorefield and the Fayetteville, or do they tend to be more perspective in different leases?

Jack Bergeron: We, as far as stack pay, we are doing stack pay on some of the benches of the Fayetteville, if you want to look at it that way. And we drill from the same pads, both Moorefield and Fayetteville wells. But they are significantly different. One wellbore will not adequately be able to develop it.

Jeffrey Campbell: Okay.

Jack Bergeron: We are doing, again, off the same pad, we'll drill a Moorefield well and a Fayetteville well, and we'll drill them to be able to optimize the recovery.

Bill Way: And if we see an opportunity as you kind of move out from wherever your focus area is and if any of these intervals or barrier intervals get thin enough, we will obviously test it to see.

Jeffrey Campbell: Right. And what I was thinking of was being able to produce both of the zones on the same pad, not a mono bore thing where you're running --

Jack Bergeron: And we do that regularly.

Jeffrey Campbell: Okay, great. Thank you.

Operator: Thank you. Brian Singer with Goldman Sachs.

Brian Singer: You had performance-related upward revisions across each of your key areas. Can you talk about the drivers of each and any future implications, and also if there was any differences in Southwest PA with regards to production mix from those revisions?

Paul Geiger: Specifically to the performance revision, as you look at the SEC pricing, real world pricing, you have a lot of those wells come off of the reserve deck.

And so as you go forward, there's a mechanism that brings those back on if you've got them, and they come back on as PDP. And so that's the basis of some of those performance revisions.

The performance revisions we continue to see in Northeast Appalachia have to do with a production mechanism that we've got those wells continued by their production regime to outperform our decline base that we've got in the reserve system. And so those are the continued performance revisions that you see to the positive up there.

Brian Singer: Is there a sense of what, and maybe you mentioned this, but of the performance-related revisions, which ones were essentially price revisions or what percent is more true performance versus just say higher prices allowed the bookings again?

Paul Geiger: Sure, the vast majority of those are performance-based. The price-based were negative in period. So those were against your performance revisions to the positive.

Brian Singer: Okay.

Paul Geiger: The other pieces of revision that we have that you might be seeing is, is we had significant operating expense benefits on the performance that were rolled up to a performance revision.

The big driver of those in West Virginia had to do with improved gathering and processing fees that we gained at the beginning of last year, and then we had also, as the guys have talked about, an aggressive assault on margin improvement there that has yielded quite a bit of success in driving costs out of our system.

Re-forecasting those wells with that lower operating expense is a significant gain on not only additional value created in period, but an extension of tail reserves as those wells have longer lives.

Brian Singer: Got it. Okay. Thank you. And then shifting back to the Moorefield, what are you looking for from the wells that you'll be bringing online, to define success?

Jack Bergeron: Economics success without a doubt. Our best well ever drilled in the Fayetteville is a Moorefield well as far as EUR. We're looking - we've got some very long laterals. We're just looking to prove up areas. We've moved out a few that I would call step-out areas, but just testing to see the economics of the play there.

We're very confident that the Moorefield works. We've determined where to land a well optimally and we've added more and more sand trying to make better and better wells, just like we've done everywhere else, again with the idea of creating economic value.

Brian Singer: Is there a 30-day or 90-day or 180-day rate you're looking for to say, okay, this it's achieved the economics you're looking for?

Jack Bergeron: We could usually tell within 100 days of production, get an early indication of EUR, initial rate does give us, the 30-day rate will give us, the amount of water that comes back, the Moorefield generally has more water.

But we're able to determine fairly quickly about economics and whether we're going to expand the program based on the rates that we have after we bring the wells on.

Bill Way: And, Brian, you've probably seen some of the public data we have on that. But the Moorefield, as Jack said, has outperformed a standard Fayetteville well on rate, reserves, little bit higher cost, but not significant. So that is driving those economics.

And an actual number, 30-day test or 180, it all just depends on where we are and kind of what those costs are.

But really back to Jack's point, it's all driven by economics and whether that's an initial rate or overall value driven based on EUR and overall cost. That's what we're driving towards ultimately.

Jack Bergeron: And then there's a flow-through improvement because this gas gets gathered by our midstream business and taken onto market. So the benefits continue through all the way to the market. And one of the things about having a program in the Fayetteville this year that's more extensive, it really lowers our cost by able to reuse the water that does come out of these Moorefield wells. And so that improves the economics even more.

Brian Singer: Great. Thank you very much.

Operator: Thank you. Kashy Harrison with Simmons Piper Jaffray.

Kashy Harrison: Thank you for taking my question. So in the Northeast PA, you're making solid progress on well performance. I understand that it's too early to quantify the improvement in EURs. But if, say, you held that EUR just flat and you assumed that you were just accelerating those reserves, can you just help us quantify how much, by how much the value or the returns of those wells are improving?

Jack Bergeron: This is Jack, Kashy. We use PVI as a metric. Bringing the value forward if we got no additional reserve, adds anywhere from $0.10 to $0.12 of PVI just by, again, bringing on a well that's averaging 17 million a day versus a well that would average 5 million a day and stay flat for quite awhile.

The big change in EUR and partial in the rates, but even more on the EUR that we expect, is the fact that we're putting more sand, tighter stage spacing, and touching more rock. That's why we think the EURs, we're confident they will increase.

Bringing the value forward through our flow techniques, again adds -- it's accretive and it just brings value forward and helps our PVI metrics.

Kashy Harrison: That's fantastic color there. And then can you just give us just your current views on the natural gas macro and the NGL macro, just for everyone on the call?

Randy Curry: Sure, Kashy. This is Randy. On the natural gas macro, clearly the 2017 curve was negatively impacted by primarily weather-related influences, extremely warm winter again.

That being said, I think there is an emerging consensus that the supply/demand balance normalized for weather is tightening year over year, somewhere in the tune of three to five Bcf a day.

And I believe there's some, actually a reason to have some positive outlook that we will go back to a storage position maybe middle of the year, that's closer to the five-year curve. And so I think it portends some strengthening there.

NGL prices on the macro level, again, I think there's a positive outlook, really on the basis of the anticipated demand coming online in the Gulf Coast, Mont Belvieu area, to the tune of 600,000 barrels a day or so.

That, coupled with some of the export capacity that's come on has really lifted the NGL complex year over year. Our NGL realizations for the first quarter this year are going to be double what they were the year before.

And so, and with our access to the Belvieu area, with the capacity out of Southwest Appalachia, we fully intend to ride that and capture some of that uplift.

Kashy Harrison: Thank you.

Operator: Thank you. (Operator Instructions) Dan McSpirit with BMO Capital Markets.

Dan McSpirit: You talked about reducing debt in the press release as the opportunity is presented.

Could you expand on that statement and maybe how proceeds would be sourced to do so?

Craig Owen: Hi, Dan. This is Craig. We've got $40 million of bonds due in 2017. And I think if you add up the midpoints of the cash flow, the guidance that we've given plus that equity raise, that's a number that's above our capital investments. So certainly can be sourced from that.

But just an overall theme is we're not going to do any harm to the balance sheet on a leverage or anything like that, with an outspend or whatnot. So we're going to source from cash flow and the cash we have on hand.

But that will be for that $40 million, and we can easily take care of that within our cash flow generation for the year.

And then, certainly, we've got some bonds sometime in January, February of 2018 comes most of them, some later in the year. And we'll think about those and think about our 2020s. We've got, between bank debt and bonds, we've got a lot of flexibility, I guess is the point, a lot of options on how we can address that.

We'll kind of look at the overall complex as we go through. And to the extent we change our capital program based on economic factors, any of that cash flow could be utilized for debt, and we'll just manage that throughout the year.

Dan McSpirit: Got it. On the PDP F&D costs, they're trending lower. That's a good thing, obviously.

Any thoughts on what should be expected on the magnitude of that change over time, and maybe what that means for the all-in economic breakeven price for the locations and the portfolio today?

Craig Owen: Yes. Those PDP F&Ds, certainly have seen the benefit of those coming down over the last couple years. And you see that with continued focus and, really, the lion share of our capital allocation going to our Appalachian assets.

We kind of lay out a kind of magnitude of what those look like between the different types of wells we can drill in West Virginia, then Northeast Appalachia as well.

Certainly, you see that, just call it in the $0.40 to $0.60 range, $0.40 to $0.70 range for those assets in particular. So certainly, continue to focus on that as that drives those economics.

Dan McSpirit: Okay, great.

Craig Owen: You had a second part of your question. I've missed it at this point.

Dan McSpirit: Yes. Just and what that means for the all-in economic breakeven price for the locations in the portfolio today.

Craig Owen: Yes. Those breakevens, as Randy mentioned, with NGL pricing looking to be maybe 2x of last year, certainly, that has a big driver on the economics of the West Virginia assets. I think a significant increase there or that type of increase really pushes down that breakeven from a natural gas perspective.

And that better well performance, along with just the pricing we are at today, drives up our inventory as well.

Dan McSpirit: Okay, great. And then just lastly here, just revisiting the question on differentials, just to clarify that the low end of the differential guidance range reflects Rover being operational and maybe that's as good as it gets for differentials, at least where we sit today. Is that correct?

Randy Curry: It does reflect kind of the Company's guidance on an in-service date for midyear 2017. And then as Bill had mentioned earlier, we do have an active hedging program now that will ensure that we're able to lock in differentials consistent with the plan.

Dan McSpirit: Very good. Thank you. Have a great day.

Operator: Thank you. Ladies and gentlemen, we have reached the end of our allotted time for questions. I would now like to turn the floor back over to Mr. Way for closing comments.

Bill Way: Thank you and thanks for all the questions, and we're happy to answer any other ones along the way.

Before I kind of go through my closing comments, I do want to say that I trust that we've cleared up any concerns about any outspend of capital and any concerns about our commitment to the discipline that we have delivered and shown throughout this entire year of 2016, through some very tough times. But we've emerged from that and with that same level of rigor and discipline.

2016 was a transformational year for our Company. And as you can see, we have much to be excited about from that work and for 2017, and beyond.

We've already begun building on momentum created through our lower cost structure, again economic and capital allocation discipline, operational and technical excellence that's growing by the day, and ability to reach all key high-value markets for our products and focused on economics ahead of production growth from our vast assets.

We are one of the nation's largest suppliers and we take a lot of pride in that, and, therefore, managing our business with rigor and discipline around economics and driving economic value lets us stay in that position.

Our relentless focus on creating long-term economic value for our shareholders drives everything we do, and I hope that we've been able to give you some color on that.

And we look forward to sharing more of these results. And I know the wells that everyone's excited about, especially we look forward to getting those out as well. And we look forward to continuing to talk to you about other areas where we reached to add value-plus and increase our performance.

So thanks all of you for joining us on our call today, and we hope you have a great weekend.

Operator: Thank you. This concludes today's teleconference. You may disconnect your lines at this time. Thank you for your participation.