Transcript of
Southwestern Energy Company
Third Quarter 2017 Earnings Teleconference Call
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Participants

Michael Hancock - Vice President of Investor Relations
Bill Way - President and Chief Executive Officer
Jennifer Stewart - Chief Financial Officer
Jack Bergeron - Senior Vice President of Operations
Jason Kurtz - Vice President of Marketing and Transportation
David Cecil - Executive Vice President of Corporate Development
Paul Geiger - Senior Vice President of SWN Advance

Analysts

Charles Meade - Johnson Rice
Arun Jayaram - JPMorgan
Kashy Harrison - Simmons Piper Jaffray
David Deckelbaum - KeyBanc Capital Markets
Josh Silverstein - Wolfe Research
Michael McAllister - MUFG Securities
James Spicer - Wells Fargo
John Abbott – Bank of America
Brian Singer - Goldman Sachs
Scott Hanold - RBC Capital Markets

Presentation

Operator
Greetings, and welcome to the Southwestern Energy Company Third Quarter 2017 Earnings Teleconference Call. At this time, all participants are in a listen-only mode. A brief question-and-answer session will follow the formal presentation. In the interest of time, please limit yourself to two questions. Afterward, you may feel free to re-queue for additional questions. [Operator instructions]. As a reminder, this conference is being recorded.

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

Michael Hancock - Vice President of Investor Relations
Thank you, Tim. Good morning, and thank you for joining us today. With me today are Bill Way, our President and Chief Executive Officer; Jennifer Stewart, our Chief Financial Officer; Jason Kurtz, our Vice President of Marketing and Transportation; Jack Bergeron, our Senior Vice President of Operations; Paul Geiger, our Senior Vice President of SWN Advance; and David Cecil, Executive Vice President of Corporate Development.

If you've not received last night's press release regarding our third quarter 2017 financial and operating results, you can find it 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 the forward-looking statement section 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 results and recent activity.

Bill Way - President and Chief Executive Officer

Thank you, Michael. Good morning, everyone, and thank you for joining us. We're delighted to be here today to discuss the strong third quarter results we disclosed in last night's press release and 10-Q. These results emanate from our strategy of focused, risk-adjusted value growth and continued the trend of delivering on the commitments we laid out earlier in the year.

Our strategy consists of five key elements that define who we are as a company and how we are delivering value. First, we have premier quality, large scale, and long-life assets. We leverage the quality, scale and diversity in this portfolio, along with the leading performance from our vertical integration and operational teams, to enhance the economics of each investment and of the deep inventory of future value-adding projects in our company.

Second, we demonstrate rigorous financial discipline. We invest within cash flow and backstop the economics we commit to deliver for each project through our risk management program to protect cash flows and investment returns while retaining a large portion of the upside should commodity prices or basis improve.

Third, we have a stringent value-focused capital allocation process where we require each $1 invested to create at least a $1.30 of present value discounted at 10%, and we prioritize those investments by where we see the highest value added. We utilize strip pricing for economic analysis because we can hedge the strip, bringing greater transparency to the performance against commitments of our investment program.

Fourth, we are increasing capital efficiency and margin expansion across the portfolio. We are laser-focused on delivering the full potential value from our assets and continue to add to the list of numerous accomplishments in this arena, including strategic negotiations of third-party contracts to improve margin, technical and operating improvements in the way we drill and complete wells to drive down F&D cost, and operational process improvements including water handling and flow-back optimization, all of which are contributing material savings to both our individual well costs and to the company. Jack will discuss a couple of new additional items that will improve margins even further in a few moments.

And finally, our leading technology, operating and commercial capabilities allow us to stay on the front line of innovation. This has been evidenced by the leading completion testing in the Appalachia Basin, along with our drilling technology advancement from our company-owned drilling rigs, which has resulted in the achievement of significantly higher percentage of wells being placed nearly 100% in a targeted zone while setting lateral length records for SWN. Both of these are major contributors to the step change in well performance we have delivered this year and our operational and financial results are clearly demonstrating the effectiveness of this strategy.

While the focus on returns and capital discipline has recently started getting more attention in the industry, this is not a new concept for us, but rather it defines who we are, and we will continue the returns-focused culture that we believe so strongly in and consistently demonstrate. As you should have come to expect, this disciplined return-focused culture will be at the core of our 2018 plans as well. We'll discuss the detailed plan in February once we see how the winter impacts 2018 commodity prices, so we can be sure to align projected activity with projected cash flows. But our approach is clear. We will invest within cash flow and allocate capital to the highest returning projects, and production will be an outcome of our drive for improving value creation.

Let me briefly touch on a few third quarter highlights. In the third quarter, we delivered 5% of sequential value-adding production growth, once again within guidance range we provided in February, despite one-off gathering and transportation challenges from third-party providers. We partially mitigated the impacts from the downed compressor station we discussed in August and downtime associated with three days of unplanned maintenance on one of our long-haul transportation third-party pipelines.

Flexibility in our leading transportation portfolio also helped us limit the impact of these two challenges on this quarter's production volumes, and we still hit guidance. As we mentioned previously, these were one-off issues and are no longer needing attention.

We ended the quarter with a strong finish. We achieved a record gross daily exit production rate in the Appalachian Basin of almost 2.4 billion cubic feet equivalent per day. This included over 1.4 Bcf per day from the Northeast Appalachia assets and 958 million cubic feet equivalent per day from the Southwest Appalachia assets. The momentum we've built in these two assets positions us for a strong finish to 2017.

Price realizations have received a lot of attention recently from the investment community as new infrastructure in-service dates move around. However, the combination of our diversified transport portfolio, our basis hedges and our people mitigate the risk for Southwestern when compared to peers. Despite the delays in some of the larger new pipelines, our combined Appalachia differentials were $0.05 per Mcf better during the third quarter compared to the same period in 2016, and this is in addition to the $0.09 of financial basis hedge gains that were realized in Northeast Appalachia in the quarter.

Looking forward to the fourth quarter, in Northeast Appalachia, basis differentials continue to be a challenge for many, but we have substantial basis hedges in place for October and the fourth quarter, which we expect to have positive impact of approximately $0.40 per Mcf and $0.11 per Mcf for October and the fourth quarter, respectively. In line with our risk management process, we continue to add basis hedges moving into 2018 to align our basis hedge protection with our commodity hedge protection. Jennifer will speak to you about the next steps we took on our liability management plan to strengthen our liquidity and balance sheet strength.

Looking forward, we're excited about delivering the value that we continue to unlock through our continuous capital efficiency and margin enhancement drive. We have a clear path to further improving well economics and driving additional value out of each investment that is made.

Our core focus remains to improve economic contribution of every $1 we invest, which strengthens the economic value and investment returns of our vast inventory and drives growth through the value-generating capability of our investments.

Let me now turn over to Jennifer, who'll discuss some highlights for the quarter.

Jennifer Stewart - Chief Financial Officer

Thanks, Bill, and good morning, everyone. We had another strong quarter as we continue to focus on improving margins and providing meaningful corporate-level returns. We generated $248 million in net cash flow, a 43% increase compared to the third quarter of 2016. This increase was primarily the result of positioning ourselves to take advantage of improving commodity prices, with liquids providing a $0.14 per Mcfe price uplift compared to a $0.01 per Mcfe uplift in the third quarter of 2016.

Our total NGL barrel realizations, inclusive of transportation charges, was $14.47 per barrel, or 30% of WTI, up 105% compared to the third quarter of 2016. These realizations were a record high for our Southwest Appalachia asset, and we believe these should continue to improve as incremental demand for NGLs increase.

As Bill mentioned, financial discipline is a core tenet of our strategy. We took meaningful liability management steps this quarter by opportunistically extending our maturities in an attractive debt capital markets environment. In September, the company improved its debt maturity profile through a $1.2 billion notes offering and tender offer for our 2020 notes. The successful offering was used to fully repay our $327 million unsecured term loan and retire 89% of our 2020 notes, leaving only $92 million of bond debt due before 2022.

This is important. Our secured term loan that matures in 2020 contains a springing maturity feature. It requires if we do not retire or refinance 90% of our 2020 notes prior to the fall of 2019, the maturity springs to 2019. With this successful tender of 89% of the 2020 notes, we are within approximately $7 million of eliminating this springing maturity, which we can easily address in the near future. Additionally, we and our banks modified covenants in our existing credit facility, which include the easing of liquidity requirements if certain thresholds are met.

We continue to add to our hedge portfolio as part of our commitment to ensure economic returns on our capital investment. As of October 24th, we had 473 Bcf of our 2018 production hedged at an average swap or purchased put strike price of approximately $3, with upside exposure up to $3.39 per Mcf on approximately 62% of those protected volumes. The company also had 165 Bcf of 2019 production hedged at an average swap or purchased put strike price of approximately $2.97, with upside exposure up to $3.32 on approximately 66% of those protected volumes. Our 2018 and 2019 positions continue to be predominantly collars in order to retain upside exposure to expected improvements in commodity prices.

I'll now turn it over to Jack for an operational update.

Jack Bergeron - Senior Vice President of Operations

Thanks, Jennifer, and good morning, everyone. In the third quarter, we invested approximately $320 million in our E&P business and reached many operational milestones across the company. For example, in Southwest Appalachia, we achieved record drilling times, drilling over 6,200 feet in a 24-hour period while drilling 100% in our 10- to 15-foot target zone. The team continues to focus on cycle time reduction to maximize capital efficiency.

Additionally, as Bill mentioned earlier, we had a record gross exit production rate in the Appalachian Basin of almost 2.4 billion cubic feet equivalent a day, an increase of over 40% compared to the third quarter of 2016. Across the portfolio we continue to look for opportunity to expand margins and increase capital efficiency, thereby increasing the value of our inventory.

In the third quarter, we finalized several commercial development projects that will provide significant long-term value enhancement. In Southwest Appalachia, we commenced a water infrastructure project throughout our West Virginia Panhandle acreage that is expected to generate savings of approximately $500,000 per well beginning in late 2018. This project increases our operational flexibility and will reduce the breakeven gas price economics by approximately $0.25 per Mcf.

We also finalized an agreement that expanded our wet gas Marcellus processing capacity in Marshall and Wetzel counties in West Virginia that will provide capacity up to 660 net million cubic feet per day at immediately reduced processing rates. This agreement also provides connectivity options to several premium gas outlets and NGL hubs while reducing gathering fees.

Combined with our enhanced completion designs, these improvements are expected to create significant long-term value, and will increase the net present value for each well by approximately $2.8 million, with large upside remaining still, on over 900 wet Marcellus wells in the Panhandle of West Virginia. This agreement also provides gathering services for our future Utica development in the southern portion of the West Virginia Panhandle at very competitive rates.

In Fayetteville, we announced the successful renegotiation of our firm transportation agreement, which remains subject to FERC approval. This agreement is expected to provide savings of $70 million from 2017 through 2020, through the reduction of current excess capacity. The savings in 2018 alone are estimated to be approximately $45 million. Additionally, this secures flexible takeaway capacity beginning in 2021 at $0.10 per MMBtu, a 60% reduction compared to the current average rates.

We also continued our delineation efforts across the portfolio in the third quarter with encouraging results in each asset. In Northeast Appalachia, the company placed its first four-well development pad to sales in Tioga County, with a combined maximum rate of over 80 million cubic feet per day flowing against 1,200 PSI of line pressure. The performance of this pad demonstrates the high quality of this previously undeveloped acreage and continues our drive to lower the economic threshold of our inventory. Based on the successful results we've seen there to-date, the company plans to place two additional wells to sales in the fourth quarter with additional development across the approximately 28,000 acres in 2018.

In Fayetteville, the company placed two Moorefield delineation wells to sales that had an average initial production rate of 5.4 million cubic feet per day at an average estimated ultimate recovery of 5.5 Bcf per well. These wells are performing at or above our expectations and continue to confirm our geologic and reservoir modeling of the play. We plan to test an additional two wells in the fourth quarter that are located about 10 to 15 miles away from the successful 7-well English pad placed to sales in the first quarter.

In Southwest Appalachia, the company placed its second company drilled Utica well to sales in Washington County Pennsylvania in the quarter. This well had a lateral length of 4,572 feet and had an average 60-day rate of 17.7 million cubic feet per day as part of our pressure management program. While we focus on bringing down the costs, the deliverability of the reservoir of our first two Utica wells is very encouraging and will compete very well for capital once our costs are reduced to the expected $12 million to $14 million per well range.

This concludes our prepared remarks. We'll now turn it back to the operator, who will explain the procedure for asking questions.

Operator
Thank you. We will now be conducting a question-and-answer session. [Operator instructions]. Our first question comes from the line of Charles Meade of Johnson Rice. Please proceed with your question.

Q: Good morning, Bill, to you and your whole team there. If I can ask about those Tioga wells, can you give us an idea of how far west from your best Susquehanna acreage that is and how close those results that you're getting in Tioga are to the best stuff that you're doing in Susquehanna?

Jack Bergeron - Senior Vice President of Operations
This is Jack. I can't tell you exactly how many miles it is, but our Susquehanna County is separated from Tioga County by Bradford, and it's quite a ways miles, it's several hours' drive.

Q: Got it. And then the economics of well, so I guess what I'm getting at is when you guys do your PVI, are you within striking distance, or is this more just encouragement to do more work?

Jack Bergeron - Senior Vice President of Operations
No, we believe we're in the development phase there. These wells average 7,200 foot lateral length. We're shooting for and think we're—it's still early, but greater than 2 Bcf per 1,000 feet. These wells cost about $7.4 million per well. We had to truck a lot of water there because it was early. So we think we can still drive the costs down. But we're very encouraged and continuing on and believe it's a development project at this point.

Michael Hancock - Vice President of Investor Relations
And Charles, this is Michael. One thing I'll add there, this is the first time in that county that we've had a multi-well pad. So, now you have a four-well pad that they're competing for the same rock and you've got really good results, which tells you even more about the quality of that acreage.

Q: Got it. That's helpful color, guys. Thanks for that. And then if I could maybe ask a related question about the Moorefield. So, I get that you're going to be doing this step out 10 to 15 miles away from your existing pad with these last two wells in 2017. Can you talk us through the possible paths that you'll be on in 2018 with respect to the Moorefield? Will these two wells be definitive about condemning or confirming the application and the concept to a wider footprint? Or will we still be in investigation in 2018 with respect to the Moorefield?

Jack Bergeron - Senior Vice President of Operations
Well, what we've done is laid out geographically, we've mapped the area where the Moorefield is and we've initially went in and did our development pad on the English pad. And now we've stepped out to the edges of what we've mapped, and these are our delineation wells. It will prove up there's gas between the wells. We still need to prove up the economics. But we think a lot of these delineation wells, each prove up somewhere between 10,000 and 12,000 acres, and we think we're on the way to finding the limits of our 100,000-plus acre, 115,000-acre possibility in the Moorefield.

Q: Got it. Thank you.

Operator
Our next question comes from the line of Arun Jayaram of JPMorgan. Please proceed with your question.

Q: Good morning, Arun Jayaram from JPM. Bill, you guys were able to get some favorable agreement in terms of your MVCs at Fayetteville. And I was just wondering how we think about your future reinvestment opportunities in the Fayetteville and obviously the Moorefield could play into that. But just talk about given the lower midstream costs how you think about reinvesting in 2018 and beyond.

Bill Way - President and Chief Executive Officer
I'll start with the agreement that we were able to reach at a high level. And these agreements for transport expire in 2020 and 2021. And so, the opportunity to amend them and extend them, to consolidate with a very strong player and stretch those agreements out into the future are indicative to the fact that we've got a long tail of production in the Fayetteville.

Second, the opportunity to structure an agreement whereby the first tranche of that rides a base decline curve takes the risk out of excess MVCs from us, and then provides opportunities for both us and the pipeline with option capacity above that as we optimize the capital investments going forward to look at Moorefield results, such as some of these other opportunities. And so it's a very well-structured agreement that enables us to improve the capital for the competitiveness of the entire Fayetteville asset as we prioritize capital to the highest PVI projects.

So, when you step back and you look at how do we allocate capital, we allocate capital to the highest PVI projects and we challenge each of the areas to drive further competitiveness of their individual plays by sharing knowledge, applying that knowledge and taking actions like this, the work we did in West Virginia, around renegotiating our gathering and processing agreements, the work we're doing on well improvements, all to drive that realized value improvement and then we allocate capital based on the highest returns on those investments.

Q: Great. Great. And my follow-up is, Bill, as you can tell, the market is just not valuing growth in the same way and there's clearly been a premium on free cash flow generation. As you think about your 2018 program and beyond, how do you think about the value proposition of the company and how could that shift the way you're thinking about allocating capital on a go-forward basis?

Bill Way - President and Chief Executive Officer
Well, I think that our allocation of capital on the highest return projects is perfectly in line with the way to create shareholder value, improve returns. It is perfectly aligned with the dialogue of the day in the industry, and especially in the investment community, of focusing on quality returns and quality projects over production growth. And so that's exactly what we are doing.

As we look at the allocation of capital for 2018, it will be like any other year. Our focus is on creating value, improving returns on every $1 we invest. We'll take the options of investing at the drill bit and weigh those with debt reduction and any other options that come to the table to, again, create the highest value-adding plan to go forward. We already have begun to shape that plan. As we work through the balance of the year, look at the winter, look at how pricing comes together, we'll be able to lock that down more.

But this isn't about production growth at all costs. It hasn't been for us and it won't be for us going forward. It's an outcome growth.

Q: Thanks a lot.

Operator
Our next question comes on the line of Kashy Harrison of Simmons Piper Jaffray. Please proceed with your question.

Q: Good morning, everyone, and thanks for taking my questions. So, in reference to the presentation which outlines the remaining locations at various NYMEX gas prices, Jack, I was just wondering if you could help us think through the combination of the agreement with Williams and the water infrastructure build-out. When you put all that together, what does that do to the economic inventory at $3 gas prices in Southwest Appalachia, just in higher-level percentage terms?

Jack Bergeron - Senior Vice President of Operations
Well, go ahead, Michael.

Michael Hancock - Vice President of Investor Relations
This is Michael. When you talk about the Panhandle, you still have 500 or 600 rich gas wells and almost 400 lean gas wells. Those are already in that deal. Most of those, because of liquids pricing, are already very economic at $3. But what you're doing now is you're enhancing those economics even lower. And then on some of those, like dry Marcellus and Utica, all of those obviously get the help, too. So, I don't know exact number in the $3 bucket from these enhancements, but you're definitely driving some into that bucket.

Q: Got it. Got it. And then in the press release last night there was mention of an advanced completion design in Susquehanna, but it was a little bit light on the details. I was just wondering if you could share what the new advanced completion design was, and perhaps more importantly, the broader application towards the other pieces in your portfolio?

Jack Bergeron - Senior Vice President of Operations
Well, this is Jack. Without giving you all of the details, because we think it's a competitive advantage, it is tighter cluster spacing, stage spacing. And we long ago went to a pretty high sand loading there, but it's really changing the stage spacing and completion intensity.

Bill Way - President and Chief Executive Officer
And the application of that learning, and just to broaden the question a bit, any operational or commercial technical learning that we have in a particular area, is immediately transferred to the other parts of the company and evaluated for application and then applied. And you get different results. You can have an advance completion in this case. You'll recall, we are one of the leaders in upsizing sand loading up to as high as 5,000 pounds a foot.

All of those kinds of activities are looked at to be applied everywhere else, and you get greater impacts on some in some areas and greater impacts in others in other areas. And that blend, and the way we operate those assets as a joined-up view, is enabling the transfer of knowledge and, more importantly, the application of knowledge to move faster across the enterprise.

Q: Got it. Thanks very much.

Operator
Our next question comes from the line of David Deckelbaum of KeyBanc Capital Markets. Please proceed with your question.

Q: Good morning, everyone. Thanks for taking my questions. I wanted to ask a question first, I guess, on the added basis hedges that you put in place. You're securing a much better basis protection relative to what you're realizing now, and granted there's probably some seasonality in those contracts, but is there a practical limit to how much you'd be willing to hedge on basis? And do you have a general view for how your corporate-wide basis should improve in 2018?

Jason Kurtz - Vice President of Marketing and Transportation
David, this is Jason Kurtz. Yes, so what we're looking at when we continue to add basis is we try to match those basis hedges with our NYMEX hedge program that we have in place. So, what we're trying to achieve is an overall effective hedge with our program.

Michael Hancock - Vice President of Investor Relations
Then the second part of that—this is Michael—going back to what you say for next year, obviously we'll have to see how the winter shapes up and all that, but you're probably looking, with today's guess, at $0.10 to $0.15 improvement company-wide next year.

Q: Okay. I appreciate that. And then just on the water handling project that you're undertaking, I guess long-term vision for this, one, I guess, is this included in your capital plan already? And then, two, are there applications to other areas where you'd want to put this in? And then ultimately once the infrastructure is built out, is it something that you'd like to retain or is it something that you'd like to monetize?

Bill Way - President and Chief Executive Officer
Well, the water project is—the genesis of it I think is really leveraging off of the practice that we use very, very successfully in Pennsylvania, where we have quite a network of capability to move water from pad to pad and avoiding both trucking cost on the road and trucking cost which is higher to move water around.

This opportunity, especially in West Virginia with the terrain and the remote sites and the space needed and everything, really brings further enhancement to the well economics. It will be a part of how we develop this play because of the results that we got in Pennsylvania. And as we look to expand it across our development areas, we'll do that in phases. It is in our capital program, the first three phases of it actually are in the capital program, and we'll continue to look for opportunities to expand it going forward.

And to your question around will we keep it, it's certainly an integral part of our operation, but you always look for opportunities to enhance value and we'll see when the time comes.

Q: I guess in the context of spending within cash flow and looking at opportunities to delever, I know people have asked other questions about non-core assets. Are you trying to make some strategic investments right now that you'd be able to ARP [ph] externally through monetization?

Bill Way - President and Chief Executive Officer
It's not the direct intent. Obviously when you think long-term, you keep the breadth of those out there. But the real power in this at the present time is significant PVI generation, value generation, significant as we've talked about, in the improvement in well economics, the deepening of the economic portfolio, there's significant drivers in that space. And realizing that value in the company is what we're focused on now.

Q: Thank you, guys.

Operator
Our next question comes from the line of Josh Silverstein of Wolfe Research. Please proceed with your question.

Q: Good morning, guys. I wanted to just stick on that last question and go down the path of corporate restructuring. Because to improve margins and the balance sheet in a flat $3 world, you mentioned the well performance improvement, and the pipeline updates certainly help. But, on paper, it does look like the Fayetteville exit, if that's contemplated, it looks like it significantly improves all the above. And it hasn't really competed for capital in three years.

So, I wanted to see if this is something that that you might consider, something of this magnitude. And, if not, what would be the obstacles to not make you go down this path?

David Cecil - Executive Vice President of Corporate Development
It's David Cecil. I appreciate the question. Look, I think as we think through the entire portfolio, we've got great assets here. We've got a lot of optionality in the assets. It creates a lot of opportunity for us to create value. And I think as the results that we've announced they're emblematic of that. Part and parcel all of this is portfolio management and we continue to focus intently around portfolio management and looking for all avenues or looking at all avenues to expand that value and unlock that value for shareholders.

So, as we move forward and we look at the things that we're doing operationally with Fayetteville in particular, but also with the other assets, we continue to look for the various means by which that we would unlock that value. So, we're excited about what we're doing, we're excited about where we're going. I think there's a lot of opportunity in front of us here. And so, we look forward to keeping the throttle down on those initiatives.

Q: I guess maybe asked another way, what does the Fayetteville serve within the current asset portfolio? Is it you guys wanted to generate free cash for you guys? This asset has been on the decline for the past few years and just curious how you see it within the portfolio right now.

David Cecil - Executive Vice President of Corporate Development
This is David. As I look at the portfolio today and the importance of Fayetteville, Fayetteville is obviously a very large asset in the portfolio; it generates a tremendous amount of production and also a lot of cash flow. So, as we think about driving performance and growth, value-earning growth in our other divisions, Fayetteville is key at this point in time in allowing us to do that.

But, again, we continue to look for ways to unlock value in the Fayetteville. And as we talked about the Moorefield and some other things we're looking at, it continues to be an asset that is creating some optionality for us. And as we move forward we will continue to look at all those ways that will unlock that value. So, it's got a place today; we continue to see a relative importance with where we stand.

Q: Thanks for that. And then you went through the refinancings a little fast there. I just wanted to see if you can go back through those and walk through the covenants. If you do have an asset sale contemplated, how much would need to go to debt reduction versus development capital, or even if it's a large asset sale, potentially share repurchases?

Jennifer Stewart - Chief Financial Officer
Good morning. This is Jennifer. So, to start, to recap, we issued $1.2 billion of notes with 2026 and 2027 maturities. We used the proceeds of that $1.2 billion to pay off our $327 million unsecured term loan with the banks and to retire 89% of our 2020 notes. So, we did that to extend maturities, to extend our maturity wall out beyond 2022 and to prevent the springing maturity of our secured term loan.

So, in combination with that, we also worked with our banks to modify the covenants on our existing credit facility. One of those covenants that we modified gave us some additional flexibility in the event there were asset sales, so that they increased the amount of proceeds that we could use with asset sales. We have up to $1 billion, up to that cap we can use as we please on an asset sale. And then anything after that has to go toward reducing the commitment on the $743 million credit facility.

Q: Got it. Thanks for the clarification. Thanks, guys.

Operator
Our next question comes from the line of Michael McAllister of MUFG Securities. Please proceed with your question.

Q: Good morning, everyone. Just off of the last question, what percentage of your proved reserves is from the Fayetteville at this juncture?

Paul Geiger - Senior Vice President of SWN Advance
Michael, this is Paul Geiger. We release that on an annual basis, and so the quarterly numbers are not something we put out. But generally, as we look at that now, you've got about a third of the reserve base is Fayetteville.

Q: Okay. Thank you. And then off of the water infrastructure projects, the $500,000 savings, is that net of the capital put in to build out the infrastructure?

Jack Bergeron - Senior Vice President of Operations
No. That will be what we realize after building.

Q: At the well. Okay.

Jack Bergeron - Senior Vice President of Operations
Yes.

Michael Hancock - Vice President of Investor Relations
And just for color on that, Mike, you have the ability to expand it as quickly as you need to or do it in phases. And so, you have control over that capital outflow. But the way we see things right now, it's probably $25 million this year, $75 million next year, and $50 million in 2019 that gets it all done.

Q: Okay. That's great. Thank you for that. And the Tioga acreage count? I think you mentioned it.

Jack Bergeron - Senior Vice President of Operations
Yes, 28,000 approximately, acres.

Q: I guess the way I would phrase it, is the drilling locations that you guys put on the slide, does that include Tioga?

Bill Way - President and Chief Executive Officer
It includes a portion of that.

Q: Okay.

Bill Way - President and Chief Executive Officer
And we only put them in the count when we are confident that we've delineated enough and are sure they belong in there.

Q: Got it. That's great. Thank you very much.

Operator
Our next question comes from the line of James Spicer of Wells Fargo. Please proceed with your question.

Q: Hi. Good morning. I've got a couple of balance sheet questions. Obviously, you've made good progress here particularly with your recent liability management transactions. But, clearly, there's still a lot of inefficiencies with carrying such a large cash balance. What's the next step towards getting a traditional revolver in place, whether that's perhaps refinancing your secured term loan or going out to bondholders for a consent to change that 15% of ACNTA covenant?

Jennifer Stewart - Chief Financial Officer
James, good morning, this is Jennifer. You're right. We're considering all options with respect to our secured debt [audio disruption] in the 2022s and 2025s. We haven't committed to one direction or another right now, but we're definitely working that path. And that will set the stage and open the gates for clearing a path to a more streamlined capital structure. We definitely have a line of sight towards taking the steps we need to to eliminate the negative carry associated with the large cash amount on our balance sheet.

Q: Okay. That's helpful. Thank you. And then secondly, with the recent amendments to your credit facility, that they provided you with the ability to replace your minimum liquidity covenants with a leverage covenant, is there any reason why you wouldn't go ahead and do that?

Jennifer Stewart - Chief Financial Officer

Right now, we don't want to get boxed into something until we have a better view on what 2018 looks like. So, what we like is we have that optionality, we can flip back and forth as we would need to. But as of right now, we're just kind of standing pat until we see what our long-range plan looks like.

Q: Okay. Got it. Thank you.

Operator
Our next question comes from the line of Doug Leggate of Bank of America. Please proceed with your question.

Q: Good morning. This is John Abbott calling in for Doug Leggate. Just a quick question related to the water infrastructure project in Southwest PA. When you think about getting a rate of return on that, do you have the opportunity to sell services to third-party operators?

Bill Way - President and Chief Executive Officer
We absolutely do. And we would set the project up for that opportunity.

Q: All right. And then second question with regards to the additional value for the processing agreement, that $1.4 million per well, how much of your remaining inventory in Southwest Appalachia is lean gas, out of your inventory?

Michael Hancock - Vice President of Investor Relations
Yes, it's probably 400 wells or so.

Q: That helps. Thank you.

Operator
Our next question comes from the line of Brian Singer of Goldman Sachs. Please proceed with your question.

Q: Thank you. Good morning. Can you talk more about lateral lengths in both Northeast Pennsylvania and then in the Southwest Appalachia, and how you see your lateral length moving over the next year and what any constraints may be on that?

Jack Bergeron - Senior Vice President of Operations
Well, the lateral length, we do try and maximize lateral length wherever we've successfully gone over 12,000 feet with good success. We have no issues there. Currently, our lateral lengths average 5,500 feet in Northeast Appalachia and 7,500 feet in Southwest Appalachia. We do look to expand that. We work with landowners. Usually the requirement is that if it's already a unit, you have to work with the landowners. We've successfully been able to do that in some areas, and we're continuing to pursue that. We feel very comfortable with longer lateral lengths where we can drill them and are working on those as we speak.

Bill Way - President and Chief Executive Officer
We've done a handful of 12,500-foot laterals without any issue at all, 100% zone wells have looked strong. We're trying to move our targets up. We're targeting just under 10,000 feet, 9,900 feet of laterals where we can do that, and so we've got a lot more flexibility where we're able to form those units. There's also commercial discussions that you can have, even after they're set, to try to figure out how to share. And we've really opened up the commercial guys' minds to let's set a target and go after it and make that target up there in the 9,900-foot range.

Q: I guess relative to where the averages are, then, would that warrant, or should we expect there would be a step change next year? Or, no, it would just be more gradual as you work in some of these longer laterals and continue to work them into average to average, slightly higher?

Bill Way - President and Chief Executive Officer
Yes, I think it'll be gradual at first. I think as we, again, have to look at the geography of where we are, what units are set, what acreage there is. We actively trade acreage all the time to extend lateral lengths and make wells even more economic and that will continue as well.

Q: Okay, thanks. And then just one more quick one on the Moorefield, you put out the numbers for the well costs and then what you expect the EURs from the most recent wells to be. Can you just comment on how you'd see the economics of the Moorefield competing relative to Appalachia and relative to the Fayetteville for capital? I know it's very, very early.

Jack Bergeron - Senior Vice President of Operations
Well, now, the well costs for these most recent wells, they were one-off wells so they were higher-cost wells. That's one reason we did a pad development early is to demonstrate, and if you notice, the first quarter well costs were I believe sub-$4 million per well, and they compete very well in a development mode.

Again, right now our best economics are in the Appalachian Basin, and Fayetteville is driving—we're working to drive the cost down and improve the well productivity to allow it to compete. We do have economic wells to drill in the Moorefield. It's really a matter of, at this point, competing for capital in our allocation system.

Q: Great. Thank you.

Operator
Our next question comes from the line of Scott Hanold of RBC Capital Markets. Please proceed with your question.

Q: Thanks, hi. My question dovetails nice with Brian's there. When you look at optimizing activity in the future in the Fayetteville shale area, it looks like some of those more recent Moorefield wells had a longer lateral length. I think traditionally the Fayetteville ones were a little over 5,000 feet. What is the limitation on drilling like longer laterals in the Fayetteville? Is it just the depth that you're working there, or can you extend those a little bit longer?

Jack Bergeron - Senior Vice President of Operations
We have drilled some longer and we will do that. We actually have easier land situation there than we do in Appalachia. But, yes, and we are very comfortable. Even the depth, we have no problem drilling 7,500 to 9,000 feet there.

Q: So I guess so then my question would be, why haven't we seen more of that? Why aren't we pushing the limits a little bit faster on those lateral lengths there?

Jack Bergeron - Senior Vice President of Operations
Really, our goal on these delineation wells is to prove productivity on a EUR per 1,000 feet, and then we will go to development mode and drill longer laterals.

Q: Okay. So it's more a staging. First you want to understand it, then we'll go to that next stage, okay.

Bill Way - President and Chief Executive Officer
It's the most capital efficient way to test.

Q: Okay. No, that all makes sense. And then in Appalachia, that recent Utica well you drilled looks pretty good, especially considering it had a shorter lateral than the first. What is the next step out there? And what does that well tell you about your acreage overall?

Jack Bergeron - Senior Vice President of Operations
It just, again, the repeated good deliverability and potential from that is just more convincing and encouraging that the reservoir is there, the gas is there. Our job and all of industry's challenge right now is to do it economically, to be able to drill the wells and complete the wells. The reservoir deliverability is there.

Bill Way - President and Chief Executive Officer

And we are working with operators in our area to exchange data and to look at how do we learn together faster, which results in learning together at a less cost, and so that work continues. Our drilling of wells is not the only way we're learning, so there is a lot of activity going on behind the scenes.

Q: Okay. And then so as far as next steps, is it still in project mode versus something that you would consider to move to more development as you look into 2018?

Bill Way - President and Chief Executive Officer
Yes, really, really, we need to continue to understand the expanse of the Utica under our acreage, and the quality of it. And then as we've very clearly disclosed, we've got to get the well costs down. There's a continuous drive to understand the risks associated with drilling these wells. Once we go to development mode, we have a very, very clear track record of driving well costs down dramatically. These are expensive wells, so we've challenged the teams to get the one-off wells performance down as well and that gives us the confidence to go forward.

But the subsurface, what we're seeing, we're interested in. We've just got to get the costs down. We have a path to get there and that path is mapped out and so the teams need to demonstrate that in the coming wells and then we can put it in the capital allocation analysis system that we have and, again, it's heads-up competition.

Q: That all makes sense. I appreciate the answer. Thanks.

Bill Way - President and Chief Executive Officer
And I don't know if it was lost or not, but we did get—a part of the West Virginia gathering and processing agreement changes is finding a solution for gathering of the Utica wells. So, we have entered into those agreements, which is another piece of confidence that we have in the ultimate development of the Utica.

Operator
Our next question comes from the line of David Deckelbaum of KeyBanc Capital Markets. Please proceed with your question.

Q: Thanks for letting me re-queue. I just wanted to follow up. Could you quantify the impact of some of the third-party outages in Northeast Appalachia?

Michael Hancock - Vice President of Investor Relations
So, I'll give you kind of the ballpark. You move gas different directions to offset some of that, so it's hard to say exactly what you lost. But when you look at it between the Millennium downtime and the compressor, it was probably somewhere in that 3 Bcf range.

Q: Okay. And then just one other follow-up. In Southwest Appalachia, you guys have been able to achieve some pretty strong sequential growth despite maybe some limited tie-ins there. I guess when we think about the base decline in that asset, just given I guess the constraints and the amount of choking that you're doing on the wells, should we think about this as a very minimal base decline right now to almost flat?

Jack Bergeron - Senior Vice President of Operations
Well, what we're doing is, again, on especially the ones that have condensate, we're doing a pressure management program so that we don't draw down too fast and we maximize EUR. That's why we have a pressure management program. I wouldn't say we're choking the wells back to hold them back. We're choking the wells back to manage the subsurface pressure and maximize value coming out of the wells as far as condensate goes.

Q: Understood. But I guess by coincidence with that pressure management program, when you think about continuing that managed pressure program throughout 2018, should we think about that corporate level decline in Southwest Appalachia before putting on new wells as being extremely minimal?

Bill Way - President and Chief Executive Officer

It’s not minimal, but certainly the individual well declines and the base decline together, each one of those is advantaged, especially the single well economics, are very, very competitive with the other areas, if not improved because of that and the strong performance out of the wells.

Q: I appreciate it. Thank you.

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 - President and Chief Executive Officer
We want you to thank you for joining us today and thank our shareholders for your continued support as we execute our strategy to deliver improving shareholder value and enhanced returns. We’re driving down breakeven thresholds to expand the inventory at lower commodity prices. We’re applying ongoing technological learnings across our company to maximize future investment economics, unlocking our vast resource potential by targeting the stack pay opportunities in our assets.

We’re leveraging our leading transportation portfolio to access high-value markets. We’re strengthening the balance sheet through EBITDA expansion and opportunistic debt reduction, and we’re identifying additional opportunities throughout the value chain to extract value. Our strong operational momentum from our high-quality assets and our teams and our stringent capital discipline sets us up to accomplish even more moving forward.

So, we look forward to joining you on again on our next call to discuss our fourth quarter highlights and discuss our 2018 plan. And, with that, we thank you for joining the call today and hope you all have a great weekend.