Southwestern Energy Company

Q3 2019 Earnings Conference Call

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CORPORATE PARTICIPANTS

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PRESENTATION

Operator
Good morning ladies and gentlemen and thank you for standing by. Welcome to the Southwestern Energy's Third Quarter 2019 Earnings Call. Management will open up the call for a question-and-answer session following prepared remarks. In the interest of time, please limit yourself to two questions and then re-queue for additional questions.

This call is being recorded. I would now like to turn the call over to Paige Penchas, Southwestern Energy's Vice President of Investor Relations. You may begin your call.

Paige Penchas
Thank you, Anita. Good morning and welcome to Southwestern Energy's Third Quarter 2019 Earnings Call. Joining me today are Bill Way, President and Chief Executive Officer; Clay Carrell, Chief Operating Officer; Julian Bott, Chief Financial Officer; and Jason Kurtz, Head of Marketing and Transportation. Along with yesterday's press release, we also issued our 10-Q, which is available in the Investor Relations' section of our website at www.swn.com. Before we get started, I would like to point out that many of the comments during this call 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 statements 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 development 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 will now turn the call over to Bill Way.

William J. Way
Thank you, Paige. Good morning everybody. We appreciate all of you joining us today. To state the obvious, today's commodity price environment is tough. Consistent with our previous conversations, one of the core objectives of the company is to be rigorous and disciplined in our approach to value creation. We have led the discussions regarding the importance of remaining resilient in any commodity price environment, and we have already taken clear actions designed to assure that we are. The challenges the industry faces today play to our strengths and further differentiate SWN. So, let me share with you what resilience looks like.

First, SWN has one of the strongest balance sheets and a leading debt maturity profile with nothing material due in the next five years, thus no looming high-cost refinancing risk or liquidity challenge. We have substantial liquidity with a $2 billion credit facility and after Moody's announcement yesterday, both rating agencies have now completed reviews of the company and our ratings have remained the same.

Second, we have a clear record of demonstrated operational and financial efficiency improvements and outperformance with dramatically lower costs from record drilling and completions execution. Further efficiency gains are in sight and being added continuously. These achievements are happening today, not forecast to happen sometime in the future.

Third, our base and leading condensate acreage in West Virginia provides commodity diversification and captures the highest margins and highest returns at current pricing. It is not enough to just own great acreage in this area, we are using our strategic reservoir management and operations capabilities to maximize the condensate yield. We have increased our condensate production by 50% in the last quarter alone to 15,000 barrels per day.

Fourth, the company has an inventory of rich, super rich and high-volume dry gas wells totaling approximately 900 core Marcellus locations, 500 of which meet our required economic threshold at current strip.

Fifth, our robust rolling 3-year hedging program is designed to protect cash flow and the rolling nature of our program means we continue to look ahead to protect future year's cash flow while retaining the opportunity to capture upside that the market fundamentals suggest. As a proof point, we realized $112 million in cash from settled hedges in the first nine months, $88 million of which was realized in the quarter. We are controlling what we can and mitigating many of the things we can’t. When you combine all of these critical criteria with our ongoing operational outperformance, the facts are quite compelling. All of this is made possible every day by the expert execution, both strategic and detailed, of our highly talented, innovative and committed team, and I am quite proud of everyone's efforts on the team.

Before I talk about 2020, I want to give you some context. In 2018, we generated free cash flow in excess of $100 million. When we repositioned the asset portfolio by successfully monetizing Fayetteville, we committed to a 2-year transition plan to reinvest a portion of the monetized cash flow in our Tier 1 Appalachia assets in order to return to cash flow neutrality by the end of 2020 while maintaining our balance sheet strength. This plan remains on track, despite the subsequent decline in commodity prices. In the first year of the plan, we have dramatically improved operational efficiency with better-than-expected performance, and we will continue to unlock incremental value. In other words, the improvements we continue to make are sustainable as we plan for 2020.

While it is still too early to be definitive on specific 2020 targets, let me give you some brief color on how we are thinking about capital allocation. For this second year of our transition plan, capital investment will be limited to cash flow, based on strip pricing at the time we set our plan, plus up to $300 million of the remaining monetized Fayetteville cash flow. Should the strip at the time we set our budget in 2020 be lower than when we set the '19 plan, I would expect a reduced capital program. Consistent with prior years, we expect to have a front-loaded program in 2020 as well. Once we have set and begin to implement our activity plan, if prices dictate a change, we will adjust accordingly, just like we have done over the last several years.

If the forward curve were to increase temporarily, we would not expect to increase capital investment beyond the plan. Instead, we would evaluate options for the use of excess cash flow, including debt reduction, purchase of shares or for other corporate purposes, but to repeat, if the forward curve goes down from where we set the budget, I would expect that the capital program will be lower for 2020, and to be clear, the discipline around this capital allocation that you have come to know over the last several years remains unchanged.

Before I hand it over to Clay, I want to mention a couple of important ESG water-related achievements for the company. Southwestern Energy continues its commitment to the environment by being freshwater-neutral. In fact, we have been freshwater-neutral since 2016. For each gallon of freshwater we use in our operations, we return at least that amount of freshwater back to the environment where we work and live through conservation projects that restore streams and aquatic habitats.

I am delighted to share with you that we have reached an important milestone of returning in excess of 10 billion gallons of freshwater to the environment over this time. In addition, through the continued implementation of the company's piped water strategy, which targets delivery of water for all well completions through our extensive freshwater pipe network, we have removed 1.3 million truckloads of water off the roadways in Pennsylvania and West Virginia, all while improving the economics of our wells. Care for the environment is a core value of SWN and it is the right thing to do.

I will now turn the call over to Clay who will discuss operational highlights in more detail.

Clay Carrell
Thanks, Bill, and good morning everyone. We had another quarter of outperformance by delivering production at the high end of guidance and continuing to reduce well costs. Our teams keep expanding our continuous improvement culture as they keep finding ways to enhance well performance, lower costs, and improve efficiencies. The performance bar keeps going up quarter over quarter, and our organization has embraced that approach.

Total production for the quarter was 202 Bcfe, including 22% liquids. The production growth was driven by both improvements in our capital program performance and continued base production optimization. A primary focus of our capital activity has been in our super rich area of Southwest Appalachia, where condensate yield is the highest. As a result, our condensate production increased 42% compared to the prior year quarter to 15,400 barrels per day, which was above the high end of our quarterly guidance. Driven by the increased condensate production, total liquids production increased 19% compared to the third quarter last year to approximately 80,000 barrels per day. Similar to 2Q, we maximized value by rejecting ethane at certain periods during the quarter, resulting in slightly lower NGL volumes.

In the third quarter, we averaged approximately 3 drilling rigs and 2 frac fleets as we delivered on our planned activity reduction. We are currently utilizing 1 drilling rig and 2 frac fleets. We invested $240 million in the quarter and the fourth quarter activity will be managed such that total capital would not exceed the $1.15 billion annual capital guidance.

We continued to reduce average well costs in the quarter on wells to sales. With the majority of our wells to sales for the year already online or are in the late stages of completion, we will beat our annual target of $875 per lateral foot, which represented a 25% cost reduction from 2018. In the third quarter, we averaged $784 per lateral foot with an average lateral length of 10,466 feet. Both the average cost per foot and the average lateral length are the best we have had this year, and they represent a continuation of the cost benefits we are realizing from longer laterals, piped water, direct source sand, and operational execution improvements.

The operational improvements are driven by our team's ongoing success in reducing cycle times on drilling, completions and facility installations. For example, in the quarter we set a new company completions record, averaging 12 stages per day on a 4-well pad. This efficiency improvement reduced well cost on these 4 wells by $575,000 each and reduced the total time to complete the wells by 16 days. Year-to-date, we are averaging 7.8 completion stages per day, which is an efficiency improvement of greater than 45% versus last year. The cost and efficiency improvements coupled with bringing wells to sales sooner are improving overall economics and we now estimate we will be at the high end of our full year wells-to-sales guidance without increasing capital.

Third quarter LOE was $0.94 per Mcfe as anticipated, given our well mix and completion timing. We expect to be within our revised lower guidance range of $0.90 to $0.94 per Mcfe for the year.

In Southwest Appalachia, we brought 21 wells online, 16 located in the company's super rich acreage, 4 located in the rich acreage, and 1 Upper Devonian delineation well. Of the super rich wells, 9 were online for at least 30 days or more and had an average 30-day rate of 13 million cubic feet equivalent per day with an average of 570 barrels per day of condensate production. The 30-day equivalent rate represents a 60% increase compared to third quarter of 2018 driven by improved well performance and longer laterals. In the rich area, the 4-well pad had a combined peak rate of 141 million cubic feet equivalent per day and an average 30-day rate of 27 million cubic feet equivalent per day per well representing 100% increase over the prior year quarter, also driven by well performance and longer laterals.

In Northeast Appalachia, we brought 13 dry gas wells online, 10 Lower Marcellus wells, and 3 Upper Marcellus delineation wells that I mentioned in our previous quarter call. Nine of the 13 wells were online for at least 30 days consisting of 6 Lower Marcellus wells and 3 Upper Marcellus wells. The 6 Lower Marcellus wells had an average 30-day rate of 15 million cubic feet per day, which represents a 14% increase from the year ago quarter. The 3 Upper Marcellus wells had an average 30-day rate of 10 million cubic feet per day, which is in line with our estimates and consistent with offset tests.

In addition, in Northeast Appalachia, we began to see the production benefit from our pad compression installations. We experienced an initial gross production uplift of 55 million cubic feet per day from 10 installations. We expect to continue this program across more of the asset and we will see a shallowing of the base decline as a result.

We continued to progress our resource to reserves effort. In Southwest Appalachia, as mentioned earlier, we brought our fourth Upper Devonian well online, which was our first test in the super rich acreage. The stand-alone initial well performance was in line with offset super rich Marcellus wells in the area. The pilot test included 2 Lower Marcellus wells that were subsequently brought online, and we are continuing to evaluate the combined production performance. Also, as I mentioned earlier, in Northeast Appalachia, we continue to evaluate the 3 Upper Marcellus wells that came online early in the third quarter. The well performance is consistent with our forecast and we expect to continue to test this interval across a larger portion of our acreage in Bradford and Susquehanna Counties.

Now I will turn the call over to Julian for the financial highlights. Julian.

Julian Bott
Thank you Clay and good morning, everyone. As reported last night, we once again met or exceeded each of our financial and operational targets this quarter, despite headwinds from the challenging price environment.

Adjusted net income for the quarter was $44 million, or $0.08 per share compared to $40 million last year -- last quarter. Adjusted EBITDA was $202 million, which is 8% higher than for Q2 2019. Our weighted average realized price, including derivatives and transportation costs, was $2.16 per Mcfe, essentially flat to second quarter. Our increased liquids production and $88 million in hedge settlements almost entirely offset the impact of decreased commodity prices. Our natural gas differential for the quarter was $0.78 compared to $0.84 in the second quarter, as we were able to proactively benefit from optimizing our low-cost transportation portfolio. During the quarter, there were several pipeline outages that affected Appalachia basis, but thanks to the diverse nature of our transportation portfolio, we were able to assure continual flow of our production to our key markets.

As Bill said, we utilized a 3-year hedging program to mitigate price risk and protect cash flow. During the quarter, we continued to layer on additional hedges for future periods as detailed in the 10-Q. Of the total 360 Bcf of natural gas hedged in 2020, roughly 60% are hedged by collars limiting our downside risk while allowing for upside and roughly 40% are fixed price swaps with an average strike price slightly below $2.60.

On the cost side, our third quarter G&A expenses were $0.15 per Mcfe, which includes the impact of decreased mark-to-market stock-based compensation expense. Excluding a small one-time charge related to the headquarter's transaction that I discussed last quarter, G&A was down $15 million compared to the third quarter last year.

The strength of our balance sheet remains a priority and a key differentiator. For this quarter, we reported net debt to EBITDA of 2.2 times excluding Fayetteville. As previously announced, during the quarter, we furthered this strength by opportunistically repurchasing $50 million of our senior notes at an average 13% discount funded principally by noncore nonproducing asset sales. The repurchased notes had a weighted average interest rate of 6.72% and the buyback results in $21 million of interest savings on senior notes over the remaining time to maturity. Our year-to-date interest expense is down $54 million compared to last year.

We also announced that our banks completed their semi-annual redetermination with no change to our borrowing base and extended the maturity of the credit facility by one year to April 2024. We are in an enviable position with our debt maturity profile, with only $265 million of bond maturities until 2025.

We remain focused on the macro environment and continue to drive to a return to free cash flow neutrality by the end of 2020, even at recent strip prices. By focusing on what we can control, managing cost downwards, following our hedging strategy, broadly challenging the team to identify further operational improvements, and the continual capture of capital efficiencies, we remain confident in delivering our plans.

That concludes our prepared remarks, so Anita you could perhaps open the line for questions.

QUESTIONS AND ANSWERS

Operator
Thank you. We will now begin the question-and-answer session. To ask a question, you may press star (*), then one (1) on your touchtone phone. If you are using a speakerphone, please pick up your handset before pressing the keys. To withdraw your question, please press star (*), then two (2). Please limit yourself to two questions and re-queue for any additional questions.

The first question today comes from Charles Meade with Johnson Rice. Please go ahead.

Charles Meade
Good morning Bill and your whole team there. I appreciate in your prepared comments you are going through the -- through your approach to the '20 CapEx, but I wonder if I could just make sure I got it right. So, I think what I heard is that you said you are going to look at your cash flow at the time -- look at the strip at the time when you set the budget and you are going to do cash flow plus $300 million. I guess what -- is that right? And what I am curious about is, if let's say you set your budget in February at when the strip is at x, if the strip goes down let's say in June of '20 to something less than x, are you also then going to decrement the capital budget just so you can stay within $300 million of cash flow?

William J. Way
Thank you for your question. Yes, the first part of what you said is accurate. At the time we set our budget, we look at the forward curve for multiple years, because we want to make sure that economics are intact for projects as well, but we set the budget off of that curve. Cash flow plus up to $300 million of the Fayetteville proceeds or the cash flow from that, and the up to part is pretty important. As we rock through past the approval time and we get to your month of June or any other month and the risk committee, which meets every week, sees the trend of strips dropping, then we will look at the -- what that looks like in terms of cash flow generation through our economic model and then we will go back to the capital stack and we will begin peeling off projects, so that we do not exceed the funded cash flow plus up to $300 million from whatever strip there is. And that is a practice that we have been doing for several years.

If you have then a subsequent period of time in the year where prices jump back up and again the economics of the projects remain robust, then we will un-red circle those projects and add them back to the list, but not go over the budget that we set. If -- and that is most important when you get these surges of pricing in say a winter month or something -- one month or 1 week or 1 -- even 1 quarter, it does not make a drilling program decision. It is a bit longer term, but it always matches and goes by what we are seeing on the strip and it is adjusted.

Charles Meade
That is helpful clarity. Thank you, Bill, and there are lot of questions that I could ask, but just for my follow-up I wonder if I could drill down a little bit more into the beat in condensate volumes on the quarter, and maybe this is for Clay, because I think he addressed some of it. I can imagine at least 3 things, and there is probably more that could be driving it. One could be timing of wells -- that you guys are getting your wells on earlier and you are going to be near the high end of your guide. And that could be two, it is just the number of wells, and maybe there is a mix shift. But then there is a third, which is maybe the most interesting, which is that the actual productivity of your wells is higher in terms of the condensate yield than you were planning. So, could you give us a sense of how that beat on condensate, what the drivers behind it are and if they are temporary or something that we should be looking forward to continue going into '20?

William J. Way
Let me -- I will make a couple of comments and hand it to Clay. First of all, our acreage has a condensate component to the gas that is leading in the basin. And so if you look across our super rich area, our super rich area contains more condensate than any other acreage out there, number one. Number two, we do a lot of yield management. So, it is all about economics and so we manage flow those wells to create the greatest yield of the most valuable product, which happens to be condensate. And so as we throttle those back on the gas side to increase the condensate yield, that is what is generating additional value for the company, and Clay has some further details to talk about on that.

Clay Carrell
Yes, as Bill mentioned, we have it in the IR materials in our Brooke and Ohio Counties, where we have the highest condensate yields, 100-plus barrel per million in some areas, and as you all know from the previous calls, we have been focusing the majority of our wells in that area. And our planned timing had the largest number of our wells coming to sales in 2Q and 3Q. And we are continuing to see the benefit of those wells coming online in 3Q and the optimization of the production performance through what Bill talked about, facility design, so that we can benefit from the max condensate production and with our subsurface knowledge maximize on how we are completing the wells and where we are landing the wells. So, we are really pleased with the growth in the condensate, and we have a healthy set of remaining drilling inventory in that area where we can continue to focus there.

Charles Meade
Thank you for the color.

Operator
Thank you. The next question comes from Drew Venker with Morgan Stanley. Please go ahead.

Drew Venker
Hi, everyone. Some really great results. I wanted to just dig in a little bit more on the Upper Devonian and the Upper Marcellus results and if you could give us some color on whether you did much different in the Upper Devonian well relative to the offsets, nevertheless it is different reservoirs, and then the Upper Marcellus similarly if there are things you are doing different on that test as well?

Clay Carrell
Certainly, this is Clay. We -- this is our first test of the Upper Devonian in the super rich, and as you know, in our previous testing during the year, we took what we learned from the testing in the rich area and adjusted our completion designs in order to maximize the economic benefit of a combined production of both the Upper Devonian and the Marcellus. So, we ended up with a reduced completion design, which helped the economics and we are seeing similar performance. So, we think we are continuing to make progress on elevating the combined development, but it is still early, and we have some ways to go to keep pushing that in the current commodity price environment.

William J. Way
And any reduction of completion designs or any reduction of cost always looks at the value creation that is involved in that, and so we do not reduce costs to reduce cost and impair value and it is a great example in how they have managed these wells to highlight that fact.

Clay Carrell
And then, on the Upper Marcellus, we, like some other operators, have been testing the Upper Marcellus this year with latest generation completion designs, landing zones, and we are really pleased that we have seen the improved production performance by those latest designs, and the results of the wells have been in line with what we thought that upgraded performance would be, and so our plans are to continue testing that as we move into 2020.

Drew Venker
Thanks for the color. So, just to follow up on the Upper Devonian. In the past, a lot of operators had seen reduced performance relative to the Marcellus, I think in part because it was lower pressure. Do you think it is probably maybe because prior operators had been drilling Upper

Devonian subsequent to drilling upper – I am sorry drilling Marcellus and thus pressure drawn on maybe reduced the productivity of the reservoir. Is it -- or maybe it is just the Upper Devonian higher pressure is more productive on your acreage?

Clay Carrell
Yes. We are aware of the kind of the past discussions around the co-development of the upper development -- Upper Devonian with the Lower Marcellus. In our minds it is -- how do you optimize the completions to limit the well interaction between the two zones and maximize the economics from co-development there, and so that is the progression that we are on. Like Bill mentioned, because of the interference that can exist there when we back off the completions, we are working on limiting that interference but yet still getting the same or better production results, which would enhance the economics.

Drew Venker
Okay. Thanks for that color, Clay. Just one last follow-up on this point. Do you have any locations identified in your -- identified drilling inventory for either of these zones, Upper Marcellus and Upper Devonian?

Clay Carrell
We definitely, in our full playground of inventory of future drilling locations, have drilling locations in both of those two areas. We have not finalized 2020 plans, and so we will factor that into the go-forward, but as I mentioned earlier, I would expect for sure that the Upper Marcellus will be in the 2020 plans.

Drew Venker
Thanks for the color.

Operator
The next question comes from Holly Stewart with Scotia Howard Well. Please go ahead.

Holly Stewart
Good morning, gentlemen, Paige.

Paige Penchas
Good Morning.

Clay Carrell
Good Morning

Holly Stewart
Just maybe, Bill, starting off with kind of a high-level question. In your prepared comments, you talk about being in a position to take advantage of financial, operational and strategic opportunities, given your maturity profile. I was wondering if you could provide some further insight here, and then maybe also, given what we have seen in other basins with mergers of equals, do you think this might make sense in the Appalachian basin?

William J. Way
Well, thank you, Holly, and good morning to you. We look constantly at creating value with our assets and beyond our assets for the shareholders, and we look at growth or expansion along the lines that you are talking about in two ways -- organic and inorganic. As we have kind of mentioned a little bit, we have got 53 TCF of resource across the Appalachian basin and in

multiple benches. We have got a science budget that helps test those all with the intent of converting resource into reserves and reserves into economic drilling opportunities to expand the base.

The shareholder already owns that and so there is a focus on making sure that we are getting all of that value. At the same time, looking for opportunities beyond that to further expand the company's ability to create greater levels of value, we look at both bolt-on opportunities for adjacent acreage where we can expand the efficiency of drilling through longer laterals or just expand the footprint as long as it is accretive, but also we look at significant additions, including combinations, including mergers. We study those opportunities all of the time, and where we can find the ability to create real accretive value that cannot be added through commercial negotiations, and there is a lot of playroom in that space, then we believe that we ought to focus on and advance our thinking around those with a couple of clear screening methodology in line.

First of all, real returns on capital accretive financial and balance sheet metrics, and then the opportunities have to have accretive inventory to us, generate real economics on full cycle basis, balance sheets have got to remain strong, synergy capture is critical. And we must assure ourselves that when we make commitments around synergies, those synergies can and will be delivered. And then if those things are in line, then the opportunity may make sense and we will continue to explore it. In a margin-based, commodity-based industry scale, materiality, resiliency in all forms of pricing environments or regulatory environments and a number of things you think about, it makes sense to explore those opportunities and we do, and as upfront, we continue to evaluate that. We prefer not to comment on the details; it is just how we work. When we sold Fayetteville, we told world. As you look through opportunities to expand the scope and scale of the company and its economic generation capability, we will keep those to ourselves for now.

Holly Stewart
Understood. Good color, and then maybe just one for Julian on the debt repurchases in the quarter. Julian, how do we think about this as we kind of proceed into the fourth quarter and then head into 2020 on further debt repo?

Julian Bott
Yes, I mean Holly we obviously are always focused on the balance sheet. We have done a lot to get it to where it is, and we look to continually find ways to improve it. There was an opportunity, based on where the market was trading, to make some repurchases. We have made some noncore asset sales, and so, it seemed like an appropriate step and consistent with our goals. We are always evaluating -- evaluating opportunities and consider debt repurchases along with any of the other investments that we might make. So, I cannot give you clear color as to what we would do at any given time, but again, I think you know what our principles are, which is maintaining the balance sheet and progressing the business.

Holly Stewart
Great, thanks guys.

Julian Bott
Thank you.

Operator
The next question comes from Arun Jayaram with JP Morgan. Please go ahead.

Arun Jayaram
Good morning. I wanted to first start off on the well cost reductions that you have been able to generate. I think you were at $784 per lateral foot in the quarter. I was wondering if you could maybe provide some commentary on how much more do you think we can go here, Bill, particularly with thoughts on service cost. I know you are partially vertically integrated, but just some thoughts on how much more do you think we could push on the well cost front? And any thoughts on sustaining CapEx requirements for 2020 if we are -- if these well costs come in at this $780 or lower number for next year.

Clay Carrell
Arun, I will start on the cost reduction discussion. As you have seen from the results, our teams are all over figuring out how we can keep being more efficient, and we continue to find those efficiency gains coupled with cost improvements in the environment right now. Us taking over self-sourcing of sand is an example where we dramatically benefited on cost and on the water system and then of course the longer lateral. So, all of that is continuing, and then when you look at the numbers we are reporting, what will be the full year numbers where we are saying we will beat the $875, when you pull out the wells that were spud under the cost structure of 2018 and look only at wells spud in 2019 and that are coming online the sales in 2019, that number is down close to $790 per lateral foot. So, directionally, we are going to budget for 2020 factoring in all of the efficiency gains that we have already realized and then raising the bar to go find more.

Arun Jayaram
Got you, Clay, and maybe just some thoughts on your sustaining CapEx requirements, if you theoretically went to -- what CapEx required to keep 2019 production flat?

William J. Way
Yes, this is Bill again. The maintenance CapEx as we call it is $600 million to $650 million. When I look at, I will reinforce something that Clay said, it is not only the drilling cost, it is every part of every piece of this company where we can make improvements. One-off improvements are great, sustainable improvements are even more exciting and all of that is built into the next year's programs why -- with -- in any kind of form of cost and the $600 million to $650 million is -- excludes CI&E.

Arun Jayaram
Right, so that is the D&C component?

William J. Way
That is right.

Arun Jayaram
Okay. My follow-up -- I was wondering if you could shed some more light on the compression work that you have done. It sounds like that helped boost production by 55 million a day. Just talk about -- I mean do you get a sugar high from this compression or is this sustainable? And thoughts on what this could mean on a go-forward basis?

Clay Carrell
Yes. So, there is an initial flush benefit, but we have the full benefit modeled as we look at how the production shallows that decline because you are lowering the line pressures at those pads. When we look at base decline, we are already able to see the trends and that it is going to help

us improve our base decline to a mid-20s, around a 25% number, down from the upper 20s where we have been at.

William J. Way
Yes, and let me put a topside on this. One of the things we are trying to do is get out of the way of the reservoir. We have a choice of either doing this at a pad location or doing it across the entire gathering system. Well we have got a lot of robust areas of -- and wells and pads in different acreage that continues to perform quite well at higher transmission level pressures, and so, we target pads in individual areas where we can draw down the pressures on the well, but maintain the more efficient and higher residue pressure into the gathering system. It is a practice that we started back in Fayetteville, very successful. You have sustained performance from it. We do the same thing with looking and optimizing any kind of Midstream, whether it is pipe restrictions or anything else, all at the same time. The goal is get out of the way of the reservoir and allow that reservoir to continue to perform, and base production improvements are great economic projects. And you talk about our capital allocation, these come up to the top of the list because of the return they generate and it stems decline.

Arun Jayaram
Yes, just maybe one housekeeping question. Bill, you did beat consensus production estimates for the quarter, yet you kept the full year the same. Any thoughts on that, just some conservatism or did it just reflect some TILs moving into the third quarter?

Clay Carrell
Yes, Arun, we are going to continue to focus on the value-added aspect of our production. As we move forward, there is the possibility of some ethane rejection that could occur, as we move through the fourth quarter like we have done at certain periods in 2Q and 3Q, which has an effect on the overall equivalent volumes. So, day to day, we are going to keep looking into maximizing the value from the production, but there are some variables that could swing it a little bit.

Arun Jayaram
Fair enough. Thanks a lot, Clay.

Operator
The next question comes from Kashy Harrison with Simmons Energy. Please go ahead.

Kashy Harrison
Good morning everyone and thank you for taking my questions. So, I guess my first question surrounds the capital and efficiency improvements that we were just discussing and that you have seen in Q3. This might be a question for Clay or Julian and I know it is not an easy one to answer. But if we took the 2019 pace of activity, so the number of wells drilled, completed, turns to sales, etc., and just marked it for the leading-edge current cost experienced in Q3. What would, and the guesstimates are fine, what would the adjusted CapEx budget be for 2019? Like would it be 10% lower? Just any rough guess on how that would change would be great?

Clay Carrell
I guess from a starting point, if I take into account the -- at least a 5% maybe adjustment, when you think about the -- solely the impact of wells that have come online in 2019 compared to the higher cost structure that came in in 2018.

Kashy Harrison
Right, and then -- that is helpful -- and then as you look to further reduce costs, do you think there might be a potential benefit to monetizing the oilfield services segment and just taking advantage of really low service pricing across the entire industry. We have seen a larger operator in the Permian do this here more recently and it sounds like it is generating positive capital efficiency rate of return. So, I was just wondering if perhaps there is a thought process on monetizing the service business?

William J. Way
Yes. I think what you have to look at it is across any part of our business, whether it is the services side, whether it is our water infrastructure or any of those kind of things, you have really got to take a look at the value they create for the company, and we do this all the time, rigorous analysis of the value we create by doing it ourselves versus what we could do on the outside. We take the flexibility that these businesses provide in moving capital around.

If you take multiples that you might want to get on any of these, we will come with drilling commitments and other -- or other project commitments, that is what drives these things to be so valuable, and you have got to balance all of that on the back of economics, and if it makes sense to do it one way, that is how we do it. If it makes sense to do it another way, we have to look at that. And that is how we -- if you look at a lot of the questions that we get asked, they all have an economic route, and that economic route is at strip pricing, that economic route is making sure that from an objective point of view whatever we are doing is delivering the value that it is supposed to, and if it does not, then we have to look at the alternative to that.

Kashy Harrison
Got you, If I could sneak one more in, and your last comment was a great segue to the question, but I was just curious, if we look at the forward strip for natural gas, we look at the implied NGL prices, they are pretty bad. And I was just wondering -- using your preferred metric of returns, are these projects generating sufficient returns to take care of corporate expenses, or is the thought process with using $300 million from the Fayetteville proceeds just countercyclical investing with the belief that eventually the price will correct itself and will land closer to the $2.85 price that you included in the initial 2019 budget?

William J. Way
When we take a look at whatever we are going to invest in, whether it is operating expenses, capital, whatever, but in case of capital, which was your question, we take each and every individual project that we plan to put on the table, supported by the fact there is cash flow to invest it in and the proceeds, as we have already talked about, we force-rank those projects against economics, and so we know the order with which they might be done in, then we add them all up and load them up with all the costs that you speak about, and if they do not generate the required return, then that package does not work and we go back and relook at it. We carve off projects. Again, it is prudent in the economic return, fully burdened, and at current strip with current differentials projected through a 3-year period. So if you are going to drill a well you kind of want to look at the forward curve for three years. So that is where the bulk of the return comes from in that 1 to 3 year period, and we run that over and over. And then, as we said earlier, if those economics change because there is a lower commodity price or higher basis in any of the areas where we work, we adjust that and then we peel off the bottom end of that stack, if you will, because they are prioritized and that is what you -- that is how we invest. And so, to be crystal clear, whether it is vertical integration, drilling wells, any kind of investment we make, it has got to earn its way to creating value and generating returns on that investment for the shareholder. That is how we run the company.

Kashy Harrison
Got you. Thank you for taking my questions.

William J. Way
Thank you.

Operator
The next question comes from Noel Parks with Coker & Palmer. Please go ahead.

Noel Parks
Good morning, just a couple of things I was wondering. At this point, because your release does -- always gives us an update on average lateral length, where is your longest lateral length sort of by region now? How far ahead have you drilled?

Clay Carrell
We have got an 18,600 foot successfully completed lateral in West Virginia and 18,000 foot in Pennsylvania.

Noel Parks
Okay. Great, and I know the data through wells that size is still in the process of accumulating it. Any signs, that you are nearing diminishing returns for going out with that length?

Clay Carrell
From a mechanical standpoint, nearing is probably relative, that is pretty far out there, but there is probably a little more room to go with current technology, and then from a well performance we are continuing to get the one-for-one benefit on the longer laterals. There is not as big a data set of those, so we continue to watch those, but everything is looking good so far. I gave you those longest laterals flip flopped. Southwest Appalachia is 18,000; Pennsylvania is 18,600.

Noel Parks
Okay, great, and I was just thinking about infrastructure in general or maybe more thinking about transportation agreement. At this point, what is sort of the oldest vintage agreements you have in place at this point, and is there anything on the way to rolling off where you might have opportunities to renegotiate terms in this environment?

William J. Way
I will take part of this and Jason can add some color if necessary. I would say that our oldest contracts are in Pennsylvania, where we have built a very flexible long-term portfolio of capacity that is well below the market for anything that is being built or operating today anywhere else, and it is really an asset to the company. It is highly flexible and gives us a lot of flexibility of the pace of investing, etc., all the way to the newest transportation portfolio that we have in West Virginia that is priced appropriately for the market in the times that it was built. It is right-sized for our company so that as we move through time and even a moderate development program you have growing into that, and a proof point around that is we are able to add transportation at a discount in the future that enables that flexibility to continue and we have not had to overcommit it and purchase a lot of transportation that we do not need, and the strategy for how we manage this is playing out.

Noel Parks
Great, thanks a lot.

Operator
The next question comes from Biju Perincheril with Susquehanna. Please go ahead.

Biju Perincheril
Hi, good morning. Thanks for taking my question. Bill, it sounds like your well mix will be shifting more toward the super rich area and I am wondering if that is going to put some upward pressure on your operating excellence or do you have projects in the works -- gathering systems or something else that is going to offset that?

William J. Way
Yes, let me just check one comment in the front of it. For the last couple of years, we have been running majority of the activity in the super rich and liquids-rich area, whatever you want to call it, in West Virginia, two-thirds or one-third-ish of the activity is in the super rich area and smaller portions in Pennsylvania. Commodity prices drive that. So, if you have 5 rigs and you put 3 of them in one place and 2 of them in another or 3 and -- 4 and 1, it bounces a little bit back and forth, but right now, even in the forward curves as we look, because of the condensate and all the liquid value that we get from that, you will be biased toward that investment. So, we constantly look at ways to renegotiate agreements where we can or expand the pie so that we can get better rates and we will keep doing that, its impact on the LOE, but it may have a higher LOE, but the great part of that is it has higher revenues, which means some margins are greater, and so we are happy to take those.

Biju Perincheril
Yes, definitely, and my follow-up was actually going back to the Upper Devonian test. It sounded like the previous test in the rich window. Perhaps you saw some interactions between the Upper Devonian and the Marcellus, and when you move over to the super rich area, is there anything changing on with respect to geology that makes the 2 zones being independent, or is it simply how you are completing sort of minimizing the intensity of the completions.

Clay Carrell
So, the 2 intervals are 150- to 200-foot apart, a little further apart in the super rich area, but we are seeing communication. It's a matter of maximizing the overall completion design to elevate the economics of a dual completion coproduction project, so that it adds value economically. It is a little bit thicker in super rich than in the rich, but we are dealing with a 150-to-200 foot between the 2 intervals.

Biju Perincheril
Got it, so you are not ruling out in the rich area that you could still have Upper Devonian as the viable zone?

Clay Carrell
Yes. I am not ruling it out anywhere. It is really early in the discussion, and continuing to adjust the completion designs, like the progress we made from rich to super rich, I think is going to continue to be an opportunity for us.

Biju Perincheril
Got it. Thank you. That is helpful.

Operator
The next question comes from Jeffrey Campbell with Tuohy Brothers. Please go ahead.

Jeffrey Campbell
Good morning and congratulations on the quarter. Going back to the super rich Upper Devonian test, was that test done, or let's put it this way, were the Marcellus offsets to that well in the high condensate region of the super rich? And if so, did the higher cut show up in the initial Upper Devonian results?

Clay Carrell
Yes, most definitely, which is how we planned the test. We – there are 2 Lower Marcellus wells right below this Upper Devonian well, all in the super rich acreage. We brought on the Upper Devonian well first, and it had all the exact same liquids and condensate-rich characteristics of our Lower Marcellus super rich wells, and that is part of the testing that we are doing.

Jeffrey Campbell
Okay, great. That is good color, and Bill, I do not want to ask a downer question, but I mean it is -- I think it is worth asking. That is -- is there a scenario where the 2020 nat gas strip could be low enough that achieving the year-end 2020 cash flow and neutrality might have to leak into 2021?

Julian Bott
Yes. I mean Jeff, Julian here. Indeed, I mean obviously it is all dependent upon what we get to invest from the cash flow. I mean there is a plan and it works in this environment, but there are clearly cases where you just -- you would not be able to accomplish that goal.

William J. Way
And the follow-on question that I think you might be asking me is, is there a price where you will stop drilling? And the answer to that question, which will affect this answer, and the answer is very clear. When the price of the commodities reaches a point where we cannot meet the company's rigorous economic threshold, we will reduce or stop activity. We did it in 2016 and -- for the same reason, and we will do it again. It is not our preference, but that is the duty we have to create and protect value for the shareholder, and it is not about activity or production growth, it is about real value creation.

We are fortunate to be in some of the richest condensate-laden acreage in West Virginia and have some terrific acreage that has high product -- production flow in Pennsylvania and a combination in the middle between the two, and so our economics stay robust, but yes to that question.

Jeffrey Campbell
Right. That is really helpful. So, I mean the point is, is you do have a goal, but it is not a rigid goal. You are going to respond to conditions and always with an eye on being able to make returns.

William J. Way
It is fundamental.

Jeffrey Campbell
Great. Thank you. I appreciate it.

Operator
The next question comes from Scott Hanold with RBC. Please go ahead.

Scott Hanold
Yes, thanks, and I apologize if I am going to re-ask a question. I have been dropped off the line a few times here, so I did not get to hear the full set of questions here. But first a follow-on on the prior question is what is the level of production? Or what do you need to hit to achieve that free cash flow -- sustainable free cash flow neutrality by year-end 2020? Is it a capital efficiency with your well cost? Is it a certain size of the production base that you need to hit? What is sort of that level we should be looking at?

Julian Bott
Yes. I mean, Scott, it is really a combination of all these things, which is why we have been able to continue to say we can hit the goal, despite the fact that the industry conditions have certainly changed. And I mean a lot of the things we have talked about on this call; the operational efficiency gains, the lowering of our capital cost structure and frankly the productivity gains that we have had, are all contributing to that. And that is what is driving it.

Scott Hanold
Okay, and so, if I can ask you more directly like, what is sort of that base production level that you feel is sort of that free cash flow like break-even level? Where is that?

Michael Hancock
Scott, there is not really a production level. I mean it is going to depend on commodity prices, right? I mean commodity prices are going to spin off different EBITDA, a different cash flow, I mean at different levels. So, there is not a production number we are chasing to deliver that. It is all combined together with the cost structure and everything else, so.

Scott Hanold
Okay. Okay, and then what impact could have those improvements on compression that you all have been talking about have on reaching that? I mean like how much -- how big is that as you kind of roll that out to -- in other well pads, in reducing your maintenance CapEx?

Julian Bott
Yes. I mean the impact that that had is it just helps further the resilience and handle the base declines and so forth. As far as rolling it out I mean, Clay?

Clay Carrell
Yes. So, we are doing -- the majority of our work in 2019, is in our Greenzweig area in Pennsylvania, in Bradford County, and then we have plans that we are finalizing for the continuation of it going into 2020.

Scott Hanold
Okay, and what would if that have an impact on maintenance CapEx, does it like reduce it by like 5% or 10%? Like how big can that be?

Clay Carrell
Yes. I think again it is this combination of things. We have a little bit higher exit rate as we come to the end of the year. Right now, we have a view of improved or shallowing base decline. So, kind of with balancing all those things, we are in that $600 million-type of number.

William J. Way
Yes. I think to cap this question off, just like in your model, you have got multiple levers that you can tweak and you will get a different answer. That is how we run the company. We look at all of

those variables. You can have lower commodity prices and bases can be awesome. It can even negate the lower commodity price. You have just got to look at every one of them and feed them into the model and that produces a glide path for investment for revenue for cost and then we go from there, and so we are keen and very clear. We can be free cash flow-neutral today if you just stop. But that is not the right thing to do and we have a model for that. So, we really look at it holistically.

Scott Hanold
Okay, understood, thanks.

Operator
Due to time constraints, this concludes our question-and-answer session. I would now like to turn the conference back over to Bill Way for any closing remarks.

CONCLUSION

William J. Way
This year is playing out fundamentally with the way we positioned the company and readied it over the last several years to face: this kind of the volatile commodity environment or any other kind of impact that the industry might get. We are running the business to ensure that we have got a compelling investment thesis today in this environment as well as over the long-term.

I think we have proven and continue to prove that we have taken intentional and very strategic actions over time to improve the quality of the earnings, advance our quality condensate acreage in Appalachia, for example, and reshape the portfolio, whether it is through divestitures, whether it is diversification in the liquids, to make Southwestern Energy a strong resilient organization with a lot of talented people who share the outperformance mindset that we hope we have gotten across to you today.

The teams continue to innovate. They continue to execute quarter after quarter. So, we thank you for your interest. Thank you for your questions and you all have a great weekend.

Operator
This concludes the Southwestern Energy's third quarter 2019 earnings call. You may now disconnect.