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02-Aug-2017

Range Resources Corp. (RRC)

Q2 2017 Earnings Call

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MANAGEMENT DISCUSSION SECTION

Laith Sando
Vice President, Investor Relations

GAAP AND NON-GAAP FINANCIAL MEASURES

- Before we begin, let me also point out that we'll be referencing certain non-GAAP measures on today's call
- Our press release provides reconciliations of these to the most comparable GAAP figures
- In addition, we've posted supplemental tables on our website to assist in the calculation of these non-GAAP measures

Jeffrey L. Ventura
Chairman, President & Chief Executive Officer

BUSINESS HIGHLIGHTS

Development Plan

- Q2 2017 was another quarter where Range successfully continued to execute on its long-term development plan across our deep inventory of high-quality assets

- As you know, Range has built a concentrated 500,000-plus net acre position in Southwest Pennsylvania and now has a 200,000-plus net acre position in North Louisiana, both of which we believe are best-in-class assets for creating shareholder value
- I want to begin by reviewing a few significant events from the quarter and then discuss that we expect to see for the remainder of 2017

Southwest Marcellus Position

DRY GAS PAD

- During the quarter, we drilled on the east and west boundaries of our Southwest Marcellus position, with great success
- Both of these pads, that I like to think of as bookends, were significant
- And at the dry gas pad on the eastern edge is now our highest rate dry gas pad on record, and our super-rich pad on the western edge is our highest-rate condensate pad on record
- If you look back at our first quarter release from April, we also highlighted a pad drilled on the north side of our Washington County acreage position
    - Production from that pad has been stellar and, after 100 days, has significantly outperformed our wet type curve
    - Ray will discuss these results in more detail in a few minutes

ACREAGE

- The bottom line is that these recent results highlight the quality of our Marcellus position and further confirm that we have consistent results across our Southwest Marcellus acreage
- Every company says that they have core acreage
- However, we encourage people to pay close attention EURs per 1,000 foot and cost per 1,000 foot when comparing quality
- To me, it's interesting and noteworthy that Range's Marcellus discovery well was completed in 2004 and, even after more than a decade of drilling, we're still improving and setting new records in different portions of the field

Southwest Pennsylvania

- We continue to drill longer laterals in an effort to optimize our development in Southwest Pennsylvania
- Importantly, our blocked-up acreage position allows us to drill some of the longest laterals in the area

AVERAGE LATERAL

- Our average lateral in Southwest Pennsylvania for H1 2017 was approximately 7,500 feet
- We're projecting to increase that to over 9,500 feet for H2 2017 and should average even longer laterals as we get into 2018
- It's worth noting that there will be an optimal lateral length when normalized EUR begins to crest and returns are maximized, but we have not found it yet
- In fact, 2017 results to-date suggest that some of our longest laterals are performing extremely well on an EUR per 1,000-foot basis, which Ray will discuss in more detail

MARKETING

- On the marketing side, our team has a first-mover advantage to plan and acquire a right-sized capacity with one of the lowest-cost firm transport portfolios in the Basin
- Importantly, this portfolio takes our gas to good markets and we have incremental demand expected in the coming years

NATURAL GAS TRANSPORTATION PROJECTS

- By year end, we should have access to additional natural gas transportation projects to take our production out of the local Appalachia markets and direct it to the Midwest and Gulf Coast regions
- Rayne/Leach Xpress, Adair Southwest and Rover Phase 2 are all currently being constructed and have scheduled in-service dates before 2018
    - The combination of these projects and strengthening local pricing will be drivers of our expected improvement in natural gas differential for 2018

North Louisiana

- We've also made progress in North Louisiana, as we continue to change development activity towards a steadier cadence
- Right off the bat, the team has done a tremendous job driving down the cost of drilling complete well, which has opened new economic locations

PRODUCTION

- As discussed last quarter, we got off to a slow start in 2017 with our North Louisiana production
- The results we've seen from the group of wells brought to sales in Q1 were not up to par with our expectations, but we are looking forward to seeing the results in Q3 and fourth quarters from redesigned wells in Terryville
- We also expect to have new test results from the North Louisiana extension area, two additional horizontal wells offsetting Vernon Field to the east and west
- In addition, we'll drill two vertical well science tests of the stacked pay potential of the eastern offset of the Vernon Field
- Well logs indicate resources of 400 Bcf per section and stacked pays with multiple targets
    - These vertical wells will help us build our future development plans

3D SEISMIC ACQUISITION

- In addition to extensive log and well test results, Range is acquiring considerable 3D seismic across some promising acreage that will help delineate and potentially expand the position
- Included in the 2017 budget is approximately $16mm for 3D seismic, covering the Western portion of our position
- As Range learned in the early stages of what has clearly been an extremely successful Marcellus development, which required several years, shortcutting the timeline in science in not an option
- Unlocking the resource potential across 220,000 net acres of stacked pay requires a certain amount of time and well repetitions in order to establish the most predictable economic development program

Inventory, Pricing and Cash Flow

- Moving back to the corporate level
- A key question for Range is how to develop our huge inventory, given the ongoing commodity price uncertainty
- For 2018, we'll be responsive to prices and set our spending at or near cash flow, including any asset sales
    - This should lead to annual y-over-y production growth of 10% to 20% over the next couple of years, depending on commodity prices
- Given our peer-leading well costs and EURs per 1,000 foot of lateral basis, on a relative basis, Range's growth per-dollar spent should remain amongst the best in the industry
- Longer term, our sizable inventory of high-quality locations provides Range the ability to grow at a significant rate for a long time, if economically warranted
- Also important, thinking long term is the benefit that Range has in having stacked horizons in both Appalachian and North Louisiana with the added optionality of drilling dry, wet or super-rich wells
- And looking at where we'll set the growth throttle over time, we'll continually seed to balance operational efficiencies, balance sheet strength, acceleration of NAV in return of capital to shareholders
- Over the long term, we expect to generate significant FCF for Range

CLOSING REMARKS

- In closing, Range's long-term planning has taken the company from its discovery of the Marcellus 13 years ago through years of significant growth while leasing and holding over a half million acres in Appalachia with stacked pay potential
- And not to be overlooked is the innovative nature of our marketing and midstream arrangements that this long-term outlook has generated
    - This is reflected in the improvements we are seeing in y-over-y differentials and our corporate recycle ratio, both enhanced by our North Louisiana assets
- I believe the Range has the size, the scale and the quality of inventory that is extremely difficult to match
- We will continue to shape our long-term planning around both strategic assets, seeking to create long-term shareholder value

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Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President

OPERATING HIGHLIGHTS

Production

- Production for Q2 came in at 1.945 Bcf equivalent per day, exceeding our guidance of 1.93 Bcf equivalent per day
- Guidance for Q3 is 1.97 Bcf equivalent per day and for Q4 is expected to be 2.17 Bcf equivalent per day, resulting in annual growth of 30%
    - This is below our previous guidance of 33% to 35%

NORTH LOUISIANA WELLS

- And there are two main drivers behind this change

- First, as mentioned on the last earnings call, the performance of the North Louisiana wells in Q1 was below our expectations
- Using round numbers, the underperformance of these wells and the corresponding frac hits to offset production accounts for the loss of approximately $75mm a day for the year
    - By itself, this would explain a 5% difference in growth for 2017
- Despite the early North Louisiana setback, we were still expecting to hit our full-year guidance of 33% to 35% growth, as our Marcellus wells have continued to perform well, in many cases, significantly above our average type curves
- However, we've been hampered by delays in obtaining the necessary permits
- Again, using round numbers, six pads representing 32 wells were delayed an average of 25 days per well
    - This represents 800 combined sales days and approximately $75mm a day of production for the year, coincidentally very similar to the underperformance from North Louisiana

PENNSYLVANIA

- So, we could have withstood some underperformance in the early North Louisiana production or we could have withstood some delays in Pennsylvania permitting, but the cumulative effect of both results in a reduction to our annual guidance
- Importantly, the Pennsylvania permitting issues have been resolved and we do not expect any delays going forward and we anticipate significantly better well results in North Louisiana for H2
- I want to emphasize that we still expect to exit the year above 2.2 Bcf equivalent per day, which is in line with our plans when we started the year
    - This $200mm a day ramp of new production coming online during Q4, both in North Louisiana and in Appalachia, fits well with our anticipated incremental pipeline capacity, expected improving pricing differentials and sets us up really well for 2018

Appalachia

- Looking at some of the operational highlights for the quarter, let me start with Appalachia
- We had two exceptional multi-well pads brought online in June
- These pads happen to be on the eastern and western edges of our acreage position
    - These pads, in conjunction with two other pads that were announced over the last couple of quarters on the northerly and southerly portions of our development, have essentially book-ended our entire position
    - This highlights the high degree of confidence we have across our acreage

AVERAGE LATERAL LENGTH

- In the super-rich portion of the field on the Western edge, we recently completed a seven-well pad with an average lateral length of 10,685 feet, with the longest lateral being 14,444 feet
- The wells averaged 54 stages on a per-well basis, with 2,000 to 2,500 pounds per foot of proppant placed with optimized completion designs that I'll discuss in just a few minutes
- We're currently flowing five of the seven wells under constrained conditions, with two wells to be opened up later
- The average IP per well is 29.1mm cubic feet equivalent per day, or 4,843 barrels of oil equivalent per day being 73% liquids
- We've achieved and maintained rates of over 5,000 barrels a day of condensate off the pad for 24 days, setting a pad and per-well record for condensate production

- During the first two weeks of production, average gas and condensate rates were more than 40% higher than the next-best offset pad
- On the opposite side of the field, in our dry acreage, we recently brought online a four-well pad with an average lateral length of 11,100 feet
- Two of the four wells have lateral lengths in excess of 15,000 feet, with up to 78 frac stages per well
- All four wells are now producing, with the pad currently flowing 100mm a day
    - The average IP for these wells is 30mm a day per well and the 30-day average IP is 26mm a day per well
    - These are proven to be some of our strongest dry gas Marcellus wells ever, as we've been able to maintain 100mm a day flat for 40 days from that pad

North

- Moving to the north
- The super-rich pad we talked about last quarter, near the planned MarkWest Harmon Creek Plant, continues to perform well and is 65% above the type curve after approximately three months
- A similar story exists in the wet area, where 23 wells have been drilled over the last nine months
    - These wells average 10% above the type curve after 65 days
    - Included in those results is a four-well pad on the southern edge of our position in the wet area that we announced a couple of quarters back that averaged 9,625-foot laterals with 46 stages and IPs at over 35mm cubic feet equivalent per day per well
    - Today, those four wells are forecasted to average over 4 Bcf equivalent per 1,000 foot of lateral
    - These results are exciting, not just because they're some of our best performers to-date, but also because they illustrate consistent performance enhancements

DEVELOPMENT PLANS AND DESIGNS

- Our development plans and designs have been evolving since we discovered the Marcellus almost 13 years ago
- And over the last few years, we've utilized technologies such as real-time data streaming, advanced data visualization, machine learning and predictive analysis
    - The performance of these new wells demonstrates early wins using this technology, identifying opportunities for improved well performance and returns through optimization of our completion designs, which involves changes like using different proppant loading for specific cases

SPENDING

- Spending just a minute on the technology
- Our most recent evolution of this multi-disciplined process involves developing a software platform driven by machine learning
- This tool is used to address one of the most significant challenges, the non-linear, non-parametric and highly dimensional nature of predicting well performance
    - This platform that our team developed connects our engineering teams to a single source of data combined with interactive and predictive models
    - This allows them to focus their time on improving the economic outcomes of our capital program
    - It makes it possible to evaluate field development decisions in almost real time
    - We believe these tools and the multi-disciplined approach that we've developed represents a unique and competitive advantage for Range

MACHINE LEARNING AND PREDICTIVE ANALYSIS

- While we haven't been very vocal about it, our teams have been working with machine learning and predictive analysis for years
- And what's critically important is that it's truly driving improvements, as demonstrated by recent well performance
  - Going further, these examples clearly illustrate the quality of our low-risk long lateral inventory in Appalachia across the dry, wet and super-rich areas
  - These types of improving results, when combined with going back onto existing pads with existing gathering and compression infrastructure, generate economics that are among the best in the business
  - I'll repeat again, we literally have thousands of these types of opportunities

CAPITAL EFFICIENCY

- And I still don't believe we drilled out best well yet
- Here we are almost 13 years after the discovery, and well performance is still getting better
- One big driver of capital efficiency is our lateral lengths
- In H1, our lateral lengths averaged 7,500 feet
- But in H2, we expect length to be turned in line to exceed 9,500 feet
  - These longer laterals increase the cycle time slightly as we make the transition, but they really set us up well heading into 2018

DRILLING TEAM

- Continuing with what was reported during our first quarter conference call, the drilling team continues to drill longer laterals this year and has drilled seven of the top ten longest laterals since inception
- Of the seven laterals, four were drilled in Q2, averaging over 14,000 feet
- Daily drilled lateral footages have increased by 57% vs
- Q2 2016, resulting in a 23% reduction in dollar per foot drilled
  - This type of reduction in cost offsets some of the increases we've seen in services and supplies
- The completions team finished Q2 completing 20% more stages than the same time period last year, while utilizing less than three frac crews
- As drilling was able to successfully drill record lateral lengths for the division, the completions team has been successful in completing these longer wells safely while continuing to test new technologies and processes

North Louisiana

- Shifting to North Louisiana
- Our plan for the year remains consistent: focusing on Terryville while methodically testing and delineating the extension areas over time

TERRYVILLE

- In Terryville, we've made great strides in improving cost while driving operational efficiencies
- And we're continuing to delineate the stacked pay potential of the field

- As of the end of June, we have 23 additional wells expected to be online this year, with most of that activity in November and December
- This group of wells includes 12 Upper Red, five Lower Red, and three Deep Pink wells in Terryville
- The other three wells will be in the expansion areas
    - This is all designed to better understand the full potential of the Lower Cotton Valley
- By year end, we'll also have 3D coverage across some very promising areas south of Terryville that will further assist in our delineation efforts

DUCS

- Looking ahead, we expect the Terryville wells in H2 2017 to perform significantly better than the wells turned to sales in H1 for a couple of good reasons
- First, as mentioned on the last call, the initial batch of wells included many that had been sitting as DUCs for quite some time, over a year in many cases, and probably for good reason
    - We looked at these DUCs on a cost-forward basis and made the decision to go forward with the completion
- Second, because the majority of the DUCs were in a concentrated development area, we experienced significant frac hits to offset production as we completed the wells
- We discussed this on the last call

COMPLETION DESIGNS

- In experimenting with completion designs in order to help mitigate that interference, we made changes to fluid intensity
- Essentially, we pumped the designed amount of proppant with significantly less fluid
- With additional production history, it is now apparent that we under-stimulated the wells, or more simply, the wells have had lower IPs with flatter declines, indicating a less-than-optimum stimulation
- On an average, we used approximately 40% less fluid per foot and the resulting production showed a similar percent decrease from what was expected

TERRYVILLE-SIZED COMPLETION

- Going forward, we're going back to using a typical Terryville-sized completion
- We have confidence in this because of the six wells we turned to sales in Q2, which were made up of three Upper Reds and three Lower Reds
    - In these six wells, we pumped larger volumes, but not as large as the original completions, as we were in the middle of analyzing the data and beginning to determine that frac volume and not proppant volume was the key
    - Early indications from these six wells show that the results will be better than the quarter one wells and closer to our expectations
- Thus, going forward, we're headed back to larger frac volumes and better outcomes

Marcellus

- Again, we believe the wells coming online in H2 should meet our expectations and compete with the Marcellus
- We're bringing in a frac crew later this month and the crew will run steady throughout the rest of the year

- The first of these wells will likely come online in mid to late September, so we should have some very early results from the improved completion designs in our next earnings release and call
- With over half the wells coming online in November and December, we expect a significant ramp in North Louisiana production in Q4, setting us up well going into 2018

Extension Areas

- Switching to the extension areas
- The exceptional work the team has done in reducing well cost has allowed us to do more work in and around the Vernon Field, which is south of Terryville
- The two expansion wells previously announced, each located in separate Terryville-sized fault blocks, again, one to the east and one to the west of the Vernon Field, continued to perform
- And plans are underway to offset each well with another horizontal well
- We should spud the first of those next month, expecting both wells to be online late this year
- Additionally, we have two vertical science wells in the extension areas designed to test multiple horizons individually
  - This allows us to determine reservoir and rock properties unique to each layer in order to identify the best lateral targets
  - With over 400 Bcf per square mile and up to six target intervals, the potential is large

CLOSING REMARKS

- In closing, in North Louisiana, where we've improved well costs, operational efficiencies and we're gaining more understanding of a full potential of the assets
- In the Marcellus, we're still continuing to improve returns through newer technologies, lower costs, longer laterals and improved well performance
- We expect solid growth in H2 this year, setting us up well for 2018

Roger S. Manny
Chief Financial Officer & Executive Vice President

FINANCIAL HIGHLIGHTS

Production and Unit Cost

- The big story this time last year was the dramatic production and unit cost and continued improvement in capital efficiency
- These positive trends continue this year, and for Q2 this year are coupled with higher realized prices such that our quarterly cash flow has more than doubled from last year
- Meanwhile, our DD&A rate and direct operating expense combined is now down to $1.04 in mcfe

Net Income

- GAAP net income for Q2 was $70mm
- Net income adjusted for non-cash and non-recurring items, to match analyst methodology, was $16mm
- This quarter, like Q1 2017, was profitable even before considering the earnings contribution from our hedge book

Cash Flow and EBITDAX

- Second quarter cash flow was $194mm, a 108% increase over Q2 last year
- Fully diluted cash flow per share for the quarter was $0.79, a 41% increase over last year's second quarter
- Second quarter YTD cash flow totaled $452mm, a 135% increase over the same period last year
- EBITDAX for Q2 was $240mm
- YTD EBITDAX was $543mm
- These figures are 86% and a 106% higher, respectively, than the corresponding periods from last year

Cash Margin and Expenses

- Cash margin for Q2 was $1.09 per Mcfe, 55% higher than Q2 last year, while our cash margin YTD is $1.28 an Mcfe, 74% higher than H1 2016
- With two consecutive quarters of profitability and improving margins and cash flow over last year, Range is off to a great H1, with the majority of our annual production growth for the year and improved takeaway capacity still to come
- Looking at our second quarter 2017 expenses, all items were at or below guidance except for exploration expense, which came in $1mm higher than guidance due to the timing of budgeted 2017 seismic expenditures
- Expense guidance for Q3 2017 may be found in the earning release

Liquidity

- Committed liquidity under our bank credit facility is just under $800mm and our unhedged recycle ratio is approximately 2.5 times
- With the ability to replace each unit of reserves produced with 2.5 new ones out of existing cash flow, our liquidity is more than adequate for our current and anticipated pace of operations
- And as Jeff mentioned, the drilling throttle can be adjusted in response to commodity prices, available cash flow and asset sale proceeds

Hedge Position

- Range has continued to add hedges to its current hedge position and presently maintains price protection on over 75% of its anticipated 2017 natural gas production at a floor price of $3.23 an Mmbtu
- Also approximately 65% of our 2017 oil and NGL production is hedged above current market
- During Q2, additional 2017 and 2018 natural gas, oil and NGL hedges were added
    - Details of these hedge additions may be found in the earnings release and Range website
- I would also like to draw your attention to the other Supplemental Tables posted on the website, particularly Table 9, which provides an illustration of our estimated third quarter 2017 natural gas price differential, including basis hedges

Memorial Transaction

- Lastly, as we're approaching the one-year mark for the Memorial transaction, investors can expect to see us file soon with the SEC the documents required to publically register the 144A Exchange Notes issued with the transaction last fall

SUMMARY

- In summary, with another quarter of solid profitability accomplished and the outlook for H2 2017 pointing toward improved margins and stronger growth, we are clearly seeing the benefits of our hard-fought effort to reduce our cost structure and improve our capital productivity flowing through our financial statements

QUESTION AND ANSWER SECTION

Daniel Eugene McSpirit
BMO Capital Markets (United States)

Q

Turning to the Cotton Valley. In light of recent results here, how cautious are you in changing or experimenting further with the completion technique? I'm asking in an effort here to get a better sense of the rate of change going forward and whether Range will show better results than what the prior operator delivered or even with the acquisition economics were based on. I guess put differently here, are the results expected later this year as good as it's going to get?

Jeffrey L. Ventura
Chairman, President & Chief Executive Officer

A

That's an interesting question, Dan. I hope not. We are pretty confident, really confident, in fact, that the wells are going to be a lot better in H2. First of all, I think I discussed this in detail on the last call, that you group the wells that are happening in Terryville into three groups. First group was wells that we really didn't have the ability to change hardly anything and then the second group were sort of in transition where we might have changed the targeting of the well or something like that. And then finally, the third group is what, of course, we're all interested in, the Range wells.

Range picks the location, we pick the target, we pick the spacing, we pick all the parameters around the well. Those wells really started with the six wells that came online in Q2. And we began working on what is the most important factor in the completion design that impacts production. And we are pretty confident that we realize now that that is volume of fracture. It's different than in the lot of the shale plays. Again, remember, this is a really tight sandstone and it's a whole different frac geometry and it's a whole different world essentially.

So what we've learned is that frac volume is important. And as we were in the middle of determining that, we made some significant steps in volume sizes through those six wells. And of course six wells is not enough to be statistically significant yet, but we did see enough of a correlation there to be really confident going forward that with our plans starting later this month that the completion designs going forward will perform a whole lot better.

Roger S. Manny
Chief Financial Officer & Executive Vice President

A

Well, I think another key thing to look back on the acquisition economics is prior to Range announcing the acquisition, those wells were costing 10 plus million dollars, $10mm or $11mm. When we mentioned it, on our acquisition economics were based on $8.7mm drill and complete per well. We're at $7.4mm. So when you take the $7.4mm against the type curves we have in the book that we expect that we'll get for the rest of the year, you're looking at really strong economics that compete with the Marcellus. And we have confidence that's what we're going to see for H2.

Daniel Eugene McSpirit
BMO Capital Markets (United States)

Q

Okay. Great. And as a quick follow-up to that, you talked about spending your cash flow, including proceeds from an asset sale or asset sales. What could be divested to cover the difference between cash flow and capital spending? And maybe how much is needed next year to generate, say, 20% growth at $3 NYMEX pricing?

Roger S. Manny
Chief Financial Officer & Executive Vice President

A

Yeah, when you look at we've sold, as you know, a lot of non-core assets over the years, about $4B worth. So we still have assets in the Mid-Continent that would be deemed non-core. One can make the case that the stuff we have in Northeast Pennsylvania, although it's high quality, is away from that core blocky stacked pay position we have in the Southwest. So there's other assets we have that we could sell. It's early to put out 2018. So we have assets we could sell to fill the gap. Clearly we've done that in the past and we'll be disciplined, but actively trying to do that.

The other thing is, we said last October, consensus at that time was $3.25, and we said for $3.25 we could grow at 20%. So, obviously, with all else being equal, if prices are lower than at $3.25, then growth would be less than the 20%. But I don't have a specific number to give for you today, but that's currently where we are.

Ronald E. Mills
Johnson Rice & Co. LLC

Q

As it relates to 2018, you talked about further differential improvement from those three pipeline systems. This year, I think you expect $0.10 to $0.15 improvement in differentials. Can we expect something similar next year? And how much, if any of that, would potentially be offset by higher transportation costs to get to those better markets?

Roger S. Manny
Chief Financial Officer & Executive Vice President

A

Yeah, I think that we're looking at significant improvements next year on the order of what you just stated. So net-net, when you look the cost to get to the markets, we're still expecting the benefit of improvements in differentials with nat gas coming in again. So the story of continued improvement differentials we see for natural gas, I think we see for NGLs as well.

Ronald E. Mills
Johnson Rice & Co. LLC

Q

Okay. And, Ray, for you. In the Marcellus or just Appalachian Basin in general, in addition to drilling longer laterals, you've talked about the use of the machine learning. What other changes has that learning resulted in, whether it's are you using non-geometric completions, are you using more proppant? Or what are some of the benefits that you're seeing from that machine learning?

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President

A

Well, it's a good question, Ron. The ultimate benefit is well performance. And we're clearly seeing, in lot of the examples I just went through in my remarks, significant improvements above the type curves, our average type curves, that we've got published.

So, to me, that's always the true measure is are we seeing it in well performance. And we are. It involves a lot of things from well design, from the standpoint of what target it should be in. Although the Marcellus is one compact package of shale, if you want to think about it that way, there are different layers in it. And, again, we talk about the super-rich, the wet and the dry area. But what this machine learning capability allows us to do is take this tremendous amount of data, whether it's geological, geophysical, rock properties, all of the completion histories and reservoir pressures and everything else that we see there, and look at this in multi-dimensional views. In other words, there's no bounds on the machine as to how many different things it can consider at one-time.

And so it allows us to take an approach to use all of those things you mentioned, whether it's changing the perforation design, cluster spacing, the proppant loading, the amount of fluid that we pump, exactly which target we put the lateral in. And it allows you to look at not just one well on a specific well basis, but it allows you to take your capital program and say what's the best way to get the best return in well performance out of this amount of capital in this field with these sorts of parameters.

And so it's been a really eye-opening experience for an old frac guy like me to see this team and the technical ability that they have today to develop that. We hope to do the same thing in North Louisiana eventually, but it will take some time. Again, we've only had that property for less than a year now. And we're beginning to apply a lot of those technologies, but it's going to take a long time to build that model.

Ronald E. Mills
Johnson Rice & Co. LLC

Q

And then just to clarify, did you say the recent six wells that you mentioned in Terryville, are those the first wells that you've done from soup to nuts in terms of Range drilling, design completion, [ph] design (38:36), bring online? And would there be any legacy Memorial wells left, or have you moved through that whole inventory?

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President

A

Yeah, I think we own it from this point forward, bottom line. Those wells were pretty much Range wells. A couple of them, we may have used permits that MRD already had in hand or something like that, but I think that we would consider those our wells.

But, again, we were in the middle of determining the results of what we saw in Q1, and clearly we made a mistake. We made what we thought was a good decision at the time, but looking at the results, it didn't turn out like we hoped. But going forward, we think we've cracked the code and, again, we'll start seeing those results in a couple of months from now.

Adam Meyers
Cowen & Co. LLC

Q

Just had a quick question. Obviously given some of your peers and their pending merger, was kind of interested in what your thoughts are regarding industry consolidation, really looking at how Range fits the mix there given the current low price per reserve that Range appears to be trading at?

Jeffrey L. Ventura
Chairman, President & Chief Executive Officer

A

Well, you're talking about the EQT Rice merger.

Adam Meyers
Cowen & Co. LLC

Q

Sure.

Jeffrey L. Ventura
Chairman, President & Chief Executive Officer

A

If you think about it at a very high level, fewer companies I think in the Basin drilling is probably a positive thing. It's probably a more pace development, a more prudent and more rational development. So I think that's a good thing for the macro.

In terms of Range and the price we're trading at it, I think when you look at the quality of our assets, the wells we're posting, the improvements in cash flow per share, I think we're on sale. So I would say that it's low.

Adam Meyers
Cowen & Co. LLC

Q

Yeah. Okay.

Jeffrey L. Ventura
Chairman, President & Chief Executive Officer

A

Our share price is a bargain, it's clear. $0.73, our IR team was pointing that out last night. When you look at where we trade vs. some of our peers and any compared quality of assets on an equivalent basis, I think for investors that believe in gas markets long term, Range is a good place to be.

Adam Meyers
Cowen & Co. LLC

Q

Yeah. No, definitely makes sense. And then I guess for my follow-up, it seems like investors are gaining more traction with this idea of maybe the Cabot business model, switching to sustainable growth that returns cash to shareholders. Do you see Range moving to that business model long term? Is that something that you see on the horizon?

Jeffrey L. Ventura
Chairman, President & Chief Executive Officer

A

Yeah, I think when you look at us long term, we expect to generate significant FCF, as I mentioned in my opening remarks. And with long term, when you look at that, we'll look at all the different things you can do from working with the balance sheet to returning capital to shareholders. So we'll be looking at all those different options.

Neal D. Dingmann
SunTrust Robinson Humphrey, Inc.

Q

Roger – or probably for Ray actually, my first question. Ray, you talked just two things here. You mentioned about, I think it was you, talked about the constrained conditions, how you're running a number of your wells. Will you continue to do that? And is that more just – I know I've talked to Jeff and you all about this, just the natural practice? Or is this more about you don't want to have to overbuild the infrastructure and then have the wells settle down? And certainly wells are impressive. So I'm just wondering, when you talk about this constrained condition what is driving that. And how do you see that playing out going forward?

Roger S. Manny
Chief Financial Officer & Executive Vice President
A

Yeah, that's a good question, Neal. And it's a philosophy we've had for many, many years now. Basically, when you design production facilities and things like that, you could design them to be able to produce the IP of the well unconstrained. But I think if you did that, it would be very uneconomical because you would have facilities out there that you paid for that would only be used for a month or two or maybe three at the best case.

So what we choose to do is look at it from a project standpoint and the optimal economic approach of what is the best – when you are looking at the fact that we're going to do thousands of wells over the years and we're going to build this infrastructure system and, again, our design from the early, early on, and it took us 10 years probably get it in place, was that we would have this existing infrastructure of pads and pipelines and compression stations and water infrastructure and all of that that would allow us to optimally develop the properties going forward at the lowest cost. And I think you see that in our cost structure quarter after quarter. We're getting better, LOEs are getting better, all that.

But what that does is you bring on some of these wells, and especially as we drill longer laterals and we're seeing the performance enhancements that we've talked about this morning, all of that means that the wells come on and they're basically choked back for months at a time before you start seeing those declines and we believe that the best economic, lowest-cost approach for developing those resources, we're going to take a very similar approach in North Louisiana, and we've talked about that, which is significantly different than what they were doing before.

Neal D. Dingmann
SunTrust Robinson Humphrey, Inc.
Q

No, great. Good point. And then just moving over to slide 10 where you talk about quality of your North Louisiana acreage, you hit this a little bit earlier. Could you talk about when you look and think about the delineation, even going down as far as Jackson Parish, is most of that delineated? Or how do you anticipate your plan over the next couple, two, three quarters, will you still have to delineate down in that southern area? Or maybe just talk about the delineation plan in general, if you could. Thanks.

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President
A

Well, H2 is pretty well lined out. And like we've talked about, I think it was 23 wells that I mentioned in my prepared remarks. And I think it was 12 Upper Reds and five Lower Reds and three Deep Pinks and then three more wells in the extension area.

Most of the focus this year still remains on Terryville. And I think going into 2018, that won't change. We're still looking at delineating the edges of Terryville. In other words, taking tiers of wells south from the existing development. We see a lot of potential there. There's still potential for stacked pay and in-fill potential inside Terryville. It's going to take some time to build the reservoir models and determine that. So we'll be working on that also.

And then, like Jeff mentioned and I talked about a little bit, the extension wells, we've had some pretty exciting early results, but pretty exciting, to the east and west of Vernon Field, so we're going to continue some work there with some additional offsets. We've got some science work going on the east side of Vernon Field to try to determine just how much potential was there and what's going to be the best way to develop that.

One of the things we've learned in the Marcellus in the stacked pay position that we have in Southwest Pennsylvania, that it takes years and you need to be very thoughtful and strategic about how you develop and stack those laterals and what that program is going to look like. We're taking all of that learning and we're basically going to take our time and be very strategic in the same way throughout that whole 220,000-acre position. We have a big 3D that's going to be coming in later this year that is going to open up a lot more of that extension area to the south of Terryville.

So all of that said, the primary focus is still going to be drilling development wells in and around Terryville. But we're still going to have a pretty steady program, pretty consistently, but strategically, delineating that acreage around to the south. But I think it's going to take some time to do that because we are going to be very scientific, strategic and data-based and really develop some long-term plans around that.

Robert Alan Brackett
Sanford C. Bernstein & Co. LLC

Q

Could you guys talk about the 25-day per well delay up in Pennsylvania and your comfort level that that won't recur?

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President

A

Sure, Bob. What happened is the DEP had some issues with staffing and different things. And the permitting delays just kept getting longer and longer and longer. We have worked with the DEP. They have developed a solution worked with us very well. We have permits in the hand now for 2017. We feel very confident going forward. They have done a wonderful job in working with us to solve that issue.

So what that caused us to do throughout the year was to substitute and move different wells around. It wasn't the same plan as we had early in the year when we developed the forecast for production growth. And so you substitute some wells, you delay some wells, you move some wells around, add a couple of wells to a pad here and there. And it just changes timing. And, again, it doesn't change the economics of the well. The capital still gets spent, the EUR doesn't change. In fact, the EURs are getting better just because we're using all the new technology.

But what it does is when you take like the four-well pad that we did on the east side, that's 100mm a day for 40 days, that's an outstanding well. We knew it was going to be a good well, but it's a really great well. But it ended up online three months or four months later than we expected. And so when you take a big pad like that and it's delayed three months or four months, that just impacts your year's growth. And so here we're with five months left in the year, you just can't make it up.

Robert Alan Brackett
Sanford C. Bernstein & Co. LLC

Q

Got you.

Jeffrey L. Ventura
Chairman, President & Chief Executive Officer

A

And you think of the progress we've made, if you think back two years or three years ago, that was unheard of. And now we have that pad actually initially come in at 100mm per day from three wells.

Robert Alan Brackett
Sanford C. Bernstein & Co. LLC

Q

Right.

Jeffrey L. Ventura
Chairman, President & Chief Executive Officer

A

Great economics. No change to any economic parameter. No change to capital in year spent but you slide that, like Ray said, three months or four months, it makes a difference. And then you do that with the numbers Ray said, it's impactful. But we're excited we have those kind of pads. And that situation going forward looks like it's solved.

Michael Dugan Kelly
Seaport Global Securities LLC

Q

Jeff, you gave that 10% to 20% growth range earlier in the call. And I'm just curious on the commodity price you envision on the bottom end of that range. And I believe last quarter you laid out in $60 oil, $3 gas world, you could be 20% plus. What's the bottom end envisioned? Thanks.

Jeffrey L. Ventura
Chairman, President & Chief Executive Officer

A

Well, you look at strip pricing for next year, and I'm probably a week out, is it $2.90 or something like that, $2.80 something. First quarter is good. We have good hedges in there. And we think when you look at the pricing for oil and for gas and you look at the rig counts and where they are, I think Appalachian rig count right now is around 60 actually combined Marcellus, Utica, haven't been spiking up, and you look at the cash flow that's available for Permian players at, call it, $49 a barrel oil or $45 to $50 or something like that, cash flow will be down. So we think that strip historically is wrong. It probably will come up a little bit.

And interestingly, if you look in the back of our book on slide 66, it has total macro Lower 48 oil production streaming up, like everybody sees it. But when you look at the total gas position in U.S.-ex to Northeast, it's pretty flat. So you look at the Northeast, its constrained, far Northeastern Pennsylvania until Atlantic Sunrise comes on. That's basically you're looking at probably middle of 2018 or before.

So we think that the macro setting up, strip pricing may be a little better. We said that $3.25 gas last October about where consensus was that we'd grow at 20%. Consensus today, I think it is $3.12 or $3.14 something like that, so growth may be a little lower. And not going to throw a specific number out, but we'll be in good shape I think. With where gas is next year, most likely expectation is that 10% to 20% range.

Michael Dugan Kelly
Seaport Global Securities LLC

Q

Okay. That lower end of 10%, is that something that you could achieve at $2.50 gas price? How should we think about that lower end?

Jeffrey L. Ventura
Chairman, President & Chief Executive Officer

A

Yeah, $2.50, I think the whole industry slows down dramatically at $2.50. You saw what the rig count did early part of 2016 as the gas went to $2.50 and ultimately broke $2 for a little bit. And the only good part, I think the industry is pretty sensitive, the message anymore is most of the operators are going to be living at or near cash flow. So I don't think you're going to see the big out-spends.

If prices dip down, we'll be sensitive to cash flow. I'm sure you have a model of Range and you can model what that cash flow is. But we're going to be sensitive and set the throttle somewhere in that position. I think if gas goes to $2.50, you'll see the industry slow down dramatically. I don't think it'll stay there that long.

Michael Dugan Kelly
Seaport Global Securities LLC
Q

Got it. Appreciate it. And just a quick one for Ray. In H2 this year, if these 22 wells in the Terryville don't really pan out and you don't see the results that you're looking to see, I'm just curious how you could think about or how quickly you could pull capital away potentially from the Terryville in 2018, maybe slow down there and shift that back toward Appalachia. Thanks.

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President
A

Well, it's a good point, Mike. Of course, if we don't see the results, then, yeah, we're going to slow down and look at this a lot harder. We have a lot of confidence in what we're doing going forward. And we've seen the data. We've looked at it seems like 1,000 different ways with 1,000 different experts. And so I feel very confident that the team has their arms around it and that we're really confident going forward. But, again, we're going to learn a lot in the third and fourth quarter. We should see some really improving results in North Louisiana, but we're also moving the needle forward in Marcellus. We continue to make better wells there. So I think we'll look at all of that as we approach the budgeting time. And the board approves the budget in December and I think that's when we'll know what the plans are for next year.

Brian Singer
Goldman Sachs & Co.
Q

Range is often lumped into the higher-levered balance sheet camp. And there's always been the case that I think you've made, that EBITDA growth will help to de-lever. You highlighted in one of your slides that you have been active in asset sales in the past. How close are you to considering more meaningful asset sales, equity issuance or other ways to bring that leverage down further, particularly if the $3.25 doesn't materialize?

Roger S. Manny
Chief Financial Officer & Executive Vice President
A

Yeah, Brian. This is Roger. I'll comment on the leverage. And you're exactly right. With our windshield ratio, the recycle ratio at 2.5%, even with a pretty dismal backward-dated strip, we're able to grow within cash flow at a respectable rate. So that gives us a lot of comfort. The rear-view mirror ratio at 3 times debt to EBITDAX, at this point in the cycle we're comfortable with it, but long term, we're not. We want to get that back down to historical levels. And as you know, the first lever we pull when we want to do that is the asset sale lever. And as Jeff said, $4B is what we've sold in the past.

We've still got some attractive assets to sell. And it would be imprudent for me to comment on the likelihood or expectations of that effort. But that's clearly the next stop on the waterfall for those proceeds.

When you look at our debt structure, it's a very stable balance sheet. Our bondholders are obviously pleased with the paper. The spreads remain tight to our index. We trade tighter than a lot of our even higher-rated peers. S&P

has us at BB+, both agencies at stable outlook, which is all appropriate given our low cost structure, our asset quality, the deep inventory we've got, the track record.

So as I said, we're comfortable at this point in the cycle. But we're going to work hard to get that leverage down. I think when you look at the composition of the liability structure, one thing you'll notice and investors will notice is we're carrying over $900mm in floating rate bank debt right now, which we're real comfortable with, because we've got a rock-solid borrowing base, no pun intended, and ample liquidity for whatever we have planned. But we really like having pre-payable debt that we can pay down literally at a moment's notice with some asset sale proceeds or if we're blessed with a normal winter. So that's going to be the first place we go is to reduce that debt. And we're positioned to be able to do that with that revolver balance.

Brian Singer
Goldman Sachs & Co.

Q

Great. Thank you. And then my follow-up is with regards to guidance for next year. You talked about the risks from a gas price perspective. What do you have baked in in terms of Louisiana well performance, Marcellus well performance and pipeline takeaway and timing out of Appalachia, what are the risks around the volume guidance one way or the other for reasons other than gas price?

Jeffrey L. Ventura
Chairman, President & Chief Executive Officer

A

Well, I think when you look at, again, we'll have a lot of flexibility on where we allocate capital. As Ray said, the good part is you look at the big fourth quarter ramp, 200mm per day, it's timely when you look at the pipes that are coming on that I mentioned in my notes. It's also timely that differentials tend to be – improve up in Appalachia in the fourth and first quarter.

So we'll have a nice ramp going into there. We have flexibility. By the time we get to the end of the year, we'll know lot more about the Terryville wells. Like Ray said, we have confidence in those wells in H2. And with the expectations that we have, those economics will compete with the Marcellus.

However you look at the Marcellus, we're drilling longer laterals and we're getting some spectacular wells. And we do think basis will improve up there for 2018 given the new pipes that are coming on and the fact that we think overall that those pipes won't fill the rig count, like I said, up there currently around 60. We had commented in the past, to fill those pipes, the industry would have to be we think somewhere around 120 to 130 rigs. And that would have been a few months ago. And I've heard other people say the rig count needs to be at least 90 to fill them by 2019. So I think Range is in good shape. And we have adequate flexibility.

We've talked all along, one of the advantages of the acquisitions was to be able to toggle capital either way. And I can sit here and build a case where, with success in Terryville and success in the extension areas, you'd toggle more capital that way, or with basis coming in the Marcellus and longer laterals, we'd toggle more capital in Appalachia. So we'll look at that very hard as we go into next year.

But with the pipes we have, I think our team's done a good job of thinking through the flexibility. And couple of those pipes that I mentioned, for us, we're expecting should be on in Q4, that's Rayne/Leach, Adair Southwest, Rover is scheduled to be on. But even if there's slight delays, I think our team does a good job of thinking through the various outcomes and planning for contingencies